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Clean Coal Technology Demonstration Program

Program Update 1993

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Executive Summary

Role of the Program

The Clean Coal Technology Demonstration Program (also referred to as the CCT Program) is a \$6.9 billion cost-shared industry/government technology development effort. The program is to demonstrate a new generation of advanced coal-based technologies, with the most promising technologies being moved into the domestic and international marketplace.

Coal is a major contributor to the energy and economic well-being of the United States, accounting for almost 25 percent of the primary energy consumed. Approximately 55 percent of the electricity generated in 1992 came from coal and this is not expected to change in 1993. It is forecasted that coal will continue to dominate as a fuel for U.S. electric power production at least through 2010, with a significant need for additional baseload capacity starting about the middle of the first decade (nominally 2005). Coal is also an important source of energy for the industrial sector, particularly in the generation of heat and power and in the production of iron, steel, and cement. Coal is a vital contributor to the U.S. economy, making a \$21-billion direct annual contribution and accounting for over 1 million jobs. Additionally, coal exerts a positive influence on the nation's trade deficit with annual exports valued at nearly \$5 billion leaving U.S. ports to Canada and overseas destinations.

Technology has a vital role in ensuring that coal can continue to serve U.S. energy interests and enhance opportunities for economic growth and employment while meeting the national commitment to a clean and healthy global environment. These technologies are being advanced through the CCT Program.

The CCT Program supports three substantive national objectives:

- Ensuring a sustainable environment through technology
- Enhancing energy efficiency and reliability
- Providing opportunities for economic growth and employment

The technologies being demonstrated under the CCT Program reduce the emissions of sulfur oxides, nitrogen oxides, greenhouse gases, hazardous air pollutants, solid and liquid wastes, and other emissions resulting from coal use or conversion to other fuel forms. These emissions reductions are achieved with efficiencies greater than or equal to currently available technologies.

Clean coal technologies being demonstrated under the CCT Program are creating the technology base that allows the nation to meet its energy and environmental goals efficiently and reliably. The fact that most of the demonstrations are being conducted at commercial scale, in actual user environments, and under conditions typical of commercial operations allows the potential of the technologies to be

evaluated in their intended commercial applications. The technologies are categorized into four market sectors:

- Advanced electric power generation
- Environmental control devices
- Coal processing for clean fuels
- Industrial applications

Approximately 78 percent, or about \$5.4 billion, of the total CCT Program costs is directed toward enhancing efficiency and reliability of electric power production by addressing the advanced electric power generation and environmental control devices market applications. Over 1,200 MWe of new capacity and over 800 MWe of repowered capacity are represented by 15 advanced electric power generation projects valued at over \$4.7 billion. There are 19 environmental control device projects valued at more than \$686 million. These projects include NO_x controls, SO₂ controls, and combined SO₂/NO_x controls.

Participation in these projects involve over 55 investor-owned utilities, nonutility generators, municipalities, and cooperatives. These electric power generators represent approximately 50 percent of the coal-fired capacity in the United States and almost 70 percent of the Phase-I-affected units under Title IV of the Clean Air Act Amendments (CAAA) of 1990.

There are five coal processing for clean fuels projects valued at over \$466 million. These projects

produce solid, high-energy-density compliance fuels and coal-derived liquids that can be used as electric power generation fuel and as a chemical or transportation fuel feedstock. One project is demonstrating a method to allow optimum matching of the boiler's performance to coal feedstock.

The final market application category is industrial applications. There are six projects in this category valued at over \$1.1 billion encompassing the iron, steel, and cement industries and industrial boilers.

The contribution of the \$6.9 billion CCT Program to direct employment in the 21 states where projects are located is significant. Each advanced electric power generation project can create more than 1,000 construction jobs and 50–130 permanent operator jobs, while a typical retrofit emissions control project employs 100–200 construction workers. Thus, the 45 clean coal projects are estimated to create between 15,000 and 20,000 construction and service jobs, up to 2,000 permanent operating jobs and over 500 jobs in coal mining and related industries.

Section 1 provides an indepth discussion of the role of the program and the technologies involved.

Program Implementation

The CCT Program has been implemented through a series of five nationwide competitive solicitations conducted over a period of 9 years, with each competition associated with a specific level of government funding and program objectives. The first three solicitations were aimed primarily at

technologies that could mitigate the potential impacts of acid rain. The fourth and fifth solicitations addressed the post-2000 situation with SO₂ emissions capped under the CAAA of 1990, increasing need for electric power, and continuing concerns over global climate change—a situation which translates into a need for technologies with very high efficiencies and extremely low emissions.

A critical aspect in implementing the CCT Program involves compliance with the requirements of the National Environmental Policy Act (NEPA), executing the environmental monitoring plans (EMP), and the monitoring of hazardous air pollutants (HAPs).

The CCT Program complies with the NEPA regulations through a process which includes (1) preparing a programmatic environmental impact statement (PEIS); (2) preparing preselection, project-specific environmental reviews; and (3) preparing postselection, site-specific documentation.

By the end of 1993, NEPA actions had been completed for 32 of the 45 projects. Additionally, during 1993, two public scoping meetings were convened as the first step in the environmental impact statement process for another proposed project.

Sponsors of CCT projects are required to develop and implement an EMP which is intended to ensure collection and dissemination of the significant technology, project, and site-specific environmental data. At the end of 1993, EMPs had been completed for 27 projects.

The CAAA of 1990 calls for the eventual establishment of HAPs emission standards for various source categories. The program recognizes that

HAPs emissions from clean coal technologies will become part of the characterization of environmental performance used to evaluate commercial deployment potential. Therefore, DOE established a HAPs monitoring program which is being implemented in 19 active projects and is being negotiated in 5 additional projects. This data is being shared with the U.S. Environmental Protection Agency which is responsible for evaluating HAPs emissions.

A detailed discussion of CCT Program implementing legislation, solicitations, and environmental aspects is contained in Section 2.

Funding

Congress has appropriated nearly \$2.75 billion as federal budget for the CCT Program. These funds have been committed to demonstration projects through five competitive solicitations. Project awards have been completed for the first four solicitations and project selections for the fifth solicitation were announced in May 1993.

The five solicitations have resulted in a combined commitment by the federal government and the private sector of about \$6.97 billion. DOE's share of the project cost is \$2.37 billion or approximately 34 percent of the total. The project sponsors (i.e., the non-federal government participants) are providing the remainder—nearly \$4.60 billion or approximately 66 percent of the total estimated cost.

Although all funds necessary to implement the entire CCT Program were appropriated by Congress prior to fiscal year (FY) 1990, the legislation directs

that these funds be made available (i.e., apportioned) to DOE on a time-phased basis. Total funding has been apportioned for the first three solicitations. Funding for the projects selected under the CCT-IV (\$563 million) were apportioned for FY 1991 through FY 1996. The \$568 million for projects selected in the fifth solicitation are apportioned for FY 1992 through FY 1996.

Section 3 contains detailed data on program funding, cost sharing, and recovery of government outlays (recoupment).

Commercial Deployment

The success of the CCT Program ultimately will be measured by the degree to which the technologies are commercialized and by their contribution to the resolution of energy, economic, and environmental issues. This contribution can be maximized best if those in the public and private sectors appreciate that clean coal technologies increase the efficiency of energy use and enhance environmental quality at costs which are competitive with alternative energy options.

In 1993, an active program was expanded to define and understand the potential domestic and international markets for clean coal technologies. This program involved interviews with electric utility executives, public utility commissioners, and financiers. Analyses were made of utility integrated resource plans, environmental compliance strategies, state regulations, and legislation that impact commercial deployment.

A highlight of the continuing CCT Program outreach effort was the Second Annual Clean Coal Technology Conference, attended by nearly 400 persons from 16 nations. The conference examined the domestic and international markets for clean coal technologies and some of the issues which will affect commercial deployment in the United States and abroad. Four issues of the *Clean Coal Today* newsletter were prepared for distribution to 3,700 domestic and international readers. The CCT Program staff participated in over 15 domestic and international events involving users and vendors of the technology, state institutions, state regulators, and environmental groups.

The international activities centered on participating in trade missions to Eastern Europe, People's Republic of China, and the Pacific Rim countries; developing financial and market analyses in response to Section 1331 of the Energy Policy Act of 1992; developing an international technology transfer program as defined by Section 1332 of the act; and developing a showcase demonstration program for China and Eastern Europe.

At this point in the CCT Program, there are 45 projects, with slightly more than 50 percent in operation and 20 percent completed. A number of commercial successes have been realized, including the following:

- The Babcock & Wilcox Company's commercial sale of two Low-NO_x Cell™ burners to Allegheny Power System for installation at its Hatfield's Ferry Station. This sale was based on results of the burner tests at Dayton Power and Light's J.M. Stuart Plant that showed a NO_x reduction of 55 percent.

- Retention by Ohio Edison Company of ABB Environmental Systems' SNOX™ system at its Niles Station as part of its CAAA of 1990 compliance strategy.
- Incorporation of the flue gas recovery system for SO₂ reduction demonstrated by the Passamaquoddy Tribe as a permanent part of a 1,450-ton-per-day cement plant.
- Pyropower Corporation's reduction of almost 3 years in establishing a commercial line of atmospheric circulating fluidized-bed units because of the demonstration conducted at Tri-State Generation and Transmission Association's Nucla Station between 1988 and 1991.
- Use of a commercial version of The Babcock & Wilcox Company's successfully demonstrated limestone injection multistage burner (LIMB) in an independent power production project in Canada.
- The first commercial sale of the Coal Quality Expert Acid Rain Advisor software package, made in 1993.
- Commercial sale of liquid and solid products from ENCOAL Corporation's demonstration project.
- Signing of a letter of intent between Rosebud SynCoal Partnership and Minnkota Power Cooperative, Inc., to prepare a \$2-million engineering study to examine the merits of scaling up the advanced coal conversion process to an \$80-million commercial plant.

In addition to the commercial successes, innovative business concepts also have been developed and demonstrated. Under an arrangement with Northern Indiana Public Service Company, Pure Air on the Lake, L.P., will continue to operate the advanced flue gas desulfurization (AFGD) unit as a contract service at the Bailly Station for 17 years after the 3-year CCT demonstration. It should be noted that the Bailly Station with the AFGD unit became the first power plant on the CAAA of 1990 list of affected units to meet the SO₂ standard using flue gas desulfurization.

Finally, test results from the Southern Company Services, Inc., demonstration of low-NO_x burners are being used by EPA to develop CAAA of 1990 regulations for NO_x control. Data on hazardous air pollutants collected under the CCT Program are also being shared with EPA for use in formulating air toxic control regulations required under Title III of the CAAA of 1990.

Section 4 contains a detailed discussion of the CCT Program's commitment to commercial deployment, its efforts to understand the domestic and international markets, and its activities in market communication and outreach.

Results of Completed Projects

Six projects completed operations in 1993, bringing to nine the total number of projects that have been completed under the CCT Program. These six projects demonstrated the following technologies:

- Three NO_x control technologies
 - Coal reburning for cyclone boiler—The Babcock & Wilcox Company
 - Low-NO_x Cell™ burner retrofit—The Babcock & Wilcox Company
 - 180-MWe advanced tangentially fired combustion techniques—The Southern Company Services, Inc.
- One SO₂ control technology
 - Confined zone dispersion flue gas desulfurization process—Bechtel Company
- One combined SO₂/NO_x control technology
 - SO_x-NO_x-Rox-Box™ flue gas cleanup process—The Babcock & Wilcox Company
- One industrial application technology
 - Cement kiln flue gas recovery scrubber—Passamaquoddy Tribe

The three previously completed projects are as follows:

- Nucla CFB Demonstration Project—Tri-State Generation and Transmission Association, Inc., completed in 1992
- LIMB Demonstration Project Extension and Coolside Demonstration—The Babcock & Wilcox Company, completed in 1992
- Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control—Coal Tech Corporation, completed in 1991

This portfolio of completed projects is providing valuable data for addressing pressing environmental and energy issues associated with the utility and industrial use of coal. Exhibit 1 summarizes the results of these projects. Section 5 presents further information about project results and lists available reports and project contacts.

Results and Accomplishments from Ongoing Projects

By the end of 1993, the CCT Program consisted of 45 projects. A total of 9 projects have successfully completed operations. An additional 14 projects are in the operations phase, 2 are in the construction phase, 15 are in the design and project definition phase, and 5 CCT-V projects are currently in negotiation of cooperative agreements.

Section 6 contains the highlights of the results and accomplishments of 16 projects which are in operation or well along in design and construction. For operational projects, preliminary performance data and other key results are also provided.

Project Fact Sheets

Project-specific information for each of the 45 projects is provided in the fact sheets in Section 7, which are organized by the four market application categories:

Exhibit ES-1

Summary of Results of Completed CCT Projects

Project and Sponsor	Environmental Results	Capital Cost
Demonstration of Coal Reburning for Cyclone Boiler NO _x Control (The Babcock & Wilcox Company)	NO _x reductions of 52% using bituminous coal and 62% using subbituminous coal at full load (110 MWe), ranging to 36% and 53% respectively at 60 MWe	Ranges from \$64/kW at 100 MWe to \$40/kW at 600 MWe
Full-Scale Demonstration of Low-NO _x Cell™ Burner Retrofit (The Babcock & Wilcox Company)	NO _x reductions of 54–58% using bituminous coal at full load (605 MWe); 48% at 350 MWe	\$5.50–8.00/kW at 500 MWe
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for Reduction of NO _x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	NO _x reductions of up to 48% at full load (180 MWe) for low-NO _x concentric firing system including both separated over-fire air and close-coupled over-fire air	Not available
Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)	SO ₂ reduction of 50% (1.5–2.5% sulfur bituminous coal)	Less than \$30/kW at 500 MWe
SO _x -NO _x -Rox-Box™ Flue Gas Cleanup Demonstration (The Babcock & Wilcox Company)	SO ₂ reductions of 80–90% using 3.4% sulfur bituminous coal, depending on sorbent and conditions Particulate removal of 99.89%	\$260/kW at 250 MWe
Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)	SO ₂ reduction of 90–95% (3% sulfur bituminous coal); 98% maximum reduction	\$25/ton of annual cement capacity
Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.)	SO ₂ reduction of 70–95% (up to 1.8% sulfur coal), depending on Ca/S ratio NO _x emissions average 0.18 lb/million Btu	Approximately \$1,123/net kW (repower cost)
LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)	SO ₂ reductions: LIMB—61% (3.8% sulfur coal; ligno lime) Coolside—70% (hydrated lime)	LIMB—\$31–102/kW Coolside—\$69–160/kW
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)	SO ₂ reduction of over 80% with sorbent injection; 58% maximum with limestone injection NO _x emissions of 160–184 ppm (75% reduction) Slag/sorbent retention of 55–90% in combustor; inert slag	Not available

- Advanced electric power generation
- Environmental control devices
- Coal processing for clean fuels
- Industrial applications

Project information provided in fact sheets includes the sponsor, team members, location, cost and schedule data, process flow diagram, significant project features, project objectives, description of the process and its performance attributes, progress and accomplishments, and potential commercial applications. Fact sheets for completed projects contain a brief overview of the results of the demonstration and sources of more detailed information.

Other Information

Excerpts of key legislation concerning funding and implementation of the CCT Program are contained in Appendix A. A brief history of the selection of proposals solicited and negotiations of cooperative agreements is provided in Appendix B. A list of CCT Program publications is provided in Appendix C and references for selected recent papers and presentations on the CCT Program are contained in Appendix D. Finally, Appendix E lists contacts for obtaining further information concerning a specific CCT Program demonstration project.

1. Role of the Program

National Perspective

Coal is the nation's most plentiful fossil fuel, accounting for over 94 percent of the proven fossil energy reserves in the United States. Deposits of coal can be found in 32 of the 50 states, with production contributing to the economies of 27 states; coal is used in all 50 states and the District of Columbia. It is a major contributor to the energy well-being of the United States, accounting for almost one-quarter of the primary energy consumed. Approximately 55 percent of the electricity generated in 1992 came from coal and coal's contribution is expected to remain the same in 1993; of the 691 gigawatts of U.S. electric generating capacity in 1992, almost 300 gigawatts, or 43 percent, was coal-steam capability. The Energy Information Administration (EIA) forecasts that coal will continue to dominate as a fuel for electric power production at least through 2010 (the end of the forecast period). Although coal use is expected to grow only 1.0 percent annually, generation by coal technologies will continue to command approximately 55 percent of total generation. Further, EIA forecasts show that nonutility producers are expected to increase their coal-fired generation from their current share of 2.6 percent of total nonutility generation to nearly 16 percent by 2010.

The second largest domestic market for coal is the industrial sector which accounts for 9 percent of annual consumption. Coal remains an important fuel

for heat, power, iron making, steelmaking, cement making, and other industrial and manufacturing enterprises. A number of cogeneration plants consume coal to produce steam for generating electricity and heat. Net industrial use of coal is expected to grow modestly to 2010, with steam coal use increasing and metallurgical coal decreasing.

Coal is a major energy source, and coal production is a vital contributor to the U.S. economy. A study commissioned by the National Coal Association quantified some of these contributions:

- \$21 billion in direct annual contribution
- \$81 billion of total activity generated annually in the U.S. economy
- 1 million jobs in direct annual contribution, with 120,000 in mining and related industries

Coal also exerts a positive influence on the nation's trade deficit. Coal exports valued at nearly \$5 billion annually leave from U.S. ports to overseas destinations and Canada.

Clean coal technology has a vital role in ensuring that coal can continue to serve U.S. energy interests, enhancing opportunities for economic growth and employment while meeting the national commitment to a clean and healthy global environment. These technologies are being advanced through the Clean Coal Technology Demonstration Program (also referred to as the CCT Program).

The CCT Program is a government and industry cofunded effort to demonstrate a new generation of

advanced coal-based technologies so that the most promising technologies can be moved into the marketplace.

The demonstrations, for the most part, are at a scale large enough to generate data needed to enable stakeholders to make judgements about the commercial potential of particular processes. The importance given to the commercial deployment of these technologies reflects the strategic importance of coal to the U.S. economy and the commitment to sound environmental policies. Further, the domestic and international marketplace offers opportunities to create U.S. jobs and strengthen the U.S. economy.

The CCT Program supports three substantive national objectives:

- Ensuring a sustainable environment through technology
- Enhancing energy efficiency and reliability
- Providing opportunities for economic growth and employment

Sustainable Environment through Technology

The technologies being demonstrated under the CCT Program reduce the emissions of sulfur oxides, nitrogen oxides, greenhouse gases, hazardous air pollutants, solid and liquid wastes, and other emissions

resulting from coal use or conversion. These emissions reductions are achieved with coal-use efficiencies greater than or equal to currently available technologies.

Acid Rain Mitigation

The CCT Program had its roots in the acid rain programmatic initiatives of the 1980s. It became the centerpiece for satisfying the recommendations contained in the January 1986 *Joint Report of the Special Envoys on Acid Rain*. On November 15, 1990, with the CCT Program well under way, Congress enacted the Clean Air Act Amendments (CAAA) of 1990. Title IV, Acid Deposition Control, established emissions reduction targets for sulfur dioxide (SO₂) and directed the establishment of allowable emissions limitations for nitrogen oxides (NO_x).

The acid rain provision of the CAAA of 1990 sets emission reduction requirements on SO₂ to be met in two phases. Evidence to date suggests that compliance with the Phase I targets established for 1995 will be largely achieved by switching to a lower sulfur fuel, the use of emissions credits, and, to a limited extent, flue gas scrubbing; the more stringent Phase II levels set for the year 2000 will require technological solutions.

A provision of the CAAA of 1990 allows a 4-year extension (to December 31, 2003) to comply with the requirements of Title IV if one or more units is repowered with a qualifying clean coal technology.

An equally important consideration is that the act sets a permanent cap on SO₂ emissions beyond the year 2000.

The CAAA of 1990 provided for the Administrator of the U.S. Environmental Protection Agency

(EPA) to establish annual allowable emissions limitations for NO_x in two rulings. The first ruling addresses allowable emissions rates for tangentially fired and dry bottom wall-fired boilers. These emissions rates are to go into effect on January 1, 1995, for all boilers listed in the CAAA of 1990 as affected units. It is expected that this initial ruling will be made in early 1994. The second ruling, due by January 1, 1997, will establish allowable emissions rates for wet bottom wall-fired boilers, cyclone boilers, cell burners, and all other types of utility boilers. These units must meet the allowable emissions rates by 2000. Data from tangentially fired and wall-fired low-NO_x burner demonstrations under the CCT Program are being used by EPA in setting allowable emissions rates. It is expected that data from other CCT Program NO_x control technology demonstrations will be used in establishing the 2000 allowable emissions.

The first three solicitations of the CCT Program (CCT-I-III) were aimed primarily at mitigating the potential impacts of acid rain. The resulting CCT projects are expected to provide a pool of technologies for industry to draw upon to meet specific needs in developing compliance strategies.

Global Climate Change Protection

It is U.S. policy to embark upon an action plan that returns U.S. greenhouse gas emissions to 1990 levels by the year 2000 and to develop policies to address the longer term trends in greenhouse gas emissions. The elements of the action plan are contained in President Clinton's and Vice President Gore's *The Climate Change Action Plan* published in October 1993.

Efficiency in the end use of energy is an important feature of this near-term action plan. Longer-term solutions will, among other things, rely on increased efficiency of energy supply technologies. In more efficient systems, less greenhouse gases, namely, carbon dioxide (CO₂), are produced per unit of power generated. Many clean coal technologies now being demonstrated are effective in reducing CO₂ emissions because they improve power generating efficiencies. For example, pressurized fluidized-bed and gasification combined-cycle technologies boost generating efficiencies into the 40–45 percent range, as compared to conventional technology efficiencies of approximately 33 percent. This can reduce CO₂ emissions by 17–27 percent. Clean coal technologies yet to be demonstrated, such as gasifier/fuel cell combinations and advanced turbines, could lower CO₂ emissions by up to 55 percent.

The Climate Change Action Plan includes a joint implementation pilot program to gain experience in evaluating investments in other countries for emissions reduction benefit. A central purpose of the joint implementation initiative is to “encourage the rapid development and implementation of cooperative, mutually voluntary projects between the U.S. and foreign partners aimed at reducing net emissions of greenhouse gases, particularly projects promoting technology cooperation with and sustainable development in developing countries and countries with economies in transition to market economies.”

Utilization of highly efficient clean coal technologies being developed under the CCT Program offers a major opportunity to contribute to this initiative. The benefits would be significant: reduction of “global” CO₂ emissions; improvement of U.S. bal-

ance of trade; and creation of U.S. jobs in the engineering, manufacturing, and service sectors.

The fourth and fifth solicitations (CCT-IV-V) addressed the post-2000 situation with SO₂ emissions capped; increasing need for electric power, both domestically and internationally; and continuing concerns over global climate change—a situation which translates into a need for technologies with higher efficiencies and much lower emissions.

Hazardous Air Pollutants

Title III of the CAAA of 1990, Hazardous Air Pollutants, requires the formulation of standards to achieve the maximum degree of reduction in emissions of categories and subcategories of identified hazardous air pollutants (HAPs). These standards are to be formulated in accordance with the schedule contained in Title III and are to be completed by 2000.

The U.S. Department of Energy (DOE) recognized the importance of identifying and measuring for HAPs in stack gases. A program was implemented to monitor HAPs emissions at CCT project sites, under both baseline and demonstration operating conditions. A further objective was to quantify the removal of HAPs in the gaseous streams of various emissions control subsystems. For all CCT-V projects, DOE requires that HAPs monitoring be included in environmental monitoring plans (see Section 2). For CCT-I-IV projects, DOE has sought to include HAPs monitoring, and 19 projects from these earlier solicitations are monitoring HAPs. HAPs monitoring has been completed for eight projects, and the results are being analyzed.

The CCT Program is coordinating with organizations such as the Electric Power Research Institute (EPRI) and the Ohio Coal Development Office in those activities focused on HAPs monitoring and analysis. A parallel effort under DOE's Coal Research and Development Program is being undertaken to collect HAPs data from 16 coal-fired power plants representing a cross section of technical configurations. Data collected under these programs will be shared with EPA so that the agency will have the benefit of actual data in formulating air toxics control regulations required under Title III of the CAAA of 1990.

Value-Added Solid Wastes

Current SO₂ emissions control technologies typically result in a conversion of an air emission to an emission of a "solid" waste, in most cases a scrubber sludge which must be carefully handled and disposed of in sludge ponds. Estimates are that by 2010 approximately 4,320 acres per year would be required to dispose of flue gas desulfurization sludge if wet FGD systems were used. Most of the clean coal technologies being demonstrated under the CCT Program produce a dry solid waste that significantly reduces the disposal problem. Further, many of these dry, solid waste products have economical value in that they can be used as building material, agriculture supplements, neutralizing agents for use with acid mine drainage, and for other purposes. Two CCT emission control projects produce commercial-grade gypsum. Also, a number of the CCT projects will produce a salable by-product in the form of commercial-grade sulfur or sulfuric acid.

Enhance Energy Efficiency and Reliability

Clean coal technologies being demonstrated under the CCT Program are establishing the technology data base that allows the nation to meet its energy and environmental goals efficiently and reliably. Because most of the demonstrations are being conducted at commercial scale, in actual user environments, and under conditions typical of commercial operations, the performance potential of the technologies can be meaningfully evaluated in their intended commercial applications.

Approximately 78 percent, or about \$5.4 billion, of the total CCT Program costs are directed toward enhancing efficiency and reliability of utility advanced electric power generation systems and environmental control devices.

There are over 55 investor-owned utilities, nonutility generators, municipals, and cooperatives participating in the CCT Program. These utilities represent approximately 50 percent of the coal-fired capacity in the United States and have almost 70 percent of the Phase-I-affected units under Title IV of the CAAA of 1990.

Exhibit 1-1 illustrates the extent of the geographic area served by utilities participating in the CCT Program.

The U.S. market for efficient and reliable electric power consists of retrofitting existing power plants with environmental control devices, repowering existing plants with advanced electric power generation systems, and constructing new power plants using

Exhibit 1-1
Service Areas of Utilities Participating in the CCT Program

advanced electric power generation systems or conventional power generation technology with environmental control devices. Energy projections forecast a significant need for additional baseload capacity after the turn of the century. There are, however, uncertainties which affect the projected need for new capacity, including the following:

- Extent to which demand-side management will actually achieve expected savings and thus extend adequate reserve margins
- Outlook for the nation's aging nuclear power plants which are due for relicensing early in the 21st century
- Degree to which natural gas is used for baseload power generation

CCT Program demonstrations provide a portfolio of technologies to satisfy markets for coal conversion and utilization while satisfying energy and environmental goals in a highly efficient manner.

Over 1,200 MWe of new capacity and over 800 MWe of repowered capacity are represented by 15 advanced electric power generation projects, valued at over \$4.7 billion, which have been selected and are being developed under the CCT Program. The projects are listed in Exhibit 1-2. The projects represent seven repowered existing generating plants, six new electric generating plants, and two cogeneration plants. The participants in the projects include seven investor-owned utilities, two cooperative utilities, one municipal utility, three independent power producers, and two industrial sponsors. These projects, when completed, will use over 4.4 million tons of coal per year. Because of their superior environmental performance and increased efficiency,

these units are projected to produce 42 percent less SO_2 , 83 percent less NO_x , and 15 percent less CO_2 than 2,000 MWe of conventional pulverized coal-fired capacity with flue gas desulfurization units capable of meeting New Source Performance Standards (NSPS). Based on a 3 percent sulfur coal, this represents a total reduction of approximately 68,000 tons per year of acid rain precursor emissions.

These units not only will provide environmentally sound electric power generation in the mid- to late 1990s but will also provide the demonstrated technology base required to carry the nation into the 21st century with a suite of highly efficient, reliable, environmentally superior clean coal technologies to meet new capacity requirements. Decisions on technology options to meet these requirements would occur around the year 2000. By that time, there will be sufficient technical, environmental, economic, and operational performance data available from the CCT Program to enable potential users to make informed decisions from the technology options.

In summary, over the next 7 years, it will be critical to bring new technology options into the marketplace to satisfy compliance with the CAAA of 1990 and to meet longer-range capacity growth requirements. These technologies must be able to meet the stringent performance requirements of the traditional utility industry, independent power producers, and cogenerators.

The portfolio of technology options available to existing coal-fired utility plants to comply efficiently and reliably with the CAAA of 1990 requirements is large. There are 19 environmental control devices projects, valued at more than \$686 million, which can be used to retrofit existing power plants to com-

ply with CAAA of 1990 requirements (see Exhibit 1-2). These include seven NO_x emission control systems installed on over 1,700 MWe of utility plant capacity, five SO_2 emission control projects installed on about 775 MWe of capacity, and seven combined SO_2/NO_x emission control systems installed on about 765 MWe of capacity. In addition to establishing a sound base of technical, environmental, and economic information to enable commercial deployment, these demonstrations are having an immediate and significant environmental benefit by reducing SO_2 and NO_x emissions from the uncontrolled host plants by approximately 40 percent. This represents approximately 244,000 tons per year of SO_2 and NO_x which otherwise would have been emitted into the atmosphere assuming the use of 3 percent sulfur coal. These technologies can also be used in new plants to satisfy increased capacity requirements.

Most of these environmental control devices projects will have their operating experience documented by 1995. Almost all NO_x control projects will complete testing by the end of 1994. Further, data from two of the NO_x control technologies being demonstrated by Southern Company Services, the tangentially fired and wall-fired boilers, are being used by EPA in developing NO_x control regulations under the CAAA of 1990.

The development of Phase II compliance strategies and the decision-making process regarding which technologies to use will begin in earnest in 1996. By that time, 16 of the 19 environmental control devices demonstrations will be completed and the technical, environmental, and economic performance results will be available for users and vendors to evaluate commercial deployment potential.

Exhibit 1-2 CCT Demonstration Projects, by Application Category

Application Category	Sponsor	Project	Solicitation
Advanced Electric Power Generation	ABB Combustion Engineering, Inc.	Combustion Engineering IGCC Repowering Project	CCT-II
	Alaska Industrial Development and Export Authority	Healy Clean Coal Project	CCT-III
	The Appalachian Power Company	PFBC Utility Demonstration Project	CCT-II
	Arthur D. Little, Inc.	Coal Diesel Combined-Cycle Project	CCT-V
	DMEC-1 Limited Partnership	PCFB Demonstration Project	CCT-III
	Duke Energy Corp.	Camden Clean Energy Demonstration Project	CCT-V
	Four Rivers Energy Partners, L.P.	Four Rivers Energy Modernization Project	CCT-V
	The Ohio Power Company	Tidd PFBC Demonstration Project	CCT-I
	Pennsylvania Electric Company	Warren Station Externally Fired Combined-Cycle Demonstration Project	CCT-V
	Sierra Pacific Power Company	Piñon Pine IGCC Power Project	CCT-IV
	TAMCO Power Partners	Toms Creek IGCC Demonstration Project	CCT-IV
	Tampa Electric Company	Tampa Electric Integrated Gasification Combined-Cycle Project	CCT-III
	Tri-State Generation and Transmission Association, Inc.	Nucla CFB Demonstration Project	CCT-I
	Wabash River Coal Gasification Repowering Project Joint Venture	Wabash River Coal Gasification Repowering Project	CCT-IV
	York County Energy Partners, L.P.	York County Energy Partners Cogeneration Project	CCT-I
Environmental Control Devices	ABB Environmental Systems	SNOX™ Flue Gas Cleaning Demonstration Project	CCT-II
	AirPol, Inc.	10-MW Demonstration of Gas Suspension Absorption	CCT-III
	The Babcock & Wilcox Company	Demonstration of Coal Reburning for Cyclone Boiler NO _x Control	CCT-II
	The Babcock & Wilcox Company	Full-Scale Demonstration of Low-NO _x Cell™ Burner Retrofit	CCT-III
	The Babcock & Wilcox Company	LIMB Demonstration Project Extension and Coolside Demonstration	CCT-I
	The Babcock & Wilcox Company	SO _x -NO _x -Rox-Box™ Flue Gas Cleanup Demonstration Project	CCT-II
	Bechtel Corporation	Confined Zone Dispersion Flue Gas Desulfurization Demonstration	CCT-III
	Energy and Environmental Research Corporation	Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	CCT-I
	Energy and Environmental Research Corporation	Evaluation of Gas Reburning and Low-NO _x Burners on a Wall-Fired Boiler	CCT-III

Exhibit 1-2 (continued)
CCT Demonstration Projects, by Application Category

Application Category	Sponsor	Project	Solicitation
Environmental Control Devices (continued)	LIFAC-North America	LIFAC Sorbent Injection Desulfurization Demonstration Project	CCT-III
	New York State Electric & Gas Corporation	Milliken Clean Coal Technology Demonstration Project	CCT-IV
	NOXSO Corporation and MK-Ferguson Company	Commercial Demonstration of the NOXSO SO ₂ /NO _x Removal Flue Gas Cleanup System	CCT-III
	Public Service Company of Colorado	Integrated Dry NO _x /SO ₂ Emissions Control System	CCT-III
	Pure Air on the Lake, L.P.	Advanced Flue Gas Desulfurization Demonstration Project	CCT-II
	Southern Company Services, Inc.	Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	CCT-II
	Southern Company Services, Inc.	Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	CCT-II
	Southern Company Services, Inc.	Demonstration of Selective Catalytic Reduction Technology for the Control of NO _x Emissions from High-Sulfur-Coal-Fired Boilers	CCT-II
	Southern Company Services, Inc.	180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO _x Emissions from Coal-Fired Boilers	CCT-II
	Tennessee Valley Authority	Micronized Coal Reburning Demonstration for NO _x Control on a 175-MWe Wall-Fired Unit	CCT-IV
Coal Processing for Clean Fuels	ABB Combustion Engineering, Inc., and CQ, Inc.	Development of the Coal Quality Expert	CCT-I
	Air Products and Chemicals, Inc.	Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process	CCT-III
	Custom Coals International	Self-Scrubbing Coal™: An Integrated Approach to Clean Air	CCT-IV
	ENCOAL Corporation	ENCOAL Mild Coal Gasification Project	CCT-III
	Rosebud SynCoal Partnership	Advanced Coal Conversion Process Demonstration	CCT-I
Industrial Applications	Bethlehem Steel Corporation	Blast Furnace Granulated-Coal Injection System Demonstration Project	CCT-III
	Bethlehem Steel Corporation	Innovative Coke Oven Gas Cleaning System for Retrofit Applications	CCT-II
	Centerior Energy Corporation	Clean Power from Integrated Coal/Ore Reduction (COREX®)	CCT-V
	Coal Tech Corporation	Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	CCT-I
	Passamaquoddy Tribe	Cement Kiln Flue Gas Recovery Scrubber	CCT-II
	ThermoChem, Inc.	Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal	CCT-IV

There are five coal processing for clean fuels projects, valued at over \$466 million (see Exhibit 1-2). These projects produce solid, high-energy-density compliance fuel; coal-derived liquid that can be used as a chemical or transportation fuel feedstock; and a method to allow optimum matching of boilers to coal. Over 4 million tons per year of solid and liquid products will be produced from these projects. Two of these clean fuels processing technologies are currently producing compliance fuels and could be considered in a Phase I fuel-switching scenario. These solid and liquid compliance fuels are being tested by industrial and utility customers.

There are six industrial application projects, valued at over \$1.1 billion, encompassing steel and cement industries and industrial boilers (see Exhibit 1-2). Coke oven emissions are a major concern of the steel industry. One project is to control coke oven gas emissions, another project is to substitute coal for at least 40 percent of the coke used in iron ore reduction, and a third steel industry project is directed toward eliminating the need for coke altogether. In another project, cement kiln waste was used to achieve 90 percent reduction in SO_2 . Cement, municipal waste, and paper production industries in the United States and abroad are actively considering adoption of this technology. Demonstration of two industrial-scale combustors is addressing this application area.

Opportunities for Economic Growth and Employment

Clean coal technologies can provide the utilization and conversion technologies which will enable the coal fuel cycle to remain a major component of the nation's economy while achieving the environmental quality that society demands. Coal production currently accounts for \$21 billion in the U.S. economy. There are over 1.1 million workers whose jobs directly depend on the coal industry. These jobs are dispersed through the mining, transportation, manufacturing, utility, and supporting industries. Clean coal technologies will enable the coal fuel cycle to respond to these energy markets ensuring the continued need for these jobs and their economic benefit.

The CCT Program has over 200 direct participants, including over 55 investor-owned utilities, nonutility generators, municipals, and cooperatives; 40 technology suppliers and electric and gas industry research organizations; and 5 state organization cofunders. The contribution of the \$6.97-billion program to employment in the 21 states where projects are located is significant. A typical retrofit emissions control project employs from 100 to 200 construction workers, while each advanced electric power generation project can create more than 1,000 construction jobs and 50-130 permanent operator jobs. Therefore, the 45 clean coal projects are estimated to create between 15,000 and 20,000 construction and service jobs, up to 2,000 permanent operating jobs, and 500 jobs in coal mining and related industries.

In addition to domestic opportunities, the international marketplace holds enormous potential for U.S. industry. Conservative estimates conclude that by 2010, today's worldwide coal consumption of 4.3 billion short tons per year should increase by almost 800 million short tons per year. Of this projected growth, almost 250 million short tons will be for electric power generation.

The worldwide market for clean coal technologies, just to meet electric power and industrial steam needs outside the United States, is projected to be between \$600 and \$900 billion through 2010. If the U.S. share for CCT exports approximates the current U.S. market share for power equipment, U.S. exports could increase by \$4 billion per year. This growth in U.S. exports could result in the equivalent of 30,000 person-years of U.S. employment annually. This market provides opportunities for U.S. technology suppliers, developers, architect/engineers, and other U.S. firms to capitalize on the advantages gained through experiences in the CCT Program.

Other DOE activities are aimed at creating a favorable export climate for U.S. coal and coal technology. These efforts will (1) improve the visibility of U.S. firms and their products by establishing an information clearinghouse and closer liaison with U.S. representatives in other countries, (2) strengthen interagency coordination of federal programs pertinent to these exports, and (3) improve current programs and policies for facilitating the financing of coal-related projects abroad.

Coal Technology Perspective

The DOE has structured an integrated technology development program which will enable the nation to use its plentiful domestic coal resources while meeting environmental quality requirements and ensuring reliable supplies of low-cost energy in the future.

Coal Research, Development, Demonstration, and Commercial Applications Program

The CCT Program supports DOE's energy strategy and provisions of the Energy Policy Act of 1992 (EPACT), Public Law 102-486. The clean coal technologies being demonstrated support many statutory goals and objectives, including the following:

- Ensuring a reliable electricity supply
- Achieving emissions controls at levels of efficiency greater than or equal to currently available commercial technology
- Achieving greater efficiency in conversion of coal to useful energy
- Ensuring the availability of coal-based technologies for commercial use by 2010

Further, the technologies being demonstrated under the CCT Program are the basis for establishing and implementing a clean coal program as required through the Innovative Clean Coal Technology Transfer Program. Through promoting technology transfer and exports, this program recognizes the importance to the U.S. economy of increasing the international competitiveness of U.S. technologies.

Clean Coal Research, Development and Demonstration Program

The Clean Coal Research, Development and Demonstration Program (referred to as the Clean Coal RD&D Program) implements the requirements of EPACT. This program includes the Coal Research and Development Program and the Clean Coal Technology Demonstration Program. The mission of the Clean Coal RD&D Program is to foster the commercialization of a diversity of clean, efficient, reliable, and affordable coal technology options. These coal technology options will sustain coal as a competitively available fuel to meet the nation's needs for an environmentally benign, domestically produced energy source that supports a revitalized economy and energy security, and enhances international competitiveness.

To accomplish this mission, a number of key strategies for technology development and demonstration were formulated:

- Pursue a cost-shared government/industry partnership in which industry plays a major role in defining the RD&D agenda and ultimately in assuring commercialization
- Continue to demonstrate power systems capable of achieving high levels of SO₂ and NO_x removal and improved efficiency
- Conduct a focused RD&D program to ensure development and demonstration of advanced high-efficiency, super clean power generation systems and technologies for toxics mitigation, CO₂ collection and disposal, liquid fuel production, cogeneration, and cofiring of coal

with municipal and industrial wastes; make these technologies ready for demonstration no later than 2005

- Conduct cost-shared demonstrations following the basic precepts established in the CCT Program solicitations; ready the advanced technologies through the Coal Research and Development Program and complete their demonstration by 2010
- Establish an effective means for transferring technical information between demonstration and R&D projects and optimize the use of existing demonstration sites to accomplish R&D efforts more effectively
- Work actively with industry and the appropriate agencies to remove institutional barriers and establish the necessary framework and incentives for achieving a major export role for the United States in coal and clean coal technologies
- Demonstrate appropriate clean coal technologies either in the United States or offshore as required for entry into foreign markets
- Create a clearinghouse for the export of coal technology that will provide U.S. companies with information on specific markets and act as an interagency and international advocate for U.S. coal equipment, product, and service firms; provide information to foreign buyers on economic, environmental, and technical advantages offered by U.S. clean coal technologies

During 1993, DOE enhanced the prospects for success in both the R&D and demonstration phases of technology development by closely integrating the two functionally distinct but substantially interdependent programs.

Role of the Technologies

Because the ultimate level of success of the CCT Program will be measured by the degree of deployment of certain technologies in the energy marketplace, it is most appropriate to discuss the technologies and processes from a market perspective.

Advanced Electric Power Generation

Advanced electric power generation systems must respond to the energy and environmental demands of the early 21st century. The demonstrated capabilities of these systems will be consistent with most utility expansion plans and the stringent year 2000 Phase II emissions limits under the CAAA of 1990. The technologies are characterized by high thermal efficiency, very low pollutant emissions, reduced CO₂ emissions, fewer solid waste problems, and enhanced economics. The advanced electric power generation systems may be deployed in modules, thus allowing phased construction to match demand growth more predictably and to meet the requirements of smaller municipal utilities and nonutility generators.

The eight major clean coal technologies for the advanced power generation market are discussed below.

Fluidized-Bed Combustion. Fluidized-bed combustion (FBC) reduces emissions of SO₂ and NO_x by controlling combustion parameters and by injecting a sorbent (such as crushed limestone) into the combustion chamber along with the coal. Pulverized coal mixed with crushed limestone is suspended on jets of air (or fluidized) in the combustion chamber. Sulfur released when coal burns is captured by the limestone before it can escape from the boiler. The sulfur chemically combines with the limestone to form a new solid waste product, a mixture of calcium sulfite and calcium sulfate. Some of the solid waste is removed with the bed ash through the bottom of the boiler. Small ash particles, or fly ash, that escape the boiler are captured with dust collectors (cyclones, baghouses, electrostatic precipitators, or ceramic filters). More than 90 percent of the sulfur released from coal can be captured this way.

At combustion temperatures of 1,400–1,600 °F, the fluidized mixing of the fuel and sorbent enhances both coal combustion and sulfur capture. The operating temperature range is almost half the temperature of a conventional boiler and is below the threshold where thermally induced NO_x is formed. Thus, fluidized-bed combustors substantially reduce both SO₂ and NO_x emissions. Fluidized-bed combustion has the capability of utilizing high-ash coal, compared to conventional pulverized coal units which usually burn lower ash fuels.

Fluidized-bed combustion can be either atmospheric (AFBC) or pressurized (PFBC). The atmospheric type operates at normal atmospheric pressure

while the pressurized type operates at pressure 6–16 times higher than normal atmospheric pressure. The pressurized fluidized-bed boiler offers potentially higher efficiency, reduced operating costs, and less waste product than does the atmospheric fluidized-bed boiler. Initially, fluidized-bed combustion systems were either bubbling-bed or circulating-bed configurations. System improvements have modified this earlier classification so that current designs are designated as bubbling beds with solid recirculation, fluid beds with internal circulation, hybrid designs combining several fluidization concepts, and full-fledged circulating (entrained) fuel flow.

A second-generation pressurized fluidized-bed concept is being developed and demonstrated. This concept integrates a pressurized circulating fluidized-bed combustor and a pyrolyzer to fuel a gas-turbine topping cycle and a steam-turbine bottoming cycle. The integration of the pyrolyzer and turbine topping cycle improves the efficiency when compared to first-generation PFBC systems.

Fluidized-bed combustion attributes are as follows:

- No special coal handling is needed other than the addition of limestone or other sorbent to the coal feed.
- The fluid-like motion of the solids in the combustion chamber promotes turbulent mixing that improves combustion efficiency and the capture of SO₂.
- The superior mixing also permits combustion at substantially lower and more evenly distributed temperatures, thus reducing formation of NO_x.

- Combustion occurs at temperatures below the ash melting point so that solids accumulation and boiler tube erosion and corrosion are minimized.
- All types of coals or coal wastes can be used, including high-ash coals, because FBC is relatively nonsensitive to feedstock.
- The waste generated is a dry, benign solid that can be disposed of easily or usefully employed (e.g., as material for road or building construction).
- Combined-cycle plants, in addition to increasing the efficiency of energy production, can be composed of standardized modules. This leads to ease of installation and a relatively lower cost without the usual economy-of-scale penalties.

In the case of repowering, any type or size of boiler can be repowered by a fluidized-bed combustor using the existing plant area, coal and waste handling equipment, and steam turbine equipment. This repowering extends the life of the plant. In many cases, such as where the capacity of the boiler has been reduced because of aging or the turbine generator has greater capacity than the boiler, or both, FBC can be used to repower an existing boiler and, in addition to controlling SO_2 and NO_x emissions, can increase the boiler's capacity as much as 50 percent with the use of PFBC. The costs of the additional capacity are low compared to the cost of a new plant.

Integrated Gasification Combined Cycle. The coal gasification combined-cycle process basically has the following four steps: (1) a fuel gas is generated by coal reacting with high-temperature steam and an oxidant (oxygen or air) in a reducing atmosphere; (2) the gas is cooled, producing steam, and

then purified to further remove particulates and sulfur and nitrogen compounds; (3) the clean fuel gas is combusted in a gas turbine generator to produce electricity; (4) the residual heat in the hot exhaust gas from the turbine is recovered in a heat recovery steam generator, and the steam is used to produce additional electricity in a steam turbine generator.

Gasification combined-cycle systems are among the cleanest and most efficient of the emerging clean coal technologies. Sulfur, nitrogen compounds, and particulates are removed before the fuel is burned in the gas turbine, that is, before combustion air is added. For this reason, there is a much lower volume of gas to be treated than in a postcombustion scrubber.

The gas stream must be cleaned to a high level not only to achieve low emissions but to protect downstream components, such as the gas turbine, from erosion and corrosion. In a coal gasifier, the sulfur in coal is released in the form of hydrogen sulfide rather than as SO_2 , which is the case in coal combustion. In some integrated gasification combined-cycle (IGCC) systems, as in the case of clean combustion, much of the sulfur-containing gas is captured by a sorbent injected into the gasifier. In addition, several commercial processes are capable of removing hydrogen sulfide, whereby more than 99 percent of the sulfur is removed from the gas, making it as clean as natural gas.

In a hot-gas cleanup system, the hot coal gas is passed through a bed of metal oxide particles such as zinc ferrite. Zinc ferrite can absorb sulfur contaminants at temperatures in excess of 1,000 °F, and the compound can be regenerated and reused with little loss of effectiveness. During the regeneration stage,

◀ The 70-MWe Tidd repowering demonstration project represents the nation's first commercial-scale pressurized fluidized-bed combustion plant and is one of only five similar units in the world. American Electric Power Company was awarded *Power Magazine's* 1991 Powerplant Award for the Tidd project.

▲ Destec's 160-MWe (equivalent) coal gasifier continues to operate at the Louisiana Gasification Technology, Inc., facility in Plaquemine, LA. The unit has provided data important for the design of the Wabash River Coal Gasification Repowering Project.

salable sulfur is produced. The technique is capable of removing more than 99.9 percent of the sulfur in the gas stream.

High levels of nitrogen removal are also possible. Some of the coal's nitrogen is converted to ammonia, which can be almost totally removed by

commercially available chemical processes. NO_x formed from the combustion air can be held to well within allowable levels by staging the combustion process at the turbine or by adding moisture to hold down flame temperature.

In repowering with IGCC, a gasifier, gas stream cleanup unit, gas turbine, and waste heat recovery boiler are added; in most cases, these replace the existing coal boiler. The remaining equipment is left in place, including the coal-handling equipment, the steam turbine, and electrical generator. The result is an extension of plant life to essentially that of a new plant, an increase in efficiency from a nominal 35 percent to over 40 percent, and an increase in overall plant output of 50–150 percent with significantly reduced overall emissions. The incremental costs of the additional capacity are low compared to the cost of a new conventional pulverized coal plant.

The attributes of the IGCC are summarized as follows:

- Sulfur removal levels of over 99 percent have been demonstrated. These emissions levels are well below the existing NSPS emission standard of 90 percent removal for new plants.
- NO_x reductions of over 90 percent have been demonstrated.
- Salable by-products are produced, such as elemental sulfur or material for road or building construction.
- Zero wastewater discharge criteria can be met easily.
- CO_2 emissions are reduced compared to pulverized-coal-fired plants.

- Wide variety of carbonaceous feedstock is used.
- Potentially high levels of plant availability (up to 85 percent) are achievable.
- Efficiency of energy production can be increased, while using standardized modules sized for large and small utilities.
- No special coal-handling is needed other than the potential to add limestone to the coal feed.

Indirectly Fired Cycle. An indirectly fired closed-cycle gas turbine uses a nonreacting gas (such as helium) as a working fluid. The gaseous working fluid is compressed, heated by means of a high-temperature air heater, expanded in a turbine, and cooled in a waste heat exchanger. Because the closed cycle is fuel-independent, the use of direct coal-firing or coal-derived fuels of any quality is permitted as long as fouling of the primary air heater exchanger does not occur. SO_2 emissions can be avoided through removal of sulfur in the coal conversion or coal combustion process; NO_x emissions can be controlled through improved furnace design. Removal of particulates can be achieved through current methods. An overall conversion efficiency of 50–55 percent can be obtained by combining a closed-cycle gas turbine system with a steam cycle for application in mid- and baseload plants. The mating of the steam cycle is accomplished by the replacement of the waste-heat exchanger with a waste-heat boiler.

Integrated Gasification Fuel Cell. A typical fuel cell system using coal as fuel would include a coal gasifier with a gas cleanup system, a fuel cell to generate electricity (direct current), an inverter to

convert direct current to alternating current, and a heat-recovery system. The heat-recovery system would be used to capture rejected thermal energy to produce additional electrical power in a bottoming steam cycle.

Energy conversion in fuel cells is potentially more efficient (40–60 percent, depending on fuel and type of fuel cell) than traditional energy conversion devices. This is because electricity is generated directly in the fuel cell instead of going through an intermediate conversion step (i.e., burner, boiler, turbines, and generators). Fuel cells directly transform the chemical energy of a fuel and an oxidant (oxygen) into electrical energy. Each fuel cell includes an anode and a cathode separated by an electrolyte layer. In a typical fuel cell, coal gas is supplied to the anode and air is supplied to the cathode to produce electricity and heat.

Coal-Fired Diesel. This technology involves firing a diesel-engine-driven electric generating system with a coal-oil or coal-water slurry. The hot exhaust from the diesel engine is routed through a heat-recovery steam generator to produce steam for a steam-turbine electric generating system (combined cycle). Environmental control systems for SO_2 , NO_x , and particulate removal treat the cooled exhaust before release to the atmosphere. The diesel system is expected to achieve 45–48 percent thermal efficiencies. The 10–100-MWe capacity range of the technology would be most applicable to small utility (municipal) and industrial cogeneration applications.

Coal-Fired Gas Turbine. In a coal-fired gas turbine, coal is combusted in a two-stage system. The first stage is a rich-zone combustor (reducing

atmosphere). The rich gas is then cleaned in a hot-gas cleanup system to remove sulfur impurities and particulates, and combustion is completed in a lean-zone combustor. In the second stage, the clean, hot gas is expanded in a gas turbine which drives an electric generator and the compressor for the combustion air. The turbine exhaust passes through a heat recovery steam generator which produces steam for a bottoming-cycle steam-turbine electric generator. Direct coal-fired heat-engine systems are characterized by net system efficiencies of 40 percent or higher and by the ability to meet the existing environmental regulations of the CAAA of 1990.

Slagging Combustor. Most of these new coal-burning technologies are based on the cyclone combustor concept. In a cyclone combustor, coal is burned in a separate chamber outside the furnace cavity. The hot combustion gases then pass into the boiler where the actual heat exchange takes place.

The advantage of a cyclone combustor is that the ash is kept out of the furnace cavity where it could collect on boiler tubes and lower heat transfer efficiency. To keep ash from being blown into the furnace, the combustion temperature is kept so hot that mineral impurities melt and form slag, hence the name slagging combustor. A vortex of air (the cyclone) forces the slag to the outer walls of the combustor where it can be removed as waste. Because ash removal efficiency is high, there is no degradation of boiler tube surfaces, enhancing boiler efficiency over time.

Results to date show that by positioning air injection ports so that coal is combusted in stages, NO_x emissions can be reduced by 70–80 percent. Injecting limestone into the combustion chamber

▲ The full-size precombustion module is being mounted into place at TRW's San Juan Capistrano test facility for design verification testing of the advanced combustor to be used in the Healy Clean Coal Project.

has the potential to reduce sulfur emissions by 90 percent.

Advanced combustors being demonstrated in the CCT Program could replace oil-fired units in both utility and industrial applications or be used to retrofit older, conventional cyclone boilers.

Environmental Control Devices

Environmental control devices must respond to the need for efficient, effective, and economic means whereby existing coal-fired boilers can comply with the CAAA of 1990 and, at the same time, mitigate broader environmental concerns such as solid waste disposal. Optimal performance for these retrofit devices would be highly efficient pollutant capture, low capital and operating costs, high operating efficiency and availability, and no waste products (pollutants being either recycled or converted into salable by-products). The targeted boiler population is the 929 pre-NSPS boilers that largely must continue operation through the first quarter of the 21st century to meet electricity demands.

The technologies which would find application in this market include advanced NO_x control technology, advanced SO_2 control technology, and advanced combined SO_2 , NO_x , and particulate control technology.

NO_x Control Technology. Control of NO_x emissions can be accomplished by modifying the combustion process or by postcombustion noncatalytic or catalytic selective reduction processes, or combinations of the two principal approaches.

Modified combustion processes include the use of specially designed advanced low- NO_x burners, alone or in conjunction with advanced over-fire air (AOFA) ports, AOFA ports without low- NO_x burners, or natural gas and coal-fired reburning processes. All of these technologies utilize staged combustion whereby the primary combustion zone is maintained deficient in oxygen and the combustion process is

completed in stages. The more gradual mixing of fuel and air results in lower flame temperatures and reducing-atmosphere combustion conditions before the combustion process is completed, which reduces the oxidation of nitrogen to NO_x . Emissions reductions for NO_x of 50–70 percent are achievable with these systems.

The use of air ports alone, which are installed in the furnace wall above the top row of burners, creates a fuel-rich primary combustion zone with minimal hardware changes. However, NO_x emissions reductions, which average 15–30 percent, are lower than when air ports are used in combination with low- NO_x burners.

Natural gas or coal-reburning technologies for NO_x control are also being demonstrated in the CCT Program. About 10–30 percent of the total fuel input to the boiler is injected above the normal combustion zone, creating the fuel-rich primary combustion zone. NO_x rising from the lower region of the furnace is “reburned” in the zone where the secondary fuel enters and converted to nitrogen. NO_x emissions reductions in the 60–70 percent range are achievable with this modified system. Reburning technology can be applied in conjunction with low- NO_x burners.

Postcombustion selective catalytic reduction processes are characterized by high NO_x emissions reductions of 80–90 percent or more. Selective catalytic reduction (SCR) involves injecting ammonia into the boiler flue gas and passing the gases through a catalyst bed where the NO_x and ammonia react to form nitrogen and water vapor. Noncatalytic processes utilize ammonia and/or urea injection into the boiler after combustion is complete to chemically reduce NO_x to nitrogen. NO_x emission reductions are

less than with catalytic processes. However, when noncatalytic technologies are combined with low- NO_x burners, NO_x emissions reductions of 60–70 percent are predicted.

SO_2 Control Technology. Advanced combustion or postcombustion flue gas cleaning techniques are approaches for removal of sulfur and particulates from flue gas. Examples of advanced combustion techniques are discussed in the above subsection, Advanced Electric Power Generation. These techniques involve injection of calcium sorbents (lime or limestone) into slagging combustors or into the combustion zones, i.e., fluidized-bed combustion and some coal gasification processes.

Postcombustion cleanup involves removal of SO_2 from the downstream flue gas after it exits the boiler. There are three basic approaches: (1) advanced flue gas scrubbing using lime or limestone (wet scrubbers) to capture 95 percent or more of the SO_2 in the flue gas before it exits the stack, (2) in-duct injection of sorbents utilizing the existing flue gas ductwork, and (3) inserting one or more separate vessels into the downstream ductwork where the sorbents are added.

The reliability of wet scrubbers has improved significantly along with improvements to eliminate corrosion problems, and markets (such as wallboard manufacture) have been found for the waste gypsum sludge. The improved reliability has reduced spacing requirements for scrubber systems, contributing to significant reductions in capital costs of modern scrubbers compared to earlier systems.

In-duct sorbent injection involves spraying sulfur absorbents, such as hydrated lime with water, into the center of the existing ductwork. By controlling

the humidity of the flue gas and the spray pattern for the sorbent, 50–70 percent of the SO_2 can be removed. Selective additives, such as adipic acid, may improve removal levels to around 90 percent. Advantages of this technology include the waste being composed of dry particles that can be easily removed downstream and new construction being eliminated because the plant's existing ductwork is used. This makes in-duct sorbent injection an attractive option for retrofitting smaller, older plants where space availability might be limited.

When separate vessels are used, one or more process chambers are inserted in the flue gas ductwork, and various sorbents are injected to remove the pollutants. Generally the separate vessels provide a longer residence time for the absorbent to react with the gas, and pollutant capture is greater. Although more costly than in-duct injection, this approach has the potential of capturing more than

90 percent of the pollutants. Due to the cost and added size requirements, the use of separate vessels tends to be more suitable to new plant applications or to plants that can accommodate the additional size requirements.

Depending upon process selection, advanced postcombustion cleaning technologies offer several advantages over the old conventional scrubber systems, including the following:

- High reliability and availability preclude the need for standby spare capacity.
- Physical plant size requirements are reduced.
- Increased residence time or reactivity with the sulfur sorbent leads to high levels of SO_2 removal.
- Regeneration of the sulfur-absorbing chemical reduces operating costs.

- Waste generation is reduced through production of dry, benign waste products or marketable by-products.
- Systems can be designed to remove more than one pollutant.

Combined SO_2/NO_x Control Technology.

Many of the technologies discussed above can be successfully combined with particulate removal systems to reduce emissions of SO_2 , NO_x , and particulates. Examples of this approach being utilized in the CCT Program include the following processes and systems:

- Low- NO_x burners with sorbent injection into the boiler or in-duct injection; conventional electrostatic precipitator (ESP)
- Advanced cyclone combustor with internal ash, sulfur, and nitrogen control
- Gas reburning with in-duct sorbent injection; conventional ESP
- Selective catalytic reduction; catalytic oxidation of SO_2 to SO_3 with condensation of the SO_3 in the presence of water to produce salable sulfuric acid; baghouse particulate removal
- In-duct sorbent injection and selective catalytic reduction in a baghouse where the catalyst is suspended in the bags
- Low- NO_x burners supplemented with in-boiler urea injection; noncatalytic selective reduction for NO_x control; in-duct sorbent injection for SO_2 ; conventional ESP

◀ The advanced flue gas scrubbing technology being demonstrated by Pure Air on the Lake, L.P., is able to remove 90–95% of the SO_2 in the flue gas while producing a commercial gypsum by-product.

- Formic-acid-enhanced wet limestone technology with an advanced tile-lined scrubber for SO_2 control, including recovery of marketable gypsum and calcium chloride; in-boiler urea injection for NO_x control; conventional ESP

Coal Processing for Clean Fuels

Physical and chemical processes can be applied to abundant U.S. coal reserves to transform them to an economic, energy-option fuel for at least a portion of the existing coal-fired boilers to enable them to comply with the CAAA of 1990. In addition, coal processing creates the capability to generate substitute liquid fuels from coal that can replace petroleum and petroleum-derived fuels in a wide range of applications, thus enhancing the nation's energy security. The solid products are easily transportable fuels high in energy density and low in sulfur, ash, and moisture. The liquid fuels are low in sulfur and

suitable for the transportation sector, stationary power generation, or as chemical feedstocks.

The clean coal technologies generating products for this market include physical and chemical coal cleaning, mild gasification, coal gasification, and direct and indirect liquefaction.

Coal Cleaning. About 40 percent of the coal used in U.S. utility boilers today receives some cleaning before it is burned. Most commercial coal cleaning is done on eastern and midwestern U.S. bituminous coals at more than 500 preparation plants. With wider use of conventional coal-cleaning processes, total nationwide SO_2 emissions from burning coal could be reduced by 10–15 percent. To achieve greater reductions, however, significant improvements will have to be made to coal-cleaning technology.

Traditionally, research to improve precombustion cleaning has been concentrated on two major

categories of cleaning technology: physical and chemical cleaning. Recently a new category, biological cleaning, has attracted interest as advances have been made in microbial and enzymatic techniques for liberating sulfur and ash from coal.

Virtually all coal cleaning today is done with physical techniques, some of which have been used for more than a century. Physical cleaning typically separates undesirable matter from coal by relying on differences in densities or variations in surface properties. When coal from the mine is crushed and then washed, the heavier impurities are separated.

Physical cleaning can remove only matter that is physically distinct from the coal, such as small dirt particles, rocks, and pyritic sulfur (sulfur combined with iron particles). Physical cleaning cannot remove organic sulfur that is chemically bound with the coal, nor can it remove nitrogen, another source of pollution, from the coal. Currently, physical cleaning can remove 30–50 percent of the pyritic sulfur and about 60 percent of the ash-forming minerals in domestic coals.

Conventional physical coal-cleaning methods include froth flotation and gravity separation techniques. Advanced physical cleaning techniques are expected to be significantly more effective than older techniques. An example would be electrostatic coal cleaning which utilizes opposite polarity charges on coal and mineral matter particles to accomplish separation. Increased effectiveness is achieved by first grinding the coal into much smaller sizes at which the coal releases more of the ash and pyrite. New coal-cleaning processes can remove more than 90 percent of the pyritic sulfur and undesirable minerals from the coal.

◀ Combined SO_2/NO_x control technology is represented by the integrated dry emissions control system being demonstrated by Public Service Company of Colorado. Four Babcock & Wilcox low- NO_x roof-mounted burners are shown.

Removing organic sulfur that is chemically bound to the coal is a far greater challenge than removing pyritic sulfur through physical means. Currently, chemical and biological processes which react with the coal are being used to remove organic sulfur.

One chemical technique that has shown promise is molten caustic leaching. This technique exposes coal to a hot sodium- or potassium-based chemical. The chemical leaches sulfur and mineral matter from the coal. Other chemical techniques modify the

chemical characteristics of coal in a way that makes the coal more receptive to cleaning.

Biological cleaning represents some of the most exotic techniques in coal cleaning. A potential advantage of biological techniques over chemical cleaning is that biological cleaning requires less severe operating conditions. Researchers have identified naturally occurring bacteria that can digest the organic sulfur in coal. Other approaches involve using fungi, rather than bacteria, and injecting sulfur-digesting enzymes directly into the coal.

Chemical or biological coal cleaning appears to be capable of removing as much as 90 percent of the total sulfur (pyritic and organic) in coal. Some chemical techniques also can remove 99 percent of the ash.

Mild Gasification. Mild gasification is a modification of conventional coal gasification process that produces gaseous, solid, and liquid products by heating coal in an oxygen-free reactor. The process takes an alternative approach to complete gasification of coal by driving off the condensable volatile hydrocarbons and leaving behind carbon, in lieu of converting the entire charge of coal to synthesis gas.

Mild gasification processes generate multiple fuels and chemical feedstocks by medium-temperature treatment of coal. The products generated are characterized as coal-derived liquids, gases, and solids, depending on the operating conditions. The solid product can be beneficiated further to remove both ash and pyritic sulfur. A slurry of coal-derived fuel and beneficiated solid has the potential of being a very versatile fuel that can be burned in both coal- and oil-fired boilers. If the solid product is beneficiated to a high degree, even feedstock coal with a high sulfur content can be used.

◀ Advanced thermal coal-drying coupled with physical cleaning technology is being demonstrated at the 68-ton/hr Rosebud SynCoal Partnership project in Montana

▶ The ENCOAL mild gasification technology processes about 1,000 tons/day of coal and produces an upgraded solid fuel for utility and industrial use and a liquid fuel substitutable for No. 6 fuel oil.

Coal Gasification. The basic coal gasification process was described in the Advanced Electric Power Generation market subsection above. The technology can be used to produce a low-Btu gas when air is used as the oxidant or a medium-Btu gas when oxygen is used as the oxidant. Low-Btu gas provides a clean fuel gas which can be used locally to fire boilers, gas turbines, industrial furnaces, etc. Medium-Btu gas, which is essentially carbon monoxide and hydrogen with some carbon dioxide, can be used as a fuel or transported economically by pipeline (100–200 miles) for distribution to an industrial or municipal complex. If the gas is further converted to a highly pure mixture of hydrogen and carbon monoxide, it replaces reformed natural gas as the feedstock for chemical synthesis (methanol, ammonia, hydrogen, etc.).

Coal Liquefaction. Two primary methods exist for converting coal into liquid fuels:

1. Indirect liquefaction, which is coal gasification followed by conversion of the synthesis gas to liquid fuels
2. Direct liquefaction, which is the conversion of the organic solid structures in coal directly into liquid fuels

Liquefaction of coal involves the addition of hydrogen to coal by various techniques so that the fuel's ratio of hydrogen to carbon is increased to a level comparable to petroleum-based fuels.

Coprocessing, a recent development in liquefaction technology, involves the production of liquid fuel from a mixture of coal and heavy petroleum residue, with the residual oil providing some of the hy-

drogen needed for the conversion process. Once produced, the coal-derived liquid can be cleaned of its sulfur and ash before being used.

The potential advantages of direct liquefaction include relatively high thermal efficiency (in the range of 60–70 percent), high product yield, and the potential to make products such as high-quality gasoline. Principal disadvantages stem from the severe operating conditions (temperature and pressure) required and the lack of integration among process steps. Moreover, although direct liquefaction is more efficient and more selective to fuel-grade liquids than indirect liquefaction, the indirect process is better suited to the production of diesel fuels. Indirect liquefaction is commercially proven technology which is used to produce transportation fuels and chemicals, such as methanol, from coals.

► The Passamaquoddy Technology Recovery Scrubber™ reduces SO₂ emissions from a 470,000-ton/yr cement kiln in Thomaston, ME.

Industrial Applications

Technologies developed for U.S. industry can resolve environmental problems similar to those of electric power generators, such as compliance with CAAA of 1990, toxic emissions, global climate change, and solid waste disposal. At present, the CCT Program is demonstrating specific applications for the steel and cement manufacturing industries. Also, many of the technologies principally identified in the other marketplace areas will be applicable to the industrial market, including advanced combustors, fluidized-bed combustors, coal gasification processes, and a variety of the environmental control systems.

2. Program Implementation

Introduction

The CCT Program has been implemented through a series of five nationwide competitive solicitations conducted over a period of 9 years, with each competition associated with a specific level of government funding and objectives. At the end of the five originally planned solicitations, a total of 45 projects, valued at more than \$6.97 billion and located in 21 states, are either already complete or moving forward. Government funding for the projects is approximately \$2.37 billion; the private sector is providing nearly \$4.60 billion, or 66 percent of the projects' total value.

The Legislation

The legislation authorizing the CCT Program is found in Public Law 98-473, Joint Resolution Making Continuing Appropriations for Fiscal Year 1985 and for Other Purposes. Title I set aside \$750 million of the congressionally rescinded \$7.375 billion of the Synthetic Fuels Corporation into a special U.S. Treasury account entitled the "Clean Coal Technology Reserve." This account was dedicated to "conducting cost-shared clean coal technology projects for the construction and operation of facilities to demonstrate the feasibility of future commercial applications of such technology."

Title III of this act directed the Secretary of Energy to solicit statements of interest in and proposals for clean coal projects. In keeping with this mandate, the U.S. Department of Energy (DOE) issued a program announcement which resulted in the receipt of 176 proposals representing both domestic and international projects with a total estimated cost in excess of \$8 billion.

After this significant initial expression of interest in clean coal demonstration projects, Public Law 99-190, enacted December 1985, appropriated \$400 million to conduct cost-shared demonstration projects. Of the total appropriated funds, approximately \$387 million were made available for cost-shared projects to be selected through a competitive solicitation, or Program Opportunity Notice (PON), referred to as CCT-I. (The remaining funds were required for program direction and the legislatively mandated Small Business Innovative Research, or SBIR, Program.)

In a manner similar to the initiation of CCT-I, Congress again directed DOE to solicit information from the private sector in the Department of the Interior and Related Agencies Appropriations Act for FY 1987 (Public Law 99-591, October 30, 1986). The information received was to be used to establish the level of potential industrial interest in another solicitation, this time involving clean coal technologies capable of retrofitting, repowering, or modernizing existing facilities. Projects were to be cost shared, with industry sharing at least 50 percent of the cost. As a result of the solicitation, a total of

139 expressions of interest were received by DOE in January 1987.

On March 18, 1987, President Reagan announced the endorsement of the recommendations of the Special Envoys on Acid Rain including a \$2.5-billion government share of industry/government demonstrations of innovative control technology over a 5-year period. The Secretary of Energy stated that the department would ask Congress for an additional \$350 million in fiscal year (FY) 1988 and an advanced appropriation of \$500 million in FY 1989. Additional appropriations of \$500 million would be requested in fiscal years 1990, 1991, and 1992. This request was made by the President on April 4, 1987.

Public Law 100-202, enacted December 22, 1987, as amended by Public Law 100-446, appropriated a total of \$575 million to conduct CCT-II. About \$536 million were for projects, with the remainder for program direction and the SBIR Program.

The Department of the Interior and Related Agencies Appropriations Act for FY 1989 (Public Law 100-446, September 27, 1988) provided \$575 million for necessary expenses associated with clean coal technology demonstrations in the CCT-III solicitation. Of the total funding, about \$546 million were made available for cost-sharing projects, with the remainder for program direction and the SBIR Program.

The act continued the requirement that proposals demonstrate technologies capable of retrofitting

or repowering existing facilities. The statute also authorized the use of Tennessee Valley Authority (TVA) power program funds as a source of nonfederal cost sharing. In addition, funds borrowed by Rural Electrification Administration electric cooperatives from the Federal Financing Bank became eligible as cost sharing in the CCT-III solicitation.

In the Department of the Interior and Related Agencies Appropriations Act of 1990, Public Law 101-121, enacted October 23, 1989, Congress provided \$600 million for the CCT-IV solicitation. CCT-IV, according to the act, "shall demonstrate technologies capable of replacing, retrofitting, or repowering existing facilities and shall be subject to all provisos contained under this head in Public Laws 99-190, 100-202 and 100-446 as amended by this Act." About \$563 million were made available for federal cofunding of projects selected in CCT-IV, with the remainder for program direction and the SBIR Program.

The FY 1990 Supplemental Appropriations Act, Public Law 101-302, enacted May 25, 1990, delayed issuance of the CCT-IV solicitation from June 1, 1990, until September 1, 1990. However, Public Law 101-512, the Department of the Interior and Related Agencies Appropriations Act of FY 1991, enacted November 15, 1990, subsequently directed DOE to issue the PON for CCT-IV on or before February 1, 1991.

In Public Law 101-121, enacted October 23, 1989, Congress provided \$600 million for the CCT-V solicitation. CCT-V, according to the act, "shall be subject to all provisos contained under this head in Public Laws 99-190, 100-202 and 100-446 as amended by this Act." Approximately \$568 million

were made available for federal cofunding of projects to be selected in this solicitation, with the remainder again for program direction and the SBIR Program. In Public Law 101-512, Congress directed DOE to issue the PON for CCT-V no later than March 1, 1992, and subsequently, in Public Law 102-154, postponed the PON's release to July 6, 1992. This later act also directed that the proposals should advance significantly the efficiency and environmental performance of coal-using technologies and be applicable to either new or existing facilities.

Public Law 103-138, enacted November 11, 1993, adjusted the rate at which funds were to be made available to the program in FY 1994, 1995, and 1996. Specific legislative language contained in the public laws discussed above can be found in Appendix A.

Solicitation Process

The CCT Program has been implemented through five competitive solicitations. Congress set the basic goals for the program and for each solicitation in the enabling legislation and accompanying report language. DOE subsequently translated the guidance into performance-oriented (not design-oriented) solicitations. For each solicitation, evaluation criteria were defined and weighted to reflect specific congressional guidance and the current CCT Program objectives. This process enabled industry to set the technical agenda by allowing companies to propose their own technologies as qualifying projects. This had the significant benefit of attracting higher levels of private-sector cost-sharing and increasing

the likelihood of realizing commercialization objectives.

An important attribute to the solicitation approach used to implement the CCT Program was the use of multiple solicitations spread over a number of years. Allowing time between solicitations made it possible to adjust program implementation. At the end of each solicitation, Congress provided the flexibility as needed to effectively implement the program.

Each solicitation was issued as a PON. Proposals for demonstration projects consistent with the objectives of the PON were submitted to DOE by a specific deadline. DOE evaluated the proposals and announced those projects selected for negotiation. Exhibit 2-1 summarizes the results of the solicitation processes. Exhibit 2-2 identifies the projects currently in the CCT Program and the solicitation under which they were selected. (Also see Appendix B.)

The objective of the CCT-I solicitation was to seek cost-shared projects to demonstrate the feasibility of clean coal technologies for commercial applications. The solicitation elicited 51 proposals. Nine projects were selected and 8 alternate projects were eventually selected as replacement projects because negotiations could not be completed on the originally selected projects. Projects were selected from the list of alternates on three separate occasions.

At year-end 1993, there were 8 CCT-I projects in the CCT Program: 3 were completed; 4 were in operation; and 1 was in design. The 8 CCT-I projects included 3 demonstrating advanced electric power generation; 2, environmental control devices; 2, coal processing for clean fuels; and 1, an industrial application.

The CCT-II PON solicited cost-shared, innovative clean coal technology projects to demonstrate technologies that were capable of being commercialized in the 1990s, more cost effective than current technologies, and capable of achieving significant reductions in SO₂ and/or NO_x emissions from existing coal-burning facilities, particularly those that contribute to transboundary and interstate pollution. The CCT-II PON was the first solicitation implementing the recommendations of the U.S. and Canadian Special Envoys' report on acid rain. DOE received 55 proposals and selected 16 as best furthering the goals and objectives of the PON (no alternates were selected). At the end of 1993, 12 CCT-II projects remained in the CCT Program: 4 were completed; 5 were in operation; 2 were in design; 1 had been mothballed for future operation; and 4 were withdrawn. The 12 CCT-II projects included 2 demonstrating advanced electric power generation; 8, environmental control devices; and 2, industrial applications.

The objective of the CCT-III PON was to solicit cost-shared clean coal technology projects to demonstrate innovative, energy-efficient technologies capable of being commercialized in the 1990s. These technologies were to be capable of (1) achieving significant reductions in emissions of SO₂ and/or NO_x from existing facilities to minimize environmental impacts, such as transboundary and interstate pollution, and/or (2) providing for future energy needs in an environmentally acceptable manner. DOE received 48 proposals and selected 13 projects as best furthering the goals and objectives of the PON. On December 31, 1993, all 13 projects remained in the CCT Program: 2 were completed;

Exhibit 2-1 CCT Program Selection Process Summary				
Solicitation	PON Issued	Proposals Submitted	Projects Selected	Projects in CCT Program as of December 31, 1993
CCT-I	February 17, 1986	51	17	8
CCT-II	February 22, 1988	55	16	12
CCT-III	May 1, 1989	48	13	13
CCT-IV	January 17, 1991	33	9	7
CCT-V	July 6, 1992	24	5	5
		<u>211</u>	<u>60</u>	<u>45</u>

5 were in operation; and 6 were in design. These 13 CCT-III projects included 3 demonstrating advanced electric power generation; 7, environmental control devices; 2, coal processing for clean fuels; and 1, industrial application.

The CCT-IV PON solicited proposals to conduct cost-shared clean coal technology projects to demonstrate innovative, energy-efficient, economically competitive technologies. These technologies were to be capable of (1) retrofitting, repowering, or replacing existing facilities while achieving significant reductions in the emissions of SO₂ and/or NO_x and/or (2) providing for future energy needs in an environmentally acceptable manner. A total of 33 proposals were submitted in response to the PON. Nine projects were selected; however, 2 have been withdrawn. As of December 31, 1993, the remaining 7 CCT-IV projects were in design; they included

3 demonstrating advanced electric power generation; 2, environmental control devices; 1, coal processing for clean fuels; and 1, an industrial application.

The objective of the CCT-V PON was to solicit proposals to conduct cost-shared demonstration projects that significantly advance the efficiency and environmental performance of coal-using technologies and are applicable to either new or existing facilities. In response to the solicitation, DOE received proposals for 24 projects and selected 5 projects, all of which were in negotiations at year-end 1993. Selected projects included 4 demonstrating advanced electric power generation and 1, an industrial application.

The location of the projects from all solicitations are mapped in Exhibits 2-3 through 2-6, which indicate the geographic locations of projects by application category.

Exhibit 2-2

Clean Coal Technology Demonstration Projects, by Solicitation

Project and Sponsor	Location
CCT-I	
Development of the Coal Quality Expert (ABB Combustion Engineering, Inc., and CQ, Inc.)	Homer City, PA
LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)	Lorain, OH
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)	Williamsport, PA
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)	Hennepin and Springfield, IL
Tidd PFBC Demonstration Project (The Ohio Power Company)	Brilliant, OH
Advanced Coal Conversion Process Demonstration (Rosebud SynCoal Partnership)	Colstrip, MT
Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.)	Nucla, CO
York County Energy Partners Cogeneration Project (York County Energy Partners, L.P.)	North Cordonus, PA
CCT-II	
Combustion Engineering IGCC Repowering Project (ABB Combustion Engineering, Inc.)	Springfield, IL
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	Niles, OH
PFBC Utility Demonstration Project (The Appalachian Power Company)	New Haven, WV
Demonstration of Coal Reburning for Cyclone Boiler NO _x Control (The Babcock & Wilcox Company)	Cassville, WI
SOx-NOx-Rox-Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)	Dilles Bottom, OH
Innovative Coke Oven Gas Cleaning System for Retrofit Applications (Bethlehem Steel Corporation)	Sparrows Point, MD
Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)	Thomaston, ME
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	Chesterton, IN
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)	Coosa, GA
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	Newnan, GA
Demonstration of Selective Catalytic Reduction Technology for the Control of NO _x Emissions from High-Sulfur-Coal-Fired Boilers (Southern Company Services, Inc.)	Pensacola, FL
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO _x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	Lynn Haven, FL
CCT-III	
Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process (Air Products and Chemicals, Inc.)	Kingsport, TN
10-MW Demonstration of Gas Suspension Absorption (AirPol, Inc.)	West Paducah, KY

Exhibit 2-2 (continued)
Clean Coal Technology Demonstration Projects, by Solicitation

Project and Sponsor	Location
Healy Clean Coal Project (Alaska Industrial Development and Export Authority)	Healy, AK
Full-Scale Demonstration of Low-NO _x Cell™ Burner Retrofit (The Babcock & Wilcox Company)	Aberdeen, OH
Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)	Seward, PA
Blast Furnace Granulated-Coal Injection System Demonstration Project (Bethlehem Steel Corporation)	Burns Harbor, IN
PCFB Demonstration Project (DMEC-1 Limited Partnership)	Pleasant Hill, IA
ENCOAL Mild Coal Gasification Project (ENCOAL Corporation)	Gillette, WY
Evaluation of Gas Reburning and Low-NO _x Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)	Denver, CO
LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC-North America)	Richmond, IN
Commercial Demonstration of the NOXSO SO ₂ /NO _x Removal Flue Gas Cleanup System (NOXSO Corporation and MK-Ferguson Company)	Niles, OH
Integrated Dry NO _x /SO ₂ Emissions Control System (Public Service Company of Colorado)	Denver, CO
Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	Lakeland, FL
CCT-IV	
Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International)	Stoystown and Springdale, PA Ashtabula, OH Richmond, IN
Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Corporation)	Lansing, NY
Piñon Pine IGCC Power Project (Sierra Pacific Power Company)	Reno, NV
Toms Creek IGCC Demonstration Project (TAMCO Power Partners)	Coeburn, VA
Micronized Coal Reburning Demonstration for NO _x Control on a 175-MWe Wall-Fired Unit (Tennessee Valley Authority)	West Paducah, KY
Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal (ThermoChem, Inc.)	Gillette, WY
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	West Terre Haute, IN
CCT-V	
Coal Diesel Combined-Cycle Project (Arthur D. Little, Inc.)	Easton, MD
Clean Power from Integrated Coal/Ore Reduction (COREX®) (Centerior Energy Corporation)	Cleveland, OH
Camden Clean Energy Demonstration Project (Duke Energy Corp.)	Camden, NJ
Four Rivers Energy Modernization Project (Four Rivers Energy Partners, L.P.)	Calvert City, KY
Warren Station Externally Fired Combined-Cycle Demonstration Project (Pennsylvania Electric Company)	Warren, PA

Exhibit 2-3 Geographic Locations of CCT Projects—Advanced Electric Power Generation

Exhibit 2-4 Geographic Locations of CCT Projects—Environmental Control Devices

Exhibit 2-5 Geographic Locations of CCT Projects—Coal Processing for Clean Fuels

Exhibit 2-6
Geographic Locations of CCT Projects—Industrial Applications

Environmental Aspects

DOE employs a three-step process to ensure that the CCT Program and its projects comply with the environmental requirements of the National Environmental Policy Act (NEPA) and the regulations for NEPA compliance promulgated by the Council on Environmental Quality (CEQ) (40 CFR Parts 1500-1508) and by DOE (10 CFR Part 1021). This process includes (1) preparing a programmatic environmental impact statement (PEIS); (2) preparing preselection, project-specific environmental reviews; and (3) preparing postselection, site-specific documentation. Several types of NEPA documents have been used in the CCT Program, including memoranda-to-file (MTF; discontinued as of September 30, 1990), environmental assessments (EA), and environmental impact statements (EIS). In 1992, final NEPA implementation procedures were provided for categorical exclusions (CX) for certain classes of actions.

Exhibit 2-7 shows the progress made through 1993 to complete NEPA actions on projects in the CCT Program. By year-end 1993, NEPA actions were completed for 32 projects. From 1987 through 1993, NEPA requirements were satisfied with a CX for 1 project, MTFs for 17 projects, EAs for 13 projects (including a project which was subsequently withdrawn from the CCT Program), and a final EIS for 1 proposed project. Additionally, during 1993, two public scoping meetings were convened as the first step in the EIS process for the proposed York County Energy Partners Cogeneration Project.

**Exhibit 2-7
NEPA Actions Completed**

Number of Projects

For each project cofunded by DOE under the CCT Program, the sponsor is required to develop an environmental monitoring plan (EMP) that will ensure operational compliance and that significant technical and environmental data are collected and disseminated. Data to be collected include compliance data to meet federal, state, and local requirements and performance data to aid in future commercialization of the technology.

The Role of NEPA in the CCT Program

NEPA was initially enacted in 1969 as Public Law 91-190 and has since been amended, most recently by Public Law 94-83 in 1975. The applicability of NEPA to the CCT Program is encapsulated in the following provision (Section 102):

[A]ll agencies of the Federal Government shall . . .
(C) include in every recommendation or report on proposals for legislation and other major Federal actions signifi-

cantly affecting the quality of the human environment, a detailed statement by the responsible official on—

- i. the environmental impact of the proposed action,
- ii. any adverse environmental effects which cannot be avoided should the proposal be implemented,
- iii. alternatives to the proposed action,
- iv. the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and
- v. any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.

... (E) study, develop, and describe appropriate alternatives to recommended courses of action in any proposal which involves unresolved conflicts concerning alternative uses of available resources.

NEPA created the CEQ, which has become the agency responsible for promulgating the regulations that ensure compliance with the act. This role was defined by Executive Order 11514, "Protection and Enhancement of Environmental Quality," as amended by Executive Order 11991 of May 24, 1977.

Compliance with NEPA

In November 1989, a PEIS was distributed for the entire CCT Program. The programmatic document addressed issues such as global climatic modification and the ecological and socioeconomic impacts of the CCT Program. The PEIS evaluated the following two alternatives:

- "No action," which assumed that conventional coal-fired technologies with conventional flue gas desulfurization controls would continue to be used
- "Proposed action," which assumed that successfully demonstrated clean coal technolo-

gies would undergo widespread commercialization by the year 2010

In preselection project-specific environmental reviews, DOE evaluates the environmental aspects of each proposed demonstration project. Reviews are provided to the Source Selection Official for consideration in the project selection process. The site-specific environmental, health, safety, and socioeconomic issues associated with each proposed project are examined during the environmental review. As part of the comprehensive evaluation prior to selecting projects, the strengths and weaknesses of each proposal are compared with the environmental evaluation criteria. To the maximum extent possible, the environmental impacts of each proposed project and practical mitigating measures are considered. Also, a list of necessary permits is prepared, to the extent known; these are permits that would need to be obtained in implementing the proposed project.

Upon selection, project sponsors are required to prepare and submit additional environmental information. This detailed site- and project-specific information is used, along with independent information gathered by DOE, as the basis for site-specific NEPA documents which are prepared by DOE for each selected project. These NEPA documents are prepared, considered, and published in full conformance with CEQ's and DOE's regulations for NEPA compliance.

Categorical Exclusion

"Subpart D—Typical Classes of Actions" of the new DOE NEPA regulations provide for categorical exclusions as a class of actions that DOE has determined do not individually or cumulatively have a

significant effect on the human environment. One project, TVA's Micronized Coal Reburning Demonstration for NO_x Control on a 175-MWe Wall-Fired Unit, is covered by a categorical exclusion.

Memorandum-to-File

The MTF was established when DOE's NEPA guidelines were first issued in 1980. The MTF was intended for circumstances when the expected impacts of the proposed action were clearly insignificant, yet the action had not been specified as a categorical exclusion from NEPA documentation. The use of the MTF was terminated as of September 30, 1990. Exhibit 2-8 lists the 17 projects for which an MTF was prepared.

Environmental Assessments

An EA has the following three functions:

1. To determine whether a proposed action requires preparation of an EIS
2. To aid an agency's compliance with NEPA when no EIS is necessary, i.e., to provide an interdisciplinary review of proposed actions, assess potential impacts, and help identify better alternatives and mitigation measures
3. To facilitate preparation of an EIS when one is necessary

An EA is a concise but flexible document with no prescribed format. Contents are determined on a case-by-case basis and depend on the nature of the action. If appropriate, a DOE EA also includes any floodplain or wetlands assessment that has been prepared and may include analyses needed for other environmental determinations.

Exhibit 2-8 Memoranda-to-File Completed

Project and Sponsor	Completed
CCT-I	
Development of the Coal Quality Expert (ABB Combustion Engineering, Inc., and CQ, Inc.)	4/27/90
LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)	6/2/87
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)	3/26/87
Nucla CFB Demonstration Project (Colorado-Ute Electric Association, Inc.)	4/18/88
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Hennepin) (Energy and Environmental Research Corporation)	5/9/88
Tidd PFBC Demonstration Project (The Ohio Power Company)	3/5/87
CCT-II	
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	1/31/90
SO _x -NO _x -Rox-Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)	9/22/89
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)	5/22/89
Demonstration of Selective Catalytic Reduction Technology for the Control of NO _x Emissions from High-Sulfur-Coal-Fired Boilers (Southern Company Services, Inc.)	8/16/89
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO _x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	7/21/89
CCT-III	
10-MW Demonstration of Gas Suspension Absorption (AirPol, Inc.)	9/21/90
Full-Scale Demonstration of Low-NO _x Cell™ Burner Retrofit (The Babcock & Wilcox Company)	8/10/90
Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)	9/25/90
Evaluation of Gas Reburning and Low-NO _x Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)	9/6/90
LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC-North America)	10/2/90
Integrated Dry NO _x /SO ₂ Emissions Control System (Public Service Company of Colorado)	9/27/90

If an agency determines, on the basis of an EA, that is not necessary to prepare an EIS, a "finding of no significant impact," or FONSI, is issued. CEQ regulations describe the FONSI as a document that briefly presents the reasons why an action will not have a significant effect on the human environment and for which an EIS will not be prepared. The FONSI includes the EA, or a summary of it, and notes any other related environmental documents. CEQ and DOE regulations also provide for notification of the public that a FONSI has been issued.

Exhibit 2-9 lists projects for which an EA has been prepared. The exhibit includes an EA that was completed in 1991 for a project that was subsequently withdrawn from the program—TransAlta Resources Investment Corporation's Low-NO_x/SO₂ Burner Retrofit for Utility Cyclone Boilers project.

Environmental Impact Statements

The primary purpose of an EIS is to serve as an action-forcing device to ensure that the policies and goals defined in NEPA are infused into the programs and actions of the federal government. An EIS contains a complete and unbiased discussion of all potential environmental impacts. The EIS should inform decision makers and the public of reasonable alternatives that would avoid or minimize adverse impacts or enhance the quality of the human environment.

The CEQ regulations state that an EIS is to be more than a disclosure document; it is to be used by federal officials in conjunction with other relevant material to plan actions and make decisions. Analysis of alternatives is to encompass those to be considered by the ultimate decision maker, including a

complete description of the proposed action. In short, the EIS is a means of assessing the potential environmental impacts of a proposed DOE action and alternatives to that action prior to making a decision to proceed with the proposed action. Consequently, before a "record of decision" is issued, DOE may not take any action that would have an adverse environmental effect or limit the choice of reasonable alternatives. One EIS has now been completed for a CCT project (see Exhibit 2-10), and several others are under way (see Exhibit 2-11).

NEPA Actions in Progress

Exhibit 2-11 lists the status of projects for which the NEPA process has not yet been completed.

Environmental Monitoring

Sponsors of CCT projects are required to develop and implement an EMP which addresses both compliance and supplemental monitoring. Exhibit 2-12 lists the status of EMPs for all 45 projects in the CCT Program. The EMP is intended to ensure collection and dissemination of the significant technology, project, and site-specific environmental data necessary for evaluation of impacts upon health, safety, and the environment. Further, the data is used to characterize and quantify the environmental performance of the technology in order to evaluate its commercialization and deployment potential. In addition to regulatory compliance data, further monitoring is required to fulfill the following:

- Ensure that emissions, ambient levels of pollutants, and environmental impacts do not exceed expectations projected in the NEPA documents

Exhibit 2-9 Environmental Assessments Completed

Project and Sponsor	Completed
CCT-I	
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Lakeside) (Energy and Environmental Research Corporation)	6/25/89
Advanced Coal Conversion Process Demonstration (Rosebud SynCoal Partnership)	3/27/91
CCT-II	
Combustion Engineering IGCC Repowering Project (ABB Combustion Engineering, Inc.)	3/27/92
Demonstration of Coal Reburning for Cyclone Boiler NO _x Control (The Babcock & Wilcox Company)	2/12/91
Innovative Coke Oven Gas Cleaning System for Retrofit Applications (Bethlehem Steel Corporation)	12/22/89
Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)	2/16/90
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	4/16/90
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	8/10/90
Low-NO _x /SO ₂ Burner Retrofit for Utility Cyclone Boilers (TransAlta Resources Investment Corporation) (project withdrawn)	3/21/91
CCT-III	
ENCOAL Mild Coal Gasification Project (ENCOAL Corporation)	8/1/90
Blast Furnace Granulated-Coal Injection System Demonstration Project (Bethlehem Steel Corporation)	6/8/93
CCT-IV	
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	5/28/93
Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Corporation)	8/18/93

Exhibit 2-10 Environmental Impact Statements Completed

Project and Sponsor	Completed
CCT-III Healy Clean Coal Project (Alaska Industrial Development and Export Authority) * A record of decision is to be issued in March 1994.	12/15/93*

- Identify any need for corrective action
- Verify the implementation of any mitigative measure that may have been identified in a mitigation action plan pursuant to the provisions of an EA or EIS
- Provide the essential data on the environmental performance of the technology needed to evaluate the potential impact of future commercialization, including the ability of the technology to meet requirements of the Clean Air Act and the 1990 amendments

The objective of the CCT Program's environmental monitoring efforts is to ensure that, when commercially available, clean coal technologies will be capable of responding fully to air toxics regulations which emerge from the Clean Air Act Amendments (CAAA) of 1990, and, to the extent possible, are in the vanguard of cost-effective solutions to concerns about public health and safety related to coal use.

Air Toxics

Title III of the CAAA of 1990 lists known hazardous air pollutants (HAPs) and, among other things, calls for the U.S. Environmental Protection Agency (EPA) to establish categories of sources that emit these gases. Exploratory analyses suggest that HAPs may be released by conventional coal-fired power plants and, presumably, by plants utilizing clean coal technologies. It is expected that emissions standards will be proposed for the electric-power-production-source categories. However, there are many uncertainties as to the identities of these HAPs, their prevalence in various types and sources of coal, and their nature and fate as functions of combustion characteristics and the particular clean coal technology utilized.

The CCT Program recognizes the importance of monitoring HAPs in achieving widespread commercialization in the late 1990s and beyond. For all projects with existing cooperative agreements, DOE sought to include HAPs monitoring. Nineteen

projects from the CCT-I-IV solicitations contain provisions for monitoring HAPs.

The CCT-V PON acknowledged the importance of HAPs throughout the solicitation, including them as an aspect of proposal evaluation. The PON addressed the control of air toxics as an environmental performance criterion. Also, in the instructions on proposal preparation, the PON directed proposers as follows:

With respect to emission of air toxics, Proposers should consider . . . the particular elements and compounds [listed in Table 5-1 of the PON, "Specific Air Toxics to be Monitored"]. Proposers should present any information known concerning the reduction of emissions of these toxics by [the proposed] technology. Some of the toxics for which the proposed technology may offer control are likely unregulated in the target market at present. The significance and importance of the additional control afforded by the proposed technology for the continued use of coal should be explained. An example of this kind would be one or more particular air toxic compounds controlled by a technology meant for use in power generation.

The PON also stipulates information on air toxics to be presented in the environmental information required by DOE to fulfill its responsibilities under NEPA. Exhibit 2-13 lists the 19 projects which provide for HAPs monitoring. This list excludes projects selected in CCT-V which are in negotiation.

Exhibit 2-11 NEPA Actions in Progress

Project and Sponsor	Status
CCT-I York County Energy Partners Cogeneration Project (York County Energy Partners, L.P.)	EIS projected for 12/94
CCT-II PFBC Utility Demonstration Project (The Appalachian Power Company)	EIS projected for 2/98
CCT-III Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process (Air Products and Chemicals, Inc.) PCFB Demonstration Project (DMEC-1 Limited Partnership) Commercial Demonstration of the NOXSO SO ₂ /NO _x Removal Flue Gas Cleanup System (NOXSO Corporation and MK-Ferguson Company) Tampa Electric Company Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	EA projected for 12/94 EIS projected for 11/94 EA projected for 4/95 EIS projected for 6/94
CCT-IV Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International) Piñon Pine IGCC Power Project (Sierra Pacific Power Company) Toms Creek IGCC Demonstration Project (TAMCO Power Partners) Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal (ThermoChem, Inc.)	EA projected for 2/94 EIS projected for 8/94 EIS projected for 4/96 EA projected for 5/95

Exhibit 2-12

Status of Environmental Monitoring Plans for CCT Projects

Project and Sponsor	Status
CCT-I	
Development of the Coal Quality Expert (ABB Combustion Engineering, Inc., and CQ, Inc.)	Completed 7/31/90
LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)	Completed 10/19/88
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)	Completed 9/22/87
Nucla CFB Demonstration Project (Colorado-Ute Electric Association, Inc.)	Completed 2/27/88
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)	Completed 10/15/89 (Hennepin) Completed 11/15/89 (Lakeside)
Tidd PFBC Demonstration Project (The Ohio Power Company)	Completed 5/25/88
Advanced Coal Conversion Process Demonstration (Rosebud SynCoal Partnership)	Completed 4/7/92
York County Energy Partners Cogeneration Project (York County Energy Partners, L.P.)	Projected 1/95
CCT-II	
Combustion Engineering IGCC Repowering Project (ABB Combustion Engineering, Inc.)	Completed 5/6/93
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	Completed 10/31/91
PFBC Utility Demonstration Project (The Appalachian Power Company)	Projected 7/97
Demonstration of Coal Reburning for Cyclone Boiler NO _x Control (The Babcock & Wilcox Company)	Completed 11/18/91
SO _x -NO _x -Rox-Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)	Completed 12/31/91
Innovative Coke Oven Gas Cleaning System for Retrofit Applications (Bethlehem Steel Corporation)	Completed 7/5/91
Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)	Completed 3/26/90
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	Completed 1/31/91
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)	Completed 9/14/90
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	Completed 12/18/90
Demonstration of Selective Catalytic Reduction Technology for the Control of NO _x Emissions from High-Sulfur-Coal-Fired Boilers (Southern Company Services, Inc.)	Completed 3/11/93
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO _x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	Completed 12/27/90

Exhibit 2-12 (continued)
Status of Environmental Monitoring Plans for CCT Projects

Project and Sponsor	Status
CCT-III	
Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process (Air Products and Chemicals, Inc.)	Projected 1/95
10-MW Demonstration of Gas Suspension Absorption (AirPol, Inc.)	Completed 10/2/92
Healy Clean Coal Project (Alaska Industrial Development and Export Authority)	Projected 4/94
Full-Scale Demonstration of Low-NO _x Cell™ Burner Retrofit (The Babcock & Wilcox Company)	Completed 8/9/91
Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)	Completed 6/12/91
Blast Furnace Granulated-Coal Injection System Demonstration Project (Bethlehem Steel Corporation)	Projected 11/94
PCFB Demonstration Project (DMEC-1 Limited Partnership)	Projected 1/95
ENCOAL Mild Coal Gasification Project (ENCOAL Corporation)	Completed 5/29/92
Evaluation of Gas Reburning and Low-NO _x Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)	Completed 7/26/90
LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC-North America)	Completed 6/12/92
Commercial Demonstration of the NOXSO SO ₂ /NO _x Removal Flue Gas Cleanup System (NOXSO Corporation and MK-Ferguson Company)	Projected 4/95
Integrated Dry NO _x /SO ₂ Emissions Control System (Public Service Company of Colorado)	Completed 8/5/93
Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	Projected 6/94
CCT-IV	
Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International)	Projected 8/94
Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Corporation)	Projected 4/94
Piñon Pine IGCC Power Project (Sierra Pacific Power Company)	Projected 10/94
Toms Creek IGCC Demonstration Project (TAMCO Power Partners)	Projected 4/94
Micronized Coal Reburning Demonstration for NO _x Control on a 175-MWe Wall-Fired Unit (Tennessee Valley Authority)	Projected 3/94
Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal (ThermoChem, Inc.)	Projected 9/95
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	Completed 7/9/93

Exhibit 2-13
CCT Projects Monitoring Hazardous Air Pollutants

Application Category	Sponsor	Project	Solicitation
Advanced Electric Power Generation	Alaska Industrial Development and Export Authority	Healy Clean Coal Project	CCT-III
	The Ohio Power Company	Tidd PFBC Demonstration Project	CCT-I
	York County Energy Partners, L.P.	York County Energy Partners Cogeneration Project	CCT-I
	Sierra Pacific Power Company	Piñon Pine IGCC Power Project	CCT-IV
	TAMCO Power Partners	Toms Creek IGCC Demonstration Project	CCT-IV
	Wabash River Coal Gasification Repowering Project Joint Venture	Wabash River Coal Gasification Repowering Project	CCT-IV
Environmental Control Devices	ABB Environmental Systems	SNOX™ Flue Gas Cleaning Demonstration Project	CCT-II
	AirPol, Inc.	10-MW Demonstration of Gas Suspension Absorption	CCT-III
	The Babcock & Wilcox Company	Demonstration of Coal Reburning for Cyclone Boiler NO _x Control	CCT-II
	The Babcock & Wilcox Company	SO _x -NO _x -Rox-Box™ Flue Gas Cleanup Demonstration Project	CCT-II
	New York State Electric & Gas Corporation	Milliken Clean Coal Technology Demonstration Project	CCT-IV
	Public Service Company of Colorado	Integrated Dry NO _x /SO ₂ Emissions Control System	CCT-III
	Pure Air on the Lake, L.P.	Advanced Flue Gas Desulfurization Demonstration Project	CCT-II
	Southern Company Services, Inc.	Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	CCT-II
	Southern Company Services, Inc.	Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	CCT-II
Coal Processing for Clean Fuels	Custom Coals International	Self-Scrubbing Coal™: An Integrated Approach to Clean Air	CCT-IV
	ENCOAL Corporation	ENCOAL Mild Coal Gasification Project	CCT-III
Industrial Applications	ThermoChem, Inc.	Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal	CCT-IV

3. Funding and Costs

Summary

Congress has appropriated a federal budget of nearly \$2.75 billion for the CCT Program. These funds have been committed to demonstration projects through five competitive solicitations. Project awards have been completed for the first four solicitations, and project selections for the fifth solicitation were announced in May 1993. As of December 31, 1993, the program consists of 45 active or completed projects, including five projects selected under the fifth solicitation that are in negotiation.

The five solicitations have resulted in a combined commitment by the federal government and the private sector of about \$6.97 billion. The U.S. Department of Energy's (DOE's) cost share for these projects is \$2.37 billion, or approximately 34 percent of the total. The project sponsors (i.e., the non-federal-government participants) are providing the remainder—nearly \$4.60 billion, or approximately 66 percent of the total estimated cost.

Program Funding

In the CCT Program, the federal government's contribution can not exceed 50 percent of the total cost of any individual project. The federal government's funding commitments and other terms of

federal assistance are represented in a cooperative agreement negotiated for each project in the program. Terms of the cooperative agreement also include a plan for the federal government to recoup up to the full amount of the federal government's contribution. This approach enables taxpayers to benefit from commercially successful projects. This is in addition to the benefits derived from the demonstration and commercial deployment of technologies that improve environmental quality and promote the efficient use of the nation's energy sources.

The sponsor has primary responsibility for the project. The federal government monitors project activities, provides technical advice, assesses progress by periodically reviewing project performance with the sponsor, and participates in decision making at major project junctures. Through these activities, the federal government ensures the efficient use of public funds in the achievement of individual project and overall program objectives.

Congress has provided program funding through the following appropriations acts and adjustments due to sequestering requirements of the Gramm-Rudman-Hollings Deficit Reduction Act (see Appendix A for excerpts from the relevant legislation):

- Public Law 99-190, enacted December 19, 1985, appropriated \$400 million to conduct cost-shared demonstration projects; sequestering reduced this amount by \$2.4 million.

- Public Law 100-202, enacted December 22, 1987, as amended by Public Law 100-446, appropriated a total of \$575 million; sequestering reduced this amount by \$2,600.
- Public Law 100-446, enacted September 27, 1988, as amended by Public Law 101-164, provided \$575 million; sequestering reduced this amount by \$2,028.
- Public Law 101-121, enacted October 23, 1989, as amended by Public Laws 101-512, 102-154, 102-381, and 103-138, provided the final \$1.2 billion for the program; sequestering reduced this amount by \$455.

Exhibit 3-1 presents the allocation of appropriated CCT Program funds (after adjustment) and the amount available for each CCT solicitation. The five CCT solicitations are referred to as CCT-I, CCT-II, CCT-III, CCT-IV, and CCT-V. Two additional activities funded by CCT Program appropriations are the Small Business Innovative Research (SBIR) Program and CCT program direction.

The SBIR Program implements the Small Business Innovation Development Act of 1982 and provides a role for small, innovative firms in selected research and development (R&D) areas.

The program direction budget provides for the management and administrative costs of the program and includes federal employees' salaries, benefits and travel, site support services, and services provided by national laboratories and private firms.

Exhibit 3-1
Relationship between Appropriations and Subprogram Budgets
for the CCT Program
(Dollars in Thousands)

Appropriation Enacted	Subprogram	Appropriated to DOE*	SBIR ^b Budget	Program Direction Budget	Projects Budget
P.L. 99-190	CCT-I	397,600	4,902	5,467	387,231
P.L. 100-202	CCT-II	574,997	6,781	32,512	535,704
P.L. 100-446	CCT-III	574,998	6,906	22,548	545,544
P.L. 101-121 ^c	CCT-IV	600,000	11,688	25,000	563,312
P.L. 101-121 ^c	CCT-V	600,000	7,187	25,000	567,813
Total		2,747,595	37,464	110,527	2,599,604

*FY 1991 apportionment increments for CCT-II and CCT-III were reduced by \$4,628 total due to Gramm-Rudman-Hollings sequestering requirements; original appropriations were \$575 million each; appropriations for CCT-IV were cut \$455. Previously, sequestering requirements had reduced original CCT-I appropriations of \$400 million by \$2.4 million.

^b Small Business Innovative Research Program

^c P.L. 101-121 was revised by P.L. 101-512, 102-154, 102-381, and 103-138.

Availability of Funding

Although all funds necessary to implement the entire CCT Program were appropriated by Congress prior to fiscal year (FY) 1990, the legislation also directs that these funds be made available (i.e., apportioned) to DOE on a time-phased basis. Exhibit 3-2 depicts this apportionment of funding to DOE from FY 1986, when the program was initiated, through FY 1996, when the final increment of funding is scheduled to become available to DOE. Exhibit

3-2 also shows the program's yearly funding profile by appropriations act and by subprogram.

Use of Appropriated Funds

There are five key financial terms used by the government to track the status and use of appropriated funds: (1) budget authority, (2) commitments, (3) obligations, (4) costs, and (5) expenditures. The definition of each of these terms follows:

- **Budget Authority.** This is the legal authorization created by legislation (i.e., an appropriations act) that permits the federal government to disburse funds.
- **Commitments.** Within the context of the CCT Program, a commitment is established when DOE selects a project for negotiation. The commitment amount is equal to DOE's share of the project costs contained in the approved cooperative agreement and the amount of funds needed for projects in negotiation.
- **Obligations.** The negotiated cooperative agreement for each project establishes funding increments, referred to as budget periods. The cooperative agreement defines the tasks to be performed in each budget period. An obligation occurs in the beginning of each budget period and establishes the incremental amount of federal funds available to the sponsor for use in performing tasks as defined in the cooperative agreement.
- **Costs.** A request for payment submitted by the project sponsor to the federal government for reimbursement of tasks performed under the terms of the cooperative agreement is considered a cost. Costs are equivalent to a bill for payment or invoice.
- **Expenditures.** Expenditures represent payment amounts to the project sponsor from checks drawn upon the U.S. Treasury. Expenditures directly affect the government's cash flow.

Exhibit 3-2
Annual CCT Program Funding, by Appropriations and Subprogram Budgets
(Dollars in Thousands)

Fiscal Year	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Total
Adjusted Appropriations*												
P.L. 99-190	99,400	149,100	149,100									397,600
P.L. 100-202			50,000	190,000	135,000	199,997						574,997
P.L. 101-446					419,000	155,998						574,998
P.L. 101-121 ^b						35,000	315,000	0	100,000	100,000	50,000	600,000
P.L. 101-121 ^b							100,000	0	125,000	275,000	100,000	600,000
Total	99,400	149,100	199,100	190,000	554,000	390,995	415,000	0	225,000	375,000	150,000	2,747,595
Subprogram Budgets												
CCT-I Projects	96,685	145,273	145,273									387,231
CCT-II Projects			31,094	173,800	133,313	197,497						535,704
CCT-III Projects					391,496	154,048						545,544
CCT-IV Projects						9,875	311,063	0	98,500	98,000	45,874	563,312
CCT-V Projects							74,062	0	123,125	269,500	101,126	567,813
Projects Subtotal	96,685	145,273	176,367	173,800	524,809	361,420	385,125	0	221,625	367,500	147,000	2,599,604
Program Direction	1,491	1,988	20,500	14,000	22,548	25,000	25,000					110,527
Fossil Energy Subtotal	98,176	147,261	196,867	187,800	547,357	386,420	410,125	0	221,625	367,500	147,000	2,710,131
SBIR ^c	1,224	1,839	2,233	2,200	6,643	4,575	4,875	0	3,375	7,500	3,000	37,464
DOE Total	99,400	149,100	199,100	190,000	554,000	390,995	415,000	0	225,000	375,000	150,000	2,747,595

*Shown are appropriations less amounts sequestered under the Gramm-Rudman-Hollings Deficit Reduction Act.

^bP.L. 101-121 was revised by P.L. 101-512, 102-154, 102-381, and 103-138.

^cSmall Business Innovative Research Program

Exhibit 3-3
CCT Financial Projections as of December 31, 1993
(Dollars in Millions)

The full government cost-share is considered committed to each project upon selection for negotiation. However, DOE obligates funds for the project in increments. Most projects are subdivided into several time and funding intervals, or budget periods. The number of budget periods is determined during negotiations and is incorporated into the cooperative agreement. DOE obligates sufficient funds at the beginning of each budget period to cover the government's cost share for that period. This procedure limits the government's financial exposure and assures that DOE fully participates in decisions to proceed with each major phase of project implementation.

The overall financial profile for the CCT Program is presented in Exhibit 3-3. The graph shows actual performance for FY 1986 through FY 1993 and DOE estimates for FY 1994 through program completion. Excluded from the graph are SBIR obligations, costs, and expenditures, as these funds are used and tracked separately from the CCT Program. The financial projections presented in Exhibit 3-3 are based on individual project schedules and budget periods as defined in the cooperative agreements and modifications. The projections are updated as modifications to the cooperative agreements are approved.

The current financial status of the program through December 31, 1993, is presented by subprogram in Exhibit 3-4. SBIR monies are included in this exhibit to account for all funding. Exhibit 3-4 also indicates the apportionment sequence as modified by Public Law 103-138. These values represent the amount of budget authority available for the CCT Program.

Exhibit 3-4
Financial Status of the CCT Program as of December 31, 1993
(Dollars in Thousands)

Subprogram	Appropriations Allocated to Subprograms	Apportioned to Date	Committed to Date	Obligated to Date ^b	Cost to Date	Apportionment Sequence		
						FY	Annual	Cumulative
CCT-I	387,231	387,231	244,565	174,675	162,918	1986	99,400	99,400
CCT-II	535,704	535,704	471,813	160,502	139,642	1987	149,100	248,500
CCT-III	545,544	545,544	572,706	264,690	136,717	1988	199,100	447,600
CCT-IV	563,312	419,438	533,217	207,534	59,276	1989	190,000	637,600
CCT-V	567,813	197,187	567,813	0	0	1990	554,000	1,191,600
Projects Subtotal	2,599,604	2,085,104	2,390,114	807,400	498,553	1991	390,995	1,582,595
SBIR ^a	37,464	26,964	37,464	26,964	26,964	1992	415,000	1,997,595
Program Direction	110,527	110,527	110,527	92,168	87,053	1993	0	1,997,595
Total	2,747,595	2,222,595	2,538,105	926,532	612,570	1994	225,000	2,222,595
						1995	375,000	2,597,595
						1996	150,000	2,747,595

^a Small Business Innovative Research Program

^b Sums not appear to add due to rounding.

Project Funding, Costs, and Schedules

Information for individual CCT projects, including funding and the status of key milestones, is provided in the fact sheets in Section 7. An overview of project schedules and funding is presented in the exhibit at the end of this section (Exhibit 3-6).

Cost Sharing

A characteristic feature of the CCT Program is the cooperative funding agreement between the sponsor and the federal government referred to as cost sharing. This cost-sharing approach, as implemented in the CCT Program, was introduced in Public Law 99-190, the Department of the Interior and Related Agencies Appropriations Act of 1985. General concepts and requirements of the cost-sharing principle as applied to the CCT Program include the following:

- The federal government may not finance more than 50 percent of the total costs of a project.
- Cost sharing by the project sponsors is required in each phase in design, construction, and operation.
- The federal government may share in project cost growth (within the scope of work defined in the original cooperative agreement) up to 25 percent of the originally negotiated government share of the project.

Exhibit 3-5
Cost Sharing of Active CCT Projects
(Dollars in Thousands)

	Total Project Costs	%	Cost Share		Percent	
			DOE [*]	Sponsors	DOE	Sponsors
Subprogram						
CCT-I	775,905	11	227,053	548,852	29	71
CCT-II	1,553,231	22	467,820	1,085,411	30	70
CCT-III	1,330,858	19	572,706	758,152	43	57
CCT-IV	1,155,550	17	533,216	622,334	46	54
CCT-V	2,150,892	31	567,813	1,583,079	27	73
Total	6,966,436	100	2,368,608	4,597,828	34	66
Application Category						
Advanced Electric Power Generation	4,694,944	67	1,648,440	3,046,504	35	65
Environmental Control Devices	686,616	10	288,377	398,239	42	58
Coal Processing for Clean Fuels	466,726	7	212,393	254,333	46	54
Industrial Applications	1,118,150	16	219,398	898,752	20	80
Total	6,966,436	100	2,368,608	4,597,828	34	66
* DOE share does not include \$21,505,431 obligated for withdrawn and terminated projects.						

* DOE share does not include \$21,505,431 obligated for withdrawn and terminated projects.

- The sponsor's cost-sharing contribution must occur as project expenses are incurred and can not be offset or delayed based on prospective project revenues, proceeds, or royalties.
- Investment in existing facilities, equipment, or previously expended R&D funds are not allowed for the purpose of cost sharing.

Exhibit 3-5 summarizes the cost-sharing status by subprogram and by application category. It should be noted that the projects in the advanced electric power generation category account for 67 percent of total project costs and the average private-sector sponsor cost-share in this category is 65 percent.

Recovery of Government Outlays (Recoupment)

DOE's policy objective is to recover an amount up to the government's financial contribution to each project. Sponsors are required to submit a plan outlining a proposed schedule for recovering the government's financial contribution. The solicitations have featured different sets of recoupment rules.

Under the first solicitation, repayment was derived from revenue streams including net revenue from operation of the demonstrator plant beyond the demonstration phase and the commercial sale, lease, manufacture, licensing, or use of the demonstrated technology. In CCT-II, repayment was limited to revenues realized from the future commercialization of the demonstrated technology. The government's share would be 2 percent of gross equipment sales and 3 percent of the royalties realized on the technology subsequent to the demonstration.

The CCT-III repayment formula was adjusted to 1/2 percent of equipment sales and 5 percent of royalties. Limited grace periods were allowed on a project-by-project basis. A waiver on repayment may be sought from the Secretary of Energy if the project sponsor determines that a competitive disadvantage would result in either the domestic or international marketplace.

The recoupment provisions for CCT-IV and CCT-V were identical to those in CCT-III.

Exhibit 3-6
CCT Project Schedules and Funding, by Application Category

Exhibit 3-6 (continued)
CCT Project Schedules and Funding, by Application Category

Calendar Year	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	DOE	Total
	1 2 3 4	1 2 3 4	1 2 3 4	1 2 3 4	1 2 3 4	1 2 3 4	1 2 3 4	1 2 3 4	1 2 3 4	1 2 3 4	1 2 3 4	1 2 3 4	1 2 3 4	1 2 3 4	1 2 3 4	1 2 3 4		(\$1,000)
Environmental Control Devices																		
B&W--LIMB																	7,597	19,405
SCS--Wall-Fired																	6,554	14,711
EER--GR/SI																	18,748	37,498
SCS--Tangentially Fired																	4,440	9,153
Bechtel																	5,206	10,412
B&W--Coal Reburning																	6,341	13,647
B&W--Low-NOx																	5,443	11,233
ABB ES--SNOX																	15,719	31,438
B&W--SNRB																	6,078	13,272
Pure Air on the Lake																	63,913	151,708
PSC of Colorado																	13,706	27,411
AirPol																	2,315	7,717
EER--GR-LNB																	8,906	17,811
LIFAC																	10,637	21,394
SCS--CT-121																	21,728	44,389
SCS--SCR																	9,407	23,230
TVA																	3,515	7,330
NYS Electric & Gas																	45,000	158,608
NOXSO & MK-Ferguson																	33,125	66,250
Coal Processing for Clean Fuels																		
ABB CE & CQ																	10,864	21,746
Rosebud Syncoal																	34,500	69,000
ENCOAL																	36,282	72,564
Custom Coals																	38,039	89,716
Air Products																	92,708	213,700

4. The Road to Commercial Deployment

Summary

The success of the CCT Program ultimately will be measured by the degree to which the technologies are commercialized and by the contribution the technologies make to the resolution of energy, economic, and environmental issues. This contribution can only be achieved if those in the public and private sectors understand that clean coal technologies can increase the efficiency of energy use and enhance environmental quality at costs which are competitive with alternative energy options.

In 1993, an ongoing program to define and understand the potential domestic and international markets for clean coal technologies was expanded. This program involved interviews with electric utility executives, public utility commissioners, and financiers. Analyses were made of utility integrated resource plans, environmental compliance strategies, state regulations, and legislation that may impact commercial deployment.

The CCT Program outreach effort continued to facilitate decision making regarding the selection and use of clean coal technologies on a widespread domestic and international basis. A highlight of the outreach program was the Second Annual Clean Coal Technology Conference, attended by nearly 400 persons from 16 nations. The conference examined the domestic and international markets for clean coal technologies and some of the issues which will affect

commercial deployment in the United States and abroad. Four issues of the *Clean Coal Today* newsletter were prepared for distribution to 3,700 domestic and international readers. The CCT Program staff participated in over 15 domestic and international events involving users and vendors of the technology, state institutions, state regulators, and environmental groups.

The international activities centered on participating in trade missions to Eastern Europe, People's Republic of China, and the Pacific Rim countries; developing financial and market analyses in response to Section 1331 of the Energy Policy Act of 1992; developing an international technology transfer program as defined by Section 1332 of the act; and developing a showcase demonstration program for both China and Eastern Europe.

Commitment to Commercial Deployment

The CCT Program is committed to the commercial deployment of the demonstrated technologies. This commitment involves complementary but distinct roles for the technology owner and the government. It is the technology owner's role to retain and use the information and experience gained during the demonstration to promote the utilization of the technology in the domestic and international

marketplace. The detailed technical, economic, and environmental data and experience gained during the demonstration will be vital to efforts to commercialize the technology.

The importance of this area is highlighted by the inclusion of a commercialization clause in cooperative agreements. This clause requires the technology owners to meet U.S. market demand for the technologies on a nondiscriminatory basis. Further, this clause "flows down" from the projects' industrial participants to the other project team members and contractors. The other important intellectual property provisions (in particular, the rights in technical data and patent clauses) are similarly required in cooperative agreements. The clauses concerning rights in the technical data deal with the treatment of data developed jointly in the projects as well as data brought into the project. The patent clause affords protection for new inventions developed in the projects.

These three mechanisms ensure that the demonstrated technologies can be replicated by responsible firms while protecting the proprietary commercial position of the technology owners.

The government's role is to capture, assess, and transfer sufficient technical, economic, and environmental information to a broad spectrum of the private sector and international community to allow potential commercial users to confidently screen the technologies for those meeting their operational needs. Also, the federal role includes the following:

- Developing and disseminating the technical, economic, and environmental knowledge base necessary for federal, state, and local governments to make sound policy and regulatory decisions regarding commercial deployment of clean coal technologies
- Improving the regulatory and institutional climate for deployment of demonstrated clean coal technologies at a pace consistent with domestic and international free market decision-making
- Informing the public of the increased efficiency, enhanced environmental quality, and improved energy security benefits that can be achieved through commercial use of clean coal technologies

Even though the CCT Program is in its early stages with slightly more than 50 percent of the projects in operation and 20 percent completed, a number of commercial successes have been realized. The Babcock & Wilcox Company's Low-NO_x Cell™ burner was developed specifically for the conventional high-NO_x-emitting cell burners which account for nearly 26,000 MWe of U.S. generating capacity. Tests of the Low-NO_x Cell™ burner at Dayton Power and Light Company's J.M. Stuart Plant showed that the technology could reduce NO_x emissions by approximately 55 percent. Based on these results, The Babcock & Wilcox Company will install the technology on two commercial boilers totaling more than 1,100 MWe. This first commercial sale of two Low-NO_x Cell™ burners was to Allegheny Power System for installation at its Hatfield's Ferry Station. Ohio Edison Company announced it would maintain

the ABB Environmental Systems' SNOX™ system at its Niles Station on a permanent basis and that the technology would become a key part of the utility's Clean Air Act Amendments (CAAA) of 1990 compliance strategy. The Passamaquoddy Tribe successfully demonstrated a flue gas recovery system on a 1,450-ton-per-day cement plant. The project was completed in late 1993 when the gas recovery system became a permanent part of the cement plant.

The results of completed demonstrations are being used to improve commercial offerings of the technology. For example, as a result of the 110-MWe atmospheric circulating fluidized-bed (ACFB) demonstration conducted at the Tri-State Generation and Transmission Association's Nucla Station between 1988 and 1991, Pyropower Corporation was able to save almost 3 years in establishing a commercial line of ACFB units. The Babcock & Wilcox Company successfully demonstrated the

limestone injection multistage burner (LIMB) process. A commercial version of LIMB will be used in an independent power production project in Canada.

A number of the CCT projects are producing products which are being sold on the commercial market. For example, CQ, Inc., has developed and demonstrated an expert computer model to provide utilities with a prediction tool to assist in the

◀ Niles Station is the site of the ABB Environmental Systems' SNOX™ process which has become a key part of Ohio Edison's CAAA of 1990 compliance strategy. The process routinely achieves 96% SO₂ removal efficiency, 94% reduction of NO_x, and 99.9% removal of particulates.

selection of optimum quality coal. The first commercial sale of the Coal Quality Expert (CQE) Acid Rain Advisor software package was made in 1993. A CQE prototype was demonstrated in September 1993 and a beta version is scheduled for testing in March 1994. The ENCOAL Corporation, through its low-rank-coal upgrading project, has commercial contracts in place for two products resulting from the demonstration. A Wisconsin utility will buy 30,000 tons of the solid product and

► Commercial contracts are in place for 30,000 tons of solid product and 135,000 barrels of liquid product produced from the ENCOAL mild gasification plant.

Company's Plant Hammond, Southern Company Services is demonstrating Foster Wheeler's low- NO_x burner with over-fire air in a wall-fired boiler. The test results from these two CCT Program demonstrations were used by the U.S. Environmental Protection Agency (EPA) to develop CAAA of 1990 regulations for NO_x control. Further, the hazardous air pollutant data collected under DOE's CCT Program and the Coal Research and Development Program are being shared with EPA so that the agency will have the best available data for use in formulating air toxics control regulations under Title III of the CAAA of 1990.

TEXPAR Energy, Inc., of Waukesha, Wisconsin, will buy up to 135,000 barrels of the liquid fuel. Further, seven railroad tank cars of liquids have been shipped, including four to the Great Plains Synfuels Plant in Beulah, North Dakota, where the liquid has been successfully combusted in conventional industrial boilers. Rosebud SynCoal Partnership announced the signing of a letter of intent with Minnkota Power Cooperative, Inc., a North Dakota utility, to prepare a \$2-million engineering study to examine the merits of scaling up the advanced coal conversion process to an \$80-million commercial plant. This plant would be located next to Minnkota's Milton R. Young Power Station near Center, North Dakota. If the study results are positive, a commercial plant could be on-line by 1996.

Not only have commercial successes been realized from demonstrated technologies, but innovative business concepts have also been developed. The CCT Program's Pure Air on the Lake, L.P., advanced flue gas desulfurization project

(AFGD) is an example. Pure Air on the Lake expects to specialize in pollution control activities relieving electric utilities of the ownership and operation of AFGD units. Under the arrangement with Northern Indiana Public Service Company, the Pure Air limited partnership will continue to operate the AFGD unit as a contracted service at the Bailly Station for 17 years after the 3-year demonstration. It should be noted that the Bailly Generating Station with the AFGD unit became the first power plant on the CAAA of 1990 list of affected units to meet the SO_2 standards using flue gas desulfurization.

Another important use of the technical and environmental data resulting from the projects is to establish a sound basis for making policy and regulatory decisions by all levels of government. For example, Southern Company Services has successfully demonstrated ABB Combustion Engineering's low- NO_x firing system in a tangentially fired boiler in Gulf Power Company's Plant Lansing Smith in Lynn Haven, Florida. In a sister project at Georgia Power

Understanding the Market

An effort is under way to gain a better understanding of the potential domestic market for CCTs and the organizations and factors that will influence what and when facilities get built, as well as the technologies that are used. As part of this effort, stakeholder feedback is being sought through a series of interviews with executives and senior-level representatives of investor-owned utilities, nonutility generators, state public utility commissions, and financial institutions. The purpose of these interviews is to gain insights into those factors affecting decision makers and their strategies and plans for meeting future power needs—and, consequently, the commercial deployment of CCTs. Discussions also have covered CCT Program outreach activities, and feedback has been solicited on how the CCT Program can better meet information needs.

Additionally, a series of regional studies are under way to gain a better understanding of the markets for CCTs and the regional and state factors that could have a bearing on commercial deployment. Regions selected for study account for most of the U.S. coal-fired power generating capacity. During 1993, studies were completed for three regions—Mid-Atlantic, South Atlantic, and Midwest. Detailed data and information have been compiled on regional and state energy, coal use, and electric power generation; state government agencies, including public utility commissions; regulations, legislation, and policies that could have a bearing on CCT commercial deployment; and investor-owned, rural cooperative, and municipal coal-using electric utilities in the region. The studies are based on Energy Information Administration reports, utility integrated resource plans and annual reports, and other publicly available data sources.

The insights contributed by these 1993 efforts identify some of the more significant factors and trends affecting domestic markets for CCTs and relate the contributions of CCT demonstration projects to these markets.

The U.S. market for CCTs is made up of both existing and new coal-using facilities. Current energy projections, which assume a relatively modest growth rate for the U.S. economy through the 1990s, forecast a significant need for additional baseload capacity after the turn of the century, starting about the middle of the first decade (nominally 2005). There are many uncertainties that may affect the projected need for new capacity, such as the following:

- The extent to which demand-side management (which currently plays a major role in utility resource planning) will actually achieve expected savings
- The outlook for the nation's aging nuclear power plants which are due for relicensing starting about 2005
- The degree to which natural gas is used for baseload power generation

Nevertheless, there is general agreement that there will be an increasing requirement for baseload capacity and that coal will play a major role in meeting this requirement. For new capacity additions needed around 2005, technology choices will begin to be evaluated during the latter part of the 1990s—just when many CCT demonstration projects are being completed.

Technologies being demonstrated under the CCT Program will provide a portfolio of advanced electric power generating systems and environmental control devices to satisfy the technological requirements for clean and efficient electric power generation from coal. These demonstrations will be completed on a time table which will allow potential users to evaluate the technical, economic, and environmental performance in satisfying their operational need for power in the 2005–2010 time frame. By 2000, the demonstrated technologies are expected to include two atmospheric circulating fluidized-bed systems; four pressurized fluidized-bed systems; six integrated gasification combined-cycle systems demonstrating six different combinations of gasifiers and gas cleanup subsystems; one advanced slagging combustor; one externally fired combined-cycle system; and one coal-fired diesel. These

projects represent over 2,000 MWe of capacity, of which 1,200 MWe is new capacity and 800 MWe is repowered capacity. These projects are being conducted at commercial scale and will be available for commercial replication upon successful completion of the demonstration.

A market will also exist for new capacity using pulverized coal-fired systems with environmental controls. Under the CCT Program, seven NO_x-control projects representing 1,700 MWe are under way. Three projects representing over 600 MWe are demonstrating SO₂-control technologies capable of removing over 90 percent of the SO₂ and thus meet New Source Performance Standards (NSPS) necessary for new capacity. Furthermore, there are three projects of over 400 MWe which are demonstrating combined SO₂/NO_x controls with removal efficiencies capable of meeting NSPS. In summary, sufficient technical, economic, and environmental performance data are expected to exist by 2000 to enable electric power producers to confidently screen the technologies to meet their operational needs.

Another important domestic market for advanced electric generation systems, in addition to new units, is made up of over 1,200 existing coal-fired units; many are 30 years old or more. Because proposed new power plants often encounter siting, licensing, and permitting problems, utilities are making maximum use of existing facilities. In view of the difficulty being encountered in obtaining approval at a new site, existing power plant sites, with permits and infrastructure already in place, have enormous value, regardless of the age of the facility. Utilities have been investing extensively in measures to extend unit life to 50 years or more and upgrading facilities to achieve improved heat rates. Utilities

also are replacing older coal-fired boilers with advanced coal-fired technologies while reusing coal-handling equipment and other in-place systems and infrastructures. In general, repowering and life extension tend to be more cost-effective and less risky than building a new power plant.

Seven CCT projects, amounting to over 800 MWe, are demonstrating advanced electric power generating systems in repowering applications. The other eight advanced electric power generation projects are demonstrating technologies that can also be used in repowering situations as well as in new power plants.

Retrofitting existing electric power generators to meet the Phase I and II requirements of the CAAA of 1990 represents another market opportunity. The results from the stakeholder feedback sessions and reviews of utility integrated resource plans and other reports show that compliance with Phase I requirements for SO₂ will be met largely by fuel switching and emissions credit trading. However, it may be necessary to rely on technology solutions to meet the more stringent Phase II requirements. Meeting NO_x control requirements established in Titles I and IV of the CAAA of 1990 will require technology solutions. The CCT Program contains 19 demonstrations of environmental control devices (representing over 3,300 MWe) and 3 projects directed toward production of liquid and solid fuels which will allow compliance with CAAA of 1990 requirements. It should be noted that several host utilities are retaining the demonstrated technology as part of their strategies to comply with CAAA of 1990 requirements.

The market for clean coal technologies also is being shaped by profound changes in the utility

industry as companies seek to adapt to increasingly competitive markets. Among the more significant changes are those concerning the generation and transmission of electric power. Electric utilities are striving to develop and implement business strategies and organizational structures that will lead them to enhanced competitive positions in a rapidly changing business environment. Some analysts suggest that winners in the emerging new electric power market will be those companies that can command significant resources, form effective coalitions and partnerships, and react quickly to market changes.

Further, a number of issues are expected to have significant impact on future developments of the nation's utility markets. These include (1) existence of areas in nonattainment of National Ambient Air Quality Standards, especially for SO₂ and ozone; (2) areas designated by the U.S. Environmental Protection Agency as Class I areas (e.g., because they are environmentally sensitive or of special scenic or historic value); and (3) economic, legal, and political issues relating to the efforts of some states to promote and protect their respective in-state coal-mining industry or other economic base.

Moreover, the Energy Policy Act of 1992 allows independent power producers to access a utility's transmission network in order to sell electricity to other utilities. Although the act does not permit transmission access to retail customers, some in the utility industry expect continued pressure for legislation to allow retail wheeling. The act also amended the Public Utilities Holding Company Act of 1935 to allow holding companies to form "exempt wholesale generators," or EWGs, to sell power to affiliates, under certain restrictions, and to own and operate power generating facilities in other domestic and

international markets. Domestic EWGs, for example, may sell power to more than one utility and sell power across state lines (but not to retail customers). However, there is much uncertainty about the role nonutility generators will play, as well as their impact with respect to a utility's obligation to provide reliable and economic service to customers.

The remaining market area of clean coal technology is the industrial sector, particularly steel, cement, and industrial heat and power applications. Emissions from coke ovens and cement kilns represent a major target in the reduction of acid rain precursor emissions. SO₂ emissions are approximately 300,000 tons per year from the 30 coke oven plants in the United States. The 250 cement kilns in the United States and along the St. Lawrence River in Canada emit approximately 230,000 tons of SO₂ per year. The CCT Program has three demonstrations to reduce coke oven emissions by direct control, substitution of coal for coke, and the elimination of the need for coke altogether. A completed project demonstrated that a 90 percent reduction in cement kiln SO₂ emissions could be achieved; the technology has become a permanent part of the host plant. Two industrial heat and power applications are being demonstrated under the CCT Program. In addition, two of the advanced electric power generation projects are cogeneration projects which provide heat to an industrial complex and electricity to the grid.

Internationally, efforts are under way to define market opportunities, to promote U.S. technology, and to support U.S. project development work in overseas markets. Through 2010, the potential CCT market for new facilities and retrofit installations outside the United States is projected to total \$600–900 billion. Exports from all CCT exporting

nations could account for approximately \$200 billion of the investments in this huge, overseas market (\$12 billion per year in constant 1993 dollars). If the U.S. market share for CCT exports approximates the current U.S. market share for power equipment exports, then U.S. exports of clean coal technologies could increase total U.S. exports by \$4 billion per year. In turn, this growth in U.S. exports could result in the equivalent of 30,000 person-years of U.S. employment annually.

The international activities have concentrated on providing technical support to the U.S. trade agencies, organizing trade missions, and developing financial and market analysis in response to the requirements of Section 1331 of the Energy Policy Act of 1992, and developing an international technology transfer program as defined by Section 1332 of the act.

During 1993 an outline was developed for an international technology transfer program for clean coal. Proposed program activities include a showcase demonstration in China and Eastern Europe and cost sharing of project development activities. Many government agencies, industry groups, trade groups, and companies have been consulted for ideas. A draft of a proposed approach to the program will be issued for comment at a public meeting scheduled for February 1994.

Technical assistance was provided to the U.S. Trade Development Agency to evaluate feasibility studies for retrofit and repowering projects in Eastern Europe. Support of these organizations is helping to promote U.S. technology for potential projects in Eastern Europe.

The U.S. Department of Energy (DOE) also participated in the Clean Coal Working Group of the

United Nations Committee on Energy's Working Party on Coal. This group provided a forum for discussion of clean coal technology market needs and technology development requirements to satisfy the needs of the Eastern European market. Throughout the year, DOE supported the U.S.-sponsored portion of International Energy Agency clean coal activities and the Asian Pacific Economic Council subgroup for clean coal technologies.

Market Communications

The CCT Program has established an outreach effort to convey information to provide an understanding that clean coal technologies can increase the efficiency of coal use and enhance environmental quality at competitive costs. Further, the outreach program underscores the commitment of the CCT Program to commercial deployment of the technologies. Specific outreach objectives include the following:

- Achieving public and government awareness of advanced coal-using technologies as viable energy options
- Providing potential technology users with information that is timely and relevant to their decision-making processes
- Creating a favorable policy and regulatory environment that recognizes the advantages of clean coal technologies
- Increasing the confidence of financial institutions that these technologies are viable options

The outreach program is implemented through mechanisms as follows: (1) publications, (2) Clean Coal Technology conferences, (3) presentations and exhibits, and (4) international trade missions. A principal method of disseminating information has been through the distribution of published material about the CCT Program and the clean coal technologies and processes being demonstrated in the projects under way. These reports include the annual *Program Update*, as well as *Comprehensive Reports to Congress* for each solicitation and for each project which has been successfully negotiated. Topical reports are prepared to highlight project events or to capture progress at particular points driven by project-specific considerations; in 1993, *Reduction of NO_x and SO₂ Using Gas Reburning, Sorbent Injection and Integrated Technology* was published. A number of project-specific design reports, economic evaluation reports, and final reports have been prepared for completed projects. Available reports for completed projects are identified in Section 5 and in Appendix C. The *Proceedings of the Second Annual Clean Coal Technology Conference* was published and distributed in November 1993. This two-volume set provides the papers presented at the plenary, panel, and technical sessions. All CCT reports are available through the National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Rd, Springfield, VA 22161. Four issues of the *Clean Coal Today* newsletter were prepared in 1993. The newsletter is distributed to approximately 3,700 domestic and international readers. In 1993, feature articles covered the early test results of the AirPol gas suspension absorption, LIFAC sorbent injection, and Southern Company

Services CT-121 projects; announcement of the selection of five new clean coal projects under CCT-V; and the successes achieved in NO_x control in cyclone and cell burners. To receive *Clean Coal*

Today, send name and address to U.S. Department of Energy, FE-22, Washington, DC 20585.

Fossil Energy TechLine is a 24-hour fax-on-demand system that can provide a wide variety of information on DOE's fossil energy programs, including the CCT Program. The TechLine system offers news announcements on clean coal projects, fact sheets for individual projects, and monthly updated status reports. To receive TechLine information, call (202) 586-4300 from a Touch-Tone phone and follow the voice instructions. For additional information, call (202) 586-6503.

The Second Annual Clean Coal Technology Conference was held in Atlanta, Georgia, in September 1993 and was cosponsored by the Southern States Energy Board. The objective of the conference was to identify and discuss in depth the factors affecting domestic and international markets for clean coal

technologies; the environmental considerations for commercial deployment; the current status of the projects; and the timing and effectiveness of transferring data to potential users, suppliers, financing entities, regulators, environmental community, and the public. The 2-day conference was attended by nearly 400 persons from 16 nations, including Bulgaria, Czech Republic, France, Hungary, Japan, Kazakhstan, Latvia, People's Republic of China, Poland, Romania, Russia, Slovakia, Ukraine, and United Kingdom.

A tour of the CT-121 project at Georgia Power Company's Plant Yates was conducted by Southern Company Services. Panel sessions provided forums for discussing issues that may influence the program, individual projects, and commercial deployment. These sessions addressed the following:

► Attendees to the Second Annual Clean Coal Technology Conference toured the 100-MWe CT-121 advanced flue gas desulfurization facility at Georgia Power's Plant Yates. At the center is the novel jet-bubbling reactor; left is the flue gas stack.

◀ The quarterly newsletter, *Clean Coal Today*, provides updates and highlights of significant project accomplishments.

- The Clean Coal Technology Market Session reviewed the planning, competitive climate, and policy factors which mold the domestic and international marketplace in which clean coal technologies must compete.
- The Clean Coal Technology Deployment/Technology Transfer/Outreach Session examined means to ensure clean coal technology transfer and approaches to enhance transfer effectiveness.
- The International Forum enabled delegations from Eastern European countries, the Newly Independent States, and Asia to discuss strategic plans for coal and potential opportunities for clean coal technologies.

The two plenary sessions addressed (1) the markets for clean coal technologies as seen from the utility, regulatory, and coal producers' perspectives and (2) the emerging issues that could impact the future deployment of clean coal technologies. In addition, the status and results from 34 projects were presented in 7 technical sessions.

During 1993, DOE made use of exhibits and presentations as a means of drawing attention to activities and benefits of the CCT Program at approximately 15 major conferences, trade shows, and other events, including two international conferences. These exhibits form a backdrop for individual and group discussions on the efficiency and environmental merits of clean coal technologies.

The CCT Program staff participated in trade missions to Eastern Europe, People's Republic of China, and Pacific Rim countries. Trade missions afford U.S. industry the opportunity to introduce

technologies and capabilities to the government and industry decision-makers in foreign countries. Industry can use these meetings to establish contacts for follow-up business discussions.

The Acting Assistant Secretary for Fossil Energy led the mission to the People's Republic of China in June 1993. Twenty-two delegates from U.S. companies representing clean coal, nuclear, and renewable technologies traveled to China to discuss market opportunities and barriers to U.S. project development with government and provincial leaders. As a result of this mission, a task force was established consisting of all the government agencies with responsibility for trade with China. The purpose of the task force is to pursue the recommendations of the industry group, including the development of a clean coal demonstration project in China.

► The Second Annual Clean Coal Technology Conference afforded domestic and international delegates the opportunity to discuss factors affecting clean coal technology markets and to receive updates on the status of the projects.

Another mission was the second U.S. Electric Power Technologies Conference for Eastern Europe. This was conducted in Budapest, September 19-22, 1993, with 20 U.S. engineering, technology, and financial firms participating. Energy officials from 14 Eastern European countries and Newly Independent States were in attendance. Four workshops were conducted: Developing a Financial Plan for Power Projects; Independent Power Production—Planning and Finance; Methodologies for Evaluating Financial Feasibility of Upgrading Existing Plants; and Advanced Power Generation Technologies. These workshops presented an opportunity for U.S. industry to discuss technologies and capabilities with foreign governments and companies and to identify potential business opportunities.

5. Results of Completed Projects

Summary

Six projects completed operations in 1993, bringing to nine the total number of projects for which operations have been completed under the CCT Program. These six projects demonstrated the following technologies:

- Three NO_x control technologies
 - Coal reburning for cyclone boiler—The Babcock & Wilcox Company*
 - Low-NO_x Cell™ burner retrofit—The Babcock & Wilcox Company*
 - 180-MWe advanced tangentially fired combustion techniques—The Southern Company Services, Inc.
- One SO₂ control technology
 - Confined zone dispersion flue gas desulfurization process—Bechtel Corporation*
- One combined SO₂/NO_x control technology
 - SO_x-NO_x-Rox-Box™ flue gas cleanup process—The Babcock & Wilcox Company*
- One industrial application technology
 - Cement kiln flue gas recovery scrubber—Passamaquoddy Tribe*

The three previously completed projects follow:

- Nucla CFB Demonstration Project—Tri-State Generation and Transmission Association, Inc., completed in 1992
- LIMB Demonstration Project Extension and Coolside Demonstration—The Babcock & Wilcox Company, completed in 1992
- Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control—Coal Tech Corporation, completed in 1991

This portfolio of completed projects is providing valuable data for addressing pressing environmental and energy issues associated with the utility and industrial use of coal.

The completed NO_x control technology demonstrations provide options for NO_x control covering a wide range of boiler types. The Babcock & Wilcox Company's coal-reburning technology, demonstrated at Wisconsin Power and Light Company's Nelson Dewey Station, exceeded expectations with more than 50 percent NO_x reduction on a 100-MWe cyclone boiler. Further, with the coal-reburning system, the boiler can be switched to low-sulfur subbituminous coal without being derated, as is normally required when switching a cyclone boiler to subbituminous coal. Thus the coal-reburning system even permits the un-derated unit to meet the Clean Air Act Amendments (CAAA) of 1990 requirements for SO₂ reduction without employing add-on sulfur emissions control technology. Wisconsin Power and

Light has retained the coal-reburning system for commercial use in the Nelson Dewey Station boiler.

The Babcock & Wilcox Company's Low-NO_x Cell™ burner was developed specifically for high-NO_x-emitting, difficult-to-control cell burners which today account for nearly 26,000 MWe of electric power in the United States. Tests of the Low-NO_x Cell™ burner at Dayton Power & Light Company's J.M. Stuart Plant showed that the technology could reduce NO_x emissions by approximately 55 percent. Based on these results, The Babcock & Wilcox Company will use the technology on two commercial boilers totaling more than 1,100 MWe at Allegheny Power System's Hatfield's Ferry Station near Masontown, Pennsylvania.

Southern Company Services, Inc., demonstrated the capability to reduce NO_x by up to 48 percent in Gulf Power Company's tangentially fired boiler located at Plant Lansing Smith, using ABB Combustion Engineering's low-NO_x concentric firing system. This NO_x control technology has potential application to the nearly 600 tangentially fired pulverized coal units in the United States.

The Bechtel Corporation completed the demonstration of the confined zone dispersion flue gas desulfurization (CZD/FGD) process. The results of the demonstration showed that SO₂ emissions could be reduced up to 50 percent at a total capital cost estimated to range from \$38 per kilowatt for a 500-MWe plant to \$62 per kilowatt for a 150-MWe plant. However, follow-on demonstration is required to fully

* Final reports to be delivered in 1994

commercialize this technology. The target market is to retrofit existing boilers, regardless of type, age, size, type of coal burned, or the coal's sulfur content.

The Babcock & Wilcox Company's SO_x-NO_x-Rox-Box™ (SNRB™) technology was demonstrated at Ohio Edison Company's R.E. Burger Plant in Dilles Bottom, Ohio. The SNRB™ technology controls SO₂, NO_x, and particulates. The technology exceeded its demonstration performance goals by achieving 80–90 percent SO₂ removal efficiency, 90 percent reduction in NO_x, and more than 99 percent particulate removal efficiency. The SNRB™ offers the potential for lower capital and operating costs and smaller space requirements than a combination of conventional control technologies.

The Passamaquoddy Tribe successfully demonstrated a flue gas recovery system on a 1,450-ton-per-day cement plant. The flue gas recovery system was used to (1) achieve 90–95 percent SO₂ reduction, (2) produce fertilizer, (3) convert the kiln waste to cement feedstock, and (4) eliminate all waste streams. This technology is applicable to over 250 U.S. cement kiln installations which emit approximately 230,000 tons per year of SO₂.

The results of previously completed demonstration projects are being used today to improve the technical, economic, and environmental performance of the technologies. For example, a commercial replication of the atmospheric circulating fluidized-bed combustion (ACFB) technology at 100-MWe scale is a direct consequence of demonstrating the technology under the CCT Program at the Tri-State Generation and Transmission Association, Inc., Nucla Station between 1988 and 1991. At the time of demonstration, the 110-MWe Nucla Station was the largest

ACFB application. As a result of the demonstration, Pyropower Corporation was able to save almost 3 years in establishing a commercial line of ACFB units. These units are now sold under warranty in sizes ranging up to 400 MWe.

Results summaries for the nine completed demonstration projects, as reported by the sponsors, follow for quick reference. Results are discussed in more detail in the project summaries provided in this section.

Demonstration of Coal Reburning for Cyclone Boiler NO_x Control (The Babcock & Wilcox Company)

Technology

Injection of pulverized coal (20–30% of total boiler heat input) into reburning zone to create oxygen-deficient condition

Size

100 MWe

Demonstration Duration

2,000 hrs (11/91–12/92)

Coals

- Illinois Basin bituminous (Lamar), 1.8% S avg
- Powder River Basin subbituminous, 0.6% S avg

Environmental Results

Coal	Reduction in NO _x		
	Boiler Load		
	110 MWe	82 MWe	60 MWe
Lamar Coal	52%	47%	36%
Powder River Coal	62%	55%	53%

Technical/Economic Results

- Combustion efficiency losses at full load due to unburned carbon—1.5% with bituminous; 0.3% with subbituminous
- ESP performance constant even though ash loading doubled (increased ash consisted of larger sized particulates)
- Derating normally associated with switching to subbituminous coal minimized or eliminated
- Significant reduction in slagging and fouling with bituminous coal reburning
- No furnace corrosion was observed over the 1-yr test

Capital cost—ranges from \$65/kW at 100 MWe to \$40/kW at 600 MWe

Full-Scale Demonstration of Low-NO_x Cell™ Burner Retrofit (The Babcock & Wilcox Company)

Technology

The Babcock & Wilcox Company Low-NO_x Cell™ burner (LNCB™) staged combustion

Size

605 MWe

Demonstration Duration

Continuous service (12/91–7/93)

Coals

KY, OH, and WV bituminous, 1.1% S avg

Environmental Results

- 605 MWe—NO_x reduction 54–58% (full load)
- 460 MWe—NO_x reduction 54%
- 350 MWe—NO_x reduction 48%

Technical/Economic Results

- Unit efficiency essentially unchanged from baseline
- Flyash unburned carbon averaged 1.12% for a 0.2% loss in unburned carbon efficiency
- Boiler corrosion with LNCB™ roughly equivalent to boiler corrosion prior to retrofit

Capital cost—\$5.50–8.00/kW at 500 MWe

180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for Reduction of NO_x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)

Technology

Levels I, II, and III of ABB Combustion Engineering's low-NO_x concentric firing system (LNCFS) which includes advanced over-fire air, clustered coal nozzles, and offset air

Size

180 MWe

Demonstration Duration

Continuous operation (5/91–12/92)

Coals

KY, IL, WV eastern bituminous, 2.5–3.0% S avg

Environmental Results

- LNCFS Level I includes a close-coupled over-fire air (CCOFA) system—37% maximum NO_x reduction at full load
- LNCFS Level II includes a separated over-fire air (SOFA) system—40% maximum NO_x reduction at full load
- LNCFS Level III includes both SOFA and CCOFA—48% maximum NO_x reduction at full load

Technical Results

- Increases in coal fineness increased unburned carbon levels; however, there was no effect on NO_x emissions
- CO emissions with LNCFS Level III were double those with LNCFS Level I, II, or the baseline case
- Minimal impact on unburned carbon
- LNCFS Levels II and III required higher excess air levels than baseline on LNCFS Level I

Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)

Technology

In-duct, confined zone dispersion flue gas desulfurization (CZD/FGD) process

Size

73.5 MWe

Demonstration Duration

Approx 5 mos continuous testing (operations 7/91–6/93)

Coals

PA bituminous, 1.5–2.5% S

Sorbents

- Dry hydrated calcitic lime
- Slaked calcitic lime
- Pressure-hydrated dolomitic lime

Environmental Results

SO₂—50% removal efficiency

Technical/Economic Results

- Drying and SO₂ absorption must take place in 2 seconds
- No deposits of fly ash or reaction products in flue gas duct during normal operation
- Process responded well to automated control operation; some process modifications are required before commercial use can be achieved
- Very good system availability

Capital cost—less than \$30/kW at 500 MWe

SOx-NOx-Rox-Box™ Flue Gas Cleanup Demonstration (The Babcock & Wilcox Company)

Project Technology

- SO₂—in-duct sorbent injection
- NO_x—injection with selective catalytic reduction (SCR) catalyst
- Particulate—high-temperature fabric bag filters

Size

5-MWe equiv slipstream from 150-MWe boiler

Demonstration Duration

2,300 hrs (5/92–5/93)

Coals

Ohio bituminous, 3.4% S avg

Sorbents

- Calcium based
 - Commercial-grade hydrated lime
 - Sugar hydrated lime
 - Lignosulfonate hydrated lime
- Sodium based
 - Sodium bicarbonate

Environmental Results

- 80% SO₂ removal efficiency with commercial-grade lime at 2.0 Ca/S (800–850 °F)
- 90% SO₂ removal efficiency with hydrated limes at 2.0 Ca/S (800–850 °F)
- 80% SO₂ removal efficiency with sodium bicarbonate at 1.0 Na₂/S (425 °F)
- 90% NO_x reduction with NH₃/NO_x ratio of 0.9 (800–850 °F)
- 99.89% particulate emissions removal efficiency

Technical/Economic Results

- SO₂ capture mechanism in form of filter cake on filter bags
- Demonstrated Norton Company's NC-300 zeolite SCR catalyst which was located in filter bag to protect against erosion
- Filter bags tested: 3M's Nextel ceramic fiber filter bags and Owens Corning Fiberglas's S-Glass filter bags

Capital cost—\$260/kW (250 MWe; 3.5% S coal; 1.2 lbs/million Btu NO_x)

Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)

Technology

Passamaquoddy Technology Recovery Scrubber™

Size

1,450 tons/day of cement; 250,000 std ft³/min of kiln gas; up to 274 tons/day of coal

Demonstration Duration

5,316 hrs (8/91–9/93)

Coals

PA bituminous, 3% S

Sorbent

Water solution/slurry containing potassium-rich dust recovered from kiln flue gas

Environmental Results

Achieved objective of 90–95% SO₂ reduction, with maximum reduction of 98%

Technical/Economic Results

- In 5-mo period, plant produced 140,000 tons of cement while scrubber removed 70 tons of SO₂ and treated 6,000 tons of kiln dust
- Scrubber became permanent part of commercial plant operation

Capital cost—\$25/ton annual cement capacity

Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.)

Technology

Atmospheric circulating fluidized-bed (ACFB) combustion

Size

925,000 lbs/hr (110 MWe)

Demonstration Duration

15,700 hrs (8/88–1/91)

Coals

Salt Creek & Peabody, 0.4–0.8% S; Dorchester, 1.4–1.8% S

Sorbent

Limestone

Environmental Results

- 70% SO₂ removal efficiency with 1.5 Ca/S (<1,620 °F)
- 95% SO₂ removal efficiency with 4.0 Ca/S (<1,620 °F)
- NO_x <0.34 lb/million Btu; avg 0.18 lb/million Btu

Technical/Economic Results

- Combustion efficiency—96.9–98.9%
- Heat rate—12,400 Btu/kWh (50% load);
11,600 Btu/kWh (100% load)

Capital cost—approx \$1.123/net kW (repower cost)

LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)

Technology

- Limestone injection multistage burner
- In-duct sorbent injection

Demonstration Duration

LIMB—3,521 hrs (4/90–8/91)

Coolside—1,716 hrs (7/89–2/90)

Size

105 MWe

Coals

OH bituminous, 1.6%, 3.0%, and 3.8% S

Sorbents

Calcitic limestone; Type-N atmospheric hydrated dolomitic lime; calcitic hydrated lime; calcitic hydrated lime with added calcium lignosulfonate (ligno lime)

Environmental Results

LIMB—61% SO₂ removal efficiency (3.8% S coal; ligno lime)

Coolside—70% SO₂ removal efficiency (hydrated lime; 2.0 Ca/S, 0.2 Na/Ca, and 20 °F approach to saturation)

Technical/Economic Results

LIMB and Coolside economically competitive with wet FGD processes—

- Up to 1.5% S coal for up to 500 MWe net
- Up to 2.5% S coal for up to 450 MWe net (LIMB),
220 MWe net (Coolside)
- Up to 3.5% S coal for up to 240 MWe net (LIMB),
100 MWe net (Coolside)
- Competitiveness increases with lower plant capacity factor and shorter book life, and as S removal requirements decrease below 70%

Capital cost—LIMB \$31–102/kW; Coolside \$69–160/kW

Annual levelized cost—LIMB \$392–791/ton SO₂ removal;
Coolside \$482–943/ton SO₂ removal

Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)

Technology

Air-cooled cyclone slagging combustor

Demonstration Duration

900 hrs (11/89–5/90)

Size

23 million Btu/hr

Coals

8 different PA bituminous, 1–3.3% S

Environmental Results

SO₂—over 80% reduction with sorbent injection;
maximum 58% reduction with limestone injection at
2.0 Ca/S

NO_x—160–184 ppm (75% reduction)

Solid waste—inert slag

Slag/sorbent retention—55–90% in combustor

Technical Results

Combustion efficiency—over 99%

Turndown—3-to-1 achieved

Materials—slag protection of materials achieved

Operability—computer-controlled system for automated combustor operation achieved

Demonstration of Coal Reburning for Cyclone Boiler NO_x Control (The Babcock & Wilcox Company)

The objective of the coal-reburning demonstration was to evaluate the applicability of the technology to full-scale cyclone-fired boilers for the reduction of NO_x emissions. The goals of the project were as follows:

- Achieve a minimum 50 percent reduction in NO_x emissions at full load
- Reduce NO_x emissions without serious impact to cyclone operations, boiler performance, or other emissions streams
- Demonstrate a technically and economically feasible retrofit technology

Cyclone-equipped utility boilers contribute approximately 21 percent of the NO_x emitted by utilities because of the inherent high-temperature, turbulent combustion process which is conducive to NO_x formation. Typically, NO_x levels associated with cyclone-fired boilers range from 1.0 to 1.8 pounds per million Btu input (NO_x as NO₂).

The coal-reburning process for cyclone boilers, demonstrated by The Babcock & Wilcox Company, controls NO_x formation in the main furnace through the use of multiple combustion zones. The main combustion zone uses 70–80 percent of the total heat equivalent of the fuel input to the boiler and slightly less than normal combustion air input. The balance of the coal (20–30 percent), along with significantly less than the theoretically determined requirement of air, is fed to the boiler above the cyclones in the reburning combustion zone to create an oxygen-defi-

cient (reducing) condition in the flue gas. The NO_x formed in the cyclone burners reacts with the reducing flue gas and is converted into nitrogen and water in this zone. The balance of the combustion air is introduced in the third, or burnout, combustion zone to complete the combustion process. Reburning is the only technology that has been shown to be technically feasible for NO_x control for cyclone boilers.

▲ Two coal-reburning burners, which successfully completed over 2,000 hours of operation, achieved NO_x reductions of over 50%.

The demonstration was conducted on an existing 100-MWe cyclone boiler in operation at Wisconsin Power and Light Company's Nelson Dewey Station located at Cassville, Wisconsin.

Operations were initiated in November 1991. Monitoring of air toxics emissions was included as part of the test program and was conducted in November 1992. Reburn testing of western coal and all testing scheduled for Nelson Dewey Station were completed in December 1992.

The primary test coal for the demonstration was an Illinois Basin bituminous coal (Lamar). The majority of the testing was performed firing this fuel as it is typical of the coal used by many utilities operating cyclones. Subbituminous Powder River Basin coal tests were performed to evaluate the effect of coal switching on reburn operation. Wisconsin Power and Light's strategy to meet Wisconsin's sulfur emission limitations as of January 1, 1993, was to fire low-sulfur coal.

Three sequences of testing of the coal-reburning system were used for Lamar coal. Parametric optimization testing was used to set up the automatic controls. Performance testing was run with the unit in full automatic control at set load points. Long-term testing was performed with reburn in operation while the unit followed system load demand requirements. Powder River Basin coal was tested by parametric optimization and performance modes. Exhibit 5-1 shows changes in NO_x emissions and boiler efficiency using the reburn system for various load conditions and coal types.

Reburning tests on both the Lamar and Powder River Basin coals indicate that varying reburn zone stoichiometry is the most critical factor in changing

Exhibit 5-1 Coal Reburning System Test Results

	Boiler Load		
	110 MWe	82 MWe	60 MWe
Lamar Coal			
NO _x (lb/million Btu/% reduction)	0.394/52%	0.387/47%	0.442/36%
Boiler efficiency losses due to unburned carbon	0.1%	0.25%	1.5%
Powder River Basin Coal			
NO _x (lb/million Btu/% reduction)	0.278/62%	0.287/55%	0.294/53%
Boiler efficiency losses due to unburned carbon	0.0%	0.2%	0.3%

NO_x emissions levels. The reburn zone stoichiometry can be varied by alternating the air flow quantities (oxygen availability) to the reburn burners, the percent reburn heat input, the gas recirculation flow rate, or the cyclone stoichiometry.

For Lamar coal, the full-, medium-, and low-load unburned carbon boiler efficiency losses (UBCL) were 0.1, 0.25, and 1.5 percent higher, respectively, than the baseline. Full-, medium-, and low-load UBCL with Powder River Basin coal were 0.0, 0.2, and 0.3 percent higher, respectively, than the baseline. Reburn burner flame stability improved with Powder River Basin coal.

During reburn system operation with Lamar coal, the operators continually monitored boiler internals for increased ash deposition and the on-line performance monitoring system for heat transfer changes. At no time throughout the system optimi-

zation or long-term operation period were any slagging or fouling problems observed. In fact, during scheduled outages, internal boiler inspections revealed that boiler cleanliness had actually improved. Extensive furnace wall tube ultrasonic thickness measurements were taken. No observable decrease in tube wall thickness was measured.

Another significant finding was that coal reburning minimizes and possibly eliminates a 10–25 percent derating normally associated with switching to subbituminous coal in a cyclone unit. This derating is a result of using a lower Btu fuel in a cyclone with a limited coal feed capacity. The reburn system transfers about 30 percent of the coal feed out of the cyclone to the reburn burners, bringing the cyclone feed rate down to a manageable level, while maintaining full-load heat input to the unit.

▲ Shown here is the coal pulverizer installed as part of the Babcock & Wilcox coal-reburn system demonstrated at Wisconsin Power and Light's Nelson Dewey Station.

Hazardous air pollutant (HAP) testing was performed using Lamar test coal. HAP emissions were generally well within expected levels, and emissions with reburn were comparable to baseline operation. No major effect of reburning on trace metals partitioning was discernible. None of the 16 targeted polynuclear aromatic semi-volatile organics (Title III, CAAA of 1990) was present in detectable concentrations, at a detection limit of 1.2 parts per billion.

In conclusion, for cyclones, coal reburning offers a NO_x reduction alternative at a cost expected to range from \$65 per kilowatt for a 100-MWe unit to \$40 per kilowatt for a larger, 600-MWe unit. This includes the costs for coal handling and pulverizers/coal piping. Site-specific factors related to pulverizer location and coal supply can greatly influence overall reburn system costs. However, coal reburning brings with it benefits allowing increased flexibility in coal selection which can yield significant fuel cost savings.

Coal reburning is a retrofit technology applicable to a wide range of utility and industrial boilers. The current U.S. reburn market is estimated to be approximately 26,000 MWe and con-

sists of about 120 units ranging from 100 to 1,750 MWe with most in the 100–300 MWe range.

The project technology has been retained by Wisconsin Power and Light for commercial use.

Available Reports

- *Public Design Report: Coal Reburning for Cyclone Boiler NO_x Control.* The Babcock & Wilcox Company. August 1991.

The final technical report and economic evaluation report are expected to be available in early 1994.

Contact

Todd Johnson, Senior Marketing Specialist
The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601
(216) 829-7355

Full-Scale Demonstration of Low-NO_x Cell™ Burner Retrofit (The Babcock & Wilcox Company)

The Babcock & Wilcox Company has completed demonstration of its Low-NO_x Cell™ (LNC™) burner technology. The objective was to demonstrate the capability of the LNC™ burner to achieve at least a 50 percent NO_x reduction without degradation of boiler performance and at less cost than conventional low-NO_x burners. Cell burners are designed for rapid mixing of fuel and oxidant. The tight burner spacing and rapid mixing minimizes the flame size while maximizing the heat release rate and unit efficiency. Consequently, the combustion efficiency is good, but the high heat release rate produces relatively large quantities of NO_x. Typically NO_x levels associated with cell burners range from 1.0 to 1.8 pounds per million Btu input (NO_x as NO₂).

To reduce NO_x emissions, the upper burner of the standard two-burner cell was replaced with a secondary air port, and the lower burner was replaced with a larger burner having the same fuel input capacity as the standard cell. The Low-NO_x Cell™ burner operates on the principle of staged combustion to reduce NO_x emissions. Approximately 70 percent of the total air (primary, secondary, and excess air) is supplied through or around the modified coal feed nozzle. The remainder of the air is directed to the upper port of each cell to delay and complete the combustion process.

The process was demonstrated at Dayton Power & Light Company's J.M. Stuart Plant located in Aberdeen, Ohio, and jointly owned with the Cincinnati Gas & Electric and Columbus Southern Power. All 24 of the 605-MWe unit's two-nozzle cell burners,

▲ Babcock & Wilcox's Low-NO_x Cell™ Burner has been successfully demonstrated at Dayton Power & Light's 605-MWe J.M. Stuart Plant. At left is the coal burner housing showing secondary air directional vanes and coal tube; in center, the opposite end of the coal burner is shown; on right (in background) is the over-fire air port with vanes open.

which were arranged in an opposed-firing configuration with two rows of six cells on each side, were replaced with LNC™ burners.

The LNC™ burner demonstration emphasized evaluation of boiler performance, boiler life, and environmental impact. Key boiler performance parameters that were measured included boiler output; flue gas temperature at the furnace, economizer, and air heater exits; slagging tendencies of the unit; and unburned carbon loss. Evaluation of H₂S levels, ultrasonic testing of lower furnace tube wall thicknesses,

▼ This view of the cell burner from inside the boiler shows the coal-fired nozzle and primary air port on the bottom and the directional secondary over-fire air vanes on top. In its first commercial sale, Babcock & Wilcox will install the LNC™ burner on Allegheny Power System's Hatfield's Ferry Station.

Exhibit 5-2 Low-NO_x Cell™ Burner Test Results

	Boiler Load		
	604 MWe	460 MWe	350 MWe
NO _x (lb/million Btu/% reduction)	0.53/54.4%	0.42/54%	0.37/48%
CO (ppm)	28-55	28-45	5-27
Unburned carbon in ash	1.12%	0.98%	3.17%
Efficiency loss due to unburned carbon	0.2%	0.17%	0.59%
Test duration (days)	79.02	—	—

and destruction examination of a corrosion test panel were mechanisms used to predict impact on remaining boiler life. NO_x, CO, CO₂, total hydrocarbons, particulate matter, dust loadings, and precipitator collection efficiency were measured at varying test conditions.

Preretrofit baseline testing was completed in November 1990. During 1991 the 24 new LNC™ burners were fabricated and installed and construction was completed during a scheduled outage that began in September 1991. Operation began in late 1991. During the early testing, high levels of CO were noted in the lower furnace, below the burners, when the unit was operated to achieve high NO_x removals. In May 1992, every other lower burner and NO_x port on the bottom rows were inverted and shallow-angled replacement impellers were installed in all of the coal nozzles to eliminate the problem. Optimization testing was completed in June 1992, with representative NO_x emissions reductions of 53-55 percent attained.

Long-term testing was completed in 1993. Results are summarized in Exhibit 5-2.

A corrosion test panel was installed when the LNC™ burners were installed. The panel consisted of bare tube material with some of the material aluminized, some stainless weld overlaid, and some chromized. Tube thickness wastage ranged from 2-15 mils per year on the bare tubes. Over a 15-month exposure period, this level of corrosion is roughly equivalent to the boiler's corrosion prior to the retrofit. The coated material had no losses. The project is now completing the final reporting requirements of the cooperative agreement.

The low cost and short outage time for a LNC™ burner retrofit make the option financially attractive. In a typical retrofit installation, the capital cost would include LNC™ burner hardware, coal-pipe modifications, hangers, support steel, sliding air-damper drives, and associated electrical equipment. The capital cost would be about \$5.50-8.00 per kilowatt in 1993 dollars for a reference 500-MWe plant.

The outage time can be as short as 5 weeks because the LNC™ burner is a plug-in design.

The domestic market potential for the LNC™ burner consists of about 26,000 MWe of utility boilers equipped with cell burners. This represents about 13 percent of the pre-NSPS coal-fired generating capacity in the United States.

The Babcock & Wilcox Company announced the first commercial sale of two Low-NO_x Cell™ burner systems to Allegheny Power System for installation at its Hatfield's Ferry Station near Masontown, Pennsylvania.

Available Reports

- *Public Design Report: Full-Scale Demonstration of Low-NO_x Cell™ Burner Retrofit.* The Babcock & Wilcox Company. August 1991.

The final technical report and economic evaluation report are expected to be available in early 1994.

Contact

Todd Johnson, Senior Marketing Specialist
The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601
(216) 829-7355

180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions for Coal-Fired Boilers (Southern Company Services, Inc.)

Southern Company Services, Inc., has demonstrated, several low-NO_x technologies on the 180-MWe, tangentially fired, Unit No. 2 coal boiler at Gulf Power Company's Plant Lansing Smith located at Lynn Haven, Florida. Technologies demonstrated included the low-NO_x concentric firing system (LNCFS), Levels I, II, and III. Each level of LNCFS used various combinations of over-fire air and clustered coal nozzle positioning to achieve NO_x reductions. With the LNCFS, primary air and coal are surrounded by oxygen-rich secondary air that blankets the outer regions of the combustion zone. LNCFS Level I used a close-coupled over-fire air (CCOFA) system integrated directly into the windbox of the boiler. A separated over-fire air (SOFA) system located above the combustion zone was featured in the LNCFS Level II system. This was an advanced over-fire air system that incorporates back pressuring and flow measurement capabilities. CCOFA and SOFA were both used in the LNCFS Level III tangential firing approach. In addition to conducting carefully controlled short-term tests, long-term testing under normal dispatch conditions were conducted. Long-term tests, which typically lasted 2-3 months for each phase, best represent the true emissions characteristics of each technology. The results presented are based on the long-term test data.

The LNCFS Level II tests completed in 1991 indicated that NO_x emissions are reduced up to 40 percent compared to baseline emissions data. Long-term data for the LNCFS Level III system show

that NO_x emissions are reduced by as much as 48 percent. Data for the Level I configuration indicate that under full-load conditions NO_x emissions are reduced by 37 percent. All testing is complete.

The operations phase, including tests to investigate the effects of low-NO_x combustion on the emissions of air toxics, was completed in 1992. These

▲ Southern Company Services demonstrated 48% NO_x reduction in a 180-MWe tangentially fired boiler at Plant Lansing Smith.

tests showed that the LNCFS had little or no impact on the emissions of air toxics. Final project reports will be completed in early 1994.

Commercial applications of this technology include a wide range of tangentially fired utility and industrial boilers throughout the United States and abroad. There are nearly 600 U.S. pulverized coal tangentially fired utility units. These units range from 25 to 950 MWe. A wide range of low-volatile bituminous through lignite coals are being fired in these units. LNCFS can be used in retrofitting existing units as well as in new boilers.

Available Reports

- *180 MW Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emission from Coal-Fired Boilers: Final Report and Key Project Findings.* Southern Company Services, Inc. December 1993.

◀ Shown from inside the boiler is one of four tangentially fired low-NO_x burner arrangements installed in each corner of the boiler.

- *180 MW Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emission from Coal-Fired Boilers: Chemical Emissions Report.* Southern Company Services, Inc. October 1993. (Draft Report.)
- *180 MW Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emission from Coal-Fired Boilers: Public Design Report.* Southern Company Services, Inc. September 1993.

Contact

Robert R. Hardman, Project Manager
Southern Company Services, Inc.
P.O. Box 2625
Birmingham, AL 35202-2625
(205) 877-7772

Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)

The objective of Bechtel Corporation's project was to demonstrate SO₂ removal capabilities of in-duct CZD/FGD technology; specifically to define the optimum process operating parameters and to determine CZD/FGD's operability, reliability, and cost-effectiveness during long-term testing and its impact on downstream operations and emissions.

The CZD/FGD process involves injecting a finely atomized slurry of reactive lime into the flue gas stream. The principle of the confined zone is to form a wet zone of slurry droplets in the middle of the duct confined in an envelope of hot gas between the wet zone and the duct walls. The lime slurry reacts with part of the SO₂ in the gas and the reactive products dry to form solid particles. An electrostatic precipitator, downstream from the point of injection, captures the reactive products along with the fly ash entrained in the flue gas.

The demonstration was located at Pennsylvania Electric Company's Seward Station in Seward, Pennsylvania. One-half of the flue gas capacity of the 147-MWe Unit No. 5 was routed through a modified, longer duct between the first and second electrostatic precipitator. Pennsylvania bituminous coal (approximately 1.2–2.5 percent sulfur) was used in the project.

Bechtel began its 18-month, two-part test program for the CZD process in July 1991, with the first 12 months of the test program consisting primarily of parametric testing and the last 6 months consisting of continuous operational testing. During the continuous operational test period, the system was operated

◀ This view of the completed CZD/FGD demonstration project located at Pennsylvania Electric's Seward Station shows the CZD/FGD bypass duct, process controls, electrostatic precipitator, and stack connection.

▶ The lime-slurry injector-control system has separate controls for each of the sorbent injector nozzles which are located inside the bypass duct.

under fully automatic control by the host utility boiler operators. Initially, the new atomizing nozzles were thoroughly tested both outside and inside the duct. The lime slurry injection parametric test program, which began in October 1991, was completed in August 1992.

The primary objectives of the project follow:

- Achieve an SO₂ removal rate of 50 percent
- Realize SO₂ removal costs less than \$300 per ton
- Eliminate negative effects on normal boiler operations without increasing particulate emissions and opacity

The parametric tests included duct injection of atomized lime slurry made of dry hydrated calcitic lime, fresh slaked calcitic lime, and pressure-hydrated dolomitic lime. All three reagents remove SO₂ from the flue gas but require different concentrations in the lime slurry for the same percentage of SO₂ removed. The most efficient and easiest to operate was the pressure-hydrated dolomitic lime. These parametric tests indicated that SO₂ removal above 50 percent under the following conditions are possible: flue gas temperature of 300–310 °F; boiler load of 145–147 MWe; residence time in the duct of 2 seconds; and lime slurry injection rate of 52–57 gallon per minute. It was determined that duct injection of slurry does not adversely impact stack opacity provided proper operational procedures are instituted.

The percentage of lime utilization in the CZD/FGD significantly affects the total cost per ton of SO₂ removed. An analysis of the continuous operational data indicates that the percentage of lime utilization is directly dependent on two key factors:

- Percentage of SO₂ removed
- Lime slurry concentration

For operating conditions at Steward Station, data indicate that, for 40–50 percent SO₂ removal, a 6–8 percent lime or dolomitic lime slurry concentration results in a 40–50 percent lime utilization rate. That is, 2–2.5 moles of CaO or CaO•MgO are required for every mole of SO₂ removed; or assuming 92 percent lime purity, 1.9–2.4 tons of lime are required for every ton of SO₂ removed. In summary, the demonstration showed the following:

- A 50 percent SO₂ removal efficiency with CZD/FGD is possible
- The process requires that drying and SO₂ absorption take place within 2 seconds. A long, straight (horizontal or vertical) gas duct of about 100 feet is required to assure residence time of 2 seconds.
- The fully automated system integrated with the power plant operation demonstrated that the CZD/FGD process responded well to automated control operation. However, modifications to the CZD/FGD are required to assure consistent SO₂ removal and avoid deposition of solids within the gas duct during upsets.
- Availability of the system was very good.
- At Seward Station, stack opacity was not detrimentally affected by the CZD/FGD system.
- Results of the demonstration indicated that the CZD/FGD process can achieve costs of \$300 per ton of SO₂ removed when operating a 500-MWe unit burning 4 percent sulfur coal.

Based on a 500-MWe plant retrofitted with CZD/FGD for a 50 percent rate of SO₂ removal, the total capital cost is estimated to be less than \$30 per kilowatt.

Bechtel is in the process of modifying the CZD/FGD process design to improve SO₂ removal during continuous operation. Once the CZD/FGD process modifications are made, a follow-on period of continuous boiler-integrated operations will be required. Bechtel is pursuing this follow-on work with the host utility, the Pennsylvania Electric Company.

Bechtel intends to commercialize the CZD/FGD process when operations have successfully concluded. The target market will be to retrofit existing boilers, regardless of type, age, size, type of coal burned, or the percentage of sulfur in the coal.

Available Reports

The final technical report and public design report are expected to be available in early 1994.

Contact

Joseph T. Newman, Project Manager
Bechtel Corporation
P.O. Box 3965
San Francisco, CA 94119-3965
(415) 768-1189

SO_x-NO_x-Rox-Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)

The Babcock & Wilcox Company completed the demonstration of the SO_x-NO_x-Rox-Box™ (SNRB™) process for the combined removal of SO₂, NO_x, and particulates in one piece of the equipment—a high-temperature baghouse. SNRB™ incorporates dry sorbent injection for SO₂ emissions control, selective catalytic reduction (SCR) for reducing NO_x emissions, and a pulse-jet baghouse operating at 450–850 °F for controlling particulate emissions.

The demonstration of the commercial-scale baghouse module was conducted on a 5-MWe equivalent slipstream from the 156-MWe boiler located at Ohio Edison Company's R.E. Burger Plant, Unit No. 5, in Dilles Bottom, Ohio. Gas tie-in was between the economizer and the combustion air heater where the flue gas temperature was approximately 600–650 °F.

Construction of the demonstration unit was completed in November 1991 and operations were completed in May 1993. The SNRB™ process was operated for approximately 2,300 hours.

The project consisted of four primary test programs:

- Base demonstration project
- Filter fabric assessment
- Alternative bag demonstration
- Air toxics emissions testing

The overall project objective was to achieve greater than 70 percent SO₂ removal and 90 percent or higher reduction in NO_x emissions while main-

taining particulate emissions below 0.03 pound per million Btu.

Four different sorbents were tested for SO₂ capture. Calcium-based sorbents included commercial-grade hydrated lime, sugar hydrated lime, and ligno-sulfonate hydrated lime. In addition, sodium bicarbonate was tested. The optimum location for

▲ In center foreground of this aerial view of Ohio Edison's R.E. Burger Plant is the site of the completed SNRB™ demonstration. The project operated for approximately 2,300 hours, achieving 80–90% SO₂ removal and 90% NO_x reduction.

injecting the sorbent into the flue gas was immediately upstream of the baghouse. Effectively, the SO_2 was captured by the sorbent while it was in the form of a filter cake on the filter bags (along with fly ash).

A summary of SO_2 removal performance follows:

- With the baghouse operating above 830 °F, injection of commercial-grade hydrated lime at Ca/S ratios of 1.8:1 and above resulted in SO_2 removals of over 80 percent.
- At a Ca/S ratio of 2:1, performance of the sugar hydrated lime and lignosulfonate hydrated lime increased performance by approximately 8 percent for an overall removal of over 90 percent.
- SO_2 removals of 85–90 percent were obtained with Ca utilizations of 40–45 percent.
- Injection of the calcium-based sorbents directly upstream of the baghouse at 825–900 °F resulted in higher overall SO_2 removal than injection further upstream at temperatures up to 1,200 °F.
- SO_2 removal of over 80 percent and 98 percent using sodium bicarbonate were achieved at Na₂/S ratios of 1:1 and 2:1 respectively at a significantly reduced baghouse temperature of 450–460 °F.
- SO_2 emissions were reduced to less than 1.2 pounds per million Btu with a 3–4 percent sulfur coal with Ca/S ratios as low as 1.5:1 and Na₂/S ratios less than 1:1.

To capture NO_x , ammonia was injected between the sorbent injection point and the baghouse. The ammonia and NO_x reacted to form nitrogen and water in the presence of Norton Company's NC-300 series zeolite SCR catalyst. With the catalyst being located inside the filter bags, it was well protected from potential particulate erosion or fouling. The sorbent reaction products, unreacted lime, and fly ash were collected on the filter bags and thus removed from the flue gas.

Key SNRB™ NO_x reduction observations from the demonstration tests follow:

- 90 percent NO_x emissions reduction was readily achieved with ammonia slip limited to less than 5 parts per million. This performance reduced NO_x emissions to less than 0.10 pound per million Btu.
- NO_x reduction was insensitive to temperatures over the catalyst design temperature range of 700–900 °F.
- Catalyst space velocity (volumetric gas flow/catalyst volume) had a minimal effect on NO_x removal over the range evaluated.
- Turndown capability for tailoring the degree of NO_x reduction by varying the rate of ammonia injection was demonstrated for a range of 50–95 percent NO_x reduction.
- No appreciable physical degradation or change in the catalyst activity was observed over the duration of the test program.
- The degree of oxidation of SO_2 to SO_3 over the zeolite catalyst appeared to be less than

0.5 percent. (SO_2 oxidation is a concern for SCR catalysts containing vanadium.)

- Leach potential analysis of the catalyst after completion of the field test showed that the catalyst remained nonhazardous for disposal.

Key observations related to SNRB™ particulate collection follow:

- Emissions were consistently below NSPS standards of 0.03 pound per million Btu, with an average over 30 baghouse particulate emission measurements of 0.018 pound per million Btu, which corresponds to a collective efficiency of 99.89 percent.
- Hydrated lime injection increased the baghouse inlet particulate loading from 5.6 to 16.5 pounds per million Btu.
- Emission testing with and without the SCR catalyst installed revealed no apparent differences in collection efficiency.
- On-line cleaning with a pulse air pressure of 30–40 pounds per square inch was sufficient for cleaning the bag/catalyst assemblies.
- Typically, one of five baghouse modules in service was cleaned every 30–150 minutes.

A comprehensive air toxics emissions monitoring test was performed at the end of the SNRB™ demonstration test program. Key characteristics of the program and test observations may be summarized as follows:

- The targeted emissions monitored included trace metals, volatile organic compounds, semi-volatile organic compounds, aldehydes, halides, and radionuclides. These species were a subset of the 189 substances identified in the CAAA of 1990. Mercury speciation measurements and measurement of dioxins and furans were unique features of this test program.
- The flue gas and solids streams were sampled at 12 locations in the host boiler, SNRB™ facility, and host plant electrostatic precipitator.
- The emissions control efficiencies achieved for various air toxics by the SNRB™ system were generally comparable to those of the conventional electrostatic precipitator at the power plant. However, the SNRB™ system did reduce HCl and HF emissions by over 90 percent, which was significantly higher than that observed for the electrostatic precipitator.
- For some sampling locations, conventional sampling methods were modified to handle higher than normal flue gas temperatures, particulate loading, and acid gas conditions.

Operation of the SNRB™ demonstration resulted in the production of approximately 830 tons of fly ash and by-product solids. An evaluation of potential uses for the by-product showed that the material might be used for agricultural liming (if pelletized). Further, the solids could potentially be used as a partial cement replacement to lower the cost of concrete.

A 3,800-hour durability test of three fabric filters was completed at the Filter Fabric Development Test Facility in Colorado Springs in December 1992. No

signs of failure were observed. All of the demonstration tests were conducted using the 3M Company Nextel ceramic fiber filter bags or the Owens Corning Fiberglas S-Glass filter bags. No excessive wear or failures occurred in over 2,000 hours of elevated temperature operation.

A preliminary evaluation has been made of the projected capital costs of the SNRB™ system for various utility boiler emissions control applications. For a 250-MWe boiler fired with 3.5 percent sulfur coal and generating 1.2 pounds of NO_x per million Btu, the projected capital cost of a SNRB™ system is approximately \$260 per kilowatt including various technology and project contingency factors. A combination of a fabric filter, SCR, and wet scrubber for achieving comparable emissions control has been estimated at \$360–400 per kilowatt. Variable operating costs are dominated by the cost of the SO₂ sorbent for a system designed for 85–90 percent SO₂ removal. Fixed operating costs primarily consist of system operating labor and projected labor and material for the hot baghouse and ash handling systems.

The Babcock & Wilcox Company is pursuing commercial applications of the technology, using the successful 5-MWe demonstration as proof of the technical feasibility of the process. Activity to date has been focused on smaller units where the cost advantages appear to be greatest. Potential applications to waste-to-energy plant emission control are also being investigated.

Available Reports

- *5 MWe SNRB™ Demonstration Facility: Detailed Design Report*. 1B. The Babcock & Wilcox Company. November 1992.

The final technical report and economic evaluation report are expected to be available in early 1994.

Contact

Todd Johnson, Senior Marketing Specialist
The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601
(216) 829-7355

▼ Workers are lowering one of the emissions-control catalyst-holder tubes into a mounting plate in the pent-house of the high-temperature baghouse.

Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)

A scrubbing system that can reduce SO_2 emissions from coal-burning cement kilns by more than 90 percent using waste kiln dust as the scrubbing reagent was demonstrated by the Passamaquoddy Tribe. The project is located in Thomaston, Maine, at Dragon Products' 470,000-ton-per-year cement plant which is owned by CDN U.S.A. The Passamaquoddy Technology Recovery Scrubber™ is a wet flue gas desulfurization process that uses alkaline waste materials as scrubbing reagent. These wastes may include fly ash, waste cement kiln dust, incinerator ash, biomass ash from wood-fired systems, and other similar wastes in solid or liquid form. Useful by-products that minimize or eliminate the need for landfill disposal of wastes are produced by the scrubbing reaction. Tipping fees for consumption of wastes produced by others, sale of useful by-products and emission credits, and "fee for service" pollution control generally allow profitable operation of the scrubbing process.

The scrubbing process was installed with minimum impact on the operating cement plant, being an "end of the pipeline" retrofit process. The only interconnect to the cement plant that could curtail operations is the physical tie-in of the flue gas handling duct. The demonstration project tie-in was made during a routine kiln shutdown with no impact on kiln operations.

The objectives of the project were to (1) design, build, and operate the recovery scrubber technology on a coal-fired wet-process cement-manufacturing

▲ This aerial view shows the process area with mixing and reactor tanks (lower left), heat recuperation system (left center), and the crystallizer and product silo (upper right). The process achieved 90-92% removal efficiency and is now a permanent part of the plant.

► These cement-mixing tanks and mixers use the calcium-based product from the SO_2 emission control process as a feedstock for cement making; the kiln is on the left.

kiln; (2) significantly reduce emissions of SO₂ from the combustion of coal; and (3) eliminate the landfilling of waste cement kiln dust.

Operations were initiated in August 1991 and logged over 1,500 hours until the unit was shut down in January 1992. In a 5-month period from May to September 1992, the plant produced approximately 140,000 tons of cement while the scrubber removed 70 tons of SO₂ and treated 6,000 tons of cement kiln dust for return to the kiln as raw feed. Long-term removal efficiency for SO₂ was 90–92 percent. For SO₂ inlet levels above 100 parts per million, the removal efficiency increased to 92–95 percent. NO_x reduction ranged between 5 and 15 percent. The removal percentage changes as kiln burning conditions change. Particulate emissions were very low because the method used for gas/liquid contact and mist elimination both lend themselves to low particulate emissions.

Cement kiln dust is consumed at the rate it is produced by the cement plant, normally 100–250 tons per day. For cement kiln dust to be useful as raw material feed, there are two primary requirements. First is that the potassium present in the waste must be removed so that it does not become part of the cement. The second requirement is that the sulfate levels in the waste must be reduced before being returned as raw feed. The potassium reacts with the flue gas to produce potassium sulfate and potassium chloride, both highly valued, marketable by-products. For example, potassium sulfate has a wholesale value of \$200–250 per ton and a retail value of up to \$400 per ton.

During the spring and early summer of 1993, the unit was on-line approximately 80 percent of the

time and recovered 85–90 percent of the cement kiln dust. The project continued through September 1993, when the scrubber became a permanent part of the Dragon facility.

The market potential for this technology is quite large. For example, there are over 250 cement kiln installations in the United States and along the St. Lawrence River in Canada emitting approximately 230,000 tons per year of SO₂. Based upon the characteristics of the technology, the applicable market would include approximately 75 percent of these installations. If the technology were installed in the applicable market facilities, the SO₂ emissions could be reduced by approximately 150,000 tons per year. In addition to the cement industry, the technology is applicable to a variety of fossil-fuel- or waste-fuel-fired facilities and can impact a number of industries including power, pulp and paper, waste incineration, and heavy industry.

Capital costs have been estimated at approximately \$25 per ton of annual cement capacity. Using a simple payback analysis for the cost and benefits of this technology, the projected payback period is less than 4 years.

Available Reports

- *Passamaquoddy Technology Recovery Scrubber™: Topical Report*. Report No. DOE/PC/89657-T1. Passamaquoddy Tribe. March 1992. (Available from NTIS as DE 9201-9868.)
- *Passamaquoddy Technology Recovery Scrubber™: Public Design Report*. Passamaquoddy Tribe. October 1993.

The final technical report is expected to be available in early 1994. An economic assessment will be conducted after project completion.

Contact

Garrett Morrison, Project Manager
Passamaquoddy Technology, L.P.
P.O. Box 350
Thomaston, ME 04861-0350
(207) 594-5555

Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.)

The primary objective of the Nucla project was to demonstrate the feasibility of atmospheric circulating fluidized-bed (ACFB) combustion technology at utility scale and to evaluate the economic, environmental, and operational benefits of ACFB steam generators at that scale. At the conclusion of testing in January 1991, this objective had been achieved. The Nucla CFB Demonstration Project was conducted by the Colorado-Ute Electric Association, Inc., the owner of the project site, Nucla Station. In 1992, Colorado-Ute Electric Association was purchased by Tri-State Generation and Transmission Association, Inc.

The original Nucla Station was built in 1959 and included three identical stoker-fired units, each rated at 12.5 MWe. Due to the plant's reduced position in the dispatch order resulting from poor station efficiency and increased maintenance costs, the decision was made to upgrade and repower the station with a new 925,000-pound-per-hour ACFB boiler and a 74-MWe turbine generator. Except for the old stoker-fired units, most of the equipment from the old plant, including the turbine-generator sets, was refurbished and reused, bringing the plant's total electrical output to 110 MWe. The project offered several advantages to the utility, including an improvement of 15 percent in station heat rate, reduced fuel costs due to the inherent fuel flexibility of the ACFB design, lower emissions than required by NSPS, and life extension of 30 years beyond that of the plant's original design.

Construction of the new ACFB boiler began in the spring of 1985 and was completed over a 2-year period. The first turbine roll was initiated in May 1987, followed in June by the first coal firing. Preparation for the test program had commenced in February 1987. Cold-mode shakedown was completed by the third quarter of 1988.

The plant had accumulated more than 15,700 hours of coal-fired operation by the end of the

▲ The 110-MWe Nucla project demonstrated the viability of CFB technology for utility applications. When it began operation in 1988, it was the world's largest CFB unit. Today, it continues in commercial operation and is now the world's sixth largest.

demonstration test program. In July 1988, the data acquisition system and software became fully operational. From August 1988 through January 1991, the plant operated with an average availability of 58.3 percent and a capacity factor of 39.6 percent, which are below national averages. (According to the North American Reliability Council Generating Availability Data System, between 1984 and 1988, non-CFB coal-fired units in the 100–199-MWe size range had average availability and capacity factors of 83.9 percent and 49.7 percent respectively.)

Several factors account for the differences in average availability and capacity factors, including the demonstration nature of the project and requirements for inspection of materials at the facility, equipment modification outages required for some nondesign fuel tests, and outages related to ACFB technology installation.

From April 1988 through June 1990, a total of 45 steady-state performance tests were completed. These tests established the effects of load, excess air, primary-to-secondary air ratio, unit operating temperatures, coal and limestone feed configurations, and coal type and size distributions on emissions performance and combustion and boiler efficiencies. Data were collected from these tests to quantify heat transfer in the combustion chambers, tubular air heat effectiveness, and baghouse collection efficiency.

Between July 1990 and January 1991, an additional 27 steady-state performance tests were conducted. These tests provided new information in areas with limited results during previous tests. As part of the alternate fuels testing, Dorchester coal was also tested. This coal had a much higher sulfur content (approximately 1.5 percent by weight) com-

pared to Salt Creek coal (about 0.5 percent) and a local Nucla coal used in earlier tests. In addition, dynamic response tests were completed at rates up to 7 MWe per minute.

In summary, a total of 72 steady-state performance tests were completed between 1988 and 1991. Of these tests, 8 were conducted on a local Nucla coal and 2 on a local Dorchester coal as part of alternate fuels testing; 62 were completed on Salt Creek coal, which was the baseline fuel used for the test program. A total of 22 tests were performed at 50 percent of full load (full load being 110 MWe), 6 tests at 75 percent, 2 tests at 90 percent, and 42 tests at full load. Except for limestone sizing tests, which were not possible with existing plant preparation equipment, all independent process variables proposed in the original test matrix were completed.

Some key results obtained during the performance of these tests, as reported by the sponsor, are as follows:

- **Emissions Performance.** Results indicated strong correlations of absolute CO, SO₂, and NO_x emissions levels with combustor operating temperatures. Although compliance was maintained within NSPS for each emission type, a penalty on limestone feed requirements for sulfur retention was realized at the higher operating temperatures. For temperatures below 1,620 °F, 70 percent retention was achieved with 1.5 Ca/S and 95 percent retention was achieved with 4.0 Ca/S. At combustor operating temperatures around 1,700 °F, Ca/S greater than 5.0 was required to maintain 70 percent sulfur capture.

The NO_x emissions for all tests completed were less than 0.34 pound per million Btu, which was well within the state-regulated emission limit of 0.5 pound per million Btu. The average level of NO_x emissions for all tests was 0.18 pound per million Btu. For fluidized-bed boilers operating well below the thermal NO_x formation temperature of about 2,500 °F, it is believed that NO_x emissions result from fuel-bound nitrogen being converted to NO_x, followed by the destruction of the NO_x in the combustor.

- **Combustion Efficiency.** The values obtained for combustion efficiency ranged from 96.9 to 98.9 percent. Combustion efficiency is a measure of the quantity of carbon that is fully oxidized to CO₂. Carbon in the fly ash was the largest source of heat loss from incomplete combustion of carbon at Nucla. The flue gas stream accounted for an average of about 93 percent of the incompletely burned carbon leaving the boiler. Another 5 percent was contained in the bottom ash stream. The contribution from CO in the flue gas averaged 2 percent. Hydrocarbons in the flue gas were measured and found to be negligible.
- **Boiler Efficiency.** Efficiencies for 68 performance tests varied from 85.6 to 88.6 percent. The contributions to boiler heat loss were identified as unburned carbon; sensible heat in dry flue gas; fuel and sorbent moisture; latent heat in burning hydrogen; sorbent calcination, radiation, and convection; and bottom ash cooling water. Net plant heat rate decreased

with increasing boiler load from 12,400 Btu per kilowatt-hour at 50 percent of full load to 11,600 Btu per kilowatt-hour at full load. The lowest value achieved during a full-load steady-state test was 10,980 Btu per kilowatt-hour. These values were affected by the absence of reheat, the presence of the three older 12.5-MWe turbines in the overall steam cycle, the number of unit restarts, and part-load testing. By October 1991, the Nucla ACFB unit had been restarted almost 175 times following various intervals of unit outage.

- **Operating Temperature.** Over the range of operating temperature at which testing was performed at Nucla, bed temperature was found to be the most influential operating parameter. With the possible exception of coal-fired configuration and excess air at elevated temperatures, bed temperature was the only parameter that had a measurable impact on emissions or efficiencies. Emissions of SO₂ and NO_x were found to increase with increasing combustor temperatures while CO emission decreased with increasing temperature. Combustion efficiency also improved as the temperature was increased.

An economic evaluation indicated that the final capital costs for the Nucla ACFB system were about \$112.3 million. This represents a cost of \$1,123 per net kilowatt. Total power production costs associated with test operations were about \$54.7 million, which results in a normalized power production cost of \$63.63 per megawatt-hour. Fixed costs were about 62 percent of the total, and variable costs were more

than 38 percent. Nucla's power production costs proved competitive with pulverized coal units not limiting emissions as significantly.

As a result of the demonstration, Pyropower Corporation was able to save almost 3 years in establishing a commercial line of ACFB units. Although the demonstration unit was the largest unit at 110 MWe, Pyropower's commercial units are now sold under warranty in sizes ranging up to 400 MWe.

Available Reports

- *Clean Coal Reference Plants: Atmospheric CFB.* Report No. DOE/MC/25177-3307. Gilbert/Commonwealth, Inc. June 1992. (Available from NTIS as DE 9300-0251.)
- *Economic Evaluation Report: Topical Report.* Report No. DOE/MC/25137-3127. Colorado-Ute Electric Association, Inc. March 1992. (Available from NTIS as DE 9300-0212.)
- *Demonstration Program Performance Test: Summary Reports.* Report No. DOE/MC/25137-3014. Colorado-Ute Electric Association, Inc. March 1992. (Available from NTIS as DE 9200-1299.)
- *Nucla Circulating Atmospheric Fluidized Bed Demonstration Project: Final Technical Report for the Period February 1987 through January 1991.* Report No. DOE/MC/25137-3046. Colorado-Ute Electric Association, Inc. October 1991. (Available from NTIS as DE 9200-1122.)

- *Nucla CFB Demonstration Project: Detailed Public Design Report.* Report No. DOE/MC/25137-2999. Colorado-Ute Electric Association, Inc. December 1990. (Available from NTIS as DE 9100-2081.)

Contact

Marshall L. Pendergraff, Assistant General Manager
Tri-State Generation and Transmission Association, Inc.
P.O. Box 1149
Montrose, CO 81402
(303) 249-4501

LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)

Limestone injection multistage burner (LIMB) technology was the product of a series of bench-scale and pilot-plant projects performed by the U.S. Environmental Protection Agency during the early 1980s. These studies were directed toward the development of relatively low-cost, moderately efficient, SO_2 and NO_x emissions control technologies for older fossil fuel-fired utility boilers. At about the same time, the Ohio Edison Company undertook a program to participate in emerging technology development to be in a better position to evaluate the technical, operational, and economic aspects of the newer emissions control technologies being developed. By 1984, the two programs led to the full-scale demonstration of the LIMB process.

In 1987, The Babcock & Wilcox Company, with cofunding from the Ohio Coal Development Office, was awarded a cooperative agreement under the CCT Program to extend the full-scale demonstration of the LIMB process. The project also provided for demonstration of the Coolside process, on induct injection technology developed by Consolidation Coal Company (also a cofunder). Both LIMB and Coolside were demonstrated on the 105-MWe coal-fired boiler at Unit No. 4 of Ohio Edison Company's Edgewater Station in Lorain, Ohio.

LIMB Extension

The primary purpose of the extension testing under the CCT Program was to demonstrate the generic applicability of LIMB technology. The LIMB process reduces SO_2 by injecting dry sorbent into the boiler at

a point above the burners. The sorbent then travels through the boiler and is removed along with the fly ash.

The extended effort, which began in April 1990, characterized the SO_2 removal efficiency for the following four sorbents:

- Calcitic limestone (CaCO_3)
- Type-N atmospherically hydrated dolomitic lime [$\text{Ca}(\text{OH})_2 \cdot \text{MgO}$]
- Calcitic hydrated lime [$\text{Ca}(\text{OH})_2$]
- Calcitic hydrated lime [$\text{Ca}(\text{OH})_2$] with added calcium lignosulfonate (ligno lime)

These tests were conducted over a range of Ca/S and humidification conditions while burning Ohio coals with nominal sulfur contents of 1.6, 3.0, and 3.8 percent by weight. Each of the different sorbents was injected while burning each of the three different coals. Other variables examined were stoichiometry, humidifier outlet temperature, and injection level. The reported results of these tests follow.

▲ Babcock & Wilcox completed operational testing of LIMB and Coolside processes on the 105-MWe unit at Ohio Edison's Edgewater Station. Shown are the humidification water tower and duct work with guillotine dampers on the roof.

▲ Water mist sprayed into the flue gas enhances sulfur capture by the sorbent by approximately 10%.

- **Effect of Coal Sulfur Content.** The sulfur content of the coal as reflected in the SO_2 concentration in the flue gas had an effect on SO_2 removal efficiency—the higher the sulfur content, the greater the SO_2 removal for a given sorbent at a comparable stoichiometry. A 5–7 percent increase in removal was noted when switching to 3.8 percent from 1.6 percent sulfur coal and injecting at a stoichiometry of 2.0.
- **Effect of Sorbent Choice.** The highest removal efficiencies, without humidification to close approach, were attained using the ligno lime. Efficiencies on the order of 61 percent were achieved while burning a nominal 3.8 percent sulfur coal. Removal efficiencies

for dolomitic lime were about 8 percent less than those for calcitic or ligno lime, at a stoichiometry of 2.0. All sorbents tested were found to be capable of removing SO_2 although calcium utilization of even finely pulverized limestone was not nearly as high as those of the limes.

- **Effect of Limestone Particle Size.** While injecting commercial limestone with 80 percent of the particles less than 44 microns in size, removal efficiencies of about 22 percent were

obtained at a stoichiometry of 2.0 while burning 1.6 percent sulfur coal. However, removal efficiencies of about 32 percent were achieved at a stoichiometry of 2.0 when using a limestone with a smaller particle size (i.e., all particles were less than 44 microns). A third limestone with essentially all particles less than 10 microns was used to determine what might be the removal efficiency limit. The removal efficiency for this very fine limestone was approximately 5–7 percent higher than that obtained at similar conditions for limestone with particles all sized less than 44 microns.

- **Effect of Injection Level.** During the design phase, it was expected that injection at the 181-foot plant elevation level inside the boiler would permit the introduction of the limestone at close to the optimum furnace temperature of

2,300 °F. Testing confirmed that injection at this level, just above the nose of the boiler, yielded the highest SO_2 removal. Injection was also performed at the 187-foot level and similar removals were observed. Removal efficiencies while injecting at these levels were about 5 percent higher than while injecting sorbent at the 191-foot level.

- **Effect on Humidification.** Removal efficiencies were enhanced by approximately 10 percent over the range of stoichiometries tested when humidification down to a 20 °F approach to saturation was used.
- **NO_x Removal.** The continued use of the low- NO_x burners resulted in an overall average NO_x emissions level of 0.43 pound per million Btu.
- **Costs.** Capital costs of LIMB are estimated to range between \$31 and \$102 per kilowatt and annual leveled costs between \$392 and \$791 per ton of SO_2 removed.

Coolside Process Studies

The generic Coolside desulfurization technology involves injection of dry hydrated lime (sorbent) into the flue gas downstream of the air preheater, followed by flue gas humidification by water sprays. The SO_2 is captured by reaction with the entrained sorbent particles in the humidifier and with the sorbent collected in the particulate removal system. The humidification water serves two purposes. First, it activates the sorbent to enhance SO_2 removal and, second, it conditions the particulate matter to maintain efficient electrostatic precipitator performance.

Spent sorbent is removed from the gas along with the fly ash in the existing particulate collector. The sorbent activity can be significantly enhanced by dissolving sodium hydroxide (NaOH) or sodium carbonate (Na_2CO_3) in the humidification water.

Sorbent recycling can be used to improve the sorbent utilization if the particulate collector can handle the resulting increased solids loading.

The demonstration of the Coolside process was conducted from late July 1989 to mid-February 1990. During that period, Boiler 13, Edgewater Unit No. 4, was burning compliance (1.2–1.6 percent sulfur) and noncompliance (2.8–3.2 percent sulfur) coals. The objectives of the full-scale test program were to verify short-term process operability and to develop a design performance database to establish process economics for Coolside. Key process variables—Ca/S, Na/Ca, and approach to adiabatic saturation—were evaluated in short-term (6–8-hour) parametric tests and longer term (1–11-day) process operability tests.

The test program demonstrated that the Coolside process routinely achieved 70 percent SO_2 removal at design conditions of 2.0 Ca/S, 0.2 Na/Ca, and 20 °F approach to adiabatic saturation temperature using commercially available hydrated lime. Coolside SO_2 removal depended on Ca/S, Na/Ca, approach to adiabatic saturation, and the physical properties of the hydrated lime. Sorbent recycle showed significant potential to improve sorbent utilization. The observed SO_2 removal with recycled sorbent alone was 22 percent at 0.5 available Ca/S and 18 °F approach to adiabatic saturation. The observed SO_2 removal with simultaneous recycle and fresh sorbent feed was 40 percent at 0.8 fresh Ca/S, 0.2 fresh Na/Ca, 0.5 available recycle, and 18 °F approach to adiabatic saturation.

The capital cost for the Coolside process is estimated to range between \$69 and \$160 per kilowatt with annual levelized cost ranging \$482–943 per ton of SO_2 removed.

An economic comparison of Coolside and wet limestone FGD processes indicated the Coolside process is economically competitive with a wet limestone forced oxidation (LSFO) FGD process for baseload boiler operations (65 percent capacity factor) under the following conditions:

- 1.5 percent sulfur coal, up to 350 MWe net
- 2.5 percent sulfur coal, up to 130 MWe net

In addition, process sensitivity analyses showed the following factors favor the Coolside process for SO_2 control:

- **Lower Boiler Capacity Factors.** The Coolside process can be characterized as a low capital cost, high operating cost process. When compared to high capital cost, low operating cost processes such as LSFO FGD, the economic attractiveness of the Coolside process increases with decreasing boiler capacity factor.
- **Lower Required SO_2 Percentage Reductions.** The base case SO_2 removals are 70 percent and 95 percent respectively for the Coolside and LSFO process. As the SO_2 removal requirement decreases below 70 percent, the Coolside process becomes more economically attractive relative to the LSFO process.

- **Shorter Remaining Boiler Life.** A shorter remaining boiler life favors the low-capital-cost Coolside process.

Available Reports

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- *Coolside and LIMB: Sorbent Injection Demonstrations Nearing Completion*. Topical Report No. 2. U.S. Department of Energy and The Babcock & Wilcox Company. September 1990.
- *Public Design Report*. The Babcock & Wilcox Company. December 1988. (LIMB/Coolside demonstration.)

Contact

Todd Johnson, Senior Marketing Specialist
The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601
(216) 829-7355

Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)

In Coal Tech's demonstration, an air-cooled cyclone combustor was retrofitted to a 23-million-Btu-per-hour, oil-designed package boiler at the Tappan-Keeler boiler factory in Williamsport, Pennsylvania. The novel features of Coal Tech's patented ceramic-lined, slagging cyclone combustor include its air-cooled walls and environmental control of NO_x , SO_2 , and solid waste emissions. Air cooling takes place in a very compact combustor which can be retrofitted to a wide range of industrial and utility boiler designs without disturbing the boiler's water-steam circuit. In this technology, NO_x reduction is achieved by staged combustion, and SO_2 is captured by injection of limestone into the combustor. The cyclonic action inside the combustor forces the coal ash and sorbent to the walls where it can be collected as liquid slag. Under optimum operating conditions, the slag will contain a significant fraction of coal sulfur. Downstream sorbent injection into the boiler provides additional sulfur removal capacity.

The test effort consisted of 800 hours of operation which included five individual tests, each of 4 days duration. An additional 100 hours were performed as part of separate ash vitrification tests. Pennsylvania bituminous coals with 1.1–3.1 percent sulfur content were used throughout the demonstration. Test results obtained during operation of the combustor indicate that Coal Tech attained most of the objectives contained in the cooperative agreement. The agreement defined 10 objectives. Accomplishments reported for each follow.

- **Objective 1—To use Pennsylvania coals with up to 4 percent sulfur content.** About eight different Pennsylvania bituminous coals with sulfur contents ranging from 1 to 3.3 percent and volatile matter contents ranging from 19 to 37 percent were tested.

▲ The demonstration of Coal Tech's advanced ceramic-lined slagging combustor was completed in 1991. Shown are the advanced combustor, associated piping, and control panel.

- **Objective 2—To achieve 70–90 percent SO₂ reduction at the stack with maximum sulfur encapsulation in the slag.** With regard to the first part of the objective, a maximum of over 80 percent SO₂ reduction measured at the boiler outlet stack was achieved using sorbent injection in the furnace at various calcium-to-sulfur molar ratios (Ca/S). A maximum SO₂ reduction of 58 percent was measured at the stack with limestone injection into the combustor at a Ca/S of 2. A maximum of one-third of the coal's sulfur was retained in the dry ash removed from the combustor and furnace hearths, and a high of 11 percent of the coal's sulfur was retained in the slag rejected through the slag tap. Further sulfur retention in the slag is definitely possible by increasing the slag flow rate, by further improvements in fuel-rich combustion, and by further improvements in sorbent-gas mixing.
- **Objective 3—To achieve NO_x reductions to 100 parts per million or less.** With fuel-rich operation of the combustor, a three-fourths reduction in measured boiler outlet stack NO_x was obtained, corresponding to 184 parts per million. An additional 5–10 percent reduction was obtained by the action of the wet particulate scrubber, resulting in atmospheric NO_x emissions as low as 160 parts per million.
- **Objective 4—To produce an inert solid waste.** All the slag removed from the combustor produced trace metal leachates well below the U.S. Environmental Protection Agency's Drinking Water Standard.
- **Objective 5—To achieve 90–95 percent slag/sorbent retention in the combustor, while meeting local stack particulate emission standards.** The second part of this objective was met with the wet venturi particulate scrubber. Total slag/sorbent retention under efficient combustion operating conditions averaged 72 percent with a range of 55–90 percent. Under more fuel-lean conditions, the slag retention averaged 80 percent. In post-CCT-project tests on flyash vitrification in the combustor, modifications to the solids injection method and increases in the slag flow rate produced substantial increases in the slag retention rate.
- **Objective 6—To achieve efficient combustion under fuel-rich conditions.** This objective was met with combustion efficiencies exceeding 99 percent after proper operating procedures were achieved.
- **Objective 7—To achieve a 3-to-1 combustor turndown.** Turndown to 6 million Btu per hour from a peak of 19 million Btu per hour was achieved. The maximum heat input during the tests was around 20 million Btu per hour, even though the combustor was designed for 30 million Btu per hour and the boiler was thermally rated at around 25 million Btu per hour. This situation resulted from facility limits on water availability for the boiler and for cooling the combustor. In fact, even 20 million Btu per hour was borderline, so that most of the testing was conducted at lower rates.
- **Objective 8—To evaluate materials compatibility and durability.** Different sections of the combustor have different materials requirements. Suitable materials for each section have been identified. Also, the test effort has shown that operational procedures are closely coupled with materials durability. In other words, by implementing certain procedures, such as changing the combustor wall temperature, it has been possible to replenish the combustor refractory wall thickness with slag.
- **Objective 9—To operate the combustor on coal for approximately 1,000 hours of steady state operations with frequent start-up and shutdown.** The combustor's total operating time during the life of the CCT project was about 900 hours. This included approximately 100 hours of operation in two other flyash vitrification tests projects. Of the total time, about one-third was with coal; about 125 tons of coal were consumed.
- **Objective 10—To develop proper combustor operating procedures.** This was the most important objective. Not only were procedures for properly operating an air-cooled combustor developed, but the entire operating data base was incorporated into a computer-controlled system for automatic combustor operation.

In conclusion, the goal of this project was to validate the performance of the air-cooled combustor at a commercial scale. While the combustor is not yet fully ready for sale with commercial guarantees, it is believed to be ready for further major scaleup to commercial-scale applications such as combustion of

waste solid fuels, limited sulfur control in coal-fired boilers, and conversion of ash to slag.

Available Reports

- *The Coal Tech. Advanced Cyclone Combustor Demonstration Project—A DOE Assessment.* Report No. DOE/PC 79799-TL. U.S. Department of Energy. May 1993.
- B. Zauderer and E.S. Fleming. *The Demonstration of an Advanced Cyclone Coal Combustor, with Internal Sulfur, Nitrogen, and Ash Control for the Conversion of a 23 MMBtu/Hour Oil Fired Boiler to Pulverized Coal; Volume 1: Final Technical Report; Volume 2: Appendixes I, II, III, IV, and V; Volume 3: Appendix VI.* Coal Tech Corporation. August 1991. (Available from NTIS as DE 9200-2587 and DE 9200-2588-T7.)

Contact

Bert Zauderer, President
Coal Tech Corporation
P.O. Box 154
Merion, PA 19066
(215) 667-0442

6. Results and Accomplishments from Ongoing Projects

Introduction

By the end of 1993, the CCT Program consisted of 45 projects. A total of 9 projects have successfully completed operations and fulfilled all reporting requirements or are preparing the final project documentation. An additional 14 projects are in the operations phase, 2 are in the construction phase, 15 are in the design and project definition phase, and 5 CCT-V projects are currently in negotiation of cooperative agreements.

The true measure of the CCT Program's success will be the degree to which the clean coal technologies are adopted in the energy marketplace. The majority of the projects involve demonstrations at fully commercial scale, providing the opportunity for the participants to leave the technologies in place and continue operation as part of their strategy to comply with the Clean Air Act Amendments (CAAA) of 1990.

The number of complex, capital-intensive projects put in place is unprecedented, as is the degree of cost-sharing achieved in this cooperative government and private sector technology development program. With the government serving as a risk-sharing partner, industry funding has been leveraged to create jobs, improve the environment, reduce the cost of compliance with environmental regulations,

reduce the cost of electricity, improve power generation efficiencies, and position U.S.-based industry to export more services and equipment.

In this section of the *Program Update*, the status for each of the projects is summarized, and highlights of the results and accomplishments are presented for those projects now in operation or which initiated construction in 1993. (See Exhibits 6-2 through 6-5 for the status of each CCT project.)

Underlining the premise that success of the CCT Program depends on adoption of the technologies in the energy marketplace, project information is organized within four major product markets—advanced electric power generation, environmental control devices, coal processing for clean fuels, and industrial applications. Thus, the program can be viewed from a market perspective.

Advanced Electric Power Generation

Fifteen projects, with a total estimated cost to completion of over \$4.7 billion, involve advanced electric power generation. These projects represent approximately 1,200 MWe of new capacity and 800 MWe of repowered capacity. One project, the Nucla CFB Demonstration Project (110 MWe), in

Nucla, Colorado, completed operations in 1991 and final project documentation in 1992 (see Section 5). The Tidd PFBC Demonstration Project (70 MWe) continued its highly successful operations at Brilliant, Ohio. To date the plant has accumulated more than 5,500 hours of operation on coal and more than 1,800 hours of operation with hot particulate recovery filters on a slipstream of product gas. The Wabash River Coal Gasification Repowering Project (262 MWe), in West Terre Haute, Indiana, commemorated the beginning of construction on July 7, 1993. Operation of the repowered plant is expected to begin in August 1995. Eight other projects are in design; four CCT-V projects are in negotiation.

Advanced electric power generation technologies are characterized by high thermal efficiency, very low SO₂ and NO_x emissions, reduced CO₂ emissions and solid waste problems, and enhanced economics. The technologies are also quite flexible and will process a very wide range of carbonaceous fuels. In repowering situations, station capacity can be increased up to 150 percent.

Approximately 3 years of pioneering work have been accomplished at the Tidd PFBC Demonstration Project, leading to the establishment of a sound database for the first U.S. application of pressurized fluidized bubbling-bed combustion (PFBC). Initial objectives have been achieved and operation now is directed at further enhancing performance of the technology.

Exhibit 6-1 Highlighted CCT Projects, by Application Category

Project and Sponsor	Page
Advanced Electric Power Generation	6-1
Tidd PFBC Demonstration Project (The Ohio Power Company)	6-3
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	6-4
Environmental Control Devices	6-5
Evaluation of Gas Reburning and Low-NO _x Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)	6-6
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)	6-7
Demonstration of Selective Catalytic Reduction Technology for the Control of NO _x Emissions from High-Sulfur-Coal-Fired Boilers (Southern Company Services, Inc.)	6-8
10-MW Demonstration of Gas Suspension Absorption (AirPol, Inc.)	6-9
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	6-10
LIFAC Sorbent Injection Desulfurization Demonstration Process (LIFAC-North America)	6-11
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	6-12
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	6-13
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)	6-14
Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Corporation)	6-15
Integrated Dry NO _x /SO ₂ Emissions Control System (Public Service Company of Colorado)	6-16
Coal Processing for Clean Fuels	6-17
Development of the Coal Quality Expert (ABB Combustion Engineering, Inc. and CQ, Inc.)	6-18
Advanced Coal Conversion Process Demonstration (Rosebud SynCoal Partnership)	6-19
ENCOAL Mild Coal Gasification Project (ENCOAL Corporation)	6-20
Industrial Applications	6-21

Six different approaches to the highly efficient and environmentally clean integrated gasification combined-cycle (IGCC) technology are in various stages in the path toward full-scale commercialization. The projects cover a broad spectrum of gasifier types, coal feedstocks, gas cleanup systems, and operating conditions to satisfy various market situations.

The bulk of the projects in this market application category will not have operating data until the latter half of the 1990s. However, discussions with utilities and analyses of utility integrated resource plans and annual reports indicate this schedule is compatible with most utility expansion plans. Major baseload capacity increases are projected to begin about 2005 and extend well beyond 2010, requiring decisions on available options to take place beginning around the year 2000. For those considering repowering of existing facilities to meet the stringent year 2000 Phase II emissions requirements under the CAAA of 1990, sufficient information should be available on most technology options to assist the decision-making process.

Tidd PFBC Demonstration Project (The Ohio Power Company)

In the Tidd PFBC Demonstration Project, which is being directed by the American Electric Power Service Corporation and conducted by the Ohio Power Company, the Unit 1 boiler of Ohio Power's Tidd Plant was replaced with a 70-MWe PFBC combined-cycle system. The PFBC technology is expected to reduce SO₂ emissions by at least 95 percent and NO_x emissions by 70 percent.

During 1993 more than 2,000 hours of coal-fired operation were achieved, bringing the cumulative total since February 1991 to more than 5,500 hours. SO₂ emissions reductions of about 93 percent and NO_x emissions levels of 0.15–0.18 pound per million Btu—well below NSPS requirements—were routinely achieved.

Onstream time has steadily increased since initial problems in the coal preparation and cyclone ash-removal systems were corrected during the first year of operation. There was a prolonged outage from February to late June 1993 caused by blade failures in a low-pressure turbine. Parametric testing is now under way to collect data on process set points for use of limestone as a sorbent in lieu of dolomite, and to economically obtain 95 percent SO₂ capture.

The unit has been modified to route one-seventh of its flow of hot flue gases through advanced ceramic hot-gas filtration elements. Approximately 1,800 hours of operation with hot-particulate filters have been achieved. Plant operation is currently scheduled to be completed in 1994.

◀ In operation since February 1991, the Tidd PFBC combined-cycle system detailed in this diagram has routinely achieved 93% SO₂ reductions and NO_x emissions of 0.15–0.18 lb/million Btu. American Electric Power Company was awarded *Power Magazine's* 1991 Powerplant Award for the Tidd demonstration project, and in 1992 the company received a National Energy Resource Organization award for demonstration of energy efficient technology.

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Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)

The Wabash River Coal Gasification Repowering Project will demonstrate utility repowering with Destec Energy's two-stage, oxygen-blown IGCC system. The plant will be the largest single-train IGCC plant in the United States when operational. One of six units at PSI Energy's Wabash River Generating Station located in West Terre Haute, Indiana, is being repowered with the addition of gasification, cold-gas cleanup, by-product sulfur recovery, combustion turbine, and associated heat recovery steam generation systems.

The new combustion turbine will generate 192 MWe and the existing steam turbine will generate an additional 104 MWe (262 MWe net) of electricity using 2,544 tons per day of high-sulfur, Illinois Basin bituminous coal. This is an increase of more than 150 percent in unit capacity. The anticipated heat rate for the repowered unit is approximately 9,000 Btu per kilowatt-hour (33 percent thermal efficiency), or a 21 percent increase in station efficiency. SO_2 emissions are expected to be less than 0.2 pound per million Btu (98 percent reduction). NO_x emissions are expected to be less than 0.1 pound per million Btu (90 percent reduction).

The cooperative agreement was signed on July 28, 1992, and the NEPA process was completed in May 1993. All required environmental permits have been granted. On July 7, 1993, the commencement of construction was celebrated at the project site. Construction is expected to be complete by August 1995 and will be followed by a 36-month demonstration period.

◀ This view of site excavation for Destec Energy's two-stage, oxygen-blown IGCC system shows the gasification island and gas turbine housing in the center and PSI Energy's Wabash River Generating Station in the background.

▶ The artist's conception of the Wabash River Coal Gasification Repowering Project shows details of the gasification facility and the gas turbine building with stack.

Environmental Control Devices

The environmental control devices category includes the largest number of projects, 19; their total value is about \$686 million. These projects represent approximately 1,700 MWe of NO_x control, 770 MWe of SO₂ control, and 765 MWe of combined SO₂/NO_x control technology demonstrations. One project, the LIMB Demonstration Project Extension and Coolside Demonstration, has successfully completed the requirements of the cooperative agreement. Five projects completed operations in 1993 and participants are now preparing the final reports. Ten projects are operational, one is in construction, and two are in the advanced stages of design.

The projects are demonstrating technologies for SO₂ and NO_x emissions control and for combined SO₂/NO_x control. General characteristics of the technologies include application for retrofit of existing facilities or new electricity generation plants, high emissions-reduction efficiency, reduced capital costs through the use of innovative designs, and mitigated or eliminated solid waste management problems. Additionally, 14 of the projects are implementing hazardous air pollutant monitoring regimes.

Most of these projects will have documented their operating experience by 1995. Sources indicate that the January 1, 1995, SO₂ emission reduction targets for Phase I of the CAAA of 1990 will be met largely by fuel switching, but there are numerous low-capital-cost SO₂ control options for older, smaller boilers available as a result of the program, and it appears that there may be a significant export market for these technologies. The program has also

made available a number of technologies for the more stringent Phase II SO₂ limits which will require solutions of a more technological nature. Two advanced flue gas desulfurization technologies are routinely achieving over 95 percent capture of SO₂ and producing wallboard-grade gypsum as a by-product instead of solid waste for disposal.

Almost all of the NO_x control projects had completed testing by the end of 1993. The utility sector requires answers now on how to solve the problems of NO_x emissions control and the CCT Program along with project sponsors are in the process of responding. Six NO_x control technologies covering the

full range of boiler types have concluded operation or are in the latter stages of operation. Three of these systems have been adopted for commercial application by the demonstration project host utility. Also, at this time, one commercial sale of Low-NO_x Cell™ burners by The Babcock & Wilcox Company has taken place outside of the host utility.

Several combined SO₂/NO_x control systems are exceeding design goals. For example, the SNOX™ technology is routinely achieving 96 percent SO₂ reduction and 94 percent NO_x reduction while producing 93 percent pure sulfuric acid for sale and no solid waste generation.

◀ The successes of CCT projects are earning industry recognition. *Power Magazine* presented Northern Indiana Public Service Company its 1993 Powerplant Award based on Pure Air on the Lake's project at Bailly Generating Station. In 1991 Tidd won the award. Projects also have received environmental and engineering awards.

Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)

Energy and Environmental Research Corporation is evaluating gas reburning and low-NO_x burners on a wall-fired boiler at Public Service Company of Colorado's 172-MWe Cherokee Station, Unit No. 3. This demonstration, located near Denver, Colorado, is using western bituminous coals.

Gas reburning involves firing natural gas (up to 20 percent of total fuel input) above the main coal combustion zone in a boiler to create a slightly fuel-rich zone. NO_x rising from the lower region of the furnace is "reburned" in this zone and converted to harmless nitrogen. Low-NO_x coal burners suppress the production of NO_x by staging the combustion process. The combined effect of adding a reburning stage to wall-fired boilers equipped with low-NO_x burners is expected to lower NO_x emissions by 70 percent or more.

Optimization of the gas-reburning unit started in late September 1992. Baseline testing with all 16 low-NO_x burners in operation was successfully completed in December 1992. Baseline tests were performed at varying loads—150 MWe, 120 MWe, 80 MWe, and 60 MWe. Parametric studies started in October 1992 and were completed in April 1993. Preliminary analysis indicated NO_x reductions of up to 70 percent at 150 MWe. Long-term 1-year load-following operations started in May 1993. Long-term operations will be completed in 1994.

The typical NO_x reduction has been 65 percent in the long-term, load-following operation without automatic excess air control. The NO_x reduction re-

mains fairly constant when natural gas is decreased from 18 to 10 percent of the total heat input. Both CO and CO₂ emissions from low-NO_x burner operation are reduced by gas reburning.

By the end of 1993, the Cherokee systems had been operated for more than 3,600 hours, including more than 2,700 hours of combined gas reburning, low-NO_x burner operation. No impacts on boiler thermal performance have been observed.

▲ This low-NO_x burner capable of firing gas or coal has been installed in the bottom level of the boiler; all feed lines are in place. Testing during 1993 indicated NO_x reductions up to 70% at 150 MWe.

◀ A worker inspects the new support ring and gear drives for the low-NO_x burner to be installed in the boiler wall.

Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)

Southern Company Services is conducting sequential demonstrations of four advanced NO_x control technologies applicable for retrofitting wall-fired, pulverized-coal boilers: (1) advanced over-fire air (AOFA), (2) second generation low- NO_x burners (LNB), (3) combined AOFA/LNB, and (4) advanced low- NO_x digital control system. The demonstration is being accomplished with a single furnace, which is the 500-MWe Unit No. 4 subcritical, wall-fired boiler at Georgia Power Company's Plant Hammond, located in Coosa, Georgia.

The baseline test segments for AOFA, LNB, and combined AOFA/LNB are complete. More than 80 days of AOFA operating data collected indicated that NO_x reduction of 24 percent is achievable under normal long-term conditions depending upon load. Analysis of the 94 days of LNB long-term data collected showed the full-load NO_x emission levels to be approximately 0.65 pound per million Btu. This NO_x level represents a 48 percent reduction when compared to the baseline, full-load value of 1.24 pounds per million Btu. These reductions were sustainable over the long-term test period and were consistent over the entire load range. Full-load values of flyash loss on ignition in the LNB configuration were near 8 percent, compared to 5 percent for the baseline. Results from the recently completed combined AOFA/LNB testing indicate that full-load NO_x emissions are approximately 0.40 pound per million Btu (69 percent reduction) with a corresponding value for flyash loss on ignition of near 8 percent.

However, preliminary analysis of the emissions data suggests that the incremental NO_x reduction effectiveness of the AOFA system (above LNB alone) was approximately 17 percent, with additional reductions resulting from other operational changes.

Configuration of the digital control system is nearing completion and modification of the Hammond Unit 4 control room is continuing. Following evaluation of advanced control and optimiza-

tion software packages, a core technology has been selected. Hammond Unit 4 emissions and operating characteristics are now being modeled using this package.

Air toxics testing with AOFA/LNB testing has been completed and a report on this work will be released by early 1994.

Completion of operations and issuance of the final report is scheduled for December 1994.

▲ Workers jockey a low- NO_x burner into place in the boiler wall. Testing of these burners with advanced over-fire air during 1993 resulted in NO_x emissions of about 0.40 lb/million Btu at full load.

▼ Foster Wheeler split-flow, split-flame low- NO_x burners await installation in the staging area.

Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers (Southern Company Services, Inc.)

The Southern Company Services, Inc., is demonstrating selective catalytic reduction (SCR) technology which consists of injecting ammonia into boiler flue gas and passing it through a catalyst bed where NO_x and ammonia react to form nitrogen and water vapor. The demonstration facility, located at Gulf Power Company's Plant Crist near Pensacola, Florida, consists of three 2.5-MWe-equivalent SCR reactors and six 0.2-MWe-equivalent SCR reactors, supplied by a total of nine flue gas slipstreams. These reactors are expected to produce the necessary design data for scaling up the SCR process to commercial utility size.

Construction began in March 1992 and was completed in February 1993. Commissioning tests without catalysts began the first week of March 1993, and the 2-year operations phase began on July 1, 1993.

Upon completion of the initial parametric testing in December 1993, baseline ammonia slip measurements were repeated. These tests were completed during December 1993 and the results indicate all catalysts were performing well at the targeted NO_x removal rates with slip less than 2 parts per million under baseline conditions (80 percent NO_x removal) and in many cases the measured slip was below the 1-part-per-million detection limit.

▼ This close-up of the SCR process area shows the heat exchangers for the large reactors and the three particulate collection cyclones on the bottom of the system.

▲ This view of the SCR process during construction shows the large insulated reactors on the top four levels, with the heat exchangers below and the cyclones at the bottom.

10-MW Demonstration of Gas Suspension Absorption (AirPol, Inc.)

AirPol, Inc., is demonstrating the gas suspension absorption (GSA) system. It consists of a vertical reactor in which flue gas comes into contact with suspended solids consisting of lime, reaction products, and fly ash. The solids exit the top of the absorption tower and pass through a cyclone and electrostatic precipitator before being discharged to the atmosphere. About 99 percent of the solids are recycled to the tower and the balance is withdrawn for disposal. GSA has the potential for greater than 90 percent SO_2 removal with increased lime utilization efficiency.

The demonstration is taking place at the Tennessee Valley Authority's National Center for Emissions Research in West Paducah, Kentucky, on a 10-MWe slipstream from a 150-MWe coal-fired boiler.

Construction started during mid-1992, and start-up began in October 1992. Optimization testing started in February 1993 and ended in August 1993. The major variables examined were approach-to-adiabatic-saturation temperature, calcium-to-sulfur ratio, flyash loading, coal chloride level, flue-gas flow rate, and recycle screw speed. The test concluded that the order of importance of these variables is (1) calcium-to-sulfur ratio, (2) approach-to-adiabatic-saturation temperature, and (3) coal chloride content.

The GSA system was able to operate at an 8 °F approach to saturation temperature at the low-chloride condition without any indication of plugging. This is an outstanding feature given the very low flue gas residence time in the reactor/cyclone.

Test results during a 28-day demonstration run indicate that GSA is capable of consistently maintaining 90 percent SO_2 removal at a moderate lime requirement. The GSA has also demonstrated high availability during the test period.

Air toxics testing was conducted during October 1993. The results showed that a removal rate of over 95 percent could be achieved.

An economic evaluation of the GSA process, conducted by Raytheon Engineers and Constructors, concluded that on the basis of a 300-MWe coal-fired boiler plant, the capital and operating costs for the GSA process were 31 percent and 20 percent less, respectively, than the corresponding costs for a limestone forced oxidation system.

Because of the favorable results obtained from the demonstration program, the Tennessee Valley Authority is evaluating the possibility of retrofitting a full-scale GSA unit to a 150-MWe coal-fired boiler.

FLS miljö, AirPol's parent company in Denmark, has been awarded a major project for a high-performance SO_2 removal GSA system. The GSA unit will be used to remove sulfur from the flue gas of a 4-million-ton-per-year iron ore processing plant in Sweden. The test results from the CCT Program's 10-MWe GSA demonstration project convinced the Swedish company that GSA is capable of achieving high- SO_2 -removal efficiency, which led to the award decision.

▲ This view of the Airpol GSA process area at the National Center for Emissions Research shows the GSA reactor and cyclone enclosure to the right of the Center's electrostatic precipitator and stack. To the far right is a duct for the 10-MWe slipstream from TVA's Shawnee Unit 9.

Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)

The CT-121 process is being demonstrated at Georgia Power Company's Plant Yates near Newnan, Georgia, on the 100-MWe Unit No. 1 with several design improvements. The scrubbing vessel uses an innovative jet-bubbling reactor (JBR) constructed solely of fiberglass-reinforced plastic (FRP) to avoid traditional wet-scrubbing corrosion problems. All of the scrubbing chemistry reactions (limestone dissolution, SO_2 absorption, SO_3 neutralization, sulfite to sulfate oxidation, sulfate precipitation/crystal growth) occur in the JBR. Testing will address simultaneous particulate removal by the JBR. Using FRP instead of stainless or lined steel and the lack of a spare scrubbing vessel may have economic advantages over other wet scrubbing systems. Other flue gas desulfurization parameters will be measured, including power consumption, limestone utilization, itemized maintenance requirements, and aerodynamic design additions to the FRP chimney.

Construction was completed in October 1992, and start-up activities began immediately afterward. Experience has been very good with almost no off-line time attributable to the scrubber during the more than 1 year of operation. Cumulative availability and reliability are both 98 percent. Over 7,500 hours of successful operation have been logged.

At inlet SO_2 levels of about 2,000 parts per million, the CT-121 system easily removes more than 90 percent of the SO_2 at all loads with near 100 percent limestone utilization. The process is capable of achieving virtually any desired SO_2 removal efficiency by varying selected process conditions.

During a recent performance test, 98 percent SO_2 removal efficiency was achieved. Continuous emissions and flow monitors were calibrated and certified in November 1992 and recertified in October 1993; the data collection system is compiling data every 15 seconds on over 140 data points.

The calcium sulfate produced has been placed in a Hypalon-lined gypsum "stacking" area for the development of an above-ground gypsum stack similar to those found in the phosphate fertilizer industry. Observations show no evidence of acidic "rain out" from the FRP wet chimney, indicating that the static flow-control modifications in the chimney elbow are working as expected. DOE-sponsored supplemental air toxics sampling was done in mid-1993 but results will not be available until 1994. Late in 1993, testing on an alternate limestone demonstrated the flexibility of the CT-121 process. Early in 1994 a higher sulfur coal (less than 4 percent sulfur) will be tested. The ESP will be de-energized in stages in early 1994 for the last year of operation in order to evaluate the particulate removal capability of the scrubber under high particulate loading conditions.

Plant Yates received an environmental award in August from the Georgia Chamber of Commerce, based on the success of the CT-121 scrubber.

▲ This aerial view shows the backside of the CT-121 process area (left of stack in foreground), with the Chattahoochee River in the background. The CT-121 process can remove over 90% of the SO_2 at all loads with nearly 100% limestone utilization. In 1993 the Georgia Chamber of Commerce presented its environmental award to Plant Yates based on the scrubber's success.

LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC-North America)

The LIFAC technology for desulfurization is applicable to power plants that have space limitations and use high-sulfur coals. The process is designed to remove 75–85 percent of the SO_2 from the flue gas while producing dry solid waste suitable for disposal in a landfill.

Pulverized limestone is blown into the upper part of the boiler near the superheater. Some SO_2 is immediately captured, and the limestone is calcined into lime (calcium oxide) for additional capture of SO_2 downstream in the activation, or humidification, reactor. The activation chamber is a vertical vessel equipped with water sprays for humidification of the flue gas to enhance SO_2 capture. After leaving the chamber, the sorbent and fly ash are separated from the flue gas in the electrostatic precipitator. To increase efficiency of absorption, about 25 percent of the unreacted sorbent is recycled back through the reactor.

LIFAC-North America is demonstrating its sorbent injection process at Richmond Power and Light's Whitewater Valley Station located in Richmond, Indiana; the 60-MWe Unit No. 2 has been retrofitted for the demonstration.

Construction of the LIFAC unit was completed in June 1992, and shakedown operations began in July. Baseline testing was completed in August 1992. Parametric testing, first attempted in September 1992, was delayed until March 1993 to resolve mechanical and electrical problems. After LIFAC operations were initiated, opacity levels above ac-

ceptable limits were observed. Tests showed the opacity levels were due to reduced ash resistivity caused by lower operating temperatures in the electrostatic precipitator, resulting from humidification of the flue gas in the activation reactor. Bypassing a portion of the flue gas maintains the electrostatic precipitator's operating temperature above 200 °F, resulting in acceptable opacity levels. Results from operations indicate SO_2 reductions in the boiler of 20–30 percent and reductions in the reactor of an additional 40–55 percent, yielding overall SO_2 reductions up to 85 percent.

Parametric testing was completed at the end of December 1993. Optimization testing is scheduled to begin in early 1994.

▲ The LIFAC reactor is shown after the top section was lifted into place. LIFAC parametric testing during 1993 yielded overall SO_2 reductions of 80–85%.

◀ In this aerial view of the Whitewater Valley Station, the LIFAC reactor is on the far side of the plant; lime storage silos and the sorbent preparation and transport building are in the foreground.

Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)

Pure Air on the Lake, L.P., is demonstrating a commercial-scale, advanced wet limestone scrubber process which is treating all of the flue gas from two boilers (528 MWe total) at Northern Indiana Public Service Company's Bailly Generating Station located in Chesterton, Indiana. This is the largest absorber module in the United States and is designed to remove 90–95 percent or more of the SO_2 in the flue gas while producing a salable, commercial gypsum by-product. The project is also testing a "zero-discharge" design.

The absorber performs three functions in a single vessel: prequenching, absorption of SO_2 , and oxidation of sludge to gypsum. In the cocurrent absorber, the flue gas and scrubbing slurry move in the same direction and at a relatively high velocity compared to conventional scrubbers. The overall advanced design results in a scrubber that is more compact and less expensive than a conventional scrubber. Other process features include injection of dry pulverized limestone directly into the absorber, an air rotary sparger that combines the functions of stirring and air distribution to oxidize the calcium sulfite to gypsum, and a novel wastewater evaporation system that can provide for a zero-discharge design. For the demonstration project, about two-thirds of the wastewater generated will be processed using this wastewater evaporation system to achieve zero discharge.

The project also is demonstrating a novel business concept whereby Pure Air on the Lake owns and operates the facility, relieving the utility of the re-

sponsibility for operations. Following successful demonstration of the process, Pure Air will continue to own and operate the facility for an additional 17-year period under contract to the utility.

The advanced flue gas desulfurization system began operations in June 1992 and, operating at full capacity, is reducing SO_2 emissions by up to 95 percent and producing 96–97 percent pure gypsum. The gypsum by-product is being sold to a local wallboard manufacturer. In 1 year, enough gypsum is produced to make enough wallboard for 19,000 homes.

During 1993, tests were conducted on coals with 3.5–4 percent sulfur and coals with 2.5–3 percent sulfur. Reliability has been extremely high with only 7 hours of down time for the full year. Additionally, air toxics measurements were completed.

During 1994, operations will continue, with commencement of wastewater evaporation and PowerChip™ gypsum agglomeration. The project is expected to be completed by late 1995.

This project earned the Bailly Generating Station *Power Magazine's* 1993 Powerplant Award. It was also named an Outstanding Engineering Achievement by the National Society of Professional Engineers.

▲ This side view shows the SO_2 absorber tank and duct work, with the new 480-ft stack in the background. Pure Air on the Lake's absorber module at Bailly Generating Station is the largest module in the United States. Pure Air's award-winning system, operating at full capacity, is reducing SO_2 emissions by up to 95% and producing 96–97% pure gypsum as a salable by-product.

SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)

The SNOX™ process being demonstrated by ABB Environmental Systems begins with high-efficiency particulate removal from the flue gas in a fabric filter baghouse to minimize cleaning frequency of downstream catalysts, followed by reheating of the gas, catalytic reaction of NO_x with ammonia to produce harmless nitrogen and water, catalytic oxidation of SO₂ to SO₃ in another reactor, and hydrolysis of SO₃ to sulfuric acid with recovery of the acid in a glass-tube condenser.

The SNOX™ facility, located at Ohio Edison Company's Niles Station, Unit No. 2, in Niles, Ohio, is treating a 35-MWe equivalent flue gas slipstream from a boiler fired with 3.4 percent sulfur coal.

A dedication ceremony for the facility was held on October 17, 1991. Operation of the demonstration plant started in early March 1992 and continued through 1993.

The facility has routinely operated at full capacity, achieving removal efficiencies of 96 percent for SO₂, 94 percent for NO_x, and 99.9 percent for particulates. The unit is producing 93 percent pure sulfuric acid at a rate of 28 tons per day. The sulfuric acid is sold for industrial use. Hazardous air pollutant monitoring also was conducted in 1993. Removal efficiencies for these hazardous air pollutant elements were determined for the SNOX™ baghouse and for the entire SNOX™ process. The results indicate that most elements had removal efficiencies that exceeded 99 percent for both cases. The species measured include 5 major and 16 trace elements, such as

mercury, chromium, cadmium, lead, selenium, arsenic, beryllium, and nickel.

At the end of 1993, the system had operated more than 5,700 hours, producing approximately 3,800 tons of sulfuric acid as a salable by-product. The host utility, Ohio Edison Company, has decided that the SNOX™ project has performed so well that the equipment will become a permanent part of the power plant's pollution control systems.

▼ The SCR process for NO_x control is enclosed in the structure on the left. To the right of the gas-to-gas heat exchanger (center) are the flue gas duct and fan. During routine, full-capacity operation, NO_x reductions of 94% are being achieved.

◀ In this side view of the sulfuric acid condenser, the breather tube is in the foreground and the sulfuric acid pumps are visible under the condenser. SO₂ reductions of 96% are being achieved; 93% pure sulfuric acid is a salable by-product. Ohio Edison has decided to make the SNOX™ process a permanent part of Niles Station's pollution control system.

Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)

Energy and Environmental Research Corporation is demonstrating its gas reburning and sorbent injection process on two separate boiler configurations—a tangentially fired boiler and a cyclone-fired boiler. The process is applicable to over 900 pre-NSPS utility boilers in the United States.

A matrix of 32 gas reburn tests have been completed on the tangentially fired 80-MWe boiler at the Illinois Power Company's Hennepin Plant in Hennepin, Illinois. NO_x reductions of up to 77 percent were achieved. Evaluation of 20 over-fire air tests indicated substantial NO_x reduction was achievable at low power generation loads, with lesser reductions as load increased.

Combined operational testing of gas reburning and sorbent injection began in August 1991, and during 1992 the unit was turned over to Hennepin Plant personnel for routine operation under load-following conditions. Long-term load-following demonstration testing was completed in January 1993.

During testing, gas reburning has routinely reduced NO_x emissions by 65 percent, which exceeds the project objective of 60 percent. Sorbent injection has routinely reduced SO_2 emissions by 52–62 percent, which exceeds the project objective of 50 percent at a Ca/S ratio of 1.75.

After review of the operational performance, boiler impacts, and economics, Illinois Power has decided to retain the gas-reburning system at Hennepin for possible use in 1995 for NO_x control.

Three proprietary sorbents (including PromiSorb A, PromiSorb B, and High Surface Area Hydrated

Lime) were also tested at Hennepin. These sorbents showed higher SO_2 capture and higher calcium utilization than the regular hydrated lime.

The gas reburning and sorbent injection process reduces not only NO_x and SO_2 emissions but also CO_2 , HCl, and HF emissions. During sorbent injection, particulate emissions were reduced by flue gas humidification upstream of the ESP.

The systems installed at Hennepin were operated for more than 2,100 hours, of which about 400 hours were gas reburning; 115 hours, sorbent injection; and nearly 760 hours, combined operation (the remainder was baseline testing).

The second site is City Water, Light and Power's Lakeside Station in Springfield, Illinois, where the process was installed on a 40-MWe cyclone-fired boiler. Construction was completed by mid-1992 and baseline testing was initiated. Sorbent injection operations began in May 1993 and gas-reburning tests began in June 1993. Parametric tests of sorbent injection and gas reburning operation were conducted, progressing to optimization testing of the combined gas-reburning and sorbent injection process. As at the Hennepin site, the Springfield site achieved NO_x and SO_2 reductions better than the targets of 60 percent and 50 percent respectively. The long-term testing program began November 15, 1993, under the optimized conditions. Testing will continue through mid-1994; the final report will be issued by year-end.

▲ Flexible lime-sorbent distribution lines lead up from the distribution bottle to the top level of the boiler at Lakeside Station. Operations began in mid-1993; SO_2 and NO_x reductions are exceeding targets of 50% and 60% respectively.

Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Corporation)

New York State Electric & Gas Corporation is demonstrating a combination of cost-effective, innovative emissions reduction and efficiency improvement technologies on the 300-MWe Units 1 and 2 at Milliken Station located in Lansing, New York. Technologies include flue gas cleanup for SO₂ removal using Saarberg-Holter-Umwelttechnik's formic acid enhanced wet limestone scrubber technology; NALCO Fuel Tech's NO_xOUT urea injection system for NO_x removal; Stebbins' tile-lined split-module absorber for decreased life-cycle costs; a heat-pipe air heater by ABB Air Preheater Inc. for increased system efficiency; and an operator advisor system developed by DHR Technologies for addressing economic and environmental performance.

The project is demonstrating a "total environmental and energy management" concept encompassing low emissions, low energy consumption, improved combustion, upgraded boiler controls, and reduced solid waste. Hazardous air pollutant monitoring is part of the demonstration program.

The systems are designed to achieve up to 98 percent SO₂ removal efficiencies and up to 30 percent NO_x removal beyond that achieved with combustion modifications for NO_x control while burning high-sulfur coal. Pittsburgh, Freeport, and Kittanning coals with sulfur contents ranging from 1.5–4.0 percent are being used.

The cooperative agreement was awarded on October 20, 1992. Design, permitting, and NEPA activities were completed in 1993. The environmental assessment and finding of no significant impact were

completed in August 1993. Construction started in April 1993 and is expected to continue through mid-1995. Operations are scheduled through mid-1998.

▲ Construction began in April 1993 to retrofit Milliken Station Units 1 and 2 with a formic acid enhanced wet limestone scrubber, a urea injection system, and other systems for total environmental and energy management.

Integrated Dry NO_x/SO₂ Emissions Control System (Public Service Company of Colorado)

Public Service Company of Colorado is demonstrating an integrated dry NO_x/SO₂ emissions control system on a 100-MWe down-fired boiler with roof-mounted burners at Arapahoe Station's Unit No. 4, located in Denver, Colorado. This project utilizes The Babcock & Wilcox Company's low-NO_x DRB-XCL® down-fired burners with over-fire air, in-furnace urea injection, and in-duct sorbent injection.

The burners are mounted on the top of the boiler. Part of the coal and part of the combustion air are injected through the burners in an oxygen-deficient reducing atmosphere. Additional air is injected via over-fire air ports to complete the combustion process. Boiler urea injection is being tested to determine how much additional NO_x can be removed. The burners are expected to reduce NO_x emissions by as much as 50 percent, and with added air, by up to 70 percent. Urea injection is expected to further reduce NO_x emissions.

Alkaline sorbent injection to reduce SO₂ emissions by 50–70 percent is being tested in two locations. Either calcium-based sorbent is injected upstream of the air heater or sodium- or calcium-based sorbent is injected downstream of the air heater. The flue gas will be humidified downstream of the sorbent injection locations. Humidification aids SO₂ capture and lowers flue-gas temperature and actual gas flow, enabling the baghouse to maintain performance and improve particulate collection.

Baseline testing of the unmodified boiler was completed in December 1991. Baseline testing of the boiler with urea injection was completed in March

1992, and 35 percent NO_x reduction was achieved at an ammonia slip rate of 10 parts per million. Optimization testing of low-NO_x burner and over-fire air systems was completed in late October 1992, and NO_x removals of 63–69 percent were achieved at various loads, with no increase in unburned carbon. Optimization testing of urea injection (with low-NO_x burners), completed in April 1993, achieved nearly 80 percent NO_x reduction compared to the original baseline. Preliminary results with sodium injection indicate that over 70 percent SO₂ removal can be obtained. Preliminary data from

▼ Optimization testing of the six Babcock & Wilcox down-fired low-NO_x burners (shown here during installation on top of the boiler) and a urea injection system was completed in 1993, achieving nearly 80% NO_x reduction.

air toxics monitoring with urea injection indicate essentially all trace metals emissions are removed in the baghouse. Operational testing will continue until mid-1994.

Arapahoe Unit 4 has operated about 12,000 hours since the combustion modifications were completed in late May 1992. The equivalent availability factor over this period was over 96 percent with only a 0.20 percent forced outage factor.

▲ Lessons learned from the LIMB demonstration were incorporated into the design of this humidification water spray nozzle array, with sorbent injection nozzles interspersed. Preliminary results of sodium injection tests indicate over 70% SO₂ removal can be obtained.

Coal Processing for Clean Fuels

There are five projects in the coal processing for clean fuels category; their combined value is over \$466 million. Three of the technologies are characterized by production of high-energy-density solid compliance fuels for utility or industrial boilers, with or without the coproduction of coal-derived liquids for use as chemical or transportation fuel feedstocks. One project will demonstrate a new synthesis technology for methanol, with or without coproduction of electricity.

The fifth project involves development of software and demonstration of an expert system to predict operating performance of coals not previously burned at the facility in question. A commercial sale of the Coal Quality Expert "Acid Rain Advisor" software package developed during the project was made in 1993. This expert system will be available for fuel switching scenarios for compliance with Phase I of the CAAA of 1990.

The fuels production projects with more extended schedules should have sufficient data for evaluation of Phase I compliance and definitely can be considered for Phase II compliance scenarios. Potential utility and industrial customers are participating in these projects by conducting test burns of the fuels and evaluating the solid and liquid products.

▲ The ENCOAL mild gasification project is producing low-sulfur solid and liquid fuels; commercial contracts are in place with the first customers.

Development of the Coal Quality Expert (ABB Combustion Engineering, Inc., and CQ, Inc.)

ABB Combustion Engineering, Inc., and CQ, Inc., are demonstrating an expert system which can be run on a personal computer. The system is a predictive tool for coal-burning utilities to optimize the selection of coal for a specific boiler based on environmental emissions requirements and operational efficiency. The model predicts operating performance of coals not previously burned at the facility in question.

Data have been obtained from bench-, pilot-, and commercial-scale testing of selected coals. The results have been used to develop algorithms for use in the expert model. In large-scale field tests, a baseline coal (which is the coal currently used as fuel) was burned in the boilers of six utilities over 2-month test periods. An alternate coal, blended or cleaned to improve quality, was also burned in the boiler during the test period. Both the baseline and alternate coals were concurrently tested in bench- and pilot-scale facilities to develop data for correlations and to determine the economics of achieving various quality levels for the cleaned coals.

All of the full-scale field tests with supporting bench and pilot correlation tests were completed by the end of 1993. More than 100 algorithms based on the data generated have been developed for use in the expert model. A commercial sale of the Coal Quality Expert "Acid Rain Advisor" software package commercially released in 1992 was made in 1993. A Coal Quality Expert prototype was showcased in

September 1993. Final software development is scheduled to be completed by mid-1994, and project final reports should be available later in 1994.

◀ Software to enable a utility to analyze the effects of coal quality on power plant performance has been developed. Full-scale field tests were completed in 1993 and a prototype was showcased in September.

Advanced Coal Conversion Process Demonstration (Rosebud SynCoal Partnership)

The Rosebud SynCoal Partnership project is demonstrating an advanced thermal coal-drying process coupled with physical cleaning techniques to upgrade high-moisture, low-rank coals to produce a high-quality, reduced-ash, low-sulfur fuel called SynCoal™. The 1,000-ton-of-coal-per-day demonstration unit is located at the Rosebud Mine in Colstrip, Montana. The project, if successful, will enhance low-rank western coal, which usually has a moisture content of 25–55 percent, sulfur content of 0.5–1.5 percent, and heating value of 5,500–9,000 Btu per pound, by producing a stable, upgraded SynCoal™ with a moisture content as low as 1 percent, sulfur content as low as 0.3 percent, ash content of about 9 percent, and heating value up to 12,000 Btu per pound.

Construction was completed in early 1992, fully 8 months ahead of schedule.

Operations began in June 1992. During the summer of 1993, the facility was shutdown for extended maintenance and retrofit to the fines transport system. The plant resumed operation in August 1993 and on December 6, 1993, it exceeded the design capacity of 68 tons per hour of raw coal input by processing 70 tons per hour of Montana Rosebud coal. SynCoal™ is now being shipped by truck and rail to industrial and utility customers for handling evaluations and short-term test burns. Air quality emissions monitoring will be conducted during test burns at various utilities as well as at the demonstration plant.

Operations are scheduled to continue through mid-1995, with completion of tasks agreed to in the cooperative agreement scheduled for early 1996.

On December 20, 1993, Rosebud SynCoal Partnership announced the signing of a letter of intent with Minnkota Power Cooperative, a North Dakota utility, to prepare a \$2-million study to examine the merits of scaling up the advanced clean coal technology to an \$80-million commercial plant that would be sited next to Minnkota's Milton R. Young Power Station near Center, North Dakota. The engineering and design study is scheduled to be complete in mid-1994. If the results prove positive, a commercial plant could be in place by 1996.

▲ This close-up of the coal dryer and expansion bellows was taken during construction, which was completed a full 8 months ahead of schedule

◀ The Rosebud SynCoal™ facility, shown here to the right of the coal storage silos and coal conveyors, exceeded design capacity in December 1993 by processing 70 tons/hr of coal.

ENCOAL Mild Coal Gasification Project (ENCOAL Corporation)

ENCOAL Corporation is demonstrating the integrated operation of a number of novel process steps which involve heating coal under carefully controlled conditions to produce two higher value fuel forms from mild gasification of low-sulfur, low-heating-value subbituminous coal. The coal is dried and pyrolyzed in two rotary grates arranged in series. The process produces (1) a new solid fuel with higher heating value (about 12,000 Btu per pound) and lower sulfur content than the coal feedstock (on a pound-per-million-Btu basis) and (2) low-sulfur liquid products that can be directly substituted for No. 6 fuel oil. The solid product is usable in any scale industrial or utility boiler.

The site for this plant, which processes about 1,000 tons per day of coal, is Triton Coal Company's Buckskin Mine located about 10 miles north of Gillette, Wyoming.

Construction and preoperational testing were completed by mid-1992. The plant has made several planned runs, which required equipment or process changes after each run, in an attempt to optimize plant operability and the quality of each product. To date, a total of 17,400 tons of coal have been processed over 1,400 hours of coal-based operation, with individual test runs up to 16 days in duration. As 1993 came to a close, a 5-month outage of the facility for installation of a new, additional process step was finalized.

Commercial contracts are in place for the first customers of its two products. A Wisconsin utility

will buy 30,000 tons of the solid product and TEXPAR Energy Inc. of Waukesha, Wisconsin, will buy up to 135,000 barrels of the liquid product. To date, seven railroad tank cars of liquid product have been shipped, including four to the Great Plains Synfuels Plant in Beulah, North Dakota, where the liquid has been successfully combusted in conventional industrial boilers.

ENCOAL continued to attract a large number of international visitors, especially from the Pacific Rim countries interested in using the technology. Among them was the Indonesian ambassador to the United States.

▲ The ENCOAL process is enclosed in the center structure to the right of the silos for storing process-derived fuels. By year-end 1993, about 17,400 tons of coal had been processed.

◀ This large hot-gas duct located inside the ENCOAL process enclosure is connected to the top of the pyrolyzer/dryer.

Industrial Applications

There are six projects in the industrial applications category, valued together at over \$1.1 billion. Projects encompass the steel industry, cement industry, and industrial boiler applications.

Two projects have completed operations: Coal Tech Corporation's Advanced Cyclone Combustor with Integral Sulfur, Nitrogen, and Ash Control project completed operations in 1990 and the final report was issued in 1991. The Passamaquoddy Tribe's Cement Kiln Flue Gas Recovery Scrubber project completed operations and issued the final report at year-end 1993. This successful cement kiln project may have broader applications in paper production and municipal waste incineration. Cement kiln waste was used to achieve greater than 90 percent SO₂ emissions reductions, produce fertilizer, convert kiln waste to cement feedstocks, and eliminate all waste streams. A discussion of the completed projects is contained in Section 5.

Bethlehem Steel Corporation started construction in September 1993 for a project to demonstrate the injection of granulated coal directly into two blast furnaces at Burns Harbor, Indiana. The coal displaces up to 40 percent of the coke normally used in the process, thus reducing coke requirements and the attendant emissions associated with coke making. The reducing environment of the blast furnace enables all of the sulfur in the coal to be captured by the slag and hot metal. Project construction is on a fast track in order to coordinate critical tie-ins with one of the blast furnaces which is scheduled for relining and upgrading in the third quarter of 1994.

Another project, which utilizes coal instead of coke in steelmaking, is in negotiation. The project, to be conducted by Centerior Energy Corporation, on behalf of CPICOR Management Company, a joint venture company comprising LTV Steel Company, Inc., and Air Products and Chemicals, Inc., would integrate iron making with combined-cycle electric power production.

Meanwhile, Bethlehem Steel's Innovative Coke Oven Gas Cleaning System for Retrofit Applications project is expected to begin operation by mid-1994. Construction of the project was completed in 1991, but the facility had to be mothballed because of an unrelated shutdown of the coke ovens at the Sparrows Point Plant.

In these two photos of Bethlehem Steel's Burns Harbor Plant, structural steel is about 10% complete for the coal processing building. Coal processed here will be injected into two blast furnaces to displace up to 40% of the coke now used.

Exhibit 6-2

Status of CCT Demonstration Projects at Year-End 1993—Advanced Electric Power Generation

Project and Sponsor	Status
Fluidized-Bed Combustion	
PFBC Utility Demonstration Project (The Appalachian Power Company)	The participant has completed a number of value engineering studies to improve the efficiency and economic viability of the grassroots PFBC plant. Although results have improved the design and economics of the plant, the participant and DOE are assessing the merits of continuing the project in light of lower-than-expected power demand growth rates.
PCFB Repowering Project (DMEC-1 Limited Partnership)	The participant is performing project configuration and cost studies to assess the merits of the proposed project relative to conventional technology options. Hot-gas-filter design verification tests are being conducted.
Four Rivers Energy Modernization Project (Four Rivers Energy Partners, L.P.)	The project was selected May 4, 1993, and the cooperative agreement is in negotiation.
Tidd PFBC Demonstration Project (The Ohio Power Company)	The 3-year test program initiated in March 1991 continues. Despite a 4 1/2-month outage due to broken low-pressure turbine blades, over 2,000 hours of coal-fired operation were achieved during 1993, bringing the cumulative total to about 5,500 hours. Parametric fuel and sorbent tests are under way to economically obtain 95% sulfur capture. NO _x and particulate levels have been measured at less than 0.24 and 0.02 lb/million Btu, respectively.
Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.)	Project reporting is complete. The cooperative agreement ended in April 1992.
York County Energy Partners Cogeneration Project (York County Energy Partners, L.P.)	The project site was moved approximately 6 miles from West Manchester Township to North Codorus Township. Two public scoping meetings were held and a draft EIS is currently being prepared. The participant is applying for the permits needed to build and operate the plant.
Integrated Gasification Combined Cycle	
Combustion Engineering IGCC Repowering Project (ABB Combustion Engineering, Inc.)	An independent cost estimate was completed. Results indicated that the projected cost exceeds available funds by a considerable margin. The participant and DOE are assessing project options.
Camden Clean Energy Demonstration Project (Duke Energy Corp.)	The project was selected May 4, 1993, and the cooperative agreement is in negotiation.
Piñon Pine IGCC Power Project (Sierra Pacific Power Company)	Project design is under way. The Public Service Commission of Nevada approved the project in October 1993. The participant has contracted with Foster Wheeler for design and construction of the plant and with GE for supply of a Frame 6FA gas turbine. An EIS is being prepared.
Toms Creek IGCC Demonstration Project (TAMCO Power Partners)	In order to provide more time for the sponsor to obtain a power purchase agreement, the project definition period was extended by 3 months to March 1994.
Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	Design is approximately 30% complete. A Florida Department of Environmental Protection hearing was held in October 1993; a decision is expected in early 1994. A draft EIS is being prepared by the U.S. EPA and will be issued in early 1994.

Exhibit 6-2 (continued)
Status of CCT Demonstration Projects at Year-End 1993—Advanced Electric Power Generation

Project and Sponsor	Status
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	Design is approximately 90% complete and construction nearly 10% complete. The participant received an Air Quality Permit from the Indiana Department of Environmental Management and a Certificate of Public Convenience and Necessity from the Indiana Utility Regulatory Commission in May 1993. DOE also approved the EA and issued a finding of no significant impact in May.
Advanced Combustion/Heat Engines Healy Clean Coal Project (Alaska Industrial Development and Export Authority) Coal Diesel Combined-Cycle Project (Arthur D. Little, Inc.) Warren Station Externally Fired Combined-Cycle Demonstration Project (Pennsylvania Electric Company)	Engineering and design are complete. A final EIS was issued in December 1993, and a record of decision is scheduled to be issued in early 1994. The project was selected May 4, 1993, and the cooperative agreement is in negotiation. The project was selected May 4, 1993, and the cooperative agreement is in negotiation.

Exhibit 6-3

Status of CCT Demonstration Projects at Year-End 1993—Environmental Control Devices

Project and Sponsor	Status
NO_x Control Technologies	
Demonstration of Coal Reburning for Cyclone Boiler NO _x Control (The Babcock & Wilcox Company)	Results of parametric and optimization testing demonstrated NO _x emissions are reduced by about 52% at 110 MWe (full load), 47% at 82 MWe, and 36% at 60 MWe. For western coal, NO _x emissions were reduced by 62% at 110 MWe, 55% at 82 MWe, and 53% at 60 MWe. The project was completed as of December 31, 1993. The technology is being retained by Wisconsin Power and Light for commercial use.
Full-Scale Demonstration of Low-NO _x Cell™ Burner Retrofit (The Babcock & Wilcox Company)	Long-term testing began in July 1992 and ran for 8 months. The average NO _x emissions reduction when at full load during this period was 58%. The boiler was inspected during the April 1993 outage; only normal corrosion was discovered. The project was completed as of December 31, 1993. The burners will be used on two commercial boilers totaling 1,100 MWe at Allegheny Power System's Hatfield's Ferry Station.
Evaluation of Gas Reburning and Low-NO _x Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)	Optimization testing of gas reburning with low-NO _x burners started in November 1992 and was completed in April 1993, achieving up to 70% NO _x reduction at full load. The 12-month long-term load-following test began in April 1993.
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)	Long-term testing of advanced over-fire air (AOFA) and low-NO _x burners (LNB) has been completed and indicated NO _x reductions of 24% for AOFA, depending on load, and 48% for LNB at full load. Chemical emissions and long-term testing of the combined AOFA/LNB indicates that 67% NO _x reduction at full load is possible.
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for Reduction of NO _x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	Testing was completed in December 1992. Long-term test data from operating the low-NO _x concentric firing system Level-II equipment (one of three air/coal-feed test configurations) indicated NO _x reductions of up to 40% at full load, compared to baseline emissions data. Long-term data for Level III showed NO _x reductions of as much as 48%. Level-I long-term testing indicated NO _x reductions of 38% at full load.
Demonstration of Selective Catalytic Reduction Technology for the Control of NO _x Emissions from High-Sulfur-Coal-Fired Boilers (Southern Company Services, Inc.)	Construction was completed in February 1993. Seven suppliers of nine catalysts have been selected. The 2-year operations phase began July 1, 1993.
Micronized Coal Reburning Demonstration of NO _x Control on a 175-MWe Wall-Fired Unit (Tennessee Valley Authority)	The cooperative agreement was awarded in July 1992. Preliminary design and permitting activities are under way. Baseline testing began in the fall of 1993.
SO₂ Control Technologies	
10-MW Demonstration of Gas Suspension Absorption (AirPol, Inc.)	Optimization testing started in February 1993 and ended in August 1993. Test results indicate that the GSA is capable of consistently maintaining 90+% SO ₂ removal at a moderate lime requirement and at an 8°F approach-to-adiabatic-saturation temperature. The GSA has also demonstrated high availability during the test period. Air toxics testing conducted during October 1993 showed a removal rate of over 95%.

Exhibit 6-3 (continued)
Status of CCT Demonstration Projects at Year-End 1993—Environmental Control Devices

Project and Sponsor	Status
Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)	Bechtel notified DOE on June 30, 1993, that it was discontinuing the project effective July 1, 1993. Bechtel is in the process of modifying the CZD process design to improve continuous operation SO ₂ removal problems. Once the CZD process modifications are made, a follow-on continuous boiler-integrated operating period will be required. Bechtel is continuing work on submitting and finalizing all DOE reports required by the cooperative agreement.
LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC-North America)	Operations, started in late September 1992, have achieved SO ₂ reductions of 80–85%. Modifications have been made to the ESP to eliminate opacity problems.
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	The flue gas desulfurization unit continues operating at full capacity. Average SO ₂ removal of 95% has been achieved. The gypsum by-product is averaging 96–97% pure and is being used to manufacture wallboard.
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	The CT-121 process has operated successfully for over 1 year. The unit has been 98% reliable and 98% available, meaning that no spare scrubber would be required. SO ₂ removals are in the range of 93–98%, exceeding the project's objective of 90%.
Combined SO₂/NO_x Control Technologies	
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	The facility has routinely operated at full capacity, achieving removal efficiencies of 96% for SO ₂ , 94% for NO _x , and 99.9% for particulates. The unit is producing 93% pure sulfuric acid at a rate of 28 tons/day; the acid is being sold for industrial use. By year-end 1993, the system had operated more than 5,700 hours, producing about 3,800 tons of sulfuric acid. The system will be retained by Ohio Edison Company as part of its CAAA of 1990 compliance strategy. Operations have been extended through December 1994.
LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)	Final reports on Coolside and LIMB extension testing are complete and available to the public through NTIS. The cooperative agreement ended January 1993.
SOx-NOx-Rox-Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)	Semi-continuous operation has indicated consistent SO ₂ reduction of 85%, NO _x reductions over 90%, and particulate removal to 0.0123 lb/million Btu. Air toxics emissions testing was conducted in May 1993. The project has been completed; final reports are expected to be available in March 1994.
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)	Long-term load following and alternate sorbent testing have been completed at the Hennepin Station. The 50% SO ₂ and 60% NO _x emission reduction objectives were readily exceeded, with 52% SO ₂ and 61% NO _x reductions achieved. The final report covering Hennepin operations is in progress. Parametric testing of gas reburning, sorbent injection, and gas reburning-sorbent injection was completed, and the long-term load-following demonstration is now under way on the cyclone-fired boiler at Lakeside Station.
Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Corporation)	The cooperative agreement was awarded on October 20, 1992. Design, permitting, and NEPA activities were completed in 1993 and construction was started. The EA and finding of no significant impact were completed in August 1993.

Exhibit 6-3 (continued)
Status of CCT Demonstration Projects at Year-End 1993—Environmental Control Devices

Project and Sponsor	Status
Commercial Demonstration of the NOXSO SO ₂ /NO _x Removal Flue Gas Cleanup System (NOXSO Corporation and MK-Ferguson)	NOXSO Corporation is negotiating with several potential host utilities for a new site. Proof-of-concept pilot-plant testing, which had been proceeding in parallel with project definition, is complete, with results as expected. Preliminary process flow diagrams, piping and instrumentation diagrams, equipment specifications, and plant arrangement drawings have been prepared.
Integrated Dry NO _x /SO ₂ Emissions Control System (Public Service Company of Colorado)	Baseline testing of the boiler with urea injection was completed in March 1992, and 35% NO _x reduction at a 10 ppm ammonia slip was achieved. Optimization testing of low-NO _x burner and over-fire air systems was completed in late October 1992, and NO _x removals of 62–69% were achieved at various loads, with no increase in unburned carbon; optimization testing of urea injection (with low-NO _x burners) was completed in April 1993 and achieved nearly 80% NO _x removal from the original baseline. Preliminary results with sodium injection indicate that over 70% SO ₂ removal can be obtained. Operational testing will continue until mid-1994.

Exhibit 6-4

Status of CCT Demonstration Projects at Year-End 1993—Coal Processing for Clean Fuels

Project and Sponsor	Status
Coal Preparation Technologies Development of the Coal Quality Expert (ABB Combustion Engineering, Inc., and CQ, Inc.) Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International) Advanced Coal Conversion Process Demonstration (Rosebud SynCoal Partnership)	<p>All 6 full-scale field tests and pilot- and bench-scale correlation tests are complete. Over 100 algorithms based on data generated from the tests have been developed. Acid Rain Advisor software is commercially available; a prototype CQE has been developed. The first commercial sale of Acid Rain Advisor software was made in 1993.</p> <p>The cooperative agreement was awarded in October 1992. Design and permitting activities are under way. NEPA is expected to be satisfied by February 1994 which will permit construction to commence.</p> <p>Facility equipment modifications were made to the dust transport system during the summer of 1993. The demonstration plant resumed operation in August 1993 and continued to ship SynCoal™ to industrial customers and utilities for handling and test burns.</p>
Mild Gasification ENCOAL Mild Coal Gasification Project (ENCOAL Corporation)	<p>The 2-year test period begun in July 1992 continues. To date, the plant has completed 15 runs and logged over 1,400 hours of coal-based operation, which have included test runs of 14 days and 12 days in duration. The plant is to resume operation in January 1994 after a 7-month outage to install a new process step. Commercial contracts are in place for sale of solid and liquid products.</p>
Indirect Liquefaction Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process (Air Products and Chemicals, Inc.)	<p>Since the cooperative agreement was awarded in October 1992, the project has been restructured and the cooperative agreement was modified in October 1993. The new site is Eastman Chemical Company's Integrated Coal Gasification Facility in Kingsport, TN. Project definition activities are under way.</p>

Exhibit 6-5

Status of CCT Demonstration Projects at Year-End 1993—Industrial Applications

Project and Sponsor	Status
Blast Furnace Granulated-Coal Injection System Demonstration Project (Bethlehem Steel Corporation)	Detailed design is 90% complete. Construction was initiated in September 1993 and concrete foundations have been poured. Major structural steel and vessels have been delivered to the site, and erection of structural steel has begun.
Innovative Coke Oven Gas Cleaning System for Retrofit Applications (Bethlehem Steel Corporation)	Coke production at Sparrows Point was suspended in 1992 due to rapid deterioration of the coke ovens. The coke oven gas cleanup system has been constructed and subsequently mothballed to maintain it until coke-making resumes.
Clean Power from Integrated Coal/Ore Reduction (COREX®) (Centerior Energy Corporation)	The project was selected May 4, 1993, and the cooperative agreement is in negotiation.
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)	Project reporting is complete. The cooperative agreement ended September 1991.
Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)	Project operations were completed in September 1993 with SO ₂ removal averaging 92%. Final project reports are expected to be available in March 1994.
Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal (ThermoChem, Inc.)	Design and permitting activities are under way. Design verification tests are under way at MTCI's Baltimore Test Facility.

7. Project Fact Sheets

Summary

Included in this chapter is project-specific information for each of the 45 projects selected in the CCT Program's five solicitations. This information includes, for each ongoing project, the sponsor, team members, location, cost and schedule data, process flow diagram, significant project features, project objectives, description of the process and its performance attributes, progress and accomplishments, and commercial applications. Fact sheets for completed projects contain a brief overview of the results of the demonstration and sources of more detailed information.

The fact sheets are organized into four application categories:

- Advanced electric power generation
- Environmental control devices
- Coal processing for clean fuels
- Industrial applications

To prevent the release of project-specific information of a proprietary nature, the process flow diagrams contained in the fact sheets are presented only as illustrative of the concepts involved in the demonstration.

For the convenience of the reader, two indexes which cross-reference CCT projects by sponsors and application categories are provided as a guide to the 45 fact sheets included in this section.

- Exhibit 7-1 indexes project fact sheets by application category.
- Exhibit 7-2 indexes fact sheets by sponsor.

Additional project information can be obtained through publications listed in Appendixes C and D or from the project contacts listed in Appendix E. Full references for the final reports listed in abbreviated form in fact sheets for completed projects can be found in Appendix C. Furthermore, progress on the CCT projects and significant events can be tracked through DOE's quarterly newsletter, *Clean Coal Today*. To be included on the newsletter mailing list, send name and address to U.S. Department of Energy, FE-22, Washington, DC 20585.

Key to Milestone Charts in Fact Sheets

Each fact sheet contains a bar chart that highlights major milestones—past and planned. The bar chart shows a project's duration and indicates the time period for three general categories of project activities—preaward, design and construction, and operation. The key provided below explains what is included in each of these categories.

Preaward

Includes preaward briefings, negotiations, and other activities conducted during the period between DOE's selection of the project and award of the cooperative agreement.

Design and Construction

Includes the NEPA process, permitting, design, procurement, construction, preoperational testing, and other activities conducted prior to the beginning of operation of the demonstration.

MTF Memo-to-file

CX Categorical exclusion

EA Environmental assessment

EIS Environmental impact statement

Operation

Begins with start-up of operation and includes operational testing, data collection, analysis, evaluation, reporting, and other activities to complete the demonstration project.

Exhibit 7-1

Project Fact Sheets, by Application Category

Project	Sponsor	Page
Advanced Electric Power Generation		
Fluidized-Bed Combustion		
PFBC Utility Demonstration Project	The Appalachian Power Company	7-8
PCFB Demonstration Project	DMEC-1 Limited Partnership	7-10
Four Rivers Energy Modernization Project	Four Rivers Energy Partners, L.P.	7-12
Tidd PFBC Demonstration Project	The Ohio Power Company	7-14
Nucla CFB Demonstration Project	Tri-State Generation and Transmission Association, Inc.	7-16
York County Energy Partners Cogeneration Project	York County Energy Partners, L.P.	7-18
Integrated Gasification Combined Cycle		
Combustion Engineering IGCC Repowering Project	ABB Combustion Engineering, Inc.	7-20
Camden Clean Energy Demonstration Project	Duke Energy Corp.	7-22
Piñon Pine IGCC Power Project	Sierra Pacific Power Company	7-24
Toms Creek IGCC Demonstration Project	TAMCO Power Partners	7-26
Tampa Electric Integrated Gasification Combined-Cycle Project	Tampa Electric Company	7-28
Wabash River Coal Gasification Repowering Project	Wabash River Coal Gasification Repowering Project Joint Venture	7-30
Advanced Combustion/Heat Engines		
Healy Clean Coal Project	Alaska Industrial Development and Export Authority	7-32
Coal Diesel Combined Cycle Project	Arthur D. Little, Inc.	7-34
Warren Station Externally Fired Combined-Cycle Demonstration Project	Pennsylvania Electric Company	7-36
Environmental Control Devices		
NO_x Control Technologies		
Demonstration of Coal Reburning for Cyclone Boiler NO _x Control	The Babcock & Wilcox Company	7-40
Full-Scale Demonstration of Low-NO _x Cell™ Burner Retrofit	The Babcock & Wilcox Company	7-42
Evaluation of Gas Reburning and Low-NO _x Burners on a Wall-Fired Boiler	Energy and Environmental Research Corporation	7-44
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	Southern Company Services, Inc.	7-46
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO _x Emissions from Coal-Fired Boilers	Southern Company Services, Inc.	7-48
Demonstration of Selective Catalytic Reduction Technology for the Control of NO _x Emissions from High-Sulfur-Coal-Fired Boilers	Southern Company Services, Inc.	7-50
Micronized Coal Reburning Demonstration for NO _x Control on a 175-MWe Wall-Fired Unit	Tennessee Valley Authority	7-52

Exhibit 7-1 (continued)
Project Fact Sheets, by Application Category

Project	Sponsor	Page
SO₂ Control Technologies		
10-MW Demonstration of Gas Suspension Absorption	AirPol, Inc.	7-54
Confined Zone Dispersion Flue Gas Desulfurization Demonstration	Bechtel Corporation	7-56
LIFAC Sorbent Injection Desulfurization Demonstration Project	LIFAC-North America	7-58
Advanced Flue Gas Desulfurization Demonstration Project	Pure Air on the Lake, L.P.	7-60
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	Southern Company Services, Inc.	7-62
Combined SO₂/NO_x Control Technologies		
SNOX™ Flue Gas Cleaning Demonstration Project	ABB Environmental Systems	7-64
LIMB Demonstration Project Extension and Coolside Demonstration	The Babcock & Wilcox Company	7-66
SOx-NOx-Rox-Box™ Flue Gas Cleanup Demonstration Project	The Babcock & Wilcox Company	7-68
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	Energy and Environmental Research Corporation	7-70
Milliken Clean Coal Technology Demonstration Project	New York State Electric & Gas Corporation	7-72
Commercial Demonstration of the NOXSO SO ₂ /NO _x Removal Flue Gas Cleanup System	NOXSO Corporation and MK-Ferguson Company	7-74
Integrated Dry NO _x /SO ₂ Emissions Control System	Public Service Company of Colorado	7-76
Coal Processing for Clean Fuels		
Coal Preparation Technologies		
Development of the Coal Quality Expert	ABB Combustion Engineering, Inc., and CQ, Inc.	7-80
Self-Scrubbing Coal™: An Integrated Approach to Clean Air	Custom Coals International	7-82
Advanced Coal Conversion Process Demonstration	Rosebud SynCoal Partnership	7-84
Mild Gasification		
ENCOAL Mild Coal Gasification Project	ENCOAL Corporation	7-86
Indirect Liquefaction		
Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process	Air Products and Chemicals, Inc.	7-88
Industrial Applications		
Blast Furnace Granulated-Coal Injection System Demonstration Project	Bethlehem Steel Corporation	7-92
Innovative Coke Oven Gas Cleaning System for Retrofit Applications	Bethlehem Steel Corporation	7-94
Clean Power from Integrated Coal/Ore Reduction (COREX®)	Centerior Energy Corporation	7-96
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	Coal Tech Corporation	7-98
Cement Kiln Flue Gas Recovery Scrubber	Passamaquoddy Tribe	7-100
Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal	ThermoChem, Inc.	7-102

Exhibit 7-2 Project Fact Sheets, by Sponsor

Sponsor	Project	CCT	Page
ABB Combustion Engineering, Inc.	Combustion Engineering IGCC Repowering Project	II	7-20
ABB Combustion Engineering, Inc., and CQ, Inc.	Development of the Coal Quality Expert	I	7-80
ABB Environmental Systems	SNOX TM Flue Gas Cleaning Demonstration Project	II	7-64
Air Products and Chemicals, Inc.	Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH TM) Process	III	7-88
AirPol, Inc.	10-MW Demonstration of Gas Suspension Absorption	III	7-54
Alaska Industrial Development and Export Authority	Healy Clean Coal Project	III	7-32
The Appalachian Power Company	PFBC Utility Demonstration Project	II	7-8
Arthur D. Little, Inc.	Coal Diesel Combined-Cycle Project	V	7-34
The Babcock & Wilcox Company	Demonstration of Coal Reburning for Cyclone Boiler NO _x Control	II/Complete	7-40
The Babcock & Wilcox Company	Full-Scale Demonstration of Low-NO _x Cell TM Burner Retrofit	III/Complete	7-42
The Babcock & Wilcox Company	LIMB Demonstration Project Extension and Coolside Demonstration	I/Complete	7-66
The Babcock & Wilcox Company	SO _x -NO _x -Rox-Box TM Flue Gas Cleanup Demonstration Project	II/Complete	7-68
Bechtel Corporation	Confined Zone Dispersion Flue Gas Desulfurization Demonstration	III/Complete	7-56
Bethlehem Steel Corporation	Blast Furnace Granulated-Coal Injection System Demonstration Project	III	7-92
Bethlehem Steel Corporation	Innovative Coke Oven Gas Cleaning System for Retrofit Applications	II	7-94
Centerior Energy Corporation	Clean Power from Integrated Coal/Ore Reduction (COREX [®])	V	7-96
Coal Tech Corporation	Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	I/Complete	7-98
Custom Coals International	Self-Scrubbing Coal TM : An Integrated Approach to Clean Air	IV	7-82
DMEC-1 Limited Partnership	PCFB Demonstration Project	III	7-10
Duke Energy Corp.	Camden Clean Energy Demonstration Project	V	7-22
ENCOAL Corporation	ENCOAL Mild Coal Gasification Project	III	7-86
Energy and Environmental Research Corporation	Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	I	7-70
Energy and Environmental Research Corporation	Evaluation of Gas Reburning and Low-NO _x Burners on a Wall-Fired Boiler	III	7-44
Four Rivers Energy Partners, L.P.	Four Rivers Energy Modernization Project	V	7-12
LIFAC-North America	LIFAC Sorbent Injection Desulfurization Demonstration Project	III	7-58
New York State Electric & Gas Corporation	Milliken Clean Coal Technology Demonstration Project	IV	7-72

Exhibit 7-2 (continued)
Project Fact Sheets, by Sponsor

Sponsor	Project	CCT	Page
NOXSO Corporation and MK-Ferguson Company	Commercial Demonstration of the NOXSO SO ₂ /NO _x Removal Flue Gas Cleanup System	III	7-74
The Ohio Power Company	Tidd PFBC Demonstration Project	I	7-14
Passamaquoddy Tribe	Cement Kiln Flue Gas Recovery Scrubber	II/Complete	7-100
Pennsylvania Electric Company	Warren Station Externally Fired Combined-Cycle Demonstration Project	V	7-36
Public Service Company of Colorado	Integrated Dry NO _x /SO ₂ Emissions Control System	III	7-76
Pure Air on the Lake, L.P.	Advanced Flue Gas Desulfurization Demonstration Project	II	7-60
Rosebud SynCoal Partnership	Advanced Coal Conversion Process Demonstration	I	7-84
Sierra Pacific Power Company	Piñon Pine IGCC Power Project	IV	7-24
Southern Company Services, Inc.	Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	II	7-46
Southern Company Services, Inc.	Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	II	7-62
Southern Company Services, Inc.	Demonstration of Selective Catalytic Reduction Technology for the Control of NO _x Emissions from High-Sulfur-Coal-Fired Boilers	II	7-50
Southern Company Services, Inc.	180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO _x Emissions from Coal-Fired Boilers	II/Complete	7-48
TAMCO Power Partners	Toms Creek IGCC Demonstration Project	IV	7-26
Tampa Electric Company	Tampa Electric Integrated Gasification Combined-Cycle Project	III	7-28
Tennessee Valley Authority	Micronized Coal Reburning Demonstration for NO _x Control on a 175-MWe Wall-Fired Unit	IV	7-52
ThermoChem, Inc.	Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal	IV	7-102
Tri-State Generation and Transmission Association, Inc.	Nucla CFB Demonstration Project	I/Complete	7-16
Wabash River Coal Gasification Repowering Project Joint Venture	Wabash River Coal Gasification Repowering Project	IV	7-30
York County Energy Partners, L.P.	York County Energy Partners Cogeneration Project	I	7-18

Advanced Electric Power Generation Fact Sheets

PFBC Utility Demonstration Project

Sponsor:

The Appalachian Power Company

Additional Team Members:

American Electric Power Service Corporation—

designer, constructor, and manager

The Babcock & Wilcox Company—technology supplier

Location:

New Haven, Mason County, WV (greenfield facility adjacent to Appalachian Power Company's Mountaineer Plant)

Technology:

The Babcock & Wilcox Company's pressurized fluidized-bed combustion (PFBC) system (under license from ABB Carbon) (advanced electric power generation/fluidized-bed combustion)

Plant Capacity/Production:

340 MWe (net)

Project Funding:

Total project cost	\$917,944,000	100%
DOE	184,800,000	20
Participants	733,144,000	80

Project Objective:

To demonstrate PFBC at 340 MWe, a large utility scale representing a four-fold scaleup of the technology, the world's largest PFBC, and the first commercial application of PFBC in the United States; to assess long-term reliability, availability, and maintainability of PFBC in a commercial operating mode and the integration of a reheat steam cycle.

Technology/Project Description:

This project will be a greenfield facility located adjacent to the existing Mountaineer and Sporn plants. The most noticeable aspect of the unit is that the boiler, cyclones, reinjection vessel, and associated hardware are encapsulated in a pressure vessel 60 ft in diameter and 100 ft high.

The project incorporates a bubbling fluidized-bed process operating at 16 atm (235 lb/in² atm). Pressurized combustion air is supplied by the turbine compressor to fluidize the bed material (consisting of a coal-water fuel paste, coal ash, and a dolomite or limestone sorbent). Dolomite or limestone in the bed reacts with sulfur to form calcium sulfate, a dry, granular bed-ash material, which is easily disposed of or used as a

by-product. A low bed-temperature of 1,600 °F limits NO_x formation.

The hot combustion gases exit the bed vessel with entrained ash particles, 98% of which are removed when the gases pass through cyclones. An option being considered is to employ some advanced filtration devices in the design. The cleaned gases are then expanded through a 75-MWe gas turbine.

The reheat system turbine operates at a state-of-the-art pressure and temperature to produce at least 250 MWe. Superheated steam will be produced from pressurized boiler-feed water in the tubes submerged in the fluidized bed. The projected heat rate for this unit is 8,500 Btu/kWh (40.2% efficiency based on HHV). SO₂ emissions are expected to be reduced by 95% and NO_x emissions by 80%.

The design coal is Pittsburgh 8, high-sulfur (4% maximum), bituminous coal.

Project Status/Accomplishments:

During 1993, initial value engineering efforts aimed at reducing the technical and economic risks of the project were completed. These efforts were successful in optimizing the scaleup parameters, improving the understanding of sulfur capture, and reducing capital cost. Appalachian Power's load growth projections are being refined, but they are not expected to show a large need for power. The utility and DOE are assessing the merits of continuing the project.

Commercial Applications:

This project will be the initial version of a commercial plant. Combined-cycle PFBC systems permit the combustion of a wide range of coals, including high-sulfur coals. This technology will compete with circulating PFBC systems to repower or replace conventional power plants with a technology capable of using high-sulfur

coals in an environmentally sound manner. PFBC technology appears to be best suited for a wide range of applications beginning at the 50-MWe size. Because of modular construction capability, PFBC generating plants permit utilities to add economical increments of capacity to match load growth and/or to easily repower existing plants using available coal- and waste-handling equipment, and existing steam turbines. Another advantage for repowering is the compactness of the process because of pressurized operation.

The projected net heat rate for the commercial plant will be 8,500 Btu/kWh (based on HHV) which equates to an efficiency of 40.2%. An advanced cycle that integrates a small gasifier could yield heat rates approaching 7,500 Btu/kWh (45% efficiency). Environmental attributes include in-situ sulfur reduction of 95% and NO_x emissions reduction to 0.1 lb/million Btu. Although the system may generate a slight increase of solid waste as compared to conventional systems, the dry material is either disposable or potentially usable.

PCFB Demonstration Project

Sponsor:

DMEC-1 Limited Partnership (a partnership between Dairyland Power Cooperative and Midwest Power Systems, Inc. [previously Iowa Power, Inc.])

Additional Team Members:

Pyropower Corporation —technology supplier
Black and Veatch —architect and engineer

Location:

Pleasant Hill, Polk County, IA (Des Moines Energy Center)

Technology:

Pyropower Corporation's PYROFLOW pressurized circulating fluidized-bed combustion (PCFB) combined-cycle system (advanced electric power generation/fluidized-bed combustion)

Plant Capacity/Production:

80 MWe

Project Funding:

Total project cost	\$202,959,000	100%
DOE	93,253,000	46
Participants	109,706,000	54

Project Objective:

To demonstrate PCFB at sufficient scale to evaluate environmental, cost, and plant performance and to obtain the technical data required for commercialization of the technology; to assess operating performance of unique features that include an integral ceramic hot-gas filter and slightly modified, commercially available gas turbine.

Technology/Project Description:

In the PCFB process, coal is combusted at about 1,600 °F and 12 atm in a circulating fluidized bed contained within a pressure vessel. Coal is pumped into the PCFB via a water slurry while dolomite or limestone is added to the combustion process to absorb sulfur compounds. Particulates from the hot, pressurized combustion gases are removed by a ceramic filter, and the clean gases are then expanded through a gas turbine. The solid waste (bed and fly ash) from the process is dry, easily disposed of, and potentially usable. Steam generated within the PCFB combustor and the heat recovery system downstream of the gas turbine is used to generate power in an existing steam turbine.

The project would be the world's first large-scale demonstration of PCFB technology. The project also

would be the first commercial application of hot gas cleanup and the first use of a nonruggedized gas turbine in a pressurized fluidized-bed application.

A boiler at the Des Moines Energy Center is being repowered by a single PCFB combustor. The facility, owned by Midwest Power Company, is located southeast of Des Moines, IA. Midwest Power plans to continue PCFB operations commercially after the demonstration.

Repowering the plant with a PCFB will improve the plant's heat rate to 10,400 Btu/kWh (an efficiency of 32.8% based on HHV) which is a 15% improvement over the previous plant. SO₂ emissions will be limited to 0.71 lb/million Btu (90% reduction) and NO_x emissions will be less than 0.03 lb/million Btu (70% reduction).

The design coal for the facility is 0.36% sulfur, Wyoming subbituminous coal. Test coals are Iowa

subbituminous coal with 3.84% sulfur and Illinois bituminous coal with 3.0% sulfur.

Project Status/Accomplishments:

In October 1993, a modification was issued to extend the project for 12 months in order to complete project definition activities. During the extension, Midwest Power will finalize the selection of a ceramic filtration hot-gas cleanup system and conduct configuration studies to verify the economic viability of the project. A draft of the environmental impact statement has been prepared and is undergoing internal DOE review.

Commercial Applications:

By demonstrating plant reliability and performance, this project serves as a bridge for scaling up to a larger plant and a stepping stone toward moving PCFB to commercial readiness. The combined-cycle PCFB system permits the combustion of a wide range of coals, including high-sulfur coals, and would compete with the bubbling-bed PFBC system. Like the bubbling-bed system, PCFB

can be used to repower or replace conventional power plants. PCFB technology appears to be best suited for utility and industrial applications of 50 MWe or larger. Because of modular construction capability, PCFB generating plants permit utilities to add economical increments of capacity to match load growth and/or to repower plants using existing coal- and waste-handling equipment, and steam turbines. Another advantage for repowering applications is the compactness of the process due to pressurized operation, which reduces space requirements per unit of energy generated.

The commercial version of PCFB technology will include the integration of a topping combustor to fully utilize commercially available gas turbines. The projected net heat rate for this system is 7,964 Btu/kWh (based on HHV) which equates to 42.8% efficiency.

Environmental attributes include in-situ sulfur removal of 95%, NO_x emissions less than 0.3 lb/million Btu, and particulate matter discharge less than 0.03 lb/million Btu. Solid waste will increase slightly as compared to conventional systems, but the dry material is disposable or potentially usable.

Four Rivers Energy Modernization Project

Sponsor:

Four Rivers Energy Partners, L.P. (a limited partnership between Four Rivers Energy Partners (I), Inc., and Air Products and Chemicals, Inc.)

Additional Team Members:

Foster Wheeler Energy Corporation—combustor, carbonizer, and heat exchanger supplier; engineer
Westinghouse Electric Corporation—gas turbine, topping combustor, and carbonizer filter supplier
LLB Lurgi Lentjes Babcock Energietechnik GmbH—combustor filter, slurry feed, and ash removal system supplier

Location:

Calvert City, Marshall County, KY (Air Products and Chemicals' chemical manufacturing plant)

Technology:

Foster Wheeler's fully integrated second-generation pressurized circulating fluidized-bed (PCFB) combustion system (advanced electric power generation/fluidized-bed combustion)

Plant Capacity/Production:

95 MWe (equivalent if all steam were converted)

Project Funding:

Total project cost	\$375,178,000	100%
DOE	150,033,775	40
Participants	225,144,225	60

(Funding amounts reflect those contained in the proposal and are subject to negotiation.)

Project Objective:

To demonstrate PCFB technology at a sufficient scale to evaluate the environmental, cost, and plant performance technical data that is prerequisite to commercialization of

the technology; to assess operating performance of the world's first fully integrated second-generation PCFB system that includes a combustor, carbonizer, ceramic hot-gas filtration systems, topping combustor, and a slightly modified, commercially available gas turbine.

Technology/Project Description:

This project represents the first commercial application of Foster Wheeler's second-generation PCFB system. Coal is fed to a pressurized carbonizer that produces a low-Btu fuel gas and char. After the fuel gas is cleaned of particulates and alkali vapors by a cyclone, ceramic filter, and alkali removal system, it is burned in a topping combustor to drive a gas turbine.

The gas turbine drives a generator and a compressor that delivers air to the carbonizer and to a PCFB

combustor. Additional coal and the carbonizer char are burned in the PCFB combustor, and the flue gas is used to combust the fuel gas in the topping combustor. Prior to the topping combustor, the hot gases pass through ceramic filtration and alkali removal units.

A steam turbine is driven by steam generated in the heat recovery steam generator, which is located downstream of the gas turbine, an integrated ash-cooling heat exchanger, and the PCFB combustor.

Fuel is pumped into the PCFB carbonizer and combustor via a slurry mixture while dolomite or limestone is pneumatically added to absorb sulfur compounds. The solid waste (bed and fly ash) from the process is dry, easily disposable, and potentially usable.

The project is also in line to be one of the first commercial applications of hot-gas cleanup and one of the

first to use a non-ruggedized gas turbine in a pressurized fluidized-bed application.

At the Calvert City chemicals manufacturing plant, the second-generation PCFB process will replace the steam-generating capacity of two operating industrial process boilers. These two industrial units are spreader-stoker coal-fired units which were installed in the late 1950s. This equipment change will result in significant reductions in the current emissions of pollutants.

Project Status/Accomplishments:

The project is in negotiation.

Commercial Applications:

This project will serve as a stepping stone to move the second-generation PCFB technology to readiness for widespread commercial application. The project is expected to demonstrate plant reliability and performance and serve as a bridge for scaling to a larger plant. In addition to other advanced technology systems, second-generation PCFB technology will compete with bubbling

fluidized-bed combustion systems to repower or replace conventional fossil-fueled power plants with a technology capable of using high-sulfur coals in an environmentally sound manner.

PCFB technology appears to be best suited for a wide range of utility and industrial applications beginning at a level of 50 MWe. Because of the modular construction capability, PCFB generating plants will permit utilities to add economical increments of capacity to match load growth and/or to easily repower an existing plant using available coal- and waste-handling equipment and steam turbine equipment.

The commercial version of PCFB technology will have a greenfield net plant efficiency of 45% (which equates to heat rates approaching 7,500 Btu/kWh, based on HHV). In addition to higher plant efficiencies, the second-generation plant will (1) have a cost of electricity that is projected to be 20% lower than that of a conventional pulverized-coal-fired plant with flue gas desulfurization, (2) meet emissions limits that are half those

currently allowed by NSPS, (3) operate economically on a wide range of coals, (4) be amenable to shop fabrication, and (5) be furnished in building-block modules as large as 300 MWe.

The benefits of improved efficiency include reduced costs for fuel and a reduction in CO₂ emissions. Other environmental attributes include in-situ sulfur reduction that can meet 95% removal, NO_x emissions that will be lower than 0.3 lb/million Btu, and particulate matter discharge that approaches 0.01 lb/million Btu. Although the system will generate a slight increase of solid waste as compared to conventional systems, the material will be a dry, disposable, and potentially usable material.

Tidd PFBC Demonstration Project

Sponsor:

The Ohio Power Company

Additional Team Members:

American Electric Power Service Corporation—designer, constructor, and manager

The Babcock & Wilcox Company—technology supplier
Ohio Coal Development Office—cofunder

Location:

Brilliant, Jefferson County, OH (Ohio Power Company's Tidd Plant)

Technology:

The Babcock & Wilcox Company's pressurized fluidized-bed combustion (PFBC) system (under license from ABB Carbon) (advanced electric power generation/fluidized-bed combustion)

Plant Capacity/Production:

70 MWe

Project Funding:

Total project cost	\$193,540,000	100%
DOE	60,200,000	31
Participants	133,340,000	69

Project Objective:

To demonstrate PFBC at a 70-MWe scale, representing a 13:1 scaleup from the pilot plant facility; to verify expectations of the technology's economic, environmental, and technical performance in a combined-cycle repowering application at a utility site; and to accomplish greater than 90% SO₂ removal, NO_x emission level of 0.2 lb/million Btu, and an efficiency of 35% in a repowering mode using the existing steam system.

Technology/Project Description:

Tidd is the first large-scale demonstration of PFBC in the United States and one of only five worldwide. The boiler, cyclones, bed reinjection vessels, and associated hardware are encapsulated in a pressure vessel 45 ft in diameter and 70 ft high. The facility was designed so that one-seventh of the hot gases produced could be routed to a slipstream to test advanced filtration devices.

The Tidd facility is a bubbling fluidized-bed combustion process operating at 12 atm (175 lbs/in² atm). Pressurized combustion air is supplied by the turbine compressor to fluidize the bed material which consists of a coal-water fuel paste, coal ash, and a dolomite or limestone sorbent. Dolomite or limestone in the bed reacts with sulfur to form calcium sulfate, a dry, granular bed-ash material which is easily disposed of or is usable as a

by-product. A low bed-temperature of 1,600 °F limits NO_x formation.

The hot combustion gases exit the bed vessel with entrained ash particles, 98% of which are removed when the gases pass through cyclones. The cleaned gases are then expanded through a 15-MWe gas turbine. The gases exiting the turbine are cooled via a waste heat economizer and further cleaned in an electrostatic precipitator.

The Tidd steam turbine operates at a pressure of 1,305 lbs/in² atm and a temperature of 925 °F to produce approximately 55 MWe. Superheated steam is produced from pressurized boiler feed water in the in-bed combustor tubes. Steam generated within the combustor and the heat recovery system downstream of the gas turbine is used to generate power in a previously existing steam

turbine. Due to repowering, plant efficiency was improved by 10% to a heat rate of 9,750 Btu/kWh (an efficiency of 35.1% based on HHV).

Ohio bituminous coals having sulfur contents of 2–4% are being used in the demonstration.

Project Status/Accomplishments:

The plant accumulated over 2,000 hours of operation during 1993. Overall, coal-fueled operation now totals more than 5,500 hours. SO₂ emissions reductions of about 93% and NO_x emission levels of 0.15–0.18 lb/million Btu were routinely achieved. These levels are well below NSPS requirements.

During 1993 operations, advanced ceramic hot-gas-filtration elements were exposed to one-seventh of the slipstream; total exposure is now in excess of 1,800 hours. The unit suffered a major mechanical problem early in 1993 whenever gas turbine blades broke during routine operation. The result was severe damage to the compressor, gas turbine blades, and rotor shafts. Disregarding a 5-month outage for repairs to the gas turbine,

the unit operated for approximately 50% of the available time during 1993.

The project is due to terminate operations by the end of February 1994. However, as 1993 came to a close, Ohio Power and DOE were considering a fourth year of operations. The goal of the additional 12-month test would be to obtain additional data on long-term gas turbine survivability, economical sulfur capture at a 95% level, and exposure of advanced ceramic filtration devices.

Commercial Application:

Combined-cycle PFBC permits use of a wide range of coals, including high-sulfur coals. Bubbling PFBC technology, along with other advanced technologies, will compete with circulating PFBC systems to repower or replace conventional power plants. PFBC technology appears to be best suited for applications of 50 MWe or larger. Capable of being constructed modularly, PFBC generating plants permit utilities to add increments of

capacity economically to match load growth. Plant life can be extended by repowering with PFBC using the existing plant area, coal- and waste-handling equipment, and steam turbine equipment. Another advantage for repowering applications is the compactness of the process due to pressurized operation, which reduces space requirements per unit of energy generated.

In a fully mature system, the projected net heat rate is 8,500 Btu/kWh (based on HHV) which equates to 40.2% efficiency. An advanced cycle that integrates a small gasifier could yield heat rates approaching 7,500 Btu/kWh (45% efficiency).

The environmental attributes of a mature system include in-situ sulfur removal of 95% and NO_x emissions reduction levels less than 0.1 lb/million Btu. Although the system generates a slight increase in solid waste as compared to conventional systems, the dry material is either disposable or potentially usable.

Nucla CFB Demonstration Project

Project completed.

Sponsor:

Tri-State Generation and Transmission Association, Inc.
(formerly Colorado-Ute Electric Association, Inc.)

Additional Team Members:

Pyropower Corporation—technology supplier
Technical Advisory Group (potential users)—cofunder
Electric Power Research Institute—technical support

Location:

Nucla, Montrose County, CO (Nucla Station)

Technology:

Pyropower's atmospheric circulating fluidized-bed combustion (ACFB) system (advanced electric power generation/fluidized-bed combustion)

Plant Capacity/Production:

110 MWe

Project Funding:

Total project cost	\$54,087,000	100%
DOE	19,920,000	37
Participants	34,167,000	63

Project Objective:

To demonstrate ACFB at a scale of 110 MWe, representing a 2:1 scaleup from previously demonstrated capacities; to verify expectations of the technology's economic, environmental, and technical performance in a repowering application at a utility site; to accomplish greater than 90% SO₂ removal; to reduce NO_x emissions by 60%; and to achieve an efficiency of 34% in a repowering mode.

Technology/Project Description:

Nucla's circulating fluidized-bed system operates at atmospheric pressure. In the combustion chamber, a stream of air fluidizes and entrains a bed of coal, coal ash, and sorbent (e.g., limestone). Relatively low combustion temperatures limit NO_x formation. Calcium in the sorbent combines with SO₂ gases, and solids exit the combustion chamber and flow into a hot cyclone. The cyclone separates the solids from the gases, and the solids are recycled for combustor temperature control. Continuous circulation of coal and sorbent improves mixing and extends the contact time of solids and gases, thus promoting high utilization of the coal and high sulfur capture efficiency. Heat in the flue gas exiting the hot cyclone is recovered in the economizer. The

flue gas passes through a baghouse where the particulate matter is removed. The steam generated in the ACFB is used to generate electric power.

Three small, coal-fired, stoker-type boilers at Nucla Station were replaced with a new 925,000-lbs/hr ACFB steam generator capable of driving a new 74-MWe turbine generator. Extraction steam from this turbine generator powers three existing turbine generators (12 MWe each). Three western coals were tested: Peabody coal (0.4–0.8% sulfur), Dorchester coal (1.5% sulfur), and Salt Creek coal (0.5% sulfur).

In 1992, Colorado-Ute Electric Association, Inc., the owner of Nucla Station, was purchased by Tri-State Generation and Transmission Association, Inc.

Project Results/Accomplishments:

Between August 1988 and January 1991, a total of 72 steady-state performance tests were conducted: 22 tests at 50% load, 6 at 75% load, 2 at 90% load, and 42 at full load (110 MWe). Some key results, as reported by the sponsor, follow:

- Results indicated strong correlations of absolute CO, SO₂, and NO_x emissions levels with combustor operating temperatures. Although NSPS compliance was maintained, a penalty on limestone feed requirements for sulfur retention was realized at the higher operating temperatures. Below 1,620 °F, 70% sulfur retention was achieved with 1.5 Ca/S, and 95% sulfur retention was achieved with 4.0 Ca/S. Around 1,700 °F, Ca/S greater than 5.0 was required to maintain 70% sulfur capture.
- The NO_x emissions for all tests were less than 0.34 lb/million Btu, which was well within the state-regulated emission limit of 0.50 lb/million Btu. The average level of NO_x emissions for all tests was 0.18 lb/million Btu.
- Combustion efficiency, a measure of the quantity of carbon that is fully oxidized to CO₂, ranged from 96.9% to 98.9%. Of the four exit sources of incompletely burned carbon, the largest was carbon contained in the fly ash (93%). The next largest (5%) was carbon contained in the bottom ash stream, and the remaining feed-carbon loss (2%) was incompletely oxidized CO in the flue gas. The fourth possible source, hydrocarbons in the flue gas, was measured and found to be negligible.
- Boiler efficiencies for 68 performance tests varied from 85.6% to 88.6%. The contributions to boiler heat loss were identified as unburned carbon; sensible heat in dry flue gas; fuel and sorbent moisture; latent heat in burning hydrogen; sorbent calcination; radiation, and convection; and bottom ash cooling

water. Net plant heat rate decreased with increasing boiler load, from 12,400 Btu/kWh at 50% of full load to 11,600 Btu/kWh at full load. The lowest value achieved during a full-load steady-state test was 10,980 Btu/kWh. These values were affected by the absence of reheat, the presence of the three older 12.5-MWe turbines in the overall steam cycle, the number of unit restarts, and part-load testing.

- Over the range of operating temperatures at which testing was performed at Nucla, bed temperature was found to be the most influential operating parameter. With the possible exception of coal-feed configuration and excess air at elevated temperatures, bed temperature was the only parameter that had a measurable impact on emissions or efficiencies. Emissions of SO₂ and NO_x were found to increase with increasing combustor temperatures while CO emissions decreased with increasing temperature. Combustion efficiency also improved as the temperature was increased.

An economic evaluation indicated that the final capital costs for the Nucla ACFB system were about \$112.3 million. This represents a cost of \$1,123/net kW. Total power production costs associated with test operations were about \$54.7 million, which results in a normalized power production cost of \$63.63/MWh. Fixed costs were about 62% of the total, and variable costs were more than 38%. Nucla's power production costs proved competitive with pulverized coal units not limiting emissions as significantly.

Commercial Applications:

ACFB technology has good potential in both industrial and utility sectors for new capacity additions or for repowering existing coal-fired plants. Coal of any sulfur content can be used. Because any type or size of boiler can be repowered by ACFB using the existing plant area, coal- and waste-handling equipment, and

steam turbine equipment, the life of the plant can be extended. Benefits of ACFB include 90% SO₂ reduction, 60–80% NO_x reduction, and control of pollutants at lower costs than are offered by existing technologies.

Project Schedule:

DOE selected project (CCT-I)	10/7/87
Cooperative agreement awarded	10/3/88
NEPA process completed (MTF)	4/18/88
Environmental monitoring plan completed	2/27/88
Operational testing	8/88–1/91
Project completed/final report issued	4/92

Final Reports:

Final Technical Report	10/91
Economic Evaluation Report	3/92
Public Design Report	12/90
Performance Test Summary Reports	3/92

York County Energy Partners Cogeneration Project

Sponsor:

York County Energy Partners, L.P. (a limited partnership which includes Air Products and Chemicals, Inc.)

Additional Team Members:

P.H. Glatfelter Company—site host

Foster Wheeler Energy Corporation—technology supplier

Location:

North Codorus Township, York County, PA (greenfield site)

Technology:

Foster Wheeler's atmospheric circulating fluidized-bed (ACFB) combustor (advanced electric power generation/fluidized-bed combustion)

Plant Capacity/Production:

227 MWe (net) and 360,000 lbs/hr steam

Project Funding:

Total project cost	\$379,645,450	100%
DOE	74,733,833	20
Participant	304,911,617	80

Project Objective:

To demonstrate ACFB at 250 MWe, representing a 1.7:1 scaleup from previously constructed facilities; to verify expectations of the technology's economic, environmental, and technical performance in a greenfield cogeneration application; and to provide cogenerators, as well as utility and non-utility power producers, with the data necessary for evaluating a 250-MWe ACFB as a commercial alternative to accomplish greater than 90% SO₂ removal, to reduce NO_x emissions by 60% when compared with conventional technology, and to achieve a steam efficiency of 88%.

Technology/Project Description:

In this project, the circulating fluidized-bed combustor operates at atmospheric pressure. Coal, primary air, and a solid sorbent, such as limestone, are introduced into the lower portion of the combustor where initial combustion occurs. As coal particles decrease in size due to combustion and breakage, they are carried higher in the combustor to an area where secondary air is introduced. As the coal particles continue to be reduced in size, the coal, along with some of the sorbent, is carried out of the combustor, collected in a particle separator, and recycled to the lower portion of the combustor. The sorbent in the bed removes sulfur during the combustion process, eliminating the need for scrubbers.

Steam is generated in tubes placed along the combustor's walls and superheated in tube bundles placed in the solids-circulating stream and the flue gas stream. The steam is then used to produce power in a conventional steam cycle.

The project will demonstrate ACFB in a 250-MWe greenfield cogeneration application in York County, PA. The sponsor has an electrical power purchase agreement with Metropolitan Edison Company to supply up to 227 MWe and a steam purchase agreement with the P.H. Glatfelter Company to supply steam to the paper-making facility located adjacent to the project site.

The heat rate for this cogeneration plant is expected to be 9,200 Btu/kWh (37% efficiency). Expected SO₂ emissions from this demonstration plant are below

0.24 lb/million Btu (92% reduction). This technology operates at lower temperatures than conventional boilers, thus reducing NO_x production. In addition, installation of a selective non-catalytic reduction system planned for the facility is expected to reduce the NO_x emissions by an additional 50%.

Bituminous coals from West Virginia, Pennsylvania, and Ohio, having a nominal sulfur content of 2%, are expected to be used.

Project Status/Accomplishments:

During 1993, the project was relocated 7 miles to a new site in North Codorus, PA. The need to relocate the project has resulted in a 6–9-month delay in the schedule in order to complete the NEPA and state permitting processes. The project is in the preliminary design stage. The sponsor has finalized agreements with all major equipment vendors and with coal and limestone suppliers.

Environmental information for use in the NEPA process has been prepared. Public scoping meetings for

the new site were held in August and October 1993 to solicit public comments on preparation of the project's environmental impact statement.

Commercial Applications:

ACFB technology has good potential for application in both the industrial and utility sectors, whether for use in repowering existing plants or in new facilities. ACFB is attractive for both baseload and dispatchable power applications because it can be efficiently turned down to 25% of full load. Coal of any sulfur content can be used, and any type or size of a coal-fired boiler can be repowered. In repowering applications, an existing plant area is used, and coal- and waste-handling equipment as well as steam turbine equipment are retained, thereby extending the life of a plant.

In its commercial configuration, ACFB technology offers several potential benefits when compared to conventional pulverized coal-fired systems: lower capital costs; reduced SO₂ and NO_x emissions at lower costs;

higher combustion efficiency; and dry, granular solid waste which is easily disposed of or which may be a salable by-product.

Combustion Engineering IGCC Repowering Project

Sponsor:

ABB Combustion Engineering, Inc.

Additional Team Members:

City Water, Light and Power—cofunder and host utility
State of Illinois, Department of Energy and Natural
Resources—cofunder

Location:

Springfield, Sangamon County, IL (City Water, Light
and Power's Lakeside Station)

Technology:

ABB Combustion Engineering's integrated gasification
combined-cycle (IGCC) system (advanced electric power
generation/integrated gasification combined cycle)

Plant Capacity/Production:

65 MWe (net)

Project Funding:

Total project cost	\$270,700,000	100%
DOE	129,357,204	48
Participants	141,342,796	52

Project Objective:

To demonstrate an advanced dry-feed, air-blown, two-
stage, entrained-flow coal gasifier with a moving-bed,
zinc titanate, hot-gas cleanup system; to assess long-
term reliability and maintainability of the system at a
sufficient scale to determine commercial potential.

Technology/Project Description:

Pressurized pulverized coal is pneumatically transported to the gasifier. The gasifier essentially consists of a bottom combustor section and a top reductor section. Coal is fed into both sections. A slag tap at the bottom of the combustor allows molten slag to flow into a water-filled quench tank.

The raw, low-Btu gas and char leave the gasifier at approximately 2,000 °F and are reduced in temperature to about 1,000 °F in a heat exchanger. Char in the gas stream is captured by a high-efficiency cyclone, as well as by a subsequent fine-particulate removal system, and recycled back to the gasifier.

A newly developed process consisting of a moving bed of zinc titanate sorbent is being used to remove

sulfur from the hot gas. Particulate emissions are removed from the coal-handling system and gas stream by a combination of cyclone separators and baghouses, and a high percentage of particulates are fed back to the gasifier for more complete reaction and ultimate removal with the slag.

The cleaned low-Btu gas is routed to a combined-cycle system for electric power production. About 40 MWe (net) are generated by a gas turbine. Extracted air from the gas turbine is used to meet the high-pressure air requirements of the gasifier and the zinc titanate desulfurization system. Exhaust gases from the gas turbine are used to produce steam which is fed to a bottoming cycle to generate an additional 25 MWe (net).

The demonstration project is converting 600 tons/day of coal into 65 MWe. This is being accomplished

through the installation of an entrained-flow coal gasifier and the integration of a 25-MWe steam turbine with a 40-MWe gas turbine at City Water, Light and Power's Lakeside Station located in Springfield, IL. The anticipated heat rate for the repowered unit is 8,800 Btu/kWh (an efficiency of 38.8%). SO₂ emissions are expected to be less than 0.1 lb/million Btu (99% reduction). NO_x emissions are also expected to be less than 0.1 lb/million Btu (90% reduction).

Project Status/Accomplishments:

An environmental assessment with a finding of no significant impact was completed March 27, 1992.

System definition and preliminary design activities are complete. At the completion of preliminary engineering, a revised cost estimate was completed. The updated cost projection considerably exceeds the available funding. Efforts are currently focused on reducing the projected cost or, if necessary, restructuring the project.

Commercial Applications:

The IGCC system being demonstrated in this project is suitable for both repowering and new power plant applications. Repowering aging plants with this technology will improve plant efficiency and reduce emissions of SO₂, NO_x, and CO₂. Also, the modular design of the gasifier will permit a range of units to be considered for repowering.

Due to the advantages of modularity, rapid and staged on-line generation capability, high efficiency, fuel flexibility, environmental controllability, and reduced land and natural resource needs, the IGCC system is also a strong contender for new electric power generating facilities. Further, without the need for an oxygen plant, the ABB Combustion Engineering technology represents a potentially simpler approach to gasification-based power generation. A single-train IGCC system based on this gasifier is capable of producing more than 150 MWe. A commercial-scale facility based on the ABB Combustion Engineering technology is expected to

have a heat rate less than 8,000 Btu/kWh (efficiency greater than 43%). This heat rate is expected to realize at least a 20% improvement in efficiency compared to a conventional pulverized-coal-fired plant with flue gas desulfurization. The improved system efficiency also results in a similar decrease in CO₂ emissions.

Camden Clean Energy Demonstration Project

Sponsor:

Duke Energy Corp.

Additional Team Members:

General Electric Company—cofunder; designer and supplier of the power island equipment

Fuel Cell Engineering Corporation—designer and supplier of the fuel cell

J. Makowski Company—cofunder

British Gas plc—cofunder

Location:

Camden, Camden County, NJ (Pavonia Industrial Area)

Technology:

Integrated gasification combined-cycle (IGCC) using British Gas/Lurgi (BG/L) slagging fixed-bed gasification system coupled with Fuel Cell Engineering's molten carbonate fuel cell (advanced electric power generation/integrated gasification combined cycle)

Plant Capacity/Production:

240 MWe (net)

Project Funding:

Total project cost	\$779,950,000	100%
DOE	195,000,000	25
Participant	584,950,000	75

(Funding amounts reflect those contained in the proposal and are subject to negotiation.)

Project Objective:

To demonstrate and assess the reliability, availability, and maintainability of a utility-scale IGCC system using high-sulfur bituminous coal in an oxygen-blown, fixed-bed, slagging gasifier and the operability of a molten carbonate fuel cell fueled by coal gas.

Technology/Project Description:

Bituminous run-of-mine coal is screened to remove fines. The fines are formed into briquettes and fed to the gasifier along with the screened coal. The coal and briquettes are gasified in an oxygen-blown, pressurized, slagging fixed-bed gasifier. The raw product gas is quenched to reduce the temperature and remove tars, oils, ammonia, and particulates. The particulates and condensed tars and oils are recycled to the gasifier to ensure high cold-gas efficiency. The cooled product gas is routed to a conventional cold-gas cleanup system to remove sulfur compounds. The clean, medium-Btu gas is reheated and burned in an advanced 192-MWe (gross) gas turbine. A small slipstream of clean product gas is diverted to a gas-polishing and moisturization step and

used to fuel the 2.5-MWe (gross) molten carbonate fuel cell. Waste nitrogen from the air separation unit is also routed to the gas turbine to increase mass flow to the turbine and suppress NO_x formation. The hot exhaust gas from the gas turbine is passed through a heat recovery steam generator to produce high-pressure steam. The steam turbine is designed to produce 83 MWe (gross) using steam conditions of 1,450 lb/in² atm and 1,000 °F/1,000 °F reheat.

The process has the following subsystems: coal screening and briquetting; an air separation unit; a slagging, fixed-bed gasifier; a cold-gas cleanup system which produces a marketable sulfur by-product; a molten carbonate fuel cell capable of utilizing coal-derived fuel gas; a combustion turbine capable of using coal-derived

fuel gas; a heat recovery steam generator; and a steam turbine.

The demonstration unit is being designed to generate 240 MWe (net) using 1,850 tons/day of West Virginia bituminous coal containing 3% sulfur.

Project Status/Accomplishments:

The project is in negotiation.

Commercial Applications:

The IGCC system being demonstrated in this project is suitable for both repowering applications and new power plants. The wide variability in potential market applications and new power plants. The wide variability in potential market applications is due to several factors. First, the BG/L gasification technology has successfully used a wide variety of U.S. coals. Also, the highly modular approach to system design makes the BG/L-based IGCC and molten carbonate fuel cell competitive in a wide range of plant sizes. The high efficiency and excellent environmental performance of the system are

competitive with or superior to other fossil-fuel-fired power generation technologies. These characteristics result in a technology capable of widespread application in meeting future U.S. energy needs.

The heat rate of the IGCC demonstration facility is 8,200 Btu/kWh (41.6% efficiency) and the commercial embodiment of the system has a projected heat rate of 8,035 Btu/kWh (42.5% efficiency). The commercial version of the molten carbonate fuel cell fueled by a BG/L gasifier is anticipated to have a heat rate of 7,379 Btu/kWh (46.2% efficiency). These efficiencies represent greater than 20% reduction in emissions of CO₂ when compared to a conventional pulverized coal plant equipped with a scrubber. SO₂ emissions from the IGCC system are expected to be less than 0.1 lb/million Btu (99% reduction); NO_x emissions, less than 0.15 lb/million Btu (90% reduction).

Also, the slagging characteristic of the gasifier produces a non-leaching, glass-like slag that can be marketed as a usable by-product.

The system being demonstrated is adaptable to a wide range of plant sizes and applications due to (1) its modular design, (2) its ability to utilize a wide variety of coals, and (3) the system's improved efficiency and environmental performance over conventional coal-bed power generation technologies.

Piñon Pine IGCC Power Project

Sponsor:

Sierra Pacific Power Company

Additional Team Members:

Foster Wheeler USA Corporation—architect, engineer, and constructor

The M.W. Kellogg Company—technology supplier

Location:

Reno, Storey County, NV (Sierra Pacific Power Company's Tracy Station)

Technology:

Integrated gasification combined-cycle (IGCC) using the KRW air-blown, pressurized, fluidized-bed coal gasification system (advanced electric power generation/integrated gasification combined cycle)

Plant Capacity/Production:

95 MWe (net)

Project Funding:

Total project cost	\$269,993,100	100%
DOE	134,996,550	50
Participant	134,996,550	50

Project Objective:

To demonstrate air-blown, pressurized, fluidized-bed IGCC technology incorporating hot gas cleanup; to evaluate a low-Btu gas combustion turbine; and to assess long-term reliability, availability, maintainability, and environmental performance at a scale sufficient to determine commercial potential.

Technology/Project Description:

Dried and crushed coal is introduced into a pressurized, air-blown, fluidized-bed gasifier. Crushed limestone is added to the gasifier to capture a portion of the sulfur and to inhibit conversion of fuel nitrogen to ammonia. The sulfur reacts with the limestone to form calcium sulfide which, after oxidation, exits along with the coal ash in the form of agglomerated particles suitable for landfill.

Hot, low-Btu coal gas leaving the gasifier passes through cyclones which return most of the entrained particulate matter to the gasifier. The gas, which leaves the gasifier at about 1,700 °F, is cooled to about 1,100 °F before entering the hot-gas cleanup system. During cleanup, virtually all of the remaining particulates are removed by ceramic candle filters, and final traces of sulfur are removed in a fixed bed of metal oxide sorbent.

The hot, cleaned gas then enters the combustion turbine which is coupled to a generator designed to produce 61 MWe (gross). Exhaust gas is used to produce steam in a heat recovery steam generator. Superheated high-pressure steam drives a condensing steam turbine-generator designed to produce about 41 MWe (gross).

Due to the relatively low operating temperature of the gasifier and the injection of steam into the combustion fuel stream, the NO_x emissions are 0.069 lb/million Btu (94% reduction). Due to the combination of in-bed sulfur capture and hot gas cleanup, SO₂ emissions are 0.069 lb/million Btu (90% reduction).

In the demonstration project, 893 tons/day of coal are converted into 102 MWe (gross), or 95 MWe (net), for export to the grid. Western bituminous coal (0.5–0.9% sulfur) from Utah is the design coal; tests

using West Virginia or Pennsylvania bituminous coal containing 2–3% sulfur also are planned. The gasifier is being built at Sierra Pacific Power Company's Tracy Station, near Reno, NV.

Project Status/Accomplishments:

Design and permitting activities continued throughout 1993. In June, DOE approved incorporation of the newly announced GE Model 6FA gas turbine into the project. Piñon Pine will be the first plant anywhere to operate with the new turbine. This change resulted in an increase in the plant size from 80 to 102 MWe (gross).

In October, the Public Service Commission of Nevada approved Sierra Pacific's resource plan, which presented the Piñon Pine Project as the preferred option for new power generation. In its order, the Commission strongly weighed the fuel diversity benefits of the plant.

Information for preparation of the environmental impact statement has been developed. A preliminary draft of the EIS was completed in December 1993. A draft for public comment is anticipated in early 1994.

The construction schedule has been slipped to accommodate delays in the Nevada Commission approval process and the NEPA process.

Commercial Applications:

The Piñon Pine IGCC system concept is suitable for new power generation, repowering needs, and cogeneration applications. The net effective heat rate for a proposed greenfield plant using this technology is projected to be 7,800 Btu/kWh (43.7% efficiency), representing a 20% increase in thermal efficiency as compared to a conventional pulverized coal plant with a scrubber and a comparable reduction in CO₂ emissions. The compactness of IGCC systems reduces space requirements per unit of energy generated relative to other coal-based power generation systems, and the advantages provided by modular construction reduce the financial risk associated with new capacity additions.

The KRW IGCC technology is capable of gasifying all types of coals, including high-sulfur and high-swell-ing coals, as well as bio- or refuse-derived waste, with

minimal environmental impact. This versatility provides numerous economic advantages for the depressed mineral extraction and cleanup industries. There are no significant process waste streams that require remediation. The only solid waste from the plant is a mixture of ash and calcium sulfate, a non-hazardous waste. SO₂ emissions are expected to be below 0.045 lb/million Btu (98–99% reduction for most high-sulfur coals). NO_x emissions are expected to be below 0.053 lb/million Btu, and emissions of particulates are expected to be below 0.01 lb/million Btu.

Toms Creek IGCC Demonstration Project

Sponsor:

TAMCO Power Partners (a partnership between TP [TAMCO] Company, a subsidiary of Tampella Power Corporation, and CP [TAMCO] Company, a subsidiary of Coastal Power Production Company)

Additional Team Member:

Institute of Gas Technology—technology developer and consultant

Location:

Coeburn, Wise County, VA (Virginia Iron, Coal, and Coke Company's Toms Creek Mine)

Technology:

Integrated gasification combined-cycle (IGCC) using the Tampella U-GAS® fluidized-bed gasification system

Plant Capacity/Production:

190 MWe (55 MWe IGCC and 135 MWe pulverized coal) (net)

Project Funding:

Total project cost	\$196,570,000	100%
DOE	95,000,000	48
Participant	101,570,000	52

Project Objective:

To demonstrate an air-blown, fluidized-bed gasification, combined-cycle technology, incorporating hot gas cleanup, for generating electricity and to assess the system's environmental and economic performance for meeting future energy needs. Also to demonstrate the newly developed zinc titanate fluidized-bed hot-gas cleanup technology.

U-GAS is a registered trademark of the Institute of Gas Technology.

Technology/Project Description:

Being demonstrated is an IGCC system in which air-blown operation has replaced the more conventional oxygen-blown gasifier operation and hot gas cleanup has replaced cold gas cleanup with the usual associated sulfur recovery.

Coal is gasified in a pressurized, air-blown, fluidized-bed gasifier in the presence of a calcium-based sorbent. About 90% sulfur removal is accomplished in the gasifier. Solids entrained in the gas are collected by cyclones in two stages. The low-Btu gas, which leaves the secondary cyclone at 1,800–1,900 °F, is cooled to about 1,000 °F before entering the post-gasifier desulfurization unit where zinc titanate is used to remove the bulk of the remaining sulfur in the gas. This is accomplished in two fluidized beds. In the first bed, the sulfur is absorbed by the zinc titanate; the zinc titanate is

regenerated in the second bed. In the final hot-gas-cleaning step, a ceramic candle filter removes particulates. The gas is then sent to the gas turbine combustor which has been modified to burn low-Btu gas.

Hot exhaust gases from the gas turbine are directed to a heat recovery steam generator. The steam generated is used both for driving a conventional steam turbine generator to produce additional electricity and to provide steam feed to the gasifier.

About 430 tons/day of bituminous coal are converted into 55 MWe by the gas turbine. A conventional pulverized coal boiler produces another 135 MWe through the shared steam turbine generator. Also, 50,000 lbs/hr of steam are generated for export to a coal preparation plant located next to the demonstration facility. The electric power is sold to a utility.

The facility is a greenfield plant located outside Coeburn, VA, next to the Toms Creek Mine owned by Virginia Iron, Coal, and Coke Company, a subsidiary of Coastal Power Production Company.

Project Status/Accomplishments:

During 1993, efforts have been geared toward obtaining a power sales agreement with a third party purchaser of power. Preliminary design and project definition studies are under way. Environmental information is being prepared for use in the NEPA process.

Commercial Applications:

The Toms Creek IGCC system is suitable for new power plants, repowering needs, and cogeneration applications.

In recent years, IGCC has become a rapidly emerging alternative for new electric generating plants. Such plants require 15% less land area than pulverized coal plants with flue gas desulfurization, and exhibit substantially improved thermal efficiency and environmental

performance. Because of its advantages of modularity, rapid and staged on-line generation capability, high efficiency, environmental controllability, and reduced land and natural resource needs, IGCC is a strong contender for widespread application for meeting future U.S. energy needs. Another important application for IGCC is cogeneration under PURPA's Qualifying Facilities provisions.

The heat rate of the demonstration facility is expected to be 8,720 Btu/kWh (39% efficiency) with SO₂ emissions reductions of 99% (0.056 lb/million Btu release). NO_x emissions are estimated to be 0.09 lb/million Btu.

A larger, commercial-scale, 271-MWe greenfield facility based on the Toms Creek technology is estimated to have a heat rate of 7,750 Btu/kWh (44% efficiency). This represents a 20% increase in thermal efficiency and a corresponding reduction in CO₂ emissions as compared to a conventional pulverized coal plant equipped with a scrubber.

The U-GAS® technology is capable of gasifying all types of coals, including high-sulfur and high-swelling coal feedstocks.

The total system being demonstrated is compact, reducing space requirements, and is very amenable to smaller capacity, modular construction situations. There are no significant wastewater streams, and the solid waste from the gasifier is ash and calcium sulfate, which is discharged as a nonhazardous waste.

Tampa Electric Integrated Gasification Combined-Cycle Project

Sponsor:

Tampa Electric Company

Additional Team Members:

Texaco Development Corporation—gasification technology supplier

General Electric Company—combined-cycle technology supplier

GE Environmental Systems, Inc.—hot-gas cleanup technology supplier

TECO Power Services Corporation—project manager and marketer

Bechtel Power Corporation—architect and engineer

Location:

Lakeland, Polk County, FL (Tampa Electric Company's Polk Power Station)

Technology:

Integrated gasification combined-cycle (IGCC) system using Texaco's pressurized, oxygen-blown, entrained-flow gasifier technology and incorporating both conventional, low-temperature acid-gas removal and hot-gas moving-bed desulfurization (advanced electric power generation/integrated gasification combined cycle)

Plant Capacity/Production:

250 MWe (net)

Project Funding:

Total project cost	\$260,706,446	100%
DOE	130,353,223	50
Participants	130,353,223	50

Project Objective:

To demonstrate the IGCC technology in a greenfield, commercial, electric utility application at the 250-MWe

size with a Texaco gasifier. To demonstrate the integrated performance of a zinc-titanate hot-gas cleanup system, conventional cold-gas cleanup, and an advanced gas turbine with nitrogen injection (from the air separation plant) for power augmentation and NO_x control.

Technology/Project Description:

Texaco's pressurized, oxygen-blown, entrained-flow gasifier is used to produce a medium-Btu fuel gas. Coal/water slurry and oxygen are combined at high temperature and pressure to produce a high-temperature syngas. Molten coal-ash flows out of the bottom of the vessel and into a water-filled quench tank where it is turned into a solid slag. The syngas from the gasifier moves to a high-temperature heat-recovery unit which cools the gases.

The cooled gases flow to a particulate-removal section before entering gas-cleanup trains. About 50% of the syngas is passed through a moving bed of zinc-titanate absorbent to remove sulfur. The remaining syngas is further cooled through a series of heat exchangers before entering a conventional gas-cleanup train where sulfur is removed by an acid-gas removal system. These cleanup systems combined are expected to maintain sulfur levels below 0.21 lb/million Btu (96% capture). The cleaned gases are then routed to a combined-cycle system for power generation. A gas turbine generates about 192 MWe. Thermally generated NO_x is controlled to below 0.27 lb/million Btu by injecting nitrogen as a diluent in the turbine's combustion section. A heat-recovery steam-generator uses heat from the gas-turbine exhaust to produce high-pressure steam. This

steam, along with the steam generated in the gasification process, is routed to the steam turbine to generate an additional 130 MWe (gross). The IGCC heat rate for this demonstration is expected to be approximately 8,600 Btu/kWh (40% efficient). Coals being used in the demonstration are Illinois 6 and Pittsburgh 8 bituminous coals having sulfur contents ranging 2.5–3.5%.

By-products from the process—sulfuric acid and slag—can be sold commercially, sulfuric acid by-products as a raw material to make agricultural fertilizer and the nonleachable slag for use in roofing shingles and asphalt roads and as a structural fill in construction projects.

Project Status/Accomplishments:

The project has completed the preliminary design stage. All key subcontracts and licensing have been negotiated and awarded. Bechtel Power Corporation was selected as the architect and engineer for the site and a revised cost estimate for the project was developed.

The permitting process for Florida is nearing completion. Tampa Electric's site certification application was presented before the state hearing officer in October 1993. Based on the positive comments received at the hearing, all required state permits are expected during January 1994. EPA and DOE are continuing the process of developing the EIS for the Polk Power Plant. EPA expects to release a draft EIS for public comment in early 1994. The project schedule has been revised to accommodate delays in the NEPA process and time for checkout and start-up activities.

Commercial Applications:

The IGCC system being demonstrated in this project is suitable for new electric power generation, repowering needs, and cogeneration applications. The net effective heat rate for the Texaco-based IGCC is expected to be below 8,500 Btu/kWh, which makes it very attractive for baseload applications. Commercial IGCCs should achieve better than 98% SO₂ capture with NO_x emissions reduced by 90%.

The Texaco-based system has already been proven capable of handling both subbituminous and bituminous coals. This demonstration project is scaling up the technology from Cool Water's 100-MWe to the 250-MWe size.

Wabash River Coal Gasification Repowering Project

Sponsor:

Wabash River Coal Gasification Repowering Project
Joint Venture (a joint venture of Destec Energy, Inc., and
PSI Energy, Inc.)

Additional Team Members:

PSI Energy, Inc.—host utility
Destec Energy, Inc.—engineer, gas plant operator, and
technology supplier

Location:

West Terre Haute, Vigo County, IN (PSI Energy's
Wabash River Generating Station)

Technology:

Integrated gasification combined-cycle (IGCC) using
Destec's two-stage, entrained-flow gasification system
(advanced electric power generation/integrated
gasification combined cycle)

Plant Capacity/Production:

262 MWe (net)

Project Funding:

Total Project cost	\$396,000,000	100%
DOE	198,000,000	50
Participant	198,000,000	50

Project Objective:

To demonstrate utility repowering with a two-stage,
oxygen-blown IGCC system, including advancements in
the technology relevant to the use of high-sulfur bitumi-
nous coal, and to assess long-term reliability, availability,
and maintainability of the system at a fully commercial
scale.

Technology/Project Description:

Coal is ground, slurried with water, and gasified in a pressurized, two-stage (entrained flow slagging first stage and non-slagging second stage), oxygen-blown, entrained-flow gasifier. The product gas is cooled through heat exchangers and passed through a conventional cold gas cleanup system which removes particulates, ammonia, and sulfur. The clean, medium-Btu gas is then reheated and burned in an advanced 192-MWe (gross) gas turbine. Hot exhaust from the gas turbine is passed through a heat recovery steam generator to produce high-pressure steam. High-pressure steam is also produced from the gasification plant and superheated in the heat recovery steam generator. The combined high-pressure steam flow is supplied to an existing 104-MWe (gross) steam turbine.

The process has the following subsystems: a coal-grinding and slurry system, an entrained-flow coal gasifier, a cold gas cleanup system which produces a marketable sulfur by-product, a combustion turbine capable of using coal-derived fuel gas, a heat recovery steam generator, and a repowered steam turbine.

One of six units at PSI Energy's Wabash River Generating Station, located in West Terre Haute, IN, is being repowered. The demonstration unit will be designed to generate 262 MWe (net) using 2,544 tons/day of high-sulfur (2.3–5.9% sulfur), Illinois Basin bituminous coal. The anticipated heat rate for the repowered unit is approximately 9,000 Btu/kWh (38% efficiency). Using high-sulfur bituminous coal, SO₂ emissions are expected to be less than 0.2 lb/million Btu (98% reduction). NO_x emissions are expected to be less than

0.1 lb/million Btu (90% reduction). Upon completion, the project will represent the largest single-train IGCC plant in operation in the United States.

Project Status/Accomplishments:

The Indiana Utility Regulatory Commission issued Certificates of Public Convenience and Necessity on May 26, 1993. Project construction was officially initiated in a ceremony at the site on July 7, 1993. Major equipment procurement and construction are in progress.

Following the completion of an environmental assessment, DOE issued a finding of no significant impact on May 28, 1993, concluding the NEPA process. All required environmental permits have been granted.

The schedule has been revised to accommodate delays associated with the NEPA process and air emissions permitting.

Commercial Applications:

Throughout the United States, particularly in the Midwest and East, there are more than 95,000 MWe of existing coal-fired utility boilers which will be over 30 years old in 1996. Many of these aging plants are without air pollution controls and are candidates for repowering with IGCC technology. Repowering of these plants with IGCC systems will improve plant efficiencies and reduce SO₂, NO_x, and CO₂ emissions. The modularity of the gasifier technology will permit a range of units to be considered for repowering and the relatively short construction schedule for the technology will allow utilities greater flexibility in designing strategies to meet load requirements. Also, the high degree of fuel flexibility inherent in the gasifier design allows utilities greater choices in fuel supplies to meet increasingly stringent air quality regulations.

Due to the advantages of modularity, rapid and staged on-line generation capability, high efficiency, fuel flexibility, environmental controllability, and reduced land and natural resource needs, the IGCC system is also a strong contender for new electric power generating facilities. Commercial offerings of the technology will be based on a 300-MWe train which is ideally suited to utility-scale power generation applications. The system heat rate for a new power plant based on this technology is expected to realize at least a 20% improvement in efficiency compared to a conventional pulverized-coal-fired plant with flue gas desulfurization. The improved system efficiency also results in a similar decrease in emissions of CO₂.

Healy Clean Coal Project

Sponsor:

Alaska Industrial Development and Export Authority

Additional Team Members:

Golden Valley Electric Association—host utility

Stone and Webster Engineering Corp.—
engineer

TRW, Inc.—technology supplier

Joy Technologies, Inc.—technology supplier

Location:

Healy, Denali Borough, AK (adjacent to Healy Unit #1)

Technology:

TRW's advanced entrained (slagging) combustor

Joy Technologies' spray dryer absorber with sorbent
recycle

(advanced electric power generation/advanced
combustion/heat engines)

Plant Capacity/Production:

50 MWe (nominal electric output)

Project Funding:

Total project cost	\$227,000,000	100%
DOE	109,513,000	48
Participants	117,487,000	52

Project Objective:

To demonstrate an innovative new power plant design featuring integration of an advanced combustor and heat recovery system coupled with both high- and low-temperature emissions control processes.

Technology/Project Description:

The project is to be a nominal 50-MWe facility consisting of two pulverized-coal-fired combustor systems. Emissions of SO_2 and NO_x will be controlled using TRW's slagging combustion systems with staged fuel and air, a boiler that controls fuel- and thermal-related conditions, and limestone injection. Further SO_2 will be removed using Joy's activated recycle spray dryer absorber system. Performance goals are NO_x emissions of less than 0.2 lb/million Btu, particulates of 0.015 lb/million Btu, and SO_2 removal greater than 90%. The performance coal consists of 50% run-of-mine and 50% waste coal, with the waste coal having a lower heating value and significantly more ash.

A coal-fired precombustor increases the air inlet temperature for optimum slagging performance. The TRW slagging combustors are bottom-mounted on the

boiler hopper. The main slagging combustor consists of a water-cooled cylinder which slopes toward a slag opening. The precombustor burns 25–40% of the total coal input. The remaining coal is injected axially into the combustor, rapidly entrained by the swirling precombustor gases and additional air flow, and burned under substoichiometric (fuel-rich) conditions for NO_x control. The ash forms drops of molten slag which accumulate on the water-cooled walls and are driven by aerodynamic and gravitational forces through a slot into the slag recovery section. About 70–80% of the coal's ash is removed as molten slag. The hot gas is then ducted to the furnace where, to ensure complete combustion, additional air is supplied from the tertiary air windbox to NO_x ports and to final over-fire air ports located in the furnace.

Pulverized limestone (CaCO_3) for SO_2 control is fed into the combustor where most is flash calcined. The mixture of this lime (CaO) and the ash not slagged, called flash-calcined material, is removed in the fabric filter (baghouse) system. A small part of the flash-calcined material is disposed of, but most is conveyed to a mixing tank where water is added to form a 45% flash-calcined-material solids slurry. The slurry leaving the mixing tank is pumped to a grinding mill where it is mechanically activated by abrasive grinding. Feed slurry is pumped from the feed tank to the spray dryer absorber where the slurry is atomized using Joy dry scrubbing technology. SO_2 in the flue gas reacts with the slurry as water is simultaneously evaporated. SO_2 is further removed from the flue gas by reacting with the dry flash-calcined material on the baghouse filter bags.

The project site is adjacent to the existing Healy Unit #1 near Healy, AK. Power will go to the Golden Valley Electric Association. The plant will provide

3 years of data, with 2 years of data being provided at no cost to DOE. A hazardous air pollutant monitoring program will also be implemented.

In order to address concerns regarding the potential impact to the nearby Denali National Park and Preserve, DOE, the National Park Service, Golden Valley and the project sponsor entered into an agreement to reduce the emissions from Unit #1. As a result, the combined emissions from the two units should be only slightly greater than those currently emitted from Unit #1 alone. The agreement also provides that the total site emissions will be further reduced (to current levels if necessary) in order to protect the park.

Project Status/Accomplishments:

Test burns using Healy project fuel were completed at TRW's Cleveland facility. Joy/Niro testing of flash calcined sorbent was completed at the Copenhagen facility. A full-scale precombustor was constructed and test fired at TRW's Capistrano, CA, test facility to verify

scaleup designs. The design and engineering is complete; construction is scheduled to start in March 1994.

A final EIS was issued in December 1993; and a record of decision is scheduled for March 1994.

Commercial Applications:

This technology has a wide range of applications. It is appropriate for any size utility or industrial boiler in new and retrofit uses. It can be used in coal-fired boilers as well as in oil- and gas-fired boilers because of its high ash removal capability. However, cyclone boilers may be the most amenable type to retrofit with the slagging combustor because of the limited supply of high-Btu, low-sulfur, low-ash-fusion-temperature coal that cyclone boilers require. The commercial availability of cost-effective and reliable systems for SO_2 , NO_x , and particulate control is important to potential users planning new capacity, repowering, or retrofits to existing capacity in order to comply with CAAA of 1990 requirements.

Coal Diesel Combined-Cycle Project

Sponsor:

Arthur D. Little, Inc.

Additional Team Members:

Ohio Coal Development Office—cofunder

The Easton Utilities Commission—host

Cooper Energy Services (Cooper-Bessemer

Reciprocating Products Division is a division of Cooper Energy Services which is owned by Cooper Industries.)—engine supplier and commercializer

CQ, Inc.—coal-slurry supplier

POWERSERVE Inc.—cleanup system designer

Location:

Easton, Talbot County, MD (The Easton Utilities Commission's Plant #2)

Technology:

Cooper-Bessemer's coal-fueled diesel engine combined-cycle (CDCC) system (advanced electric power generation/advanced combustion/heat engines)

Plant Capacity/Production:

14 MWe (net)

Project Funding:

Total project cost	\$37,309,516	100%
DOE	18,654,758	50
Participant	18,654,758	50

(Funding amounts reflect those contained in the proposal and are subject to negotiation.)

Project Objective:

To demonstrate an advanced, coal-fueled diesel engine combined-cycle system based on Cooper-Bessemer's LSB/LSVB diesel engine series. To provide critical data on the performance, reliability, and wear information of all major subsystems.

Technology/Project Description:

The project is centered around two Cooper-Bessemer medium-speed (400 rpm) diesel engines (6.3 MWe each) modified to operate on coal-water fuel. Engine modifications include a larger camshaft and fuel cams, modified engine block, hardened piston rings and liners, and hardened turbocharger blades. The CDCC system utilizes a coal-water fuel with a nominal 50% solids loading with a 2% ash clean coal. The clean coal is ground and slurried with water and then injected into each of the engine's 20 cylinders. The exhaust gases from the engine pass through an integrated emission-control system capable of reducing pollutants while protecting the engine's turbocharger and maintaining high engine and overall system efficiency (45%). The exhaust gases pass through a heat recovery steam boiler coupled to a steam

turbine and generator to supply an additional 1.4 MWe. Critical data on performance, reliability, and wear are being collected for all major subsystems including the coal-water fuel metering and injection system, medium-speed diesel, lube oil protection system, exhaust cyclone, turbocharger, heat recovery steam boiler, steam turbine, and exhaust emission cleanup system.

The exhaust emission cleanup system incorporates cyclones to remove the larger particulates, a selective catalytic recovery system for NO_x control, a duct sorbent injection system for SO₂ control, and baghouse for final collection of ash particulates and spent sorbent.

The demonstration site is The Easton Utilities Commission's Plant #2 in Easton, MD. Planned for use is an Ohio bituminous coal with characteristics suitable for cleaning to ash levels of about 2% (sulfur content undetermined).

Advanced Electric Power Generation

Project Status/Accomplishments:

The project is in negotiation. Environmental information is being prepared for use in the NEPA process.

Commercial Applications:

The CDCC system is particularly suited for small (below 50 MWe) electric power generation markets. Projected markets include small nonutility generators and repowering applications for small coal-fired boilers. The net effective heat rate for the mature CDCC is expected to be 6,830 Btu/kWh (48%), which makes it very competitive with similarly sized coal- and fuel-oil-fired installations. Environmental emissions from commercial CDCCs should be reduced to levels between 50% and 70% below NSPS.

Cooper-Bessemer is currently the largest U.S. manufacturer of large-scale diesel engines and commands a significant share of the U.S.-based market in that size range. The CDCC system has already achieved over 200 hours of operation using coal-water fuel in a

6-cylinder engine at Cooper's test facilities in Ohio. Over 6,000 hours of coal-water fuel operation in 20-cylinder engines are planned for this project. Demonstration of the long-term reliability of the critical components in the CDCC system will provide power generators with an efficient and environmentally superior option for future power.

Warren Station Externally Fired Combined-Cycle Demonstration Project

Sponsor:

Pennsylvania Electric Company

Additional Team Members:

Hague International—technology developer and supplier
Black & Veatch—engineer and construction manager

Location:

Warren, Warren County, PA (Pennsylvania Electric Company's Warren Station Unit 2)

Technology:

Hague International's externally fired combined-cycle (EFCC) system using a novel, high-temperature, ceramic gas-to-air heat exchanger (advanced electric power generation/advanced combustion/heat engines)

Plant Capacity/Production:

62.4 MWe (net)

Project Funding:

Total project cost	\$146,438,000	100%
DOE	73,219,000	50
Participant	73,219,000	50

(Funding amounts reflect those contained in the proposal and are subject to negotiation.)

Project Objective:

To demonstrate an externally fired combined-cycle system through the use of a novel ceramic heat exchanger and to assess the system's environmental and economic performance for meeting future energy needs. Along with the heat exchanger, the system will demonstrate a ceramic slag screen for removal of combustion by-products from the product gas prior to entering the heat ex-

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changer; a staged, wet bottom, low- NO_x combustor; and the integration of the above with a gas turbine and a steam turbine.

Technology/Project Description:

In this project, an existing coal-fueled steam plant is being repowered by adding an externally fired gas turbine to form a combined-cycle system. The central feature of the EFCC is a ceramic air heater or heat exchanger (CerHx®) and an atmospheric combustor which together replace a conventional combustion system in an open-cycle gas turbine.

Coal is first combusted in a staged combustor for NO_x control. Particulate-laden gases exit the combustor and enter the slag screen where all particles larger than about 10 microns are collected. Air from the turbine

compressor is heated by exchange with the hot product gas in the CerHx®. The product gas is then passed through a heat recovery steam generator, where more heat is extracted to drive a steam turbine generator and produce electricity. The product gas is finally passed through a gas cleanup system consisting of a flue gas desulfurizer and a fabric filter before exiting to the atmosphere through the stack. The hot air from the CerHx® is passed through a gas turbine to produce additional electricity before firing the combustor.

The attractiveness of the EFCC lies in its ability to eliminate the need for a hot gas cleanup system to protect the costly gas turbine gas-path components from the corrosive and abrasive elements in the combustion product gas. Instead, the gas turbine operates on indirectly

heated clean air and the gas path is never exposed to the corrosive elements in the fuel or product gas. The CerHx® raises the temperature of the air to the turbine inlet conditions using tube elements that are manufactured from corrosion resistant, toughened, ceramic materials.

About 225,000 tons/yr of bituminous coal will be combusted to produce 62.4 MWe. The gas turbine will generate 18.3 MWe with a small amount of steam injection and the existing steam turbine will generate 47.7 MWe, for a total gross output of 66 MWe. Approximately 3.6 MWe will be consumed internally. The heat rate of the demonstration facility will be 9,650 Btu/kWh (HHV), which is a 31.3% improvement over the existing Warren Station unit. Potential SO_x release is reduced by over 90% through capture in the flue gas desulfurization system. NO_x emissions are expected to be below 0.13 lb/million Btu.

The facility being repowered is Pennsylvania Electric Company's Warren Station Unit 2 near Warren, PA.

The primary coal for the project is Pennsylvania bituminous coal containing either 1.0% or 2.3% sulfur, depending on the mine. A secondary test coal is Pennsylvania bituminous coal containing 1.6% sulfur.

Project Status/Accomplishments:

The project is in negotiation. Environmental information is being prepared for use in the NEPA process.

Commercial Applications:

The Warren Station EFCC system concept is suitable for new electric power generation, repowering needs, and cogeneration applications. The potential commercial market for such systems is expected to be about 24 GWe by 2010. The net effective heat rate for a 300-MWe greenfield plant using this technology is projected to be 7,790 Btu/kWh. This represents a 20% increase in thermal efficiency compared to a conventional pulverized coal plant with a scrubber.

SO₂ is expected to be below 0.081 lb/million Btu, which is a reduction of over 90% for most coals. NO_x emissions are expected to be less than 0.15 lb/million Btu and particulate emissions (PM10) are expected to be below 0.015 lb/million Btu.

**Environmental Control
Devices
Fact Sheets**

Demonstration of Coal Reburning for Cyclone Boiler NO_x Control

Project completed.

Sponsor:

The Babcock & Wilcox Company

Additional Team Members:

Wisconsin Power and Light Company—cofunder and host utility

Sargent and Lundy—engineer for coal handling

Electric Power Research Institute—cofunder

State of Illinois, Department of Energy and Natural Resources—cofunder

Utility companies (14 cyclone boiler operators)—cofunders

Location:

Cassville, Grant County, WI (Nelson Dewey Station, Unit No. 2)

Technology:

The Babcock & Wilcox Company's coal-reburning system (environmental control devices/NO_x control technologies)

Plant Capacity/Production:

100 MWe

Project Funding:

Total project cost	\$13,646,609	100%
DOE	6,340,788	46
Participants	7,305,821	54

Project Objective:

To evaluate the applicability of reburning technology for reducing NO_x emissions from a full-scale coal-fired cyclone boiler, pulverizing a portion of the primary coal fuel to use as the secondary, "reburning" fuel; and to

achieve greater than 50% reduction in NO_x emissions with no serious impact on cyclone combustor operation, boiler efficiency, boiler fireside performance (corrosion and deposition), or ash removal system performance.

Technology/Project Description:

The coal-reburning process reduces NO_x in the furnace through the use of multiple combustion zones. The main combustion zone uses 70–80% of the total heat equivalent fuel input to the boiler and slightly less than normal combustion air input. The balance of the coal (20–30%), along with significantly less than the theoretically determined requirement of air, is fed to the reburning zone above the cyclones to create an oxygen-deficient condition. The NO_x formed in the cyclone burners reacts with the resultant reducing flue gas and is converted into nitrogen in this zone. The completion of the combustion

process occurs in the third zone, called the burnout zone, where the balance of the combustion air is introduced. The combined production of boiler slag and dry waste from the electrostatic precipitator remains unchanged with coal reburning because the required coal input for the same boiler load is the same.

The coal-reburning technology can be applied with the cyclone burners operating within their normal, non-corrosive, oxidizing conditions, thereby minimizing any adverse effects of reburn on the cyclone combustor and boiler performance.

This project involved retrofitting an existing 100-MWe cyclone boiler that is representative of a large population of cyclone units. The boiler is located at Wisconsin Power and Light's Nelson Dewey Station in Cassville, WI.

Project Results/Accomplishments:

Coal-reburn tests were conducted to determine the reduction in NO_x emissions for the coal-reburning technology over a range of boiler loads varying from 37 MWe to 118 MWe (nominal maximum boiler load is 110 MWe). Two coals were tested, namely, the design Illinois Basin bituminous coal (Lamar, 1.8% sulfur) and a western subbituminous coal (Powder River Basin, 0.5% sulfur). The bituminous coal tests evaluated a fuel typical of the coals fired by utilities operating cyclones. The subbituminous coal tests evaluated coal switching for SO_2 reduction.

As a part of the test program, several parameters were optimized over the load range to achieve the optimum NO_x reduction while keeping other variables, such as unburned carbon and carbon monoxide emissions, within reasonable limits. The optimized parameters included the split of boiler fuel between the reburn system and the cyclone burners, the reburn burner and the reburn zone stoichiometries, the reburn burner pulverized coal fineness, flue gas recirculation, and economizer outlet O_2 content. Also, adjustments were made to the reburn burners and the over-fire air ports during the tests.

With the Lamar coal, the boiler NO_x emissions were reduced as follows:

- 52% (to 290 ppm or 0.394 lb/million Btu) at 110 MWe
- 47% (to 285 ppm or 0.387 lb/million Btu) at 82 MWe
- 36% (325 ppm or 0.442 lb/million Btu) at 60 MWe

With Powder River Basin coal, the NO_x emissions were reduced as follows:

- 62% (to 208 ppm or 0.278 lb/million Btu) at 110 MWe
- 55% (to 215 ppm or 0.287 lb/million Btu) at 82 MWe
- 53% (to 220 ppm or 0.294 lb/million Btu) at 60 MWe

Reburn testing with both coals indicated that varying reburn zone stoichiometry is the most critical factor in controlling NO_x . Reburn zone stoichiometry can be varied by altering air flow quantities to the reburn burners, percent reburn heat input, flue gas recirculation flow rate, or cyclone stoichiometry.

Burning subbituminous coal produced lower overall NO_x emissions levels and higher NO_x emissions reductions. This result is probably due to the higher volatile content of the western coal. The higher volatile content generates higher concentrations of hydrocarbon radicals in the reburn zone. With the reburn system contributing additional burning capacity for the cyclone boiler, the lower Btu content western fuel could be fired up to the full boiler load rating.

Additional effects of coal reburning on the retrofitted boiler follow:

- Loss of combustion efficiency, due to increased unburned carbon, amounted to 1.5% at full load with bituminous coal and 0.3% with subbituminous coal.
- The performance of the ESP remained constant even though its ash loading doubled. The increased ash consisted of larger sizes of particulates.
- The furnace exit gas temperature decreased by more than 100 °F at full load, contrary to expectations, and thus improved the boiler heat absorption efficiency correspondingly.
- Slagging and fouling were significantly reduced with bituminous coal reburning. The subbituminous reburn operations were too short in duration to make a reasonable observation.
- No furnace corrosion was observed over the 1-year test period.

Hazardous air pollutants (HAP) testing was performed using Lamar test coal. HAP emissions were generally

well within expected levels and emissions with reburn comparable to baseline operations.

Commercial Applications:

The current reburn market is nearly 26,000 MWe and consists of about 120 units ranging from 100 MWe to 1,150 MWe, with most in the 100–300-MWe range. Coal reburning is a retrofit technology applicable across the size range of utility and industrial cyclone boilers.

The principal environmental benefit is reduced NO_x emissions. A secondary benefit may be reduced SO_2 emissions by enabling greater use of lower sulfur western coal; due to its lower Btu content, western coals limit cyclone capacity. With the additional firing capacity of the reburn system, full-load performance on western coal may be possible for some cyclone units.

For cyclone boilers, coal reburning offers a NO_x reduction alternative at a cost expected to be in the range of \$65/kW for 100 MWe units to \$40/kW for a larger 600 MWe unit. This includes costs for coal handling and pulverizers/coal piping. Coal's cost differential and dependability of supply give it the long-run advantage. Another advantage of the reburn system is its ability to utilize different coals.

Project Schedule:

DOE selected project (CCT-II)	9/28/88
Cooperative agreement awarded	4/2/90
NEPA process completed (EA)	2/12/91
Environmental monitoring plan completed	11/18/91
Construction	11/90–11/91
Operational testing	11/91–12/92
Project completed	12/93

Final Reports:

Final Technical Report	early 1994
Economic Evaluation Report	early 1994
Public Design Report	8/91

Full-Scale Demonstration of Low-NO_x Cell™ Burner Retrofit

Project completed.

Sponsor:

The Babcock & Wilcox Company

Additional Team Members:

The Dayton Power and Light Company—cofunder and host utility

Electric Power Research Institute—cofunder

Ohio Coal Development Office—cofunder

Tennessee Valley Authority—cofunder

New England Power Company—cofunder

Duke Power Company—cofunder

Allegheny Power System—cofunder

Centerior Energy Corporation—cofunder

Location:

Aberdeen, Adams County, OH (Dayton Power and Light Company's J.M. Stuart Plant, Unit No. 4)

Technology:

The Babcock & Wilcox Company's Low-NO_x Cell™ burner (LNCB™) system (environmental control devices/NO_x control technologies)

Plant Capacity/Production:

605 MWe

Project Funding:

Total project cost	\$11,233,392	100%
DOE	5,442,800	48
Participants	5,790,592	52

Low-NO_x Cell, LNC, and LNCB are trademarks of The Babcock & Wilcox Company.

Project Objective:

To demonstrate through the first commercial-scale full burner retrofit the cost-effective reduction of NO_x from a large base-load coal-fired utility boiler with Low-NO_x Cell™ burner technology; and to achieve at least a 50% NO_x reduction without degradation of boiler performance at less cost than conventional low-NO_x burners.

Technology/Project Description:

Low-NO_x Cell™ burner technology replaces the upper coal nozzle of the standard two-nozzle cell burner with a secondary-air port. The lower burner coal nozzle is enlarged to the same fuel input capacity as the two standard coal nozzles. The Low-NO_x Cell™ burner operates on the principle of staged combustion to reduce NO_x emissions. Approximately 70% of the total air (primary,

secondary, and excess air) is supplied through or around the coal-feed nozzle. The remainder of the air is directed to the upper port of each cell to complete the combustion process. The fuel-bound nitrogen compounds are converted to nitrogen gas, and the reduced flame temperature minimizes the formation of thermal NO_x.

The net effect of this technology is greater than 50% reduction in NO_x formation with no boiler pressure part changes and no impact on boiler operation or performance. In addition, the technology is compatible with most commercial and emerging SO₂ control technologies, including confined zone dispersion, gas suspension absorption, duct injection, and advanced wet scrubbers.

The demonstration was conducted at a large-scale power plant operated by The Dayton Power and Light Company and jointly owned with the Cincinnati Gas and

Electric Company and the Columbus Southern Power Company. The boiler unit is a Babcock & Wilcox-designed, supercritical, once-through boiler equipped with an electrostatic precipitator. This unit contained 24 two-nozzle cell burners arranged in an opposed-firing configuration. Twelve burners (arranged in two rows of six burners each) were mounted on each of two opposing walls of the boiler. All 24 standard cell burners were removed, and 24 new Low-NO_x Cell™ burners were installed. Alternate Low-NO_x Cell™ burners on the bottom rows were inverted, with the air port then being on the bottom to insure complete combustion in the lower furnace.

Project Results/Accomplishments:

The initial test results on the LNCB™ were disappointing. Reducing gases containing high concentrations of carbon monoxide and hydrogen sulfide accumulated in the lower furnace below the burners, and the NO_x emissions reduction was only about 35%. By numerically modelling several possible burner configurations, Babcock & Wilcox was able to select an optimum new burner arrangement. On the lower row of burners, alternate LNC™ burners were inverted so that the air ports integral to these burners directed air into the lower furnace. Also, a design change for the burners' coal impellers increased the NO_x reduction to above the design goal.

The LNC™ burner demonstration emphasized evaluation of boiler performance, boiler life, and environmental impact. Key boiler performance parameters included boiler output (steam temperatures); flue gas temperatures at the furnace, economizer, and air heat exits; the slagging tendencies of the unit; and unburned carbon losses. Boiler life potentials (corrosion tendencies) were measured by gas sampling for high H₂S concentrations in the furnace, ultrasonic testing of lower furnace tube walls, and destructive examination of a

corrosion test panel. Environmentally, NO_x, CO, CO₂, total hydrocarbons, and particulate matter were measured at varying test conditions.

At full load (605 MWe) with all mills in service, average NO_x emissions were 0.53 lb/million Btu, a 54.4% reduction from the baseline. CO emissions ranged from 28 to 55 ppm. Flyash unburned carbon averaged 1.12%, for a 0.2% loss unburned carbon efficiency. This is a 56% improvement over baseline unburned carbon losses, probably resulting from improved air flow distribution achieved by the LNC™ burner retrofit. At reduced loads of 460 MWe and 350 MWe, the NO_x emissions reductions were 54% and 48% respectively, and CO emissions and unburned carbon values were comparable with baseline emissions.

Long-term NO_x emissions data were accumulated using a third-party continuous emissions monitor over an 8-month test period that followed the parametric and optimization test periods. On days when the boiler was operating at 590 MWe or above, and with all mills in service, NO_x emissions averaged 0.49 lb/million Btu, a 58% reduction from baseline emissions. This data set covered 79 days.

Overall unit efficiency remained essentially unchanged from baseline to optimized LNC™ burner operation. The demonstration boiler is operating at a lower overall excess air since the optimization testing, which has reduced the dry gas loss and increased the boiler efficiency slightly.

A corrosion test panel was installed when the LNC™ burners were installed. The panel consisted of SA-213T2 bare tube material with some of this material aluminized, some stainless weld overlaid, and some chromized. This level of corrosion is roughly equivalent to the boiler's corrosion prior to the retrofit. The coated materials had no loss.

Commercial Applications:

Currently there are 34 operating cell-burner-fired boilers for which the LNCB™ system is applicable. Of these boilers, 29 are opposed-wall-fired with two rows of two-nozzle cells. The average size is 766 MWe.

The low cost and short outage time for retrofit make the LNCB™ design attractive. Typically, the retrofit capital-cost will be \$5.50–\$8.00/kW in 1993 dollars, based upon DOE's 500-MWe reference unit. The outage time can be as short as 5 weeks because of the "plug-in" design. The LNCB™ system can be installed at about half the cost and outage time for other commercial low-NO_x burner installations.

Project Schedule:

DOE selected project (CCT-III)	12/19/89
Cooperative agreement awarded	10/11/90
NEPA process completed (MTF)	8/10/90
Environmental monitoring plan completed	8/9/91
Construction	9/91–11/91
Operational testing	12/91–4/93
Project completed	12/93

Final Reports:

Final Technical Report	early 1994
Economic Evaluation Report	early 1994
Public Design Report	8/91

Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler

Sponsor:

Energy and Environmental Research Corporation

Additional Team Members:

Public Service Company of Colorado—cofunder and host utility

Gas Research Institute—cofunder

Colorado Interstate Gas Company—cofunder

Electric Power Research Institute—cofunder

Location:

Denver, Adams County, CO (Public Service Company of Colorado's Cherokee Station, Unit No. 3)

Technology:

Energy and Environmental Research Corporation's gas reburning and low-NO_x burner (GR-LNB) system (environmental control devices/NO_x control technologies)

Plant Capacity/Production:

172 MWe

Project Funding:

Total project cost	\$17,811,172	100%
DOE	8,905,585	50
Participants	8,905,587	50

Project Objective:

To attain up to a 70% decrease in the emissions of NO_x from an existing wall-fired utility boiler firing low-sulfur coal using both gas reburning and low-NO_x burners.

Technology/Project Description:

Gas reburning involves firing natural gas (up to 20% of total fuel input) above the main coal combustion zone in a boiler. This upper-level firing creates a slightly fuel-rich zone. NO_x drifting upward from the lower region of the furnace is "reburned" in this zone and converted to molecular nitrogen. Low-NO_x burners positioned in the coal combustion zone retard the production of NO_x by staging the burning process so that the coal-air mixture can be carefully controlled at each stage. The synergistic effect of adding a reburning stage to wall-fired boilers equipped with low-NO_x burners is projected to lower NO_x emissions by 70% or more. Gas reburning is being demonstrated with and without the use of recirculated flue gas.

The project site is Public Service Company of Colorado's Cherokee Station, Unit No. 3, in Denver, CO. This project combines gas reburning and low-NO_x burners on a 172-MWe wall-fired utility boiler. Western bituminous coals containing 0.35–0.66% sulfur are being used in this demonstration.

Project Status/Accomplishments:

Permitting activities have been completed. Construction started in mid-1991 and was completed in June 1992, about 3 months ahead of schedule. Construction included the installation of new boiler penetrations, new burners, refractory, and insulation. All of the equipment that was installed during construction was checked out and found to be functional. Start of operation was delayed during the period July–August 1992 when the Public Service Company of Colorado rebuilt the four coal-pulverizing mills to enhance the flow of primary air to the boiler. Optimization of the gas-reburning unit started in late-September and was followed by a brief outage in November for minor modifications to the tertiary air system. Parametric studies were started in October 1992 and were completed in April 1993. Preliminary analysis indicated NO_x reductions of up to 70% at 150 MWe. Long-term 1-year load-following operations started in May 1993. Long-term operations will be completed in 1994. Following long-term operations, gas

reburning without the use of recirculated flue gas will be demonstrated along with gas firing-gas reburning.

Commercial Applications:

Gas reburning in combination with low- NO_x burners is applicable to wall-fired utility and industrial boilers. The technology can be used in new and pre-NSPS wall-fired boilers.

Specific features of this technology that increase its potential for commercialization are as follows:

- Can be retrofitted to existing units
- Reduces NO_x emissions by 70% or more
- Suitable for use with a wide range of coals
- Has the potential to improve boiler operability
- Has the potential to reduce the cost of electricity
- Consists of commercially available components
- Requires minimal space

Current estimates indicate that about 35 existing wall-fired utility installations, plus industrial boilers, could make immediate use of this technology. The technology would apply to retrofit, repowering or to new, greenfield installations. There is no known limit to the size or scope of the application of this technology combination. Presently, the largest existing utility boiler is estimated at about 1,300 MWe. The GR–LNB combination could be applied directly to this size boiler because the equipment is an integral part of the unit. For this reason, GR–LNB is expected to be less capital intensive, or less costly, than a scrubber, selective catalytic reduction, or other technology approaches. GR–LNB functions equally well with any kind of coal. NO_x emissions are reduced with internally staged low- NO_x burners, followed by gas reburning. As a side benefit, SO_2 is decreased in direct proportion to the amount of natural gas that is substituted for coal.

Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler

Sponsor:

Southern Company Services, Inc.

Additional Team Members:

Electric Power Research Institute—cofunder

Foster Wheeler Energy Corporation—technology supplier

Georgia Power Company—host utility

Location:

Coosa, Floyd County, GA (Georgia Power Company's Plant Hammond, Unit No. 4)

Technology:

Foster Wheeler's low- NO_x burner (LNB) with advanced over-fire air (AOFA) (environmental control devices/ NO_x control technologies)

Plant Capacity/Production:

500 MWe

Project Funding:

Total project cost	\$14,710,909	100%
DOE	6,553,526	45
Participants	8,157,383	55
(Of the total project cost, \$523,680 are for toxics testing.)		

Project Objective:

To achieve 50% NO_x reduction with the AOFA/LNB system; to determine the contributions of AOFA and the LNB to NO_x reduction and the parameters determining optimum AOFA/LNB system performance; and to assess the long-term effects of AOFA, LNB, and combined AOFA/LNB and advanced digital controls on NO_x reduction and boiler performance.

Technology/Project Description:

AOFA involves (1) improving the mixing of over-fire air with the furnace gases to achieve complete combustion, (2) depleting the air from the burner zone to minimize NO_x formation, and (3) supplying air over furnace wall tube surfaces to prevent slagging and furnace corrosion. The AOFA technique is expected to reduce NO_x emissions by about 35%.

In an LNB, fuel and air mixing is controlled to preclude the formation of NO_x . This is accomplished by regulating the initial fuel-air mixture, velocities, and turbulence to create a fuel-rich flame core and by controlling the rate at which additional air required to complete combustion is mixed with the flame solids and gases so as to maintain a deficiency of oxygen. Typical results for

utilities indicate that LNB technology is capable of reducing NO_x emissions by about 45%.

Based on earlier experience, the use of AOFA in conjunction with LNB can reduce NO_x emissions by as much as 65% compared with conventional burners.

The demonstration is located at the Georgia Power Company's Plant Hammond, Unit No. 4. The boiler is a nominal 500-MWe pulverized coal, wall-fired unit, which is representative of most of the existing pre-NSPS wall-fired utility boilers in the United States. The project also includes installation and testing of an advanced LNB digital control system that optimizes LNB/AOFA performance.

Project Status/Accomplishments:

Baseline, AOFA, LNB, and LNB/AOFA test segments have been completed. Analysis of more than 80 days of AOFA operating data has provided statistically reliable results indicating that, depending upon load, NO_x reductions of 24% are achievable under normal long-term operation. Analysis of the 94 days of LNB long-term data collected show the full-load NO_x emission levels to be approximately 0.65 lb/million Btu. This NO_x level represents a 48% reduction when compared to the baseline, full-load value of 1.24 lb/million Btu. These reductions were sustainable over the long-term test period and were consistent over the entire load range. Full-load, flyash loss-on-ignition values in the LNB configuration were near 8%, compared to 5% for baseline. Initial results from the LNB/AOFA testing indicate that full-load NO_x emissions are approximately 0.40 lb/million Btu with a corresponding flyash loss-on-ignition value of near 8%. Full-load, long-term NO_x emission

reductions in the LNB/AOFA configuration are near 67%. However, preliminary analysis of emissions data suggests that the incremental NO_x reduction effectiveness of the AOFA system (beyond the use of the LNB) was approximately 17 percent with additional reductions resulting from other operational changes. On September 3, 1993, Hammond Unit 4 began a 9-month outage. Configuration of the digital control system and selection of the artificial intelligence software package for optimizing NO_x reduction and boiler efficiency is continuing, and modification of the Hammond Unit 4 control room is now in progress.

Completion of the final analysis of project data and issuance of the final report are scheduled for December 1995.

Pre-retrofit LNB air toxics testing was performed to establish a baseline. Additional air toxics testing with the combined LNB/AOFA configuration has been completed. A report on this work was issued the end of December 1993.

Commercial Applications:

The technology is applicable, in the United States, for retrofitting the 422 existing pre-NSPS wall-fired boilers, which burn a variety of coals, including bituminous, subbituminous, and lignite coal.

Commercialization of the technology will be aided by the following characteristics:

- Reduced NO_x emissions by as much as 65%
- Competitive capital and operating costs
- Relatively easy retrofit
- Little or no derating of the boiler
- Use of commercially available components
- Automatic control of boiler efficiency and maximum pollution abatement through use of artificial intelligence technology in conjunction with digital control

180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers

Project completed.

Sponsor:

Southern Company Services, Inc.

Additional Team Members:

Gulf Power Company—cofunder and host utility
Electric Power Research Institute—cofunder
ABB Combustion Engineering, Inc.—cofunder and technology supplier

Location:

Lynn Haven, Bay County, FL (Gulf Power Company's Plant Lansing Smith, Unit No. 2)

Technology:

ABB Combustion Engineering's low-NO_x concentric firing system (LNCFS) with advanced over-fire air (AOFA), clustered coal nozzles, and offset air (environmental control devices/NO_x control technologies)

Plant Capacity/Production:

180 MWe

Project Funding:

Total project cost	\$9,153,383	100%
DOE	4,440,184	49
Participants	4,713,199	51

Project Objective:

To demonstrate in a stepwise fashion the short- and long-term NO_x reduction capabilities of low-NO_x concentric firing system (LNCFS) Levels I, II, and III on a single reference boiler under typical dynamic operating conditions, and evaluate the cost effectiveness of each low-NO_x combustion technique.

Technology/Project Description:

Three different low-NO_x combustion technologies for tangentially fired boilers were demonstrated. The concept of over-fire air was demonstrated in all of these systems. In LNCFS Level I, a close-coupled over-fire air (CCOFA) system is integrated directly into the windbox of the boiler. Compared to the baseline windbox configuration, LNCFS Level I is arranged by exchanging the

highest coal nozzle with an air nozzle immediately below it. This configuration provides the NO_x reducing advantages of an over-fire air system without pressure part modifications to the boiler.

In LNCFS Level II, a separated over-fire air (SOFA) system is used. This advanced over-fire air system has backpressuring and flow measurement capabilities. The air supply ductwork for the SOFA is taken off from the secondary air duct and routed to the corners of the furnace above the existing windbox. The inlet pressure to the SOFA system can be increased above windbox pressure using dampers downstream of the takeoff in the secondary air duct. Operating at a higher pressure increases the quantity and injection velocity of the over-fire air into the furnace. A multicell venturi is used to

measure the amount of air through the SOFA system. LNCFS Level III utilizes both CCOFA and SOFA.

In addition to over-fire air, the LNCFS incorporates other NO_x reducing techniques into the combustion process. Using offset air, two concentric circular combustion regions are formed. The majority of the coal is contained in the fuel-rich inner region. This region is surrounded by a fuel-lean zone containing combustion air. The size of this outer circle of combustion air can be varied using adjustable offset air nozzles. Separation of air and coal at the burner level further reduces production of NO_x.

The names of the technologies described above have been changed from those originally considered for this project to reflect the most recent knowledge. However, the basic concepts for the reduction of NO_x emissions have remained constant. These technologies provide a stepwise reduction in NO_x emissions, with LNCFS Level III expected to provide the greatest reduction.

Project Results/Accomplishments:

The LNCFS Level II tests were completed in September 1991, resulting in a maximum NO_x reduction of 40% at full load. The LNCFS Level II was converted to LNCFS Level III during a 2-week outage in November 1991 by installing close-couple over-fire air nozzles in the top of the main windbox. The LNCFS Level III testing, completed in April 1992, showed that NO_x emissions were reduced by a maximum of 48%; however, this decrease in NO_x emissions was accompanied by an increase in flyash carbon content. Finally, LNCFS Level I was evaluated by closing the separated over-fire air dampers of the Level III system. Testing of the Level I system, completed in December 1992, showed a maximum NO_x reduction of 37% at full load.

Testing to investigate the effects of low-NO_x combustion on the emissions of air toxics was also completed. These tests showed that the LNCFS had little or no impact on the emissions of air toxics. A report has been prepared.

Commercial Applications:

Commercial applications of this technology include a wide range of tangentially fired utility and industrial boilers throughout the United States and abroad. There are nearly 600 U.S. pulverized coal tangentially fired utility units. These units range in electric generating capacity from 25 MWe to 950 MWe. A wide range of coals, from low-volatile bituminous through lignite, are being fired in these units. LNCFS technologies can be used in retrofit as well as new boiler applications. Boiler operation with these in-furnace technologies does not require intensive retraining.

Environmental benefits to be realized with these in-furnace emission control technologies are primarily based upon reducing NO_x emissions from fossil-fuel-fired power plants. Potential exists for annual NO_x emission reductions of 10%, depending on the unit load scenario and the tangentially fired NO_x control selected.

Project Schedule:

DOE selected project (CCT-III)	9/28/88
Cooperative agreement awarded	9/20/90
NEPA process completed (MTF)	7/21/89
Environmental monitoring plan completed	12/27/90
Construction	11/90-5/91
Operational testing	5/91-12/92
Project completed	3/94

Final Reports:

Final Report and Key Project Findings	12/93
Chemical Emissions Report (draft)	10/93
Final Design Report	9/93

Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers

Sponsor:

Southern Company Services, Inc.

Additional Team Members:

Electric Power Research Institute—cofunder

Ontario Hydro—cofunder

Gulf Power Company—host utility

Location:

Pensacola, Escambia County, FL (Gulf Power Company's Plant Crist)

Technology:

Selective catalytic reduction (SCR) (environmental control devices/NO_x control technologies)

Plant Capacity/Production:

8.7-MWe equivalent (three 2.5-MWe and six 0.2-MWe equivalent SCR reactor plants)

Project Funding:

Total project cost	\$23,229,729	100%
DOE	9,406,673	40
Participants	13,823,056	60

Project Objective:

To evaluate the performance of commercially available SCR catalysts when applied to operating conditions found in U.S. pulverized coal-fired utility boilers using U.S. high-sulfur coal under various operating conditions while achieving as much as 80% NO_x removal.

Technology/Project Description:

The SCR technology consists of injecting ammonia into boiler flue gas and passing it through a catalyst bed where the NO_x and ammonia react to form nitrogen and water vapor.

In this demonstration project, the SCR facility consists of three 2.5-MWe-equivalent SCR reactors, supplied by separate 5,000 std ft³/min flue gas slipstreams, and six 0.20-MWe-equivalent SCR reactors. These reactors were calculated to be large enough to produce design data that will allow the SCR process to be scaled up to commercial size. Catalyst suppliers (three U.S., two European, and two Japanese) provided nine catalysts with various shapes and chemical compositions for evaluation of process chemistry and economics of operation during the operation.

The project is demonstrating, at high- and low-dust loadings of flue gas, the applicability of SCR technology to provide a cost-effective means of reducing NO_x emissions from power plants burning U.S. high-sulfur coal.

The demonstration plant, located at Gulf Power Company's Plant Crist near Pensacola, FL, utilizes flue gas from the burning of principally Illinois No. 5 coal with approximately 3% sulfur under various NO_x and particulate levels.

Project Status/Accomplishments:

Preliminary design engineering for the SCR test facility was concluded at the end of February 1991. Construction began in late-March 1992; a dedication ceremony was held on July 1, 1992. Detailed engineering was completed in December 1992. Flue gas was first passed through the SCR facility during equipment checkout on January 10, 1993. Construction was completed in February 1993. Commissioning tests without catalysts began the first week of March 1993, and the 2-year-long operations phase began on July 1, 1993.

Upon completion of the initial parametric testing in December 1993, baseline ammonia slip measurements were repeated. These tests were completed during December and the results indicate all catalysts were performing well at the targeted NO_x removal rates with slip less than 2 ppm under baseline conditions (80% NO_x removal) and in many cases the measured slip was below the 1 ppm detection limit.

Commercial Applications:

SCR technology can be applied to existing and new utility applications for removal of NO_x from flue gas for virtually any size boiler. There are approximately 1,041 coal-fired utility boilers in active commercial service in the United States; these boilers represent a total generating capacity of 296,000 MWe. Assuming that SCR technology is installed on dry-bottom boilers that are not equipped with low- NO_x combustion technologies (i.e., low- NO_x burners, over-fire air, and atmospheric fluidized-bed combustion), the potential total retrofit market for SCR technology is 154,560 MWe (642 boilers). In addition, SCR technology could be applicable to 34,700 MWe (70 boilers) of new firm (i.e., announced, sited, and committed in terms of service date or under construction) and 144,500 MWe (290 boilers) of planned dry-bottom electric generating capacity in the United States.

Micronized Coal Reburning Demonstration for NO_x Control on a 175-MWe Wall-Fired Unit

Sponsor:

Tennessee Valley Authority

Additional Team Members:

Duke/Fluor Daniel (partnership between Duke Engineering & Services, Inc., and Fluor Daniel, Inc.)—engineer and constructor

Fuller Company—technology supplier

Radian Corporation—testing/environmental/technical consultant

Location:

West Paducah, McCracken County, KY (Tennessee Valley Authority's Shawnee Fossil Plant)

Technology:

Advanced NO_x control using Fuller's micronized-coal-reburning combustion technology (environmental control devices/NO_x control technologies)

Plant Capacity/Production:

175 MWe

Project Funding:

Total project cost	\$7,330,041	100%
DOE	3,514,755	48
Participants	3,815,286	52

Project Objective:

To reduce NO_x emissions by 50–60% using micronized coal as the reburning fuel combined with advanced coal-reburning technology.

MicroMill is a trademark of the Fuller Company.

Technology/Project Description:

The technology is being applied to a 175-MWe front-wall-fired, dry-bottom furnace. The coal currently used to fire the furnace (low-sulfur bituminous coal from Kentucky or West Virginia) will be the reburning fuel. The reburning coal, which can comprise up to 30% of the total fuel, is micronized (80% below 325 mesh) and injected into the furnace above the main burner, the region where NO_x formation occurs.

Central to the project technology is the two-element system which consists of a patented centrifugal-pneumatic MicroMill™ and an external classifier. The mill is capable of grinding coal into a fine powder without the mechanical attrition or roll crushing normally associated with coal mills. The MicroMill™ takes coal away from

the existing bunker and supplies it to the new micronized coal burners.

Micronized coal has the surface area and combustion characteristics of an atomized oil flame, which allows carbon conversion within milliseconds and release of volatiles at a more even rate. This uniform, compact combustion envelope allows for complete combustion of the coal/air mixture in a smaller furnace volume than conventional pulverized coal because heat rate, carbon loss, boiler efficiency, and NO_x formation are affected by coal fineness.

The combination of micronized coal, supplying 30% of the total furnace fuel requirements, and advanced reburning utilizing that requirement in conjunction with fuel/air staging, provides flexible options for significant combustion operations and environmental improvements.

Environmental Control Devices

These options can prevent higher operating costs or furnace performance derating often associated with conventional environmental controls.

The Tennessee Valley Authority plans to retrofit its Shawnee Fossil Plant, located near West Paducah, KY, with the micronized-coal-reburning technology. Bituminous coals from Kentucky and West Virginia, containing about 1% sulfur, will be used.

Project Status/Accomplishments:

Design efforts began shortly after the cooperative agreement was awarded in July 1992. Design and construction are expected to overlap for a short period, with construction being completed in mid-1994. The environmental monitoring plan is being prepared and is expected to be complete in early 1994.

The Fuller Company purchased MicroFuel Corporation (the technology supplier) in September 1992 and assumed MicroFuel's obligations to this project. Radian Corporation joined the team in August 1993. Radian replaced Research Cottrell which withdrew in early

1993. Radian is responsible for modeling, testing, and conceptual reburner design. Boiler baseline and characterization testing started in November 1993.

NEPA compliance has been satisfied through a categorical exclusion approved on August 13, 1992.

Commercial Applications:

Micronized-coal-reburning technology can be applied to existing and greenfield cyclone-fired, wall-fired, and tangential-fired pulverized coal units. The technology reduces NO_x emissions by 50–60% with minimal furnace modifications for existing units. For greenfield units, the technology can be designed as an integral part of the system. Either way, the technology enhances boiler performance with the improved burning characteristics of micronized coal. About 25% of the more than 1,000 existing units could benefit from the use of this technology.

The availability of a coal-reburning fuel, as an additional fuel to the furnace, solves several problems concurrently. Existing units unable to switch fuels

because of limited mill capacity would be able to reach their maximum continuous rating. NO_x emissions reductions will enable lost capacity to be restored, creating a very economic source of generation. For both retrofit and greenfield facilities, reburn burners also can serve as low-load burners, and commercial units can achieve a turndown of 8:1 on nights and weekends without consuming expensive auxiliary fuel. Existing pulverizers can be operated on a variety of coals with improved performance. The combination of micronized-coal-reburning fuel and better pulverizer performance will increase overall pulverized-fuel surface area for better carbon burnout.

10-MW Demonstration of Gas Suspension Absorption

Sponsor:

AirPol, Inc.

Additional Team Members:

FLS miljo a/s (parent company of AirPol, Inc.)—
technology owner

Tennessee Valley Authority—cofunder and site owner

Location:

West Paducah, McCracken County, KY (Tennessee
Valley Authority's National Center for Emissions
Research)

Technology:

FLS miljo a/s' gas suspension absorption (GSA) system
for flue gas desulfurization (FGD) (environmental
control devices/SO₂ control technologies)

Plant Capacity/Production:

10-MWe equivalent slipstream of flue gas from a
150-MWe boiler

Project Funding:

Total project cost	\$7,717,189	100%
DOE	2,315,259	30
Participants	5,401,930	70

Project Objective:

To demonstrate the applicability of gas suspension absorption for flue gas desulfurization using high-sulfur U.S. coals by installing and testing a 10-MWe GSA demonstration system.

Technology/Project Description:

The GSA system consists of a vertical reactor in which flue gas comes into contact with suspended solids consisting of lime, reaction products, and fly ash. About 99% of the solids are recycled to the reactor via a cyclone while the exit gas stream passes through an electrostatic precipitator before being released to the atmosphere. The lime slurry, prepared from hydrated lime, is injected through a spray nozzle at the bottom of the reactor. The volume of lime slurry is regulated with a variable-speed pump controlled by the measurement of the acid content in the inlet and outlet gas streams. The dilution water added to the lime slurry is controlled by on-line measurements of the flue gas exit temperature. Solids collected from the cyclone and particulate control device are combined and disposed of in an existing site disposal area.

GSA has the potential to remove in excess of 90% of the SO₂ as well as to increase lime utilization efficiency with solids recycle.

This project is located at the National Center for Emissions Research and is utilizing a 10-MWe slipstream of flue gas from a 150-MWe coal-fired boiler at the Tennessee Valley Authority's Shawnee Fossil Plant in West Paducah, KY. A western Kentucky coal with about 3% sulfur is being used.

Project Status/Accomplishments:

Optimization testing was conducted February–August 1993 to determine the effect of the process design variables on the SO₂ removal efficiency in the reactor/cyclone and the ESP. The test indicated that the order of importance of key variables is (1) calcium-to-sulfur ratio,

(2) approach-to-adiabatic-saturation temperature, and (3) coal chloride content.

The GSA system was found to be able to operate at an 8 °F approach-to-saturation temperature at the low-chloride condition without any indication of plugging. This is an outstanding feature given the very low flue gas residence time in the reactor/cyclone.

Air toxics testing was conducted during October 1993. The results showed that a removal rate of over 95% could be achieved by the GSA. A 4-week around-the-clock demonstration run was conducted in November 1993. Results indicate that the GSA is capable of consistently maintaining 90+% SO₂ removal at a moderate lime requirement. The GSA has also demonstrated high availability.

An economic evaluation of the GSA process, conducted by Raytheon Engineers and Constructors, concluded that on the basis of a 300-MWe coal-fired boiler plant, capital costs were 31% and operating costs 20%

less than the corresponding costs for a limestone forced oxidation system.

Commercial Applications:

The GSA process offers several advantages over conventional FGD technologies: (1) GSA is 30% cheaper than wet FGD and 20% cheaper than spray drying; (2) GSA is much simpler to build and operate than wet FGD and regenerable processes and requires much less space; (3) space requirements, operability, and ease of installation are comparable to spray dryers and duct injection; and (4) the SO₂ removal capability (90%) compares to that of wet FGD and the regenerable processes. This high removal rate makes the GSA process suitable for use with high-sulfur coal.

TVA is evaluating the possibility of retrofitting a full-scale GSA unit for a 150-MWe coal-fired boiler. In addition, FLS miljo has been awarded a major project in Sweden for a high-performance GSA system to remove sulfur from the flue gas of a 4-million-ton/year iron ore

sinter plant. Sweden has stringent sulfur emission standards which require a removal efficiency of 90–95%.

The GSA should fulfill the need of the utility industry to meet the new SO₂ emission standard as set forth by the CAAA of 1990. Based on a comparison of GSA capital and operating costs with other FGD processes, the GSA is especially suited for 50–250-MWe utility plants. Simplicity in GSA design and operation plus modest space requirements make GSA ideal for retrofitting to existing plants as well as for greenfield plants. One major advantage of the GSA, as compared to other semi-dry scrubbing processes, is that operation of the GSA will not result in excessive dust loading to the gas stream, thus minimizing the cost for upgrading the existing dust collector. The potential market for the GSA is estimated at \$300 million within the next 20 years.

Confined Zone Dispersion Flue Gas Desulfurization Demonstration

Project completed.

Sponsor:

Bechtel Corporation

Additional Team Members:

Pennsylvania Electric Company—cofunder and host utility

Pennsylvania Energy Development Authority—cofunder

New York State Electric & Gas Corporation—cofunder

Rockwell Lime Company—cofunder

Location:

Seward, Indiana County, PA (Pennsylvania Electric Company's Seward Station, Unit No. 5)

Technology:

Bechtel Corporation's in-duct, confined zone dispersion flue gas desulfurization (CZD/FGD) process (environmental control devices/SO₂ control technologies)

Plant Capacity/Production:

73.5 MWe

Project Funding:

Total project cost	\$10,411,600	100%
DOE	5,205,800	50
Participants	5,205,800	50

Project Objective:

To demonstrate SO₂ removal capabilities of in-duct CZD/FGD technology; specifically, to define the optimum process operating parameters and to determine CZD/FGD's operability, reliability, and cost-effectiveness during long-term testing and its impact on downstream operations and emissions.

Technology/Project Description:

In Bechtel's CZD/FGD process, a finely atomized slurry of reactive lime is sprayed into the flue gas stream between the boiler air heater and the electrostatic precipitator (ESP). The lime slurry is injected into the center of the duct by spray nozzles designed to produce a cone of fine spray. As the spray moves downstream and expands, the gas within the cone cools and the SO₂ is rapidly absorbed in the liquid droplets. The droplets mix with the hot flue gas, and the water evaporates rapidly. Fast drying precludes wet particle buildup in the duct and aids the flue gas in carrying the dry reaction products and the unreacted lime to the ESP.

The CZD/FGD process is expected to remove up to 50% of the SO₂ emissions from coal-fired boilers. If

successfully demonstrated, this technology would be an alternative to conventional FGD processes, requiring less physical space and lower capital, operating, and maintenance costs.

This project includes injection of different types of sorbents (dolomitic and calcitic limes) with several atomizer designs using low- and high-sulfur coals to verify the effects on SO₂ removal and the capability of the ESP to control particulates. The demonstration is located at Pennsylvania Electric Company's Seward Station in Seward, PA. One-half of the flue gas capacity of the 147-MWe Unit No. 5 is being routed through a modified, longer duct between the first and second ESP. Pennsylvania bituminous coal (approximately 1.2–2.5% sulfur) is being used in the project.

Project Results/Accomplishments:

Bechtel began its 18-month, two-part test program for the CZD process in July 1991. The first 12 months of the test program consisted primarily of parametric testing. The second part was supposed to include a 6-month continuous operation test period with the system being operated under fully automatic control by the host utility boiler operators. Initially, the new atomizing nozzles were thoroughly tested both outside and inside the duct. The lime slurry injection parametric test program, which began in October 1991, was completed in August 1992.

In summary, the demonstration showed the following:

- CZD/FGD can achieve 50% SO₂ removal efficiency.
- The process requires that drying and SO₂ absorption take place within 2 seconds. A long, straight (horizontal or vertical) gas duct of about 100 feet is required to assure residence time of 2 seconds.
- During normal operations, no deposits of fly ash or reaction products took place in the flue gas duct.
- The fully automated system, fully integrated with power plant operation, demonstrated that the CZD/FGD process responded well to automated control operation.
- Availability of the system was very good.
- At Seward Station, stack opacity was not detrimentally affected by the CZD/FGD system.
- Results of the demonstration indicated that the CZD/FGD process can achieve costs of \$300/ton of SO₂ removed when operating a 500-MWe unit burning 4% sulfur coal. Based on a 500-MWe plant retrofitted with CZD/FGD for a 50% rate of SO₂ removal, the total capital cost is estimated to be less than \$30/kW.

Bechtel notified DOE on June 30, 1993, that it was discontinuing the demonstration project effective July 1, 1993. Bechtel is in the process of modifying the CZD process design to improve SO₂ removal during continuous operation. Once the CZD process modifications are made, a follow-on period of continuous boiler-integrated operation will be required. Bechtel is pursuing this follow-on work with the host utility, the Pennsylvania Electric Company.

Bechtel is continuing efforts to submit and finalize all reports required under the cooperative agreement.

Commercial Applications:

If successful, CZD can be used for retrofit of existing and installation in new utility boiler flue gas facilities to remove SO₂ derived from a wide variety of sulfur-containing coals.

A CZD system can be added to a utility boiler with a capital investment of about \$25–50/kW of installed capacity, or approximately one-fourth the cost of building a conventional wet scrubber. In addition to low capital cost, other advantages include small space requirements, ease of retrofit, low energy requirements, fully automated operation, and production of only nontoxic, disposable waste. The CZD technology is particularly well suited for retrofitting existing boilers, independent of type, age, or size. The CZD installation does not require major power station alterations and can be easily and economically integrated into existing power plants.

Project Schedule:

DOE selected project (CCT-III)	12/19/89
Cooperative agreement awarded	10/13/90
NEPA process completed (MTF)	9/25/90
Environmental monitoring plan completed	6/12/91
Construction	3/91–6/91
Operational testing	7/91–6/93
Project completed	3/94

Final Reports:

Final Technical Report
Public Design Report

early 1994
early 1994

LIFAC Sorbent Injection Desulfurization Demonstration Project

Sponsor:

LIFAC-North America (a joint venture partnership between Tampella Power Corporation and ICF Kaiser Engineers, Inc.)

Additional Team Members:

ICF Kaiser Engineers, Inc.—cofunder and project manager

Tampella Power Corporation—cofunder

Tampella, Ltd.—technology owner

Richmond Power and Light—cofunder and host utility

Electric Power Research Institute—cofunder

Black Beauty Coal Company—cofunder

State of Indiana—cofunder

Location:

Richmond, Wayne County, IN (Richmond Power & Light's Whitewater Valley Station, Unit No. 2)

Technology:

LIFAC's sorbent injection process with sulfur capture in a unique, patented vertical activation reactor (environmental control devices/SO₂ control technologies)

Plant Capacity/Production:

60 MWe

Project Funding:

Total project cost	\$21,393,772	100%
DOE	10,636,864	50
Participants	10,756,908	50

Project Objective:

To demonstrate that electric power plants—especially those with space limitations—burning high-sulfur coals, can be retrofitted successfully with the LIFAC

limestone injection process to remove 75–85% of the SO₂ from flue gas and produce a dry solid waste product for disposal in a landfill.

Technology/Project Description:

Pulverized limestone is pneumatically blown into the upper part of the boiler near the superheater where it absorbs some of the SO₂ in the boiler flue gas. The limestone is calcined into calcium oxide and is available for capture of additional SO₂ downstream in the activation, or humidification, reactor. In the vertical chamber, water sprays initiate a series of chemical reactions leading to SO₂ capture. After leaving the chamber, the sorbent is easily separated from the flue gas along with the fly ash in the electrostatic precipitator. The sorbent

material from the reactor and electrostatic precipitator will be recirculated back through the reactor for increased efficiency. The waste is dry, making it easier to handle than the wet scrubber sludge produced by conventional wet limestone scrubber systems.

The technology enables power plants with space limitations to use high-sulfur midwestern coals by providing an injection process that removes 75–85% of the SO₂ from flue gas and produces a dry solid waste product suitable for disposal in a landfill.

The process is being demonstrated at the Whitewater Valley Station, 60-MWe Unit No. 2. This coal-fired unit is owned and operated by Richmond Power and Light and is located in Richmond, IN.

Project Status/Accomplishments:

Operational testing began in September 1992 after baseline tests to characterize the 60-MWe unit were completed. Mechanical start-up and checkout were completed in February 1993.

Parametric testing was initiated in March 1993; however, LIFAC operations increased opacity levels above acceptable limits. Tests conducted during May and June 1993 showed the increased opacity levels were due to reduced ash resistivity caused by lower operating temperatures in the ESP resulting from humidification of the flue gas in the activation reactor. Bypassing a portion of the flue gas maintains the ESP operating temperature above 200 °F, which results in acceptable opacity levels. Preliminary LIFAC results show that SO₂ reductions in the boiler are between 20% and 30% and reductions through the reactor are an additional 40–55%, yielding total SO₂ reductions approaching 80–85%. Parametric testing was completed at the end of December 1993. Optimization testing is scheduled to begin in February 1994.

Commercial Applications:

This process is suitable for application to all coal-fired utility or industrial boilers, especially those with tight space limitations. The LIFAC process offers the following advantages:

- It is less expensive to install than conventional wet flue gas desulfurization processes.
- It uses dry limestone instead of more costly lime.
- It is relatively simple to operate.
- It produces a dry, readily disposable waste.
- It can handle all types of coal.

The benign waste material can be disposed of in a landfill along with the fly ash. The material also may be used as a road bed or excavation fill material. Commercial use of the LIFAC by-product in the manufacture of construction materials is currently being investigated in Finland.

The potential market penetration of LIFAC is assumed to be 20% of the smaller and medium-size power plants (500 MWe or less) and some industrial sites. LIFAC sales are projected to total 18,000 MWe of capacity over the next decade.

Advanced Flue Gas Desulfurization Demonstration Project

Sponsor:

Pure Air on the Lake, L.P. (a project company of Pure Air which is a general partnership between Air Products and Chemicals, Inc., and Mitsubishi Heavy Industries America, Inc.)

Additional Team Members:

Northern Indiana Public Service Company—cofunder and host utility
Mitsubishi Heavy Industries, Ltd.—process designer
United Engineers and Constructors (Stearns-Roger Division)—facility designer
Air Products and Chemicals, Inc.—constructor and operator

Location:

Chesterton, Porter County, IN (Northern Indiana Public Service Company's Bailly Generating Station)

Technology:

Pure Air's advanced flue gas desulfurization (AFGD) process (environmental control devices/SO₂ control technologies)

Plant Capacity/Production:

528 MWe

Project Funding:

Total project cost	\$151,707,898	100%
DOE	63,913,200	42
Participants	87,794,698	58

PowerChip is a trademark of Pure Air on the Lake, L.P.

Project Objective:

To demonstrate removal of 90–95% or more of the SO₂ at approximately one-half the cost of conventional scrubbing technology; and to demonstrate significant reduction of space requirements.

Technology/Project Description:

In this project, Pure Air has built a single SO₂ absorber for a 528-MWe power plant. Although this is the largest capacity absorber module in the United States, it has relatively modest space requirements because no spare or backup absorber modules are required. The absorber performs three functions in a single vessel: prequencher, absorber, and oxidation of sludge to gypsum. Additionally, the absorber is of a cocurrent design, in which the flue gas and scrubbing slurry move in the same direction

and at a relatively high velocity compared to conventional scrubbers. These features all combine to yield a state-of-the-art SO₂ absorber that is more compact and less expensive than conventional scrubbers.

Technical features include the injection of pulverized limestone directly into the absorber, a device called an air rotary sparger located within the base of the absorber, and a novel wastewater evaporation system. The air rotary sparger combines the functions of agitation and air distribution into one piece of equipment to facilitate the oxidation of calcium sulfite to gypsum.

The AFGD process has demonstrated simultaneous removal of 90–95% or more of the SO₂ while providing a commercial gypsum by-product in lieu of solid waste. Some of the by-product gypsum will be agglomerated and flaked into PowerChip™ gypsum to enhance its

transportation and marketability to gypsum end-users. Additionally, wastewater treatment will be demonstrated to minimize water disposal problems inherent with many high-chloride coals.

The project also seeks to demonstrate a novel business concept whereby Pure Air owns and operates the AFGD facility. Thus, Pure Air expects to specialize in pollution control activities, relieving the electric utility of the operation of the AFGD unit. Assuming that the 3-year demonstration is successful, Pure Air will continue to own the AFGD facility and to operate it as a contracted service to the utility for an additional 17-year period. The demonstration is located at Northern Indiana Public Service Company's 528-MWe Bailly Generating Station near Chesterton, IN.

Project Status/Accomplishments:

Design is complete. To confirm process design, pilot testing was performed in 1990, successfully meeting both SO₂ removal and gypsum purity levels using U.S. high-sulfur coal and limestone feedstocks. A long-term

performance test was conducted in 1991 to verify operational parameters for the air rotary sparger; it, too, was successful.

Construction was completed ahead of schedule, despite the occurrence of a ground subsidence event at the Bailly station on July 2, 1991. The AFGD facility began operations in June 1992. Operations to date have gone very well; SO₂ removals in excess of 95% and average by-product gypsum purities of 96–97% have been achieved. Tests on the utility's standard coal (3–3.5% sulfur) were completed in 1992.

During 1993, tests were conducted on coals with 3.5–4% sulfur and 2.5–3% sulfur. Additionally, air-toxics measurements were taken by the Southern Research Institute as part of a separate project that is being sponsored by DOE's Flue Gas Cleanup R&D Program.

Operations will continue through 1994 with commencement of wastewater evaporation and PowerChip™ gypsum agglomeration.

Commercial Applications:

The AFGD process is attractive for both new and retrofit utility applications. The demonstration project is using bituminous coals primarily from the Indiana-Illinois coal basin, with sulfur content ranging from 2.0% to 4.5%.

The AFGD facility will reduce SO₂ emissions at the Bailly Station by approximately 50,000 tons/yr. Further, the gypsum by-product and wastewater evaporation will demonstrate that SO₂ control can occur without increased solid waste or wastewater production.

All this can be accomplished with costs (and space requirements) that are roughly one-half of those associated with a conventional scrubber.

Demonstration of Innovative Applications of Technology for the CT-121 FGD Process

Sponsor:

Southern Company Services, Inc.

Additional Team Members:

Georgia Power Company—host utility

Electric Power Research Institute—cofunder

Radian Corporation—environmental and analytical consultant

Ershigs, Inc.—fiberglass fabricator

University of Georgia Research Foundation—by-product utilization studies

Location:

Newnan, Coweta County, GA (Georgia Power Company's Plant Yates, Unit No. 1)

Technology:

Chiyoda Corporation's Chiyoda Thoroughbred-121 (CT-121) advanced flue gas desulfurization (FGD) process (environmental control devices/SO₂ control technologies)

Plant Capacity/Production:

100 MWe

Project Funding:

Total project cost	\$44,388,886	100%
DOE	21,728,169	49
Participants	22,660,717	51

Project Objective:

To demonstrate the CT-121 flue gas desulfurization system, including several design innovations, at the 100-MWe scale; more specifically, to demonstrate 90% SO₂ control at high reliability with and without simultaneous particulate control with possible additional reductions in operating costs.

Technology/Project Description:

The project is demonstrating the CT-121 FGD process, which uses a unique absorber design known as the jet-bubbling reactor (JBR). The process combines limestone FGD reaction, forced oxidation, and gypsum crystallization in one process vessel. The process is mechanically and chemically simpler than conventional FGD processes and can be expected to exhibit lower cost characteristics.

The flue gas enters underneath the scrubbing solution in the jet-bubbling reactor. The SO₂ in the flue gas is absorbed and forms calcium sulfite (CaSO₃). Air is bubbled into the bottom of the solution to oxidize the calcium sulfite to form gypsum. The slurry is dewatered in a gypsum stack, which involves filling a dyked area with gypsum slurry. Gypsum solids settle in the dyked

area by gravity, and clear water flows to a retention pond. The clear water from the pond is returned to the process.

The project is also evaluating process innovations to determine whether costs can be reduced further by using fiberglass-reinforced plastic (FRP) absorbers, eliminating flue gas reheat and spare absorber modules, and stacking gypsum to reduce waste management costs. The ability of this technology to capture SO₂ and particulates simultaneously is also being evaluated.

A 2.5% sulfur coal is being used to demonstrate 90% SO₂ control with high reliability, with and without simultaneous particulate control.

A gypsum washing/drying operation will be used to determine if the scrubber by-product will be usable in cement and wallboard manufacturing.

Project Status/Accomplishments:

Construction at Plant Yates was completed in October 1992, and start-up activities began immediately afterward. Experience has been very good with almost no off-line time attributable to the scrubber. Cumulative availability and reliability are both 98%. Over 8,150 hours of successful operations have been logged.

At inlet SO₂ levels of about 2,000 ppm, the CT-121 system removes more than 90% of the SO₂ at all loads and conditions at expected pH and pressure drop with 100% limestone utilization. Initial testing of simultaneous particulate removal by the JBR shows over 90% removal following a fully energized ESP. Continuous emission monitors and the flow monitors were calibrated and certified in November 1992 and recertified in October 1993.

The calcium sulfate produced has been placed in a Hypalon-lined gypsum "stacking" area for the development of an above-ground gypsum stack similar to those found in the phosphate fertilizer industry. Preliminary observations show no evidence of acidic "rain out" from

the FRP scrubber chimney, indicating that the static aerodynamic internal modifications in the chimney elbow are working as expected. DOE-sponsored supplemental air toxics sampling was done in mid-1993; results will be available in 1994. Late in 1993, testing on an alternate limestone was conducted demonstrating the flexibility of the process. Early in 1994 a higher sulfur coal will be tested. The ESP will be de-energized in stages in 1994 for the last year of operation in order to evaluate the particulate removal capability of the scrubber.

Commercial Applications:

The CT-121 FGD system is applicable to both new and pre-NSPS utility and industrial boilers.

Specific features of this technology that will enhance its potential for commercialization follow: (1) fiberglass construction can be used, eliminating the need for rubber-lined carbon steel or costly alloys; (2) no spare absorber is required because the system is at least 98% reliable; (3) reheating of the flue gas is not necessary;

(4) both SO₂ and particulates are removed from flue gas; (5) more than 99% of the calcium in the limestone reagent is used; (6) the gypsum by-product can be stored safely and easily or used in commercial applications; (7) the CT-121 operating costs are the lowest for state-of-the-art FGD systems; (8) there is no known size limit for this technology; (9) utilities and industrial concerns could make immediate use of this technology; and (10) the system is not sensitive to the type of coal used or its sulfur content.

Involvement of the Southern Company (which owns Southern Company Services, Inc.), with its utility system that has over 20,000 MWe of coal-fired generating capacity, is expected to enhance the confidence of other large, high-sulfur coal boiler users in the CT-121 process. This process will be applicable to 370,000 MWe of new and existing generating capacity by the year 2010. A 90% reduction in SO₂ emissions from only the retrofit portion of this capacity represents over 10,500,000 tons/yr of potential SO₂ control.

SNOX™ Flue Gas Cleaning Demonstration Project

Sponsor:

ABB Environmental Systems

Additional Team Members:

Ohio Coal Development Office—cofunder

Ohio Edison Company—cofunder and host utility

Haldor Topsoe—patent owner for process technology, catalysts, and WSA Tower

Snamprogetti, U.S.A.—cofunder and process designer

Location:

Niles, Trumbull County, OH (Ohio Edison's Niles Station, Unit No. 2)

Technology:

Haldor Topsoe's SNOX™ catalytic advanced flue gas cleanup system (environmental control devices/combined SO₂/NO_x control technologies)

Plant Capacity/Production:

35-MWe equivalent slip-stream from a 108-MWe boiler

Project Funding:

Total project cost	\$31,438,408	100%
DOE	15,719,200	50
Participants	15,719,208	50

Project Objective:

To demonstrate on U.S. coals at an electric power plant that SNOX™ technology will catalytically remove 95% of SO₂ and more than 90% of NO_x from flue gas and produce a salable by-product of concentrated sulfuric acid.

Technology/Project Description:

In the SNOX™ process, the stack gas leaving the boiler is cleaned of fly ash in a high-efficiency fabric filter baghouse to minimize the cleaning frequency of the sulfuric acid catalyst in the downstream SO₂ converter. The ash-free gas is reheated, and NO_x is reacted with small quantities of ammonia in the first of two catalytic reactors where the NO_x is converted to harmless nitrogen and water vapor. The SO₂ is oxidized to SO₃ in a second catalytic converter. The gas then passes through a novel glass-tube condenser which allows SO₃ to hydrolyze to concentrated sulfuric acid.

The technology, while using U.S. coals, is designed to remove 95% of the SO₂ and more than 90% of the NO_x from flue gas and produce a salable sulfuric acid

by-product. This is accomplished without using sorbents and without creating waste by-products.

The demonstration unit is installed at Ohio Edison's Niles Station in Niles, OH. The process is treating a 35-MWe equivalent slipstream of flue gas from the 108-MWe Unit No. 2 boiler that burns a 3.4% sulfur coal. The process steps are virtually the same as for a full-scale plant, and commercial-scale components are being used.

Project Status/Accomplishments:

Construction was completed in December 1991, and operation commenced in March 1992. After 2 months of operation, test results met or exceeded design objectives, as follows:

- SO₂ removal—96% in tests (95% design)
- NO_x removal—94% in tests (90% design)
- H₂SO₄ purity—93% in tests (93% design)

In addition, hazardous air pollutant monitoring was conducted. Removal efficiencies for hazardous air pollutant elements were determined for the SNOX™ baghouse and for the entire SNOX™ process. The results indicate that most elements had removal efficiencies that exceeded 99% for both cases. The substances measured include 5 major and 16 trace elements, such as mercury, chromium, cadmium, lead, selenium, arsenic, beryllium, and nickel.

The system has operated more than 5,700 hours, producing approximately 3,800 tons of sulfuric acid, which was sold for industrial use.

The host utility, Ohio Edison, has decided that the SNOX™ technology has performed so well during the CCT demonstration project that it will become a permanent part of the pollution control system at Niles Station. Consequently, money set aside for site restoration will be used to fund extended operations through December 1994.

Commercial Applications:

The SNOX™ technology is applicable to all electric power plants and industrial/institutional boilers firing coal, oil, or gas. The high removal efficiency for NO_x and SO₂ will make the process attractive in many applications. Elimination of additional solid waste (except ash) enhances the marketability in urban and other areas where solid waste disposal issues are a significant impediment.

LIMB Demonstration Project Extension and Coolside Demonstration

Project completed.

Sponsor:

The Babcock & Wilcox Company

Additional Team Members:

Ohio Coal Development Office—cofunder

Consolidation Coal Company—cofunder and technology supplier

Ohio Edison Company—host utility

Location:

Lorain, OH (Ohio Edison's Edgewater Station)

Technology:

The Babcock & Wilcox Company's limestone injection multistage burner (LIMB) system; Babcock & Wilcox DRB-XCL™ low-NO_x burners

Consolidation Coal Company's Coolside duct injection of lime sorbents

(environmental control devices/combined SO₂/NO_x control technologies)

Plant Capacity/Production:

105 MWe

Project Funding:

Total project cost	\$19,404,940	100%
DOE	7,597,026	39
Participants	11,807,914	61

Project Objective:

To demonstrate, with a variety of coals and sorbents, the LIMB process as a retrofit system for simultaneous control of NO_x and SO₂ in the combustion process, and that LIMB can achieve up to 70% NO_x and SO₂

DRB-XCL is a trademark of The Babcock & Wilcox Company.

reductions; to test alternate sorbent and coal combinations, using the Coolside process, to demonstrate in-duct sorbent injection upstream of the humidifier and precipitator and to show SO₂ removal of up to 70%.

Technology/Project Description:

The LIMB process reduces SO₂ by injecting dry sorbent into the boiler at a point above the burners. The sorbent then travels through the boiler and is removed along with fly ash in an electrostatic precipitator (ESP) or baghouse. Humidification of the flue gas before it enters an ESP is necessary to maintain normal ESP operation and to enhance SO₂ removal. Combinations of three eastern bituminous coals (1.6%, 3.0%, and 3.8% sulfur) and four sorbents were tested. Other variables examined were stoichiometry, humidifier outlet temperature, and injection level.

In the Coolside process, dry sorbent is injected into the flue gas downstream of the air preheater, followed by flue gas humidification. Humidification enhances ESP performance and SO₂ absorption. SO₂ absorption is improved by dissolving NaOH or Na₂CO₃ in the humidification water. The spent sorbent is collected with the fly ash, as in the LIMB process. An eastern bituminous coal with 3.0% sulfur was used in testing.

The same low-NO_x burners (Babcock & Wilcox DRB-XCL™ low-NO_x burners), which control NO_x through staged combustion, were used in demonstrating both LIMB and Coolside technologies.

This project was conducted at Ohio Edison's Edgewater Plant in Lorain, OH, on a commercial, Babcock & Wilcox Carolina-design, wall-fired 105-MWe boiler.

Project Results/Accomplishments:

LIMB tests were conducted over a range of calcium-to-sulfur ratios (Ca/S) and humidification conditions. Each of four sorbents (calcitic limestone, type-N atmospherically hydrated dolomitic lime, calcitic hydrated lime, and calcitic hydrated lime with added calcium lignosulfonate) was injected while burning each of three coals (Ohio bituminous, 1.6%, 3.0%, and 3.8% sulfur). Tests were conducted under minimal humidification, defined as operation at a humidifier outlet temperature sufficient to maintain ESP performance. That temperature was typically 250–275 °F. Tests were also conducted at a 20 °F approach to the adiabatic saturation temperature of the flue gas to enhance SO₂ removal of the LIMB system. Close-approach operation typically meant controlling the flue gas temperature at the humidifier outlet (ESP inlet) to about 145 °F. Other variables were stoichiometry and injection level. Highlights of reported test results follow:

- The coal's sulfur content, as reflected in the SO₂ concentration in the flue gas, affected SO₂ removal efficiency—the higher the sulfur content, the greater the SO₂ removal for a given sorbent at a comparable stoichiometry. A 5–7% increase in removal occurred when switching to 3.8% from 1.6% sulfur coal and injecting at a stoichiometry of 2.0.
- The highest sulfur removal efficiencies, without humidification to close approach, were attained using the ligno lime—61% SO₂ removal was achieved while burning 3.8% sulfur coal. All sorbents tested were capable of removing SO₂ although calcium utilization of even finely pulverized limestone was not nearly as high as those of the limes.
- While injecting commercial limestone with 80% of the particles less than 44 microns in size, removal efficiencies of about 22% were obtained at a stoichiometry of 2.0 while burning 1.6% sulfur coal. However, removal efficiencies of about 32% were achieved

at a stoichiometry of 2.0 when using a limestone with all particles less than 44 microns. For a third limestone with essentially all particles less than 10 microns, the removal efficiency was about 5–7% higher than that obtained at similar conditions for limestone with all particles less than 44 microns.

- Sorbent injection at the 181-ft plant elevation level inside the boiler, just above the boiler's nose, yielded the highest SO₂ removal rates. Here, the sorbent was injected at close to the optimum furnace temperature of 2,300 °F.
- SO₂ removal efficiencies were enhanced by about 10% over the range of stoichiometries tested when humidification down to a 20 °F approach to saturation was used.

During the Coolside demonstration, compliance (1.2–1.6% sulfur) and noncompliance (3.0% sulfur) coals were burned. Key process variables—Ca/S, Na/Ca, and approach to adiabatic saturation—were evaluated in short-term (6–8-hr) parametric tests and longer term (1–11-day) process operability tests.

The Coolside process routinely achieved 70% SO₂ removal at design conditions (2.0 Ca/S, 0.2 Na/Ca, and 20 °F approach to adiabatic saturation temperature) using commercial hydrated lime. SO₂ removal depended on Ca/S, Na/Ca, approach to adiabatic saturation, and the physical properties of the hydrated lime. Sorbent recycle showed significant potential to improve sorbent utilization. Observed SO₂ removal with recycle sorbent alone was 22% at 0.5 available Ca/S and 18 °F approach to adiabatic saturation. Observed SO₂ removal with simultaneous recycle and fresh sorbent feed was 40% at 0.8 fresh Ca/S, 0.2 fresh Na/Ca, 0.5 available recycle, and 18 °F approach to adiabatic saturation.

NO_x removal was in the 40–50% range throughout both LIMB and Coolside testing.

Commercial Applications:

Both LIMB and Coolside technologies are applicable to most utility and industrial coal-fired units and provide alternatives to conventional wet flue gas desulfurization (FGD) processes. They can be retrofitted with modest capital investment and downtime, and their space requirements are substantially less. Depending on the plant capacity factor and the coal's sulfur content, they can be economically competitive with FGD systems. For example, using 2.5% sulfur coal at a 65% plant capacity factor, LIMB can be cost competitive with conventional wet FGD up to 450 MWe and Coolside up to 220 MWe. The environmental benefits for LIMB are 40–50% lower NO_x and more than 20% lower SO₂ emissions, and for Coolside up to 70% lower SO₂ emissions. The waste from each of these processes is dry and easily handled and contains unreacted lime that has potential commercial application. Both processes have the ability to handle all coal types, especially low- to medium-sulfur coals.

Project Schedule:

DOE selected project (CCT-I)	7/24/86
Cooperative agreement awarded	6/25/87
NEPA process completed (MTF)	6/2/87
Environmental monitoring plan completed	10/19/88
Construction	8/87–9/89
Coolside operational testing	7/89–2/90
LIMB extension operational testing	4/90–8/91
Project completed	11/92

Final Reports:

Final Report (LIMB/Coolside)	11/92
Topical Report (Coolside)	2/92
Topical Report (LIMB/Coolside)	9/90
Public Design Report	12/88

SOx-NOx-Rox-Box™ Flue Gas Cleanup Demonstration Project

Project completed.

Sponsor:

The Babcock & Wilcox Company

Additional Team Members:

Ohio Edison Company—cofunder and host utility
Ohio Coal Development Office—cofunder
Electric Power Research Institute—cofunder
Norton Company—cofunder and SCR catalyst supplier
3M Company—cofunder and filter bag supplier
Owens Corning Fiberglas Corporation—cofunder and filter bag supplier

Location:

Dilles Bottom, Belmont County, OH (Ohio Edison Company's R.E. Burger Plant, Unit No. 5)

Technology:

The Babcock & Wilcox Company's SOx-NOx-Rox-Box™ (SNRB™) process (environmental control devices/combined SO₂/NO_x control technologies)

Plant Capacity/Production:

5-MWe equivalent slipstream from a 156-MWe boiler

Project Funding:

Total project cost	\$13,271,620	100%
DOE	6,078,402	46
Participants	7,193,218	54

Project Objective:

To demonstrate that the SNRB™ process, used in retrofitting a high-sulfur-coal-fired power plant, can remove high levels of all three pollutants using a single process-

SOx-NOx-Rox-Box and SNRB are trademarks of The Babcock & Wilcox Company.

ing unit for treating flue gas, thereby lessening on-site space requirements and capital costs.

Technology/Project Description:

The SNRB™ process combines the removal of SO₂, NO_x, and particulates in one unit—a high-temperature baghouse. SO₂ removal is accomplished using either calcium- or sodium-based sorbent injected into the flue gas. NO_x removal is accomplished by injecting ammonia to selectively reduce NO_x in the presence of a selective catalytic reduction, or SCR, catalyst. Particulate removal is accomplished by high-temperature fiber bag filters.

The 5-MWe SNRB™ demonstration unit is large enough to demonstrate commercial-scale components while minimizing the demonstration cost. Operation at

this scale also permitted cost-effective control of the flue gas temperature which allowed for evaluation of performance over a wide range of sorbent injection and baghouse operating temperatures. Thus several different arrangements for potential commercial installations could be simulated.

The project demonstrated the technical and economic feasibility of achieving greater than 80% SO₂ removal, above 90% NO_x removal, and 99% particulate removal at lower capital, operating, and maintenance costs than a combination of conventional systems. The demonstration was conducted at Ohio Edison Company's R.E. Burger Plant, Unit No. 5, in Dilles Bottom, OH. Bituminous coal with an average sulfur content of 3.4% was burned at this site during the demonstration.

Project Status/Accomplishments:

SNRB™ demonstration tests were conducted for emissions control of SO₂, NO_x, and particulates. Four different sorbents were tested for SO₂ capture. Calcium-based sorbents included commercial-grade hydrated lime, sugar hydrated lime, and lignosulfonate hydrated lime. In addition, sodium bicarbonate was tested. The optimum location for injecting the sorbent into the flue gas was immediately upstream of the baghouse. Effectively, the SO₂ was captured by the sorbent while the sorbent was in the form of a filter cake on the filter bags (along with fly ash). To capture NO_x, ammonia was injected between the sorbent injection point and the baghouse. The ammonia and NO_x reacted to form nitrogen and water in the presence of Norton Company's NC-300 series zeolite SCR catalyst. With the catalyst being located inside the filter bags, it was well protected from potential particulate erosion or fouling. The sorbent reaction products, unreacted lime, and fly ash were collected on the filter bags and thus removed from the flue gas.

With commercial-grade lime, at a Ca/S ratio of 2, and with the baghouse temperature between 800 and 850 °F, sulfur capture was well above 80%. With the modified hydrated limes, at the same operating temperature range, and with an NH₃/NO_x ratio of 0.9, the reduction in NO_x emissions was consistently above 90% and the ammonia slip was consistently below 5 ppm. Particulate emissions were always below 0.03 lb/million Btu, the NSPS for particulates. Particulate emissions averaged 0.018 lb/million Btu (0.009 grains/std ft³), corresponding to a collection efficiency of 99.89%.

High SO₂ removal efficiency was demonstrated in a brief test program with sodium bicarbonate injection. Removal efficiency increased from 80% to 98% and the ratio of Na/S was increased from 1:1 to 2:1.

All of the demonstration tests were conducted using 3M's Nextel ceramic fiber filter bags or Owens Corning Fiberglas's S-Glass filter bags. All of the test work was

carried out at air-to-cloth ratios of 3–4 ft/min. No excessive wear or failures occurred in over 2,000 hours of elevated temperature operation.

A preliminary evaluation has been made of the projected capital cost of the SNRB™ system for various utility boilers. For a 250-MWe boiler fired with 3.5% sulfur coal and generating NO_x emissions of 1.2 lbs/million Btu, the projected cost of a SNRB™ system is approximately \$260/kW including various standard technology and project contingency factors. A combination of fabric filter, SCR, and wet scrubber for achieving comparable emissions control has been estimated at \$360–400/kW.

Commercial Applications:

Commercial application of the technology offers the potential for significant reductions of multiple pollutants from fossil-fired plants with the potential for increasing thermal efficiency. SNRB™ offers the potential for lower capital and operating costs and smaller space requirements than a combination of conventional, high-efficiency control technologies. SNRB™ is capable of reducing emissions from plants burning high- or low-sulfur coal. In retrofit applications, SNRB™ provides a means of improving particulate emissions control with the addition of SO₂ and NO_x emissions control capacity.

Commercialization of the technology is expected to develop with an initial larger scale application equivalent to 50–100 MWe. The focus of marketing efforts will be tailored to match the specific needs of potential industrial, utility, and independent power producers for both retrofit and new plant construction. SNRB™ is a flexible technology which can be tailored to maximize control of SO₂, NO_x, or combined emissions to meet current performance requirements while providing flexibility to address future needs.

Project Schedule:

DOE selected project (CCT-II)	9/28/88
NEPA process completed (MTF)	9/22/89
Cooperative agreement awarded	12/20/89
Construction	5/91–12/91
Environmental monitoring plan completed	12/31/91
Operational testing	5/92–5/93
Project completed	3/94

Final Reports:

Final Technical Report	early 1994
Economic Evaluation Report	early 1994
Detailed Design Report	11/92

Enhancing the Use of Coals by Gas Reburning and Sorbent Injection

Sponsor:

Energy and Environmental Research Corporation

Additional Team Members:

Gas Research Institute—cofunder

State of Illinois, Department of Energy and Natural Resources—cofunder

Illinois Power Company—host utility

City Water, Light and Power—host utility

Locations:

Hennepin, Putnam County, IL (Illinois Power Company's, Hennepin Plant)

Springfield, Sangamon County, IL (City Water, Light and Power's Lakeside Station)

Technology:

Energy and Environmental Research Corporation's gas reburning and sorbent injection process (environmental control devices/combined SO_2/NO_x control technologies)

Plant Capacity/Production:

Hennepin: tangentially fired 80 MWe (nominal)

Lakeside: cyclone-fired 40 MWe (nominal)

Project Funding:

Total project cost	\$37,497,816	100%
DOE	18,747,816	50
Participants	18,750,000	50

Project Objective:

To demonstrate gas reburning to attain 60% NO_x reduction along with sorbent injection to capture 50% of the SO_2 on two different boiler configurations: tangentially fired and cyclone fired.

Technology/Project Description:

Gas reburning is a postcombustion technology that is being developed primarily for the removal of NO_x . In this process, 80–85% of the fuel is coal and is supplied to the main combustion zone. The remaining 15–20% of the fuel, generally natural gas or a hydrocarbon, bypasses the main combustion zone and is injected above the main burners to form a reducing zone in which NO_x is converted to nitrogen. A calcium compound (sorbent) is injected in the form of dry, fine particulates above the reburning zone in the boiler or even further downstream. The calcium compound to be tested is $Ca(OH)_2$ (lime). The process is expected to achieve 60% NO_x reduction and 50% SO_2 reduction on different boiler configurations at power plants burning high-sulfur midwestern coal.

This project will demonstrate the gas reburning and sorbent injection process on two separate boilers representing two different firing configurations—a tangentially fired 80-MWe boiler at Illinois Power Company's Hennepin Plant in Hennepin, IL, and a cyclone-fired 40-MWe boiler at City Water, Light and Power's Lakeside Station in Springfield, IL. Illinois bituminous coal containing 3% sulfur is the test coal for both Hennepin and Lakeside.

Project Status/Accomplishments:

Permitting and engineering design efforts were completed for the three original project sites; however, in 1990, plans for the third site (Bartonville, IL) were suspended.

Operations at the Hennepin site began January 1991. Long-term testing at Hennepin started in mid-1991 after shakedown operations had been completed. All testing, including testing with a promoted and a high-surface-area lime, was completed in January 1993. During the course of testing, NO_x reductions through gas reburning have ranged as high as 77%, 65% being routine, exceeding the project objective of 60%. Sorbent injection reduced SO₂ emissions as much as 62%, with 52% reduction being routine, also exceeding the project objective of 50%. The calcium-to-sulfur ratio was about 1.75:1. The system installed at Hennepin operated for more than 2,100 hours.

Illinois Power, the host utility, has chosen to retain the gas-reburning portion of the gas-reburning and sor-

bent-injection system for potential use in NO_x control at the Hennepin Plant. The sorbent injection portion has been removed and the site restored.

At City Water, Light and Power's Lakeside site in Springfield, IL, construction was essentially completed in May 1992, and the unit was temporarily placed on hold. Some minor construction activities were completed between October 1992. Operation with sorbent injection began in May 1993 and with gas reburning in June 1993. Parametric testing began in July 1993. As at the Hennepin site, the Springfield site achieved NO_x and SO₂ reductions better than the targets of 60% and 50% respectively. The long-term test program began November 15, 1993, under optimized conditions and will conclude in September 1994.

The project schedule allows at least 12 months of gas-reburning and sorbent-injection demonstration operation under normal load dispatch at Lakeside and demonstration of one or more alternate sorbents.

Commercial Applications:

Gas reburning and sorbent injection is the unique combination of two separate technologies. The commercial applications for these technologies, both separately and combined, extend to both utility companies and industry in the United States and abroad. In the United States alone, these two technologies can be applied to over 900 pre-NSPS utility boilers; the technologies also can be applied to new utility boilers. With NO_x and SO₂ removal exceeding 60% and 50%, respectively, these technologies have the potential to extend the life of a boiler or power plant and also provide a way to use higher sulfur coals. The technologies are not sensitive to the type of coal used, regardless of its nitrogen or sulfur content.

Milliken Clean Coal Technology Demonstration Project

Sponsor:

New York State Electric & Gas Corporation

Additional Team Members:

Consolidation Coal Company—technical consultant
Saarberg-Hölter-Umwelttechnik, GmbH—technology supplier

The Stebbins Engineering and Manufacturing Company—technology supplier
NALCO Fuel Tech—technology supplier

Location:

Lansing, Tompkins County, NY (New York State Electric & Gas Corporation's Milliken Station Units 1 and 2)

Technology:

Flue gas cleanup using Saarberg-Hölter-Umwelttechnik's (S-H-U) formic-acid-enhanced, wet limestone scrubber technology; NALCO Fuel Tech's NO_xOUT urea injection system; Stebbins' tile-lined split-module absorber; and heat-pipe air-heater system (environmental control devices/combined SO₂/NO_x control technologies)

Plant Capacity/Production:

300 MWe

Project Funding:

Total Project Cost	\$158,607,807	100%
DOE	45,000,000	28
Participant	113,607,807	72

Project Objective:

To demonstrate at a 300-MWe utility-scale a combination of cost-effective and innovative emission reduction and efficiency improvement technologies, including the

S-H-U wet scrubber system enhanced with formic acid to increase SO₂ removal in a Stebbins lined scrubber; urea injection for NO_x removal; and a heat-pipe preheater.

Technology/Project Description:

The S-H-U wet flue gas desulfurization process is a formic-acid-enhanced, wet limestone process which results in very high SO₂ removal with low energy consumption and the production of commercial-grade gypsum.

The flue gas desulfurization absorber is a Stebbins tile-lined split-module vessel which has superior corrosion and abrasion resistance, leading to decreased life-cycle costs and reduced maintenance. The split-module design is constructed in the base of the stack to save space and provide operational flexibility.

The NALCO Fuel Tech NO_xOUT system removes NO_x by the injection of urea into the boiler gas. This facet of the project, in conjunction with other combustion modifications, will reduce NO_x emissions and produce marketable fly ash.

A heat-pipe air-heater system by ABB Air Preheater Inc. will be used with advanced temperature controls to reduce both air leakage and the air heater's flue gas exit temperature. Ultimate emissions reductions with increased boiler efficiencies will result.

The project is designed for "total environmental and energy management," a concept encompassing low emissions, low energy consumption, improved combustion, upgraded boiler controls, and reduced solid waste. The system is being designed to achieve at least a 95% SO₂ removal efficiency (or up to 98%) using limestone

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while burning high-sulfur coal. NO_x reductions will be achieved using selective non-catalytic reduction technology and separate combustion modifications. The system has zero wastewater discharge and produces marketable by-products (e.g., commercial-grade gypsum, calcium chloride, and fly ash), minimizing solid waste.

New York State Electric & Gas plans to demonstrate these technologies at Units 1 and 2 of its Milliken Station located in Lansing, NY. Pittsburgh, Freeport, and Kittanning coals, with sulfur contents of 1.5%, 2.9%, and 4.0%, will be used.

Project Status/Accomplishments:

The cooperative agreement was awarded on October 20, 1992. The NEPA process has been completed. The environmental assessment with a finding of no significant impact was signed August 18, 1993. The environmental monitoring plan was completed in December 1993. New York State completed its environmental review and issued permits in August 1992.

Construction is expected to continue through mid-1995 and operations are scheduled through mid-1998. Hazardous air pollutant monitoring will be part of the test program.

Commercial Applications:

The S-H-U SO₂ removal process, the NALCO NO_xOUT non-catalytic reduction process, Stebbins' tile-lined split-module absorber, and heat-pipe air-heater technology are applicable to virtually all electric utility power plants. Commercialization of all technologies in both retrofit and greenfield applications of virtually any megawatt size is expected. The high removal efficiency, up to 98% for SO₂ and up to 30% beyond combustion modifications for NO_x, will make the combination of these technologies attractive.

The space-saving design features of the S-H-U, NALCO, Stebbins, and heat-pipe technologies, combined with the production of marketable by-products, offer significant incentives to generating stations with

limited on-site space. In addition, the inherent energy efficiency of the combined technologies minimizes any secondary environmental impacts from the operation of pollution control equipment.

Commercial Demonstration of the NOXSO SO₂/NO_x Removal Flue Gas Cleanup System

Cosponsors:

NOXSO Corporation
MK-Ferguson Company

Additional Team Members:

W.R. Grace and Company—cofunder
Ohio Coal Development Office—cofunder
Gas Research Institute—cofunder
Electric Power Research Institute—cofunder
East Ohio Gas Company—cofunder

Location:

Negotiations for a new site and host utility are under way.

Technology:

NOXSO Corporation's dry, regenerable flue gas cleanup process (environmental control devices/combined SO₂/NO_x control technologies)

Plant Capacity/Production:

100 MWe (typical)

Project Funding:

Total project cost	\$66,249,696	100%
DOE	33,124,848	50
Participants	33,124,848	50

Project Objective:

To demonstrate removal of 97% of the SO₂ and 70% of the NO_x from a coal-fired boiler's flue gas using the NOXSO process.

Technology/Project Description:

The NOXSO process is a dry, regenerable system capable of removing both SO₂ and NO_x in flue gas from coal-fired utility boilers burning medium- to high-sulfur coals. In the basic process, the flue gas passes through a fluidized-bed adsorber located downstream of the precipitator; the SO₂ and NO_x are adsorbed by the sorbent. The sorbent consists of spherical beads of high-surface-area alumina impregnated with sodium carbonate. The cleaned flue gas then passes to the stack.

The NO_x is desorbed from the NOXSO sorbent when heated by a stream of hot air. The hot air containing the desorbed NO_x is recycled to the boiler where equilibrium processes cause destruction of the NO_x. The adsorbed sulfur is recovered from the sorbent in a regenerator where it reacts with methane at high temperature

to produce an offgas with high concentrations of SO₂ and hydrogen sulfide (H₂S). This offgas is processed in a Claus plant to produce elemental sulfur, a salable by-product.

The process is expected to achieve SO₂ reductions of 97% and NO_x reductions of 70%.

The NOXSO process will be demonstrated on a typical 100-MWe cyclone boiler. Presently, NOXSO Corporation is negotiating with several potential host utilities for a new site for the demonstration project. MK-Ferguson will design, construct, and operate a full-scale commercial NOXSO unit to demonstrate process feasibility. The project is being structured so that data from the proof-of-concept facility at Ohio Edison Company's Toronto Station (now completed) can be incorporated into the project definition activity.

Project Status/Accomplishments:

The proof-of-concept, pilot-plant testing, which was proceeding in parallel with the project definition phase of the demonstration project, is complete, with results as expected. Preliminary process flow diagrams, piping and instrumentation diagrams, equipment specifications, and plant arrangement drawings have been prepared. Power plant, site, and process-specific environmental information has been compiled for use in the NEPA process.

Commercial Applications:

The NOXSO process is applicable for retrofit or new facilities. The process is suitable for utility and industrial coal-fired boilers of 75 MWe or larger. Southeastern Ohio and western Pennsylvania coal (3.2–3.5% sulfur average) are intended for use in the demonstration; however, the process is adaptable to coals with higher sulfur content.

Commercial-grade sulfur, a salable by-product, is produced. The technology is expected to be especially attractive to utilities that require high removal efficiencies for both SO₂ and NO_x and/or need to eliminate solid wastes.

Integrated Dry NO_x/SO₂ Emissions Control System

Sponsor:

Public Service Company of Colorado

Additional Team Members:

Electric Power Research Institute—cofunder

Stone and Webster Engineering Corp.—engineer

The Babcock & Wilcox Company—burner developer

Fossil Energy Research Corporation—operational testing

Western Research Institute—flyash evaluator

Colorado School of Mines—bench-scale engineering research and testing

Noell, Inc.—urea-injection system provider

Location:

Denver, Denver County, CO (Public Service Company of Colorado's Arapahoe Station, Unit No. 4)

Technology:

The Babcock & Wilcox Company's low-NO_x burners, in-duct sorbent injection, and furnace (urea) injection (environmental control devices/combined SO₂/NO_x control technologies)

Plant Capacity/Production:

100 MWe

Project Funding:

Total project cost	\$27,411,462	100%
DOE	13,705,731	50
Participants	13,705,731	50

Project Objective:

To demonstrate the integration of three technologies to achieve up to 70% reduction in NO_x and SO₂ emissions;

more specifically, to assess the integration of a down-fired low-NO_x burner with in-furnace urea injection for additional NO_x removal and dry sorbent in-duct injection with humidification for SO₂ removal.

Technology/Project Description:

All of the testing is using Babcock & Wilcox's low-NO_x DRB-XCL® down-fired burners with over-fire air. These burners control NO_x by injecting the coal and the combustion air in an oxygen-deficient environment. Additional air is introduced via over-fire air ports to complete the combustion process and further enhance NO_x removal. The low-NO_x burners are expected to reduce NO_x emissions by up to 50%, and, with added air, by up to 70%. To reduce NO_x emissions even further, in-furnace

urea injection is being tested to determine how much additional NO_x can be removed from the combustion gas.

Two types of dry sorbents are being injected into the ductwork downstream of the boiler to reduce SO₂ emissions. Either calcium is injected upstream of the air heater or sodium or calcium is injected downstream of the air heater. Humidification downstream of the dry sorbent injection aids SO₂ capture and lowers flue gas temperature and gas flow, which can decrease pressure drop at the fabric filter dust collector.

Low-sulfur (0.4%) bituminous coal from Colorado is the main fuel being tested, but for a run of short duration (less than 1 month), Illinois bituminous coal containing 2.5% sulfur is the planned test fuel.

DRB-XCL is a trademark of The Babcock & Wilcox Company.

The three basic technology systems have been installed on Public Service Company of Colorado's Arapahoe Station Unit No. 4, a 100-MWe down-fired, pulverized-coal boiler with roof-mounted burners.

Project Status/Accomplishments:

Baseline testing of the boiler without any modifications was completed in mid-December 1991. Baseline testing of the boiler with urea injection began in early February 1992 and continued for approximately 1 month. Construction requiring plant outage was completed in May 1992, and then preoperational testing of the boiler with low- NO_x burners and over-fire air began. Operational testing of these two key components started in early August 1992.

Testing of the combustion modifications was completed in late October 1992. While firing western bituminous coal, NO_x was reduced from an original baseline

of 1.15 lbs/million Btu to about 0.4 lb/million Btu—a 65% reduction—with no operating problems. Short-term testing while firing natural gas was also completed. In-furnace urea injection testing began in January 1993 and continued for 3 months. At full load, 44% NO_x reduction was achieved with a 10-ppm ammonia slip. Duct sorbent-injection testing began in August 1993. Preliminary results with sodium injection indicate that over 70% SO_2 removal can be obtained. Baseline and urea injection air toxics monitoring has been performed. Preliminary data indicate that the baghouse successfully removes nearly all air toxics emissions. Air toxics testing during calcium and sodium injection was conducted during October 1993.

Arapahoe 4 has operated over 12,000 hours since combustion modifications were completed in May 1992. The availability factor during this period was over 96%.

Commercial Applications:

Either the entire integrated dry NO_x/SO_2 emissions control system or the individual technologies are applicable to most utility and industrial coal-fired units. They provide a lower capital-cost alternative to conventional wet flue gas desulfurization processes. They can be retrofitted with modest capital investment and downtime, and their space requirements are substantially less. They can be applied to any unit size but are mostly applicable to the older, small- to mid-size units. They can reduce NO_x emissions by up to 70% and SO_2 emissions by 50–70%, and they produce a dry solid waste product. These processes have the ability to handle all coal types, especially coals with low- to mid-sulfur content.

Coal Processing for Clean Fuels Fact Sheets

Development of the Coal Quality Expert

Cosponsors:

ABB Combustion Engineering, Inc.
CQ, Inc.

Additional Team Members:

Black and Veatch—cofunder and expert system developer
Electric Power Research Institute—cofunder
The Babcock & Wilcox Company—cofunder and pilot-scale testing
Guild Products, Inc.—expert system architecture developer
Electric Power Technologies, Inc.—field testing
University of North Dakota, Energy and Minerals Research Center—bench-scale testing
Alabama Power Company—host utility
Mississippi Power Company—host utility
New England Power Company—host utility
Northern States Power Company—host utility
Public Service of Oklahoma—host utility

Locations:

Alliance, Columbiana County, OH (pilot-scale tests)
Windsor, Hartford County, CT (pilot-scale tests)
Grand Forks, Grand Forks County, ND (bench tests)
Wilsonville, Shelby County, AL (Gatson, Unit 5)
Gulfport, Harrison County, MS (Watson, Unit 4)
Somerset, Bristol County, MA (Brayton Point, Units 2 and 3)
Bayport, Washington County, MN (King Station)
Oologah, Rogers County, OK (Northeastern, Unit 4)

Technology:

CQ, Inc.'s EPRI coal quality expert (CQE) computer model (coal processing for clean fuels/coal preparation technologies)

Plant Capacity/Production:

Full-scale testing will take place at six utility sites ranging in size from 250 to 880 MWe.

Project Funding:

Total project cost	\$21,746,004	100%
DOE	10,863,911	50
Participants	10,882,093	50

Project Objective:

To demonstrate an expert system that can be run on a personal computer and provide coal-burning utilities with a predictive tool to assist in the selection of optimum quality coal for a specific boiler based on operational efficiency, cost, and environmental emissions.

Technology/Project Description:

Data derived from bench-, pilot-, and full-scale testing are being used to develop algorithms for inclusion into an expert model, the Coal Quality Expert, that can be run on a personal computer. Utilities may use the information to predict the operating performance and cost of coals not previously burned at a particular facility.

Six large-scale field tests consist of burning a baseline coal and an alternate coal over a 2-month period. The baseline coal, the one currently used as fuel, is used to characterize the operating performance of the boiler. The alternate coal, a blended or cleaned coal of improved quality, is burned in the boiler for the remaining test period.

The baseline and alternate coals for each test site also are burned in bench- and pilot-scale facilities under similar conditions. The alternate coal is cleaned at CQ, Inc., to determine what quality levels of clean coal can be produced economically and then transported to the bench- and pilot-scale facilities for testing. All data from bench-, pilot-, and full-scale facilities are evaluated and correlated to formulate algorithms being used to develop the model.

Bench-scale testing will be performed at ABB Combustion Engineering's facilities in Windsor, CT, and the University of North Dakota's Energy and Mineral Research Center in Grand Forks, ND; pilot-scale testing will be done at ABB Combustion Engineering's facilities in Windsor, CT, and Alliance, OH. The six field test sites are: Gatson, Unit 5 (880 MWe), Wilsonville, AL; Watson, Unit 4 (250 MWe), Gulfport, MS; Brayton Point, Unit 2 (285 MWe) and Unit 3 (615 MWe), Somerset, MA; King Station (560 MWe), Bayport, MN; and Northeastern, Unit 4 (445 MWe), Oologah, OK.

Project Status/Accomplishments:

All six field tests have been completed. A commercial sale of the CQE Acid Rain Advisor software package was made in 1993. A CQE prototype was showcased in September 1993. A CQE beta version is scheduled for testing in March 1994.

Commercial Applications:

The expert system will enable coal-fired utilities to select the optimum quality coals at the lowest price for their specific boilers to reduce SO₂ and NO_x emissions.

The CQE system is applicable to all electric power plants and industrial/institutional boilers that burn coal. The system will predict the operational and emission reduction benefits of using cleaned coal. Following the demonstration, CQ, Inc., and Black and Veatch, will market the CQE system in the United States and abroad.

Self-Scrubbing Coal™: An Integrated Approach to Clean Air

Sponsor:

Custom Coals International (a joint venture between Genesis Coals Limited Partnership and Genesis Research Corporation)

Additional Team Members:

Duquesne Light Company—host utility
Richmond Power & Light—host utility
Centerior Service Company—host utility
CQ, Inc.—operator

Locations:

Central City, Somerset County, PA (advanced coal-cleaning plant)
Springdale, Allegheny County, PA (combustion tests at Duquesne Light Company's Cheswick Power Station)
Richmond, Wayne County, IN (combustion tests at Richmond Power & Light's Whitewater Valley Station, Unit No. 2)
Ashtabula, Trumbull County, OH (combustion tests at Centerior Service Company's Ashtabula C-Plant)

Technology:

Coal preparation using Custom Coals' advanced physical coal cleaning and fine magnetite separation technology plus sorbent addition technology (coal processing for clean fuels/coal preparation technologies)

Plant Capacity/Production:

500 tons/hr

Project Funding:

Total project cost	\$89,715,781	100%
DOE	38,038,656	42
Participants	51,677,125	58

Self-Scrubbing Coal and Carefree Coal are trademarks of Custom Coals International.

Project Objective:

To demonstrate advanced coal-cleaning unit processes to produce low-cost compliance coals that can meet full requirements for commercial-scale utility power plants to satisfy CAAA of 1990 provisions.

Technology/Project Description:

An advanced coal-cleaning plant will be designed, blending existing and new processes, to produce, from high-sulfur bituminous feedstocks, two types of compliance coals—Carefree Coal™ and Self-Scrubbing Coal™.

Carefree Coal™ is produced by breaking and screening run-of-mine coal and by using innovative dense-media cyclones and finely sized magnetite to remove up to 90% of the pyritic sulfur and most of the ash. Carefree Coal™ is designed to be a competitively priced,

high-Btu fuel that can be used without major plant modifications or additional capital expenditures. While many utilities can use Carefree Coal™ to comply with SO₂ emissions limits, others cannot due to the high content of organic sulfur in their coal feedstocks. When compliance coal cannot be produced by reducing pyritic sulfur, Self-Scrubbing Coal™ can be produced to achieve compliance.

Self-Scrubbing Coal™ is produced by taking Carefree Coal™, with its reduced pyritic sulfur and ash content, and adding to it sorbents, promoters, and catalysts. Self-Scrubbing Coal™ is expected to achieve compliance with virtually any U.S. coal feedstock through in-boiler absorption of SO₂ emissions. The reduced ash content of the Self-Scrubbing Coal™ permits the addition of relatively large amounts of sorbent without exceeding the

ash specifications of the boiler or overloading the electrostatic precipitator.

A 500-ton/hr advanced coal-cleaning plant is being designed and constructed at a site near Central City, PA. The advanced coal-cleaning plant will manufacture Self-Scrubbing Coal™ and Carefree Coal™. Two medium- to high-sulfur coals—Illinois No. 5 from Wabash County, IL, and Lower Freeport Seam coal from Belmont County, OH—will be used to produce Self-Scrubbing Coal™. Carefree Coal™ will be made using Sewickley coal from Greene County, PA. The Sewickley coal will be combustion tested at Duquesne Light Company's Cheswick Power Station located near Pittsburgh, PA; the Illinois No. 5 coal will be tested at Richmond Power & Light's Whitewater Valley Station Unit No. 2 located in Richmond, IN; and the Lower Freemont Seam coal will be tested at Centor Service Company's Ashtabula C-Plant.

Project Status/Accomplishments:

The cooperative agreement was awarded in October 1992. Design work has started. Foundations were completed in January 1994. An environmental assessment has been prepared, and approval is expected in February 1994.

Commercial Applications:

Commercialization of Self-Scrubbing Coal™ has the potential of bringing into compliance about 164 million tons/yr of bituminous coal that cannot meet emissions limits through conventional coal cleaning. This represents over 38% of the bituminous coal burned in 50-MWe or larger U.S. generating stations.

The technology produces coal products that can be used to reduce a utility or industrial power plant's total sulfur emissions 80–90%.

Advanced Coal Conversion Process Demonstration

Sponsor:

Rosebud SynCoal Partnership (a partnership between Western Energy Company and the NRG Group, a nonregulated subsidiary of Northern States Power Company)

Additional Team Member:

Stone and Webster Engineering Corp.—architect/engineer

Location:

Colstrip, Rosebud County, MT (adjacent to Western Energy Company's Rosebud Mine)

Technology:

Western Energy Company's advanced coal conversion process for upgrading low-rank subbituminous and lignite coals (clean processing for clean fuels/coal preparation technologies)

Plant Capacity/Production:

45 tons/hr of SynCoal™ product (300,000 tons/yr)

Project Funding:

Total project cost	\$69,000,000	100%
DOE	34,500,000	50
Participants	34,500,000	50

Project Objective:

To demonstrate Western Energy's advanced coal conversion process to produce a stable coal product having a moisture content as low as 1%, sulfur content as low as 0.3%, and heating value up to 12,000 Btu/lb.

SynCoal is a trademark of the Rosebud SynCoal Partnership.

Technology/Project Description:

Being demonstrated is an advanced thermal coal-drying process coupled with physical cleaning techniques to upgrade high-moisture, low-rank coals to produce a high-quality, low-sulfur fuel. The coal is processed through two fluidized-bed reactors that remove loosely held water and then chemically bound water, carboxyl groups, and volatile sulfur compounds. After drying, the coal is put through a deep-bed stratifier cleaning process to effect separation of the ash.

The technology, if successfully demonstrated, enhances low-rank western coals, usually with a moisture content of 25–55%, sulfur content of 0.5–1.5%, and heating value of 5,500–9,000 Btu/lb, by producing a stable, upgraded SynCoal™ product with a moisture

content as low as 1%, sulfur content as low as 0.3%, and heating value up to 12,000 Btu/lb.

The 45-ton/hr unit is located adjacent to a unit train loadout facility at Western Energy Company's Rosebud coal mine in Colstrip, MT. Although the demonstration plant is one-tenth the size of a commercial facility, the process equipment is at commercial scale because a full-sized commercial plant has multiple process trains.

Project Status/Accomplishments:

On December 12, 1990, Western Energy Company, a subsidiary of Montana Power Company, announced that it had joined with the NRG Group, a nonregulated subsidiary of Northern States Power Company based in Minneapolis, MN, to demonstrate and commercialize this coal conversion technology.

Ground was broken on March 28, 1991. By June, pieces of major equipment were arriving on site. The construction of two 6,000-ton product storage silos and all foundation work was completed by July. The main process facility structure and the control/administration building were completed by November. Initial "turn-over" of equipment started in December, and final construction was completed in February 1992. Initial "hot" operations began in March 1992.

During the summer of 1993, the facility was shut down for extended maintenance and retrofit to the dust transport system. The plant resumed operation in August 1993 and reached 100% capacity on December 6,

1993. SynCoal™ is being shipped by truck and rail to industrial and utility customers for handling tests and short-term test burns.

Commercial Applications:

Western Energy's advanced coal conversion process has the potential to enhance the use of low-rank western subbituminous and lignite coals. Many of the power plants located throughout the upper midwest have cyclone boilers, which burn low-ash-fusion-temperature coals. Presently, most of these plants burn Illinois Basin high-sulfur coal. SynCoal™ would be an ideal low-sulfur coal substitute for these and other plants, because it will allow operation under more restrictive emissions guidelines without requiring derating of the units or the addition of costly flue gas desulfurization systems. The advanced coal conversion process will produce SynCoal™ which has a very low sulfur content, high heating value, and stable physical/chemical characteristics; it could have significant impact on SO₂ reduction.

Western Energy's process, therefore, will be attractive to utilities because the upgraded fuel will be less costly to use than would the construction and use of flue gas desulfurization equipment. This will allow plants that would otherwise be closed to remain in operation.

On December 20, 1993, Rosebud SynCoal Partnership announced the signing of a letter of intent with Minnkota Power Cooperative to prepare a \$2-million study to examine the merits of scaling up the coal processing technology to an \$80-million commercial plant. If results are positive a commercial plant could be in place by 1996.

ENCOAL Mild Coal Gasification Project

Sponsor:

ENCOAL Corporation (a subsidiary of SMC Mining Company)

Additional Team Members:

SMC Mining Company—cofunder

TEK-KOL (partnership between SMC Mining Company and SGI International)—technology owner, supplier, and licensor

SGI International—technology developer

Triton Coal Company (subsidiary of SMC Mining Company)—host facility and coal supplier

The M.W. Kellogg Company—engineer and constructor

Location:

Near Gillette, Campbell County, WY (Triton Coal Company's Buckskin Mine)

Technology:

SGI International's liquids from coal process (coal preparation for clean fuels/mild gasification)

Plant Capacity/Production:

1,000 tons/day of subbituminous coal feed

Project Funding:

Total project cost	\$72,564,000	100%
DOE	36,282,000	50
Participants	36,282,000	50

Project Objective:

To demonstrate the integrated operation of a number of novel processing steps to produce two higher value fuel forms from mild gasification of low-sulfur subbituminous coal; and to provide sufficient products for potential end users to conduct burn tests.

Technology/Project Description:

The ENCOAL mild coal gasification process involves heating coal under carefully controlled conditions. Coal is fed into a rotary grate dryer where it is heated by a hot gas stream to reduce the coal's moisture content. The solid bulk temperature is controlled so that no significant amounts of methane, CO, or CO₂ are released from the coal. The solids from the dryer are conveyed to the pyrolyzer where the rate of heating of the solids and residence time are controlled to achieve desired properties of the fuel products. During processing in the pyrolyzer, all remaining free water is removed, and a chemical reaction occurs that results in the release of volatile gaseous material. Solids exiting the pyrolyzer are quenched, cooled, and transferred to a surge bin.

The gas produced in the pyrolyzer is sent through a cyclone for removal of the particulates and then cooled to condense the liquid-fuel products. Most of the gas from the condensation unit is recycled to the pyrolyzer. The rest of the gas is burned in combustors to provide heat for the pyrolyzer and the dryer. NO_x emissions are controlled by staged air injection.

The offgas from the dryer is treated in a wet venturi scrubber to remove particulates and a horizontal scrubber to remove SO₂, both using a sodium carbonate solution. The treated gas is vented to a stack, and the spent solution is discharged into a pond for evaporation.

The ENCOAL project is located within Campbell County, WY, at Triton Coal Company's Buckskin Mine, 10 miles north of Gillette. The plant makes use of the

present coal-handling facilities at the mine. Subbituminous coal having sulfur content of 0.4–0.9% is being used.

Project Status/Accomplishments:

Operation continued during 1993. Fifteen runs have been conducted to date, logging more than 1,400 hours of operation. A major milestone was achieved in April 1993 when the plant completed a 16-day run. The run confirmed that the plant had been able to overcome several mechanical problems that had previously prevented sustained operations beyond 7 days. During the run, more than 5,000 tons of low-rank Powder River Basin coal were processed, yielding more than 125,000 gallons of high-quality liquid fuel and several thousand tons of clean solid product.

ENCOAL operators logged another milestone run in June 1993, this one 12 days in duration. The plant reached 100% of design capacity for a short period during the run, which ended in a planned shutdown. On

June 15, the plant was shut down to enable a major modification which incorporates a new step in the overall solids-cooling system to continuously produce a solid product sufficiently stable for long-distance shipping. Operations are expected to resume in January 1994.

The ENCOAL plant continued to attract a large number of international visitors, especially from Pacific Rim countries, interested in using the technology or in purchasing fuel products. Among these was the Indonesian ambassador to the United States who visited the plant in June. On the domestic front, commercial contracts are in place for the first customers of its products. A Wisconsin utility will buy 30,000 tons of the solid product and TEXPAR Energy Inc., of Waukesha, WI, will buy up to 135,000 barrels of the liquid product. Further, ENCOAL announced in November an agreement with Dakota Gasification Company to burn up to 250,000 barrels of product liquid at the Great Plains Synfuel Plant at Beulah, ND.

Commercial Applications:

The liquid products from mild coal gasification can be used in existing markets in place of No. 6 fuel oil. The solid product can be used in most industrial or utility boilers. The feedstock for mild gasification facilities is being limited to high-moisture, low-heating-value coals.

The potential benefits of this mild gasification technology in its commercial configuration are attributable to the increased heating value (about 12,000 Btu/lb) and lower sulfur content (per unit of fuel value) of the new solid-fuel product compared to the low-rank coal feedstock, and the production of low-sulfur liquid products requiring no further treatment for the fuel oil market. The product fuels are expected to be used economically in commercial boilers and furnaces and to reduce significantly SO₂ emissions at industrial and utility facilities currently burning high-sulfur bituminous coals or fuel oils.

Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process

Sponsor:

Air Products and Chemicals, Inc.

Additional Team Members:

Acurex Environmental Corporation—fuel methanol testing and cofunder

Eastman Chemical Company—host site and cofunder

Location:

Kingsport, Sullivan County, TN (Eastman Chemical Company's Integrated Coal Gasification Facility)

Technology:

Air Products and Chemicals' liquid-phase methanol (LPMEOH™) process (coal processing for clean fuels/indirect liquefaction)

Plant Capacity/Production:

200 tons/day of methanol

Project Funding:

Total project cost:	\$213,700,000	100%
DOE	92,708,370	43
Participants	120,991,630	57

Project Objective:

To demonstrate on a commercial scale the production of methanol from coal-derived synthesis gas using the LPMEOH™ process; and to determine the suitability of methanol produced during this demonstration for use as a chemical feedstock or as a low-SO_x, low-NO_x alternative fuel in stationary and transportation applications. In addition, the production of dimethyl ether (DME) as a mixed coproduct with methanol will be demonstrated.

LPMEOH is a trademark of Air Products and Chemicals, Inc.

Technology/Project Description:

This project is demonstrating the LPMEOH™ process to produce methanol from coal-derived synthesis gas on a commercial scale. The combined reactor and heat removal system is different from other commercial methanol processes. The liquid phase not only supports the catalyst but functions as an efficient means to remove the heat of reaction away from the catalyst surface. This feature permits the direct use of synthesis gas streams as feed to the reactor without the need for shift conversion.

The performance of the LPMEOH™ process for the synthesis of methanol is characterized as follows:

- Carbon monoxide conversion to methanol—13% per reactor per pass in a hydrogen-rich feed

- Methanol productivity comparable to gas-phase systems—6,000 lbs of methanol per 1 lb of catalyst
- Raw methanol purity—97.5%
- Feed gas flexibility—permits the synthesis gas produced by any commercial coal gasification system to be used without shift conversion

The Eastman Chemical Company's integrated coal gasification facility at Kingsport, TN, has operated commercially since 1983. At this site, it will be possible to ramp up and down to demonstrate the unique load-following flexibility of the LPMEOH™ unit for application to coal-based electric power generation facilities. Methanol fuel testing will be conducted in both on- and off-site stationary and mobile applications, such as boilers,

buses, and van pools. The operation at Kingsport also includes the planned production of DME as a mixed coproduct with methanol for demonstration as storable fuel.

Project Status/Accomplishments:

The cooperative agreement was modified in October 1993 to recognize a change in the host site from the Cool Water Gasification Facility in Daggett, CA, to Eastman Chemical Company's Integrated Coal Gasification Facility in Kingsport, TN. The host-site change became necessary when the project sponsors determined that restarting the mothballed Cool Water facility—a demonstration coal-gasification combined-cycle power plant—was not economically feasible.

The participants are initiating project definition activities and developing the relevant environmental information needed for the NEPA process. The Eastman Chemical site offers the advantage of using existing, operating coal gasifiers which will require little, if any, modification to support the LPMEOH™ demonstration.

Commercial Applications:

The LPMEOH™ process has been developed to enhance integrated gasification combined-cycle (IGCC) power generation by producing a clean burning, storable liquid fuel—methanol—from the clean coal-derived gas. Methanol also has a broad range of commercial applications. Methanol can be substituted for conventional fuels in stationary and mobile combustion applications. Methanol is an excellent fuel for peak power production. Methanol contains no sulfur and has exceptionally low- NO_x characteristics when burned. Methanol can be produced from coal as a co-product in an IGCC facility.

Among the cleanest coal technologies for generating electric power, IGCC can economically satisfy the most stringent environmental limits for SO_2 and NO_x . About 99% of the sulfur can be removed in the manufacturing process and converted into salable elemental sulfur or sulfuric acid. The solid waste from the gasifier is an inert, granular slag which can be used as an aggregate for road and building materials.

DME has several commercial uses. In a storable blend with methanol, the mixture can be used as peaking fuel in IGCC electric power generating facilities. DME can also be used to increase the vapor pressure of a methanol blend. The resulting higher volatility is expected to provide beneficial "cold start" properties to methanol being used as a diesel engine fuel. Blends of methanol and DME can also be used as a chemical feedstock for the synthesis of chemicals or new, oxygenate fuel additives. Pure DME has been gaining acceptance as an environmentally friendly aerosol in personal products.

Typical commercial-scale LPMEOH™ units are expected to range in size from 150 to 1,000 tons/day of methanol produced when associated with commercial IGCC power generation trains of 200–350 MWe. Air Products and Chemicals expects to market the LPMEOH™ technology through licensing, owning/operating, and tolling arrangements.

Industrial Applications Fact Sheets

Blast Furnace Granulated-Coal Injection System Demonstration Project

Sponsor:

Bethlehem Steel Corporation

Additional Team Members:

British Steel Consultants Overseas Services, Inc.
(marketing arm of British Steel Corporation)—
technology owner
Simon-Macawber, Ltd.—equipment supplier
Fluor Daniel, Inc.—architect and engineer
ATSI, Inc.—injection equipment engineer (U.S.
technology licensee)

Location:

Burns Harbor, Porter County, IN (Bethlehem Steel's
Burns Harbor Plant, Blast Furnace Units C and D)

Technology:

British Steel's blast furnace granulated-coal injection
(BFGCI) process (industrial applications)

Plant Capacity/Production:

7,000 net tons/day of hot metal (each blast furnace)

Project Funding:

Total project cost	\$191,700,000	100%
DOE	31,259,530	16
Participants	160,440,470	84

Project Objective:

To demonstrate that existing iron-making blast furnaces can be retrofitted with blast furnace granulated-coal injection technology; and to demonstrate sustained operation with a variety of coal particle sizes, coal injection rates, and coal types, and to assess the interactive nature of these parameters.

Technology/Project Description:

In the BFGCI process, both granulated and pulverized coal is injected into the blast furnace in place of natural gas (or oil) as a blast furnace fuel supplement. The coal along with heated air is blown into the barrel-shaped section in the lower part of the blast furnace through passages called tuyeres, which creates swept zones in the furnace called raceways. The size of a raceway is important and is dependent upon many factors including temperature. Lowering of a raceway temperature, which can occur with gas injection, reduces blast furnace production rates. Coal, with a lower hydrogen content than either gas or oil, does not cause as severe a reduction in raceway temperatures. In addition to displacing injected natural gas, the coal injected through the tuyeres displaces coke, the primary blast furnace fuel and reductant

(reducing agent), on approximately a pound-for-pound basis. Because coke production results in significant emissions of NO_x , SO_2 , and air toxics and coal could replace up to 40% of the coke requirement, BFGCI technology has significant potential to reduce emissions and enhance blast furnace production.

Emissions generated by the blast furnace itself remain virtually unchanged by the injected coal; the gas exiting the blast furnace is clean, containing no measurable SO_2 or NO_x . Sulfur from the coal is removed by the limestone flux and bound up in the slag, which is a salable by-product. In addition to the net emissions reduction realized by coke displacement, blast furnace production is increased by maintaining high raceway temperatures.

Two high-capacity blast furnaces, Units C and D at Bethlehem Steel Corporation's Burns Harbor Plant, are being retrofitted with BFGCI technology. Each unit has a production capacity of 7,000 net tons/day of hot metal. The two units will use about 2,800 tons/day of coal during full operation. Bituminous coals with sulfur content ranging from 0.8% to 2.8% from West Virginia, Pennsylvania, Illinois, and Kentucky are to be used. A western subbituminous coal having 0.4–0.9% sulfur might be tested also.

Project Status/Accomplishments:

Bethlehem Steel has signed a turnkey contract with Fluor Daniel, Inc., of Greenville, SC, for the project's engineering, procurement, and construction. Project design continued throughout the year and by December 1993 was approximately 90% complete.

An environmental assessment with a finding of no significant impact was approved in June 1993, completing the NEPA process. With receipt of a construction permit from the state of Indiana also in June, site work

was initiated. By the end of the year, excavation work was completed, the pouring of foundations was well under way, and erection of structural steel was beginning.

Facilities being constructed include those needed to prepare the coal, to deliver the prepared coal to the two blast furnaces, and to inject it into the furnaces. In addition, the blast furnaces will be modified to accept the prepared coal. The necessary modifications to furnace D will be made on-the-fly through a series of short outages on the operating furnace. Furnace C will be modified during a reline scheduled for third quarter 1994.

Commercial Applications:

BFGCI technology can be applied to essentially all U.S. blast furnaces. The technology should be applicable to any rank coal commercially available in the United States. The environmental impacts of commercial application are primarily indirect and consist of a significant reduction of emissions resulting from diminished coke-making requirements.

Innovative Coke Oven Gas Cleaning System for Retrofit Applications

Sponsor:

Bethlehem Steel Corporation

Additional Team Member:

Still-Otto—technology developer

Location:

Sparrows Point, Baltimore County, MD (Bethlehem Steel Corporation's Sparrows Point Plant, Coke Oven Batteries A, 11, and 12)

Technology:

Still-Otto's process for precombustion cleaning of coke oven gas (COG) (industrial applications)

Plant Capacity/Production:

74 million std ft³/day of COG

Project Funding:

Total project cost	\$45,239,781	100%
DOE	13,500,000	30
Participant	31,739,781	70

Project Objective:

To demonstrate a first-of-a-kind novel integration of commercially available process steps for simultaneous removal of hydrogen sulfide and ammonia from COG, recovery of hydrogen sulfide and ammonia, destruction of ammonia, and recovery of sulfur in a commercial-sized application; and to reduce SO₂ emissions by at least 80% accompanied by substantially reduced emissions of volatile organic compounds and discharge of ammonia to wastewater treatment.

Technology/Project Description:

This project is demonstrating an innovative technology developed by Still-Otto for removing hydrogen sulfide and ammonia from COG. The process uses contaminated water produced in the coke oven batteries to absorb the hydrogen sulfide and ammonia contained in the COG. Both hydrogen sulfide and ammonia are steam stripped from the absorption liquor. The ammonia is destroyed in a catalytic reactor; hydrogen sulfide is converted to elemental sulfur in a conventional Claus plant, and sulfur is recovered as a salable by-product.

The technology is expected to reduce the hydrogen sulfide concentration in the cleaned COG by 88% and the ammonia concentration by approximately 99%. Because the reagents used are indigenous in COG, costs

associated with the purchase and handling of feed reagents, the handling and treatment of by-products, labor, and utilities are reduced.

This project involves the modification of the COG processing units at Bethlehem Steel's Sparrows Point Plant in Baltimore County, MD. The demonstration facility is designed to process the entire COG stream from Coke Oven Batteries A, 11, and 12, which amounts to 74 million std ft³/day. These coke oven batteries have the capability to produce up to 1.2 million tons/yr of coke from a blend of Pennsylvania and Virginia coals having sulfur contents ranging from 0.8% to 1.37%. The raw COG has a hydrogen sulfide content of 175–340 grains/100 ft³. Currently, only 60% of this COG stream is desulfurized. The remaining 40% is used directly for fueling the fire under the coke ovens.

Project Status/Accomplishments:

On September 16, 1991, Bethlehem Steel Corporation announced that all coke production will be suspended at its Sparrows Point facility for at least 2 years. This decision was made due to the rapid deterioration of the coke ovens. During this period, an evaluation will be made to explore alternatives for resumption of coke production. Bethlehem Steel's intent is for long-term coke independence at the facility.

Construction of the coke oven gas cleaning demonstration facility is complete, and the unit has been mothballed to maintain it in good shape so that hot commissioning, start-up, and operation can be accomplished successfully when coke-making operations are resumed.

Given the high background levels of contaminants present in the coke oven batteries, specific air toxics monitoring is not contemplated at this time. Baseline environmental sampling is complete.

Commercial Applications:

The design for this innovative COG cleaning system is based on operating data that have been collected from individual process steps or combinations of individual process steps that have been successfully operated at commercial-sized COG treatment facilities. The novel integration of commercially available process steps is expected to reduce the overall cost of desulfurization, ensure reliable operation in applications exceeding 20 years, and provide a viable alternative to conventional technologies. Because the demonstration is designed to treat 74 million std ft³/day of COG (a commercial size), the project will demonstrate that it is possible to retrofit any existing coke-making facility in the United States with essentially no scaleup involved and without significant downtime.

Bethlehem Steel will license the use of this COG-cleaning technology through Still-Otto to the existing 30 coke oven plants in the United States which emit

about 300,000 tons/yr of SO₂. This COG-cleaning process could be applicable to 24 plants with corresponding SO₂ emission levels of 200,000 tons/yr. If the technology were installed in all 24 plants, the SO₂ emissions could be reduced by 160,000 tons/yr. Eliminated would be the ammonium sulfate which is difficult to market and usually is disposed of as a solid waste. Every 5–8 years, 5 tons of spent nickel catalyst would need to be returned to the vendor or disposed of as a hazardous waste, and 10 tons of spent alumina catalyst would need to be disposed of as a nonhazardous solid waste. Depending on the configuration of the coke oven facility where the technology is being implemented, the amount of water needed for cooling purposes would remain the same or be reduced, and the amount of pollutants in the wastewater would remain the same or be reduced.

Clean Power from Integrated Coal/Ore Reduction (COREX®)

Sponsor:

Centerior Energy Corporation

Additional Team Members:

LTV Steel Company—site owner; constructor and operator of COREX® unit

Air Products and Chemicals, Inc.—designer, engineer, constructor, and operator of air separation and combined-cycle units

Deutsche Voest-Alpine Industrieanlagenbau GmbH—COREX® developer/supplier; designer and engineer of COREX® unit

Electric Power Research Institute—cofunder

Ohio Coal Development Office—cofunder

Location:

Cleveland, Cuyahoga County, OH (LTV Steel Company's Cleveland Works)

Technology:

Integration of Deutsche Voest-Alpine Industrieanlagenbau's COREX® iron-making process with a combined-cycle power generation system (industrial applications)

Plant Capacity/Production:

150 MWe (net) and 3,200 tons/day of hot metal (liquid iron)

Project Funding:

Total project cost	\$825,092,000	100%
DOE	150,000,000	18
Participants	675,092,000	82

(Funding amounts reflect those contained in the proposal and are subject to negotiation.)

COREX is a registered trademark of Deutsche Voest-Alpine Industrieanlagenbau GmbH.

Project Objective:

To demonstrate the integration of a direct iron-making process (COREX®) with the production of electricity using various U.S. coals in an efficient and environmentally responsible manner.

Technology/Project Description:

The clean power from integrated coal/ore reduction (CPICOR) process integrates two historically distinct processes—iron-making and electric power generation. COREX® is a novel iron-making technology which eliminates the need for coke production. The key innovative features of the COREX® process include the reduction shaft furnace, which is used to reduce the iron ore to iron, and the melter-gasifier, located beneath the reduction furnace, which gasifies the coal and melts the iron.

The gasification process generates the reducing gas for use in the reduction furnace as well as sufficient heat to melt the resulting iron in the melter-gasifier.

Excess reducing gas exiting the reduction furnace is cooled, cleaned, compressed, mixed with air and nitrogen, and burned in a gas turbine generator system capable of combusting low-Btu fuel gas. The hot exhaust from the turbine is then delivered to a heat recovery steam generator where process steam is made for utilization in a steam turbine generator system to produce additional electric power.

During the demonstration, about 2,800 tons/day of coal will be gasified to produce 3,200 tons/day of hot metal and 150 MWe for sale.

CPICOR technology is less complex and environmentally superior when compared to competing

iron-making and power-generating technologies. All criteria air pollutants are reduced by more than 85% due largely to (1) the inherent desulfurizing capability of the COREX® process wherein the limestone fed to the reduction furnace captures the sulfur present in the coal and (2) the efficient control systems within the combined-cycle power generation process. Because coke is not used, coke plants and their associated pollutants can be eliminated.

The energy efficiency of the CPICOR process is over 35% greater than competing commercial technology. This efficiency advantage is gained by more effective use of both the sensible heat in the process and the volatile matter in the coal, as well as by incorporation of the combined-cycle power generation system.

The technology is being demonstrated at LTV Steel Company's Cleveland Works in Cleveland, OH.

Project Status/Accomplishments:

The project is in negotiation.

Commercial Applications:

The CPICOR technology is a direct replacement for existing blast furnace and coke-making capacity with the additional benefit of combined-cycle power generation. A full-scale commercial plant based on the CPICOR demonstration project will produce nearly 200 MWe (net exportable) and 1,200,000 tons/yr of hot metal while expanding the type of coals that can be used to produce hot metal into the much larger non-coking range.

The total emissions of NO_x from the commercial plant are expected to be 0.012 lb/million Btu, which is a reduction of more than 97% from the combination of a comparably sized blast furnace, associated coke-making facilities, and a comparably sized pulverized coal power plant with flue gas desulfurization. Similarly, the total emissions of SO₂ from the commercial facility are expected to be 0.0244 lb/million Btu, a reduction of more than 90%. The net electrical generating efficiency of the commercial facility will be 47.2% (a net effective heat

rate of 7,232 Btu/kWh on an LHV basis). This is to be compared to a net efficiency of 29.1% for comparably sized conventional facilities.

Overall, a CPICOR commercial plant would produce minimal solid or liquid impacts to the environment, especially when compared to existing competing facilities. All solid wastes are expected to be exempt from the Resource Conservation and Recovery Act requirements. The majority of solid wastes are beneficially reused, which increases the economic benefit of the technology and avoids burdening landfills. Most of the solid waste is slag from the iron-making process, which is reusable as ballast for road construction and foundations.

Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control

Project completed.

Sponsor:

Coal Tech Corporation

Additional Team Members:

Commonwealth of Pennsylvania Energy Development Authority—cofunder

Pennsylvania Power and Light Company—supplier of test coals

Tampella Power Corporation—host site

Location:

Williamsport, Lycoming County, PA (Tampella Power Corporation boiler manufacturing plant)

Technology:

Coal Tech's advanced, air-cooled, slagging combustor (industrial applications)

Plant Capacity/Production:

23 million Btu/hr

Project Funding:

Total project cost	\$984,394	100%
DOE	490,149	50
Participants	494,245	50

Project Objective:

To demonstrate that an advanced cyclone combustor can be retrofitted to an industrial boiler and that it can simultaneously remove up to 90% of the SO_2 and 90–95% of the ash within the combustor and reduce NO_x by up to 100 ppm.

Technology/Project Description:

Coal Tech's horizontal cyclone combustor is internally lined with ceramic that is air-cooled. Pulverized coal, air, and sorbent are injected tangentially toward the wall through tubes in the annular region of the combustor to cause cyclonic action. In this manner, coal-particle combustion takes place in a swirling flame in a region favorable to particle retention in the combustor. Secondary air is used to adjust the overall combustor stoichiometry. The ceramic liner is cooled by the secondary air and maintained at a temperature high enough to keep the slag in a liquid, free-flowing state. The secondary air is preheated by the combustor walls to attain efficient combustion of the coal particles in the fuel-rich combustor. Fine coal pulverization allows combustion of most of the coal particles near the cyclone wall, with the balance burned

on or near the wall. This improves combustion in the fuel-rich chamber, as well as slag retention. The slag contains over 80% of the ash and sorbent fed to the combustor. For NO_x control, the combustor is operated fuel rich, with final combustion taking place in the boiler furnace to which the combustor is attached.

In Coal Tech's demonstration, an advanced, air-cooled, cyclone coal combustor was retrofitted to a 23-million-Btu/hr, oil-designed package boiler located at the Tampella Power Corporation boiler factory in Williamsport, PA. Air cooling in this combustor takes place in a very compact combustor which can be retrofitted to a wide range of industrial and utility boiler designs without disturbing the boiler's water-steam circuit. NO_x reduction is achieved by staged combustion, and SO_2 is captured by injection of limestone into the combustor.

The cyclonic action inside the combustor forces the coal ash and sorbent to the walls where it can be collected as liquid slag. Under optimum operating conditions, the slag contains a significant fraction of vitrified coal sulfur. Downstream sorbent injection into the boiler provides additional sulfur removal capacity.

Project Results/Accomplishments:

The test effort consisted of 800 hours of operation which included five individual tests, each of 4 days duration, plus another 100 hours of operation as part of separate ash vitrification tests. Eight Pennsylvania bituminous coals with sulfur contents ranging from 1% to 3.3% and volatile matter ranging from 19% to 37% were tested.

Under fuel-rich conditions, combustion efficiencies exceeding 99% after proper operating procedures were achieved. Turndown to 6 million Btu/hr from a peak of 19 million Btu/hr was achieved. Due to facility limits on water availability for the boiler and for cooling the combustor, the maximum heat input during the tests was around 20 million Btu/hr even though the combustor was designed for 30 million Btu/hr and the boiler was thermally rated at around 25 million Btu/hr.

Coal Tech reported the following test results:

- With fuel-rich operation of the combustor, a 75% reduction in boiler-outlet-stack NO_x was obtained, corresponding to 0.3 lb/million Btu (184 ppmv). An additional 5–10% NO_x reduction was obtained by the action of the wet particulate scrubber, resulting in atmospheric NO_x emissions as low as 0.26 lb/million Btu (160 ppmv).
- Over 80% SO_2 reduction measured at the boiler outlet stack was achieved using sorbent injection in the furnace at various calcium-to-sulfur molar ratios (Ca/S). A maximum SO_2 reduction of 58% was measured at the stack with limestone injection into the combustor at a Ca/S of 2. A maximum of 33% of

the coal sulfur was retained in the dry ash removed from the combustor and furnace hearths, and a high of 11% of the coal sulfur was retained in the slag rejected through the slag tap.

- Local stack particulate emission standards were met with the wet venturi particulate scrubber.
- Total slag/sorbent retention in the combustor, under efficient combustion operating conditions, averaged 72% and ranged from 55% to 90%. Under more fuel-lean conditions, the slag retention averaged 80%. In post-CCT-project tests on flyash vitrification in the combustor, modifications to the solids injection method and increases in the slag flow rate produced substantial increases in the slag retention rate.
- All slag removed from the combustor produced trace metal leachates well below the EPA drinking water standard.
- Different sections of the combustor had different materials requirements. Suitable materials for each section were identified. Also, the test effort showed that operational procedures were closely coupled with materials durability. By implementing certain procedures, such as changing the combustor wall temperature, it was possible to replenish the combustor refractory wall thickness with slag.
- Procedures for properly operating an air-cooled combustor were developed, and the entire operating database was incorporated into a computer-controlled system for automatic combustor operation.

Commercial Applications:

Coal Tech has concluded that, while the combustor is not yet fully ready for sale with commercial guarantees, it is ready to be further scaled up for commercial applications (100 million Btu/hr), such as combustion of waste solid

fuels, limited sulfur control in coal-fired boilers, and conversion of ash to slag.

Coal Tech's advanced, air-cooled, slagging combustor can use a wide range of U.S. coals and can be retrofitted to existing or new units. The target market is industrial and utility boilers sized 20–100 million Btu/hr or more; multiple combustors can be attached to larger boilers. The near-term focus is on using the combustor in combined-cycle industrial and small utility power plants in the 10–50-MWe range. The combustor is capable of using pulverized coal, coal-water slurry, cofired pulverized coal, and refuse-derived fuels (e.g., industrial sludge and coal-mine waste).

Project Schedule:

DOE selected project (CCT-I)	7/24/86
Cooperative agreement awarded	3/20/87
NEPA process completed (MTF)	3/26/87
Environmental monitoring plan completed	9/22/87
Construction	7/87–11/87
Operational testing	11/87–5/90
Project completed	9/91

Final Reports:

Final Technical Report	8/91
DOE Assessment	5/93

Cement Kiln Flue Gas Recovery Scrubber

Project completed.

Sponsor:

Passamaquoddy Tribe

Additional Team Members:

Dragon Products Company—project manager and host
E.C. Jordan Company—engineer for overall scrubber system

HPD, Incorporated—designer and fabricator of tanks and heat exchanger

Cianbro Corporation—constructor

Location:

Thomaston, Knox County, ME (Dragon Products Company's coal-fired cement kiln)

Technology:

Passamaquoddy Technology Recovery Scrubber™ (industrial applications)

Plant Capacity/Production:

1,450 tons/day of cement; 250,000 std ft³/min of kiln gas; and up to 274 tons/day of coal

Project Funding:

Total project cost	\$17,800,000	100%
DOE	5,982,592	34
Participants	11,817,408	66

Project Objective:

To retrofit and demonstrate a full-scale industrial scrubber and waste recovery system for a coal-burning wet process cement kiln using waste dust as the reagent to accomplish 90–95% SO₂ reduction using high-sulfur

Passamaquoddy Technology Recovery Scrubber is a trademark of the Passamaquoddy Tribe.

eastern coals and to produce a commercial by-product, potassium-based fertilizer.

Technology/Project Description:

The Passamaquoddy Technology Recovery Scrubber™ uses a water solution/slurry containing potassium-rich dust recovered from the kiln flue gas, which serves as the scrubbing medium. No other chemicals are required for the process. After scrubbing the gas, the slurry is separated into liquid and solid fractions. The solid fraction is returned to the cement plant as renovated and usable raw feed material. The liquid fraction is passed to a crystallizer that uses waste heat in the exhaust gas to evaporate the water and recover dissolved alkali metal salts.

The Passamaquoddy Tribe's recovery scrubber was constructed at the Dragon Products Company's cement

plant in Thomaston, ME, a plant that processes approximately 470,000 tons/yr of cement. The process was developed by the Passamaquoddy Indian Tribe while it was seeking ways to solve landfill problems, which resulted from the need to dispose of waste kiln dust from the cement-making process.

The kiln burns Pennsylvania bituminous coal containing approximately 3% sulfur.

Project Results/Accomplishments:

The recovery scrubber began operations in August 1991 and has continued operations with several temporary shutdowns for normal kiln repairs and maintenance and a more lengthy shutdown from January to May 1992 due to poor economic conditions in the area. In a 5-month period from May to September 1992, the plant produced approximately 140,000 tons of cement while the scrubber removed 70 tons of SO₂ and treated 6,000 tons of kiln dust for return to the kiln as raw feed. Initial testing of the scrubbing system achieved the project objective of 90–95% SO₂ emission reduction, with a maximum reduction of 98%. Operations have totaled 5,316 hours. Capital costs are approximately \$10 million for a 450,000-ton/yr plant, with a simple payback estimated to be 3–4 years. Project operations continued through September 1993 when the scrubber became a permanent part of the Dragon Products facility.

Commercial Applications:

The recovery scrubber permits the use of high-sulfur coal in cement kilns using available waste dust as the reagent, without requiring the purchase of other materials as scrubber reactant.

There are over 250 cement kiln installations in the United States and along the St. Lawrence River in Canada emitting approximately 230,000 tons/yr of SO₂. Based upon the characteristics of the technology, the applicable market would include approximately 75% of these installations. If the technology were installed in the applicable market facilities, the SO₂ emissions could be reduced by approximately 150,000 tons/yr.

The effect on NO_x emissions is being determined during the demonstration. Some reductions in NO_x emissions are expected.

Water usage might or might not increase depending on the configuration of the existing kiln facility. However, the quality of wastewater would be improved and

the amount reduced because the technology produces distilled water either for sale or discharge.

The waste dust that previously would have been sent to a landfill would be recovered for recycling to the kiln and to produce by-product fertilizer. Essentially, the solid waste stream would be eliminated through recovery.

Project Schedule:

DOE selected project (CCT-II)	9/28/88
Cooperative agreement awarded	12/20/89
NEPA process completed (EA)	2/16/90
Environmental monitoring plan completed	3/26/90
Construction	4/90–5/91
Operational testing	8/91–9/93
Project completed	2/94

Final Reports:

Final Technical Report	early 1994
Topical Report	3/92
Public Design Report	10/93
An economic assessment will be conducted after project completion.	

Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal

Sponsor:

ThermoChem, Inc.

Additional Team Member:

Manufacturing and Technology Conversion International, Inc.—technology supplier

Location:

Near Gillette, Campbell County, WY (Caballo Rojo Mine)

Technology:

Advanced combustion using Manufacturing and Technology Conversion International's (MTCI) pulse combustor/gasifier (industrial applications)

Plant Capacity/Production:

161 million Btu/hr of 325 Btu/std ft³ medium-Btu fuel gas plus 40,000 lb/hr of export steam

Project Funding:

Total project cost	\$37,333,474	100%
DOE	18,666,737	50
Participants	18,666,737	50

Project Objective:

To demonstrate the MTCI pulse combustor in an application for steam gasification of coal to produce a medium-Btu fuel gas from subbituminous coal.

Technology/Project Description:

The MTCI fluidized-bed gasifier incorporates an innovative indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean, medium-Btu fuel gas without the need for an oxygen plant. The indirect heat transfer is provided by MTCI's multiple resonance tube pulse combustor technology with the resonance tubes comprising the heat exchanger immersed in the fluidized-bed reactor. Heat transfer is 3–5 times greater than other indirectly heated gasifier concepts, allowing the heat transfer surface to be minimized.

The demonstration plant's overall efficiency is expected to be 72% or more. In major commercial applications, char combustion and heat recovery operations can be included to enhance overall plant efficiency.

SO₂ emissions are controlled by scrubbing the product gas using commercially available processes. A market for the by-product sulfur is being sought, and disposal methods are being evaluated.

The demonstration facility will be built at the Caballo Rojo Mine in conjunction with a new facility to demonstrate the K-Fuel coal-upgrading process. Water required to gasify the subbituminous coal will be produced by the K-Fuel process and the steam produced in the gasification demonstration facility will be used in the K-Fuel facility. The product gas will be burned in a gas turbine to generate electricity to operate both facilities.

Project Status/Accomplishments:

The cooperative agreement was awarded on October 27, 1992, and design activities are under way. Design verification tests are under way at MTCI's Baltimore facility. The design tests include the construction and test firing of one full-size pulse combustor tube bundle. Environmental information is being prepared for use in the NEPA process.

Commercial Applications:

The MTCI fluidized-bed gasifier is expected to provide the exceptional environmental performance exhibited by coal gasification in general. SO₂ emissions are controlled by removing hydrogen sulfide from the product gas prior to combustion; removal efficiencies approaching 99% are possible. Particulate emissions are also controlled in highly efficient scrubbers. Finally, the MTCI pulse combustion technology that provides the required gasifier heat is an inherently low-NO_x combustion process, thereby assuring that NO_x emissions are substantially below acceptable limits.

Because of its potential for reducing emissions while producing a clean-burning, hydrogen-rich fuel gas, the MTCI fluidized-bed gasifier is expected to have considerable commercial potential. Some of the early industrial applications of this technology are expected to be waste-to-energy or waste and coal cofired facilities for power and steam generation. One of the more promising non-coal applications is processing of kraft black liquor.

The processing of pulp results in the production of about 88 million tons of by-product black liquor. The current practice of using black liquor recovery boilers to produce steam and electricity is inefficient. Replacing these boilers with MTCI gasifiers would significantly improve the conversion efficiency. The estimated market for MTCI gasifiers in this application alone is 28 units annually.

Another potential application for the technology is in industrial coal gasification because of its modularity and ability to produce a medium-Btu gas without requiring an oxygen plant.

Appendix A: Relevant Legislation

Public Law 99-190

CLEAN COAL TECHNOLOGY

Within 60 days following enactment of this Act, the Secretary of Energy shall, pursuant to the Federal Nonnuclear Energy Research and Development Act of 1974 (42 U.S.C. 5901, et seq.), issue a general request for proposals for clean coal technology projects for which the Secretary of Energy upon review may provide financial assistance awards. Proposals for clean coal technology projects under this section shall be submitted to the Department of Energy within 60 days after issuance of the general request for proposals. The Secretary of Energy shall make any project selections no later than August 1, 1986: *Provided*, That the Secretary may vest fee title or other property interests acquired under cost-shared clean coal technology agreements in any entity, including the United States: *Provided further*, That the Secretary shall not finance more than 50 per centum of the total costs of a project as estimated by the Secretary as of the date of award of financial assistance: *Provided further*, That cost-sharing by project sponsors is required in each of the design, construction, and operating phases proposed to be included in a project: *Provided further*, That financial assistance for costs in excess of those estimated as of the date of award of original financial assistance may not be provided in excess of the proportion of costs borne by the Government in the original agreement and only up to 25 per centum of the original financial assistance: *Provided further*, That revenues or royalties from prospective operation of projects beyond the time considered in the award of financial assistance, or proceeds from prospective sale of the assets of the project, or revenues or royalties from replication of technology in future projects or plants are not cost-sharing for the purposes of this appropriation: *Provided further*, That other appropriated Federal funds are not cost-sharing for the purposes of this appropriation: *Provided further*, That existing facilities, equipment, and supplies, or previously expended research or development funds are not cost-sharing for the purposes of this appropriation, except as amortized, depreciated, or expensed in normal business practice.

Conference Report (H. Rep. 99-450)

CLEAN COAL TECHNOLOGY

The managers have agreed to a \$400,000,000 Clean Coal Technology program as described under the Department of the Treasury, Energy Security Reserve. Bill language is included which provides for the selection of projects no later than August 1, 1986. Within that period, a general request for proposals must be issued within 60 days and proposals must be submitted to the Department within 60 days after issuance of the general request for proposals. Language is also included allowing the Secretary of Energy to vest title in interests acquired under agreements in any entity, including the United States, and delineating cost-sharing requirements. Funds for these activities and projects are made available to the Clean Coal Technology program in the Energy Security program.

It is the intent of the managers that contributions in the form of facilities and equipment be considered only to the extent that they would be amortized, depreciated or expensed in normal business practice. Normal business practice shall be determined by the Secretary and is not necessarily the practice of any single proposer. Property which has been fully depreciated would not receive any cost-sharing value except to the extent that it has been in continuous use by the proposer during the calendar year immediately preceding the enactment of this Act. For this property, a fair use value for the life of the project may be assigned. Property offered as a cost-share by the proposer that is currently being depreciated would be limited in its cost-share value to the depreciation claimed during the life of the demonstration project. Furthermore, in determining normal business practice, the Secretary should not accept valuation for property sold, transferred, exchanged, or otherwise manipulated to acquire a new basis for depreciation purposes or to establish a rental value in circumstances which would amount to a transaction for the mere purpose of participating in this program.

The managers agree that, with respect to cost-sharing, tax implications of proposals and tax advantages available to individual proposers should not be considered in determining the percentage of Federal cost-sharing. This is consistent with current and historical practices in Department of Energy procurements.

It is the intent of the managers that there be full and open competition and that the solicitation be open to all markets utilizing

the entire coal resource base. However, projects should be limited to the use of United States mined coal as the feedstock and demonstration sites should be located within the United States.

The managers agree that no more than \$1,500,000 shall be available in FY 1986 and \$2,000,000 each year thereafter for contracting, travel, and ancillary costs of the program, and that manpower costs are to be funded under the fossil energy research and development program.

The managers direct the Department, after projects are selected, to provide a comprehensive report to the Congress on proposals received.

The managers also expect the request for proposals to be for the full \$400,000,000 program, and not only for the first \$100,000,000 available in fiscal year 1986.

Public Law 100-202

CLEAN COAL TECHNOLOGY

For necessary expenses of, and associated with, Clean Coal Technology demonstrations pursuant to 42 U.S.C. 5901 et seq., \$50,000,000 are appropriated for the fiscal year beginning October 1, 1987, and shall remain available until expended, and \$525,000,000 are appropriated for the fiscal year beginning October 1, 1988, and shall remain available until expended.

No later than sixty days following enactment of this Act, the Secretary of Energy shall, pursuant to the Federal Nonnuclear Energy Research and Development Act of 1974 (42 U.S.C. 5901 et seq.), issue a general request for proposals for emerging clean coal technologies which are capable of retrofitting or repowering existing facilities, for which the Secretary of Energy upon review may provide financial assistance awards. Proposals under this section shall be submitted to the Department of Energy no later than ninety days after issuance of the general request for proposals required herein, and the Secretary of Energy shall make any project selections no later than one hundred and sixty days after receipt of proposals: *Provided*, That projects selected are subject to all provisos contained under this head in Public Law 99-190: *Provided further*, That pre-award costs incurred by project sponsors after selection and before signing an agreement are allowable to the extent that they are related to (1) the preparation of material requested by the Department of Energy and identified as required for the negotiation; or (2) the preparation and submission of environmental data requested by the Department of Energy to complete National Environmental Policy Act requirements for the projects: *Provided further*,

That pre-award costs are to be reimbursed only upon signing of the project agreement and only in the same ratio as the cost-sharing for the total project: *Provided further*, That reports on projects selected by the Secretary of Energy pursuant to authority granted under the heading "Clean coal technology" in the Department of the Interior and Related Agencies Appropriations Act, 1986, as contained in Public Law 99-190, which are received by the Speaker of the House of Representatives and the President of the Senate prior to the end of the first session of the 100th Congress shall be deemed to have met the criteria in the third proviso of the fourth paragraph under the heading "Administrative provisions, Department of Energy" in the Department of the Interior and Related Agencies Appropriations Act, 1986, as contained in Public Law 99-190, upon expiration of 30 calendar days from receipt of the report by the Speaker of the House of Representatives and the President of the Senate.

Conference Report (H. Rep. 100-498)

CLEAN COAL TECHNOLOGY

Appropriates \$575,000,000 for clean coal technology instead of \$350,000,000 as proposed by the House and \$850,000,000 as proposed by the Senate. The comparison by year is as follows:

	House	Senate	Conference
Fiscal year			
1988	\$50,000,000	\$350,000,000	\$50,000,000
1989	200,000,000	500,000,000	525,000,000
1990	100,000,000		
Total	350,000,000	850,000,000	575,000,000

Bill language, proposed by the House, which would have prohibited using grants has been deleted. The managers agree that project funding is expected to be based on cooperative agreements, but that grants might be applicable to support work also funded from this account.

The managers agree to delete Senate language providing personnel floors for Clean Coal Technology. The managers further agree that the budget estimates for personnel and contract support are to be followed. The agreement includes 58 new positions above current employment floors for the fossil energy organization and 30 positions within the floors. Out of clean coal technology funds, up to \$3,980,000 is for fiscal year 1988 personnel-related costs and up to \$16,520,000 is for all contract costs needed to make project selections and complete negotiations for both clean coal procurements. Contract costs necessary to monitor approved projects should be requested in the fiscal year 1989 budget. Increases above those

amounts are subject to reprogramming procedures. No funds other than personnel related costs for the 30 positions included in program direction are to be provided from the fossil energy research and development account.

The length of time for selection of projects by the Secretary of Energy has been extended from 120 days to 160 days based on experience from the original clean coal procurement. Once projects have been selected the Secretary should establish project milestones and guidelines for project negotiations in order to expedite the negotiation process to the extent feasible.

The managers agree that the funds provided are available for non-utility applications as well as for utility applications.

The managers agree that no funds are provided for the demonstration of clean coal technologies which are intended solely for new, stand alone, applications. The Senate had proposed up to 25% of the funds be available for this purpose.

Bill language has been included which provides that reports on projects selected in the first round of clean coal procurements that are received before the end of the first session of the 100th Congress will satisfy reporting requirements 30 calendar days after receipt by Congress. This provision applies to a maximum of two project reports.

Public Law 100-446

CLEAN COAL TECHNOLOGY

For necessary expenses of, and associated with, Clean Coal Technology demonstrations pursuant to 42 U.S.C. 5901 et seq., \$575,000,000 shall be made available on October 1, 1989, and shall remain available until expended: *Provided*, That projects selected pursuant to a general request for proposals issued pursuant to this appropriation shall demonstrate technologies capable of retrofitting or repowering existing facilities and shall be subject to all provisos contained under this head in Public Laws 99-190 and 100-202 as amended by this Act.

The first paragraph under this head in Public Law 100-202 is amended by striking "and \$525,000,000 are appropriated for the fiscal year beginning October 1, 1988" and inserting "\$190,000,000 are appropriated for the fiscal year beginning October 1, 1988, and shall remain available until expended, \$135,000,000 are appropriated for the fiscal year beginning October 1, 1989, and shall remain available until expended, and \$200,000,000 are appropriated for the fiscal year beginning October 1, 1990": *Provided*, That outlays in fiscal year 1989 resulting from the use of funds appropriated

under this head in Public Law 100-202, as amended by this Act, may not exceed \$15,500,000: *Provided further*, That these actions are taken pursuant to section 202(b)(1) of Public Law 100-119 (2 U.S.C. 909).

For the purposes of the sixth proviso under this head in Public Law 99-190, funds derived by the Tennessee Valley Authority from its power program are hereafter not to be precluded from qualifying as all or part of any cost-sharing requirement, except to the extent that such funds are provided by annual appropriations Acts: *Provided*, That unexpended balances of funds made available in the "Energy Security Reserve" account in the Treasury for The Clean Coal Technology Program by the Department of the Interior and Related Agencies Appropriations Act, 1986, as contained in section 101(d) of Public Law 99-190, shall be merged with this account: *Provided further*, That for the purposes of the sixth proviso in Public Law 99-190 under this heading, funds provided under section 306 of Public Law 93-32 shall be considered non-Federal: *Provided further*, That reports on projects selected by the Secretary of Energy pursuant to authority granted under the heading "Clean coal technology" in the Department of the Interior and Related Agencies Appropriations Act, 1986, as contained in Public Law 99-190, which are received by the Speaker of the House of Representatives and the President of the Senate prior to the end of the second session of the 100th Congress shall be deemed to have met the criteria in the third proviso of the fourth paragraph under the heading "Administrative provisions, Department Energy" in the Department of the Interior and Related Agencies Appropriations Act, 1986, as contained in Public Law 99-190, upon expiration of 30 calendar days from receipt of the report by the Speaker of the House of Representatives and the President of the Senate.

Conference Report (H. Rep. 100-862)

CLEAN COAL TECHNOLOGY

Amendment No. 131: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate with an amendment as follows:

In lieu of the matter proposed by said amendment insert the following: *For necessary expenses of, and associated with, Clean Coal Technology demonstrations pursuant to 42 U.S.C. 5901 et seq., \$575,000,000 shall be made available on October 1, 1989, and shall remain available until expended: Provided*, That projects selected pursuant to a general request for proposals issued pursuant to this appropriation shall demonstrate technologies capable of retrofitting or repowering existing facilities and shall be subject to all provisos

contained under this head in Public Laws 99-190 and 100-202 as amended by this Act.

The managers on the part of the Senate will move to concur in the amendment of the House to the amendment of the Senate. The amendment provides \$575,000,000 in fiscal year 1990 for a third Clean Coal Technology procurement as proposed by the Senate, and clarifies that the procurement is for retrofit and repowering technologies and is subject to the cost-sharing provisions of the previous two procurements.

The managers agree that a request for proposals should be issued by May 1, 1989, with proposals due no later than 120 days after issuance of the request for proposals, and that the Secretary of Energy should make project selections no later than 120 days after receipt of proposals.

Amendment No. 132: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate with an amendment as follows:

Restore the matter stricken by said amendment, amended to read as follow: *The first paragraph under this head in Public Law 100-202 is amended by striking "and \$525,000,000 are appropriated for the fiscal year beginning October 1, 1988" and inserting "\$190,000,000 are appropriated for the fiscal year beginning October 1, 1988, and shall remain available until expended, \$135,000,000 are appropriated for the fiscal year beginning October 1, 1989, and shall remain available until expended, and \$200,000,000 are appropriated for the fiscal year beginning October 1, 1990": Provided, That outlays in fiscal year 1989 resulting from the use of funds appropriated under this head in Public Law 100-202, as amended by this Act, may not exceed \$15,500,000: Provided further, That these actions are taken pursuant to section 202(b)(1) of Public Law 100-119 (2 U.S.C. 909).*

The managers on the part of the Senate will move to concur in the amendment of the House to the amendment of the Senate. The amendment changes the availability of \$525,000,000 originally made available for fiscal year 1989 in Public Law 100-202 by making \$190,000,000 available in 1989, \$135,000,000 available in 1990, and \$200,000,000 available in 1991 and also provides an outlay ceiling in fiscal year 1989. The House had proposed \$100,000,000 in fiscal year 1989, \$225,000,000 in fiscal year 1990, and \$200,000,000 in fiscal year 1991, and the Senate struck the House language.

Both of these changes are necessary because of budget allocation constraints, but neither action has an effect on the execution of the Clean Coal program, or on the Congress' overall support for the

program, as is evidenced by additional appropriations provided for a third procurement of technologies.

The managers agree that administrative contract expenses may be incurred up to the budget level of \$9,820,000, but caution that close control of such expenditures is necessary to assure that the outlay ceiling provided will be sufficient to cover project costs.

Amendment No. 133: Modifies public law citation as proposed by the Senate.

Amendment No. 134: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate which clarifies that funds borrowed by REA Electric Cooperatives from the Federal Financing Bank are eligible as cost-sharing in the clean coal technology program.

Amendment No. 135: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate which specifies clean coal projects may proceed 30 calendar days after receipt by Congress of required reports, provided the reports are received prior to the end of the 100th Congress.

Public Law 101-45

CLEAN COAL TECHNOLOGY

Notwithstanding any other provision of law, funds originally appropriated under this head in the Department of the Interior and Related Agencies Appropriations Act, 1989, shall be available for a third solicitation of clean coal technology demonstration projects, which projects are to be selected by the Department not later than January 1, 1990.

Public Law 101-121

CLEAN COAL TECHNOLOGY

For necessary expenses of, and associated with, Clean Coal Technology demonstrations pursuant to 42 U.S.C. 5901 et seq., \$600,000,000 shall be made available on October 1, 1990, and shall remain available until expended, and \$600,000,000 shall be made available on October 1, 1991, and shall remain available until expended: *Provided, That projects selected pursuant to a separate general request for proposals issued pursuant to each of these*

appropriations shall demonstrate technologies capable of replacing, retrofitting or repowering existing facilities and shall be subject to all provisos contained under this head in Public Laws 99-190, 100-202, and 100-446 as amended by this Act: *Provided further*, That the general request for proposals using funds becoming available on October 1, 1990, under this paragraph shall be issued no later than June 1, 1990, and projects resulting from such a solicitation must be selected no later than February 1, 1991: *Provided further*, That the general request for proposals using funds becoming available on October 1, 1991, under this paragraph shall be issued no later than September 1, 1991, and projects resulting from such a solicitation must be selected no later than May 1, 1992.

The first paragraph under this head in Public Law 100-446 is amended by striking "\$575,000,000 shall be made available on October 1, 1989" and inserting "\$450,000,000 shall be made available on October 1, 1989, and shall remain available until expended, and \$125,000,000 shall be made available on October 1, 1990": *Provided*, That these actions are taken pursuant to section 202(b)(1) of Public Law 100-119 (2 U.S.C. 909).

With regard to funds made available under this head in this and previous appropriations Acts, unobligated balances excess to the needs of the procurement for which they originally were made available may be applied to other procurements for which requests for proposals have not yet been issued: *Provided*, That for all procurements for which project selections have not been made as of the date of enactment of this Act no supplemental, backup, or contingent selection of projects shall be made over and above projects originally selected for negotiation and utilization of available funds: *Provided further*, That reports on projects selected by the Secretary of Energy pursuant to authority granted under this heading which are received by the Speaker of the House of Representatives and the President of the Senate less than 30 legislative days prior to the end of the first session of the 101st Congress shall be deemed to have met the criteria in the third proviso of the fourth paragraph under the heading "Administrative provisions, Department of Energy" in the Department of the Interior and Related Agencies Appropriations Act, 1986, as contained in Public Law 99-190, upon expiration of 30 calendar days from receipt of the report by the Speaker of the House of Representatives and the President of the Senate or at the end of the session, whichever occurs later.

Conference Report (H. Rep. 101-264)

CLEAN COAL TECHNOLOGY

Amendment No. 112: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede

and concur in the amendment of the Senate which adds the word "replacing" to the definition of clean coal technology. The managers agree that the inclusion of "replacing" for clean coal IV and V is intended to cover the complete replacement of an existing facility if, because of design or site specific limitations, repowering or retrofitting of the plant is not a desirable option.

Amendment No. 113: Appropriates \$450,000,000 for fiscal year 1990 for clean coal technology instead of \$500,000,000 as proposed by the House and \$325,000,000 as proposed by the Senate. This appropriation along with \$125,000,000 provided for fiscal year 1991 in Amendment 114 fully funds the third round of clean coal technology projects. The managers agree that additional manpower is required, particularly at the Department's Energy Technology Centers, in order to manage adequately the increased workload from the accumulation of active clean coal technology projects and the inclusion of additional procurements in this bill. Although a legislative floor is not included, the managers agree that at least eighty personnel will be required in addition to the approximately thirty FTE's now included in the fossil energy research and development appropriation. The managers agree further that funds from the fossil energy research and development appropriation should not be used to pay the cost of more than the equivalent FTE's paid under that account in fiscal year 1989.

Amendment No. 114: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate with an amendment as follows:

In lieu of the matter stricken and inserted by said amendment, insert: *and shall remain available until expended, and \$125,000,000*

The managers on the part of the Senate will move to concur in the amendment of the House to the amendment of the Senate. The amendment provides \$125,000,000 in fiscal year 1991 for the third clean coal technology procurement instead of \$75,000,000 as proposed by the House and \$100,000,000 as proposed by the Senate.

Amendment No. 115: Deletes Senate proposed appropriation of \$150,000,000 for fiscal year 1992 for clean coal technology. The House proposed no such appropriation.

Amendment No. 116: Restores House language stricken by the Senate which prohibits the use of supplemental, backup, or contingent project selections in clean coal technology procurements.

Amendment No. 117: Restores the word "further" stricken by the Senate.

Public Law 101-164

CLEAN COAL TECHNOLOGY

The second paragraph under this head contained in the Act making appropriations for the Department of the Interior and Related Agencies for the fiscal year ending September 30, 1990, is amended by striking "\$450,000,000" and inserting "\$419,000,000" and by striking "\$125,000,000" and inserting "\$156,000,000".

Conference Report (H. Rep. 101-315)

The managers have agreed to reduce the funds appropriated by the Energy and Water Development Appropriations Act for Fiscal Year 1990 (Public Law 101-101) for the "Nuclear Waste Disposal Fund" by \$46,000,000. This reduction will make funds available for the drug prevention effort.

The managers have agreed to reductions to the Interior and Related Agencies Appropriations Act for Fiscal Year 1990 (Public Law 101-121) in order to accommodate additional drug related appropriations.

The reductions are in three areas. The new budget authority for Clean Coal Technology of \$450,000,000 for fiscal year 1990 is reduced by \$31,000,000 with this same amount added to the advance appropriation for fiscal year 1991. With this change the new amount for fiscal year 1990 is \$419,000,000 while fiscal year 1991 increases to \$156,000,000. The second area of change is the imposition of an outlay ceiling on Strategic Petroleum Reserve oil acquisition. Outlays will be reduced from an estimated \$169,945,000 to \$147,125,000 and will decrease the fill rate from approximately 50,000 barrels per day to approximately 46,000 or 47,000 barrels per day. The third reduction relates to the Pennsylvania Avenue Development Corporation. The borrowing authority is reduced from \$5,000,000 to \$100,000.

The conference agreement includes bill language reducing the amount of funds transferred from trust funds to the Health Care Financing Administration Program Management account by \$32,000,000, from \$1,917,172,000 to \$1,885,172,000. This reduction, along with the outlays reserved from the regular 1990 Labor, Health and Human Services, and Education appropriations bill, will be sufficient to support the Subcommittee's share of the cost of anti-drug abuse funding. The conferees intend that the reduction in trust fund transfers be associated with activities to implement catastrophic health insurance, where funding needs may be diminished.

Public Law 101-302

CLEAN COAL TECHNOLOGY

Funds previously appropriated under this head for clean coal technology solicitations to be issued no later than June 1, 1990, and no later than September 1, 1991, respectively, shall not be obligated until September 1, 1991: *Provided*, That the aforementioned solicitations shall not be conducted prior to the ability to obligate these funds: *Provided further*, That pursuant to section 202(b) of the Balanced Budget and Emergency Deficit Control Reaffirmation Act of 1987, this action is a necessary (but secondary) result of a significant policy change: *Provided further*, That for the clean coal solicitations identified herein, provisions included for the repayment of government contributions to individual projects shall be identical to those included in the Program Opportunity Notice (PON) for Clean Coal Technology III (CCT-III) Demonstration Projects (solicitation number DE-PSO1-89 FE 61825), issued by the Department of Energy on May 1, 1989.

Conference Report (H. Rep. 101-493)

CLEAN COAL TECHNOLOGY

Amendment No. 89. Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate with an amendment as follows:

In lieu of the matter proposed by said amendment insert:

DEPARTMENT OF ENERGY

CLEAN COAL TECHNOLOGY

Funds previously appropriated under this head for clean coal technology solicitations to be issued no later than June 1, 1990, and no later than September 1, 1991, respectively, shall not be obligated until September 1, 1991: Provided, That the aforementioned solicitations shall not be conducted prior to the ability to obligate these funds: Provided further, That pursuant to section 202(b) of the Balanced Budget and Emergency Deficit Control Reaffirmation Act of 1987, this action is a necessary (but secondary) result of a significant policy change: Provided further, That for the clean coal solicitations identified herein, provisions included for the repayment of government contributions to individual projects shall be identical to those included in the Program Opportunity Notice (PON) for Clean Coal Technology III (CCT-III) Demonstration Projects (solicitation

number DE-PS01-89 FE 61825), issued by the Department of Energy on May 1, 1989.

The managers on the part of the Senate will move to concur in the amendment of the House to the amendment of the Senate.

The amendment delays the fourth and fifth clean coal technology solicitations as proposed by the Senate and specifies that, when issued, these solicitations must use repayment provisions used successfully in the third solicitation. This provision was included in the House introduced bill (H.R. 4828) and modifies a Senate amendment to the original Dire Emergency Supplemental.

The managers agree that changes to the clean air bill, proposed by a House authorizing committee, that would modify the clean coal technology program must be resolved before a reasonable solicitation can be issued. The proposed delay will allow such resolution.

The managers have added language to ensure that provisions dealing with the repayment of government provided funds will remain the same as in the third round of procurements. These provisions were developed over a four year period based on the experience of previous procurements and negotiations, and input from industrial participants, Congress, and the managers of the program. They appear to be working well.

Based on this long-term experience, and the clear fact that the implementation of this type of technology will become even more important with the passage of clean air legislation, the managers reject proposals put forth by the Department of Energy to increase repayment rates substantially. Such proposals, while they might increase the recovery of government-provided funds over periods of up to twenty years, might also act as a deterrent to industrial participation in the program, which is already over 50 percent cost-shared by industry. The purpose of the program is to accelerate the introduction of clean uses of coal in a more efficient manner in compliance with stringent new air quality standards, not the provision of investment returns to the Government at the expense of nascent markets.

Public Law 101-512

CLEAN COAL TECHNOLOGY

The first paragraph under this head in Public Law 101-121 is amended by striking "\$600,000,000 shall be made available on October 1, 1990, and shall remain available until expended, and

\$600,000,000 shall be made available on October 1, 1991, and shall remain available until expended" and inserting "\$600,000,000 shall be made available as follows: \$35,000,000 on September 1, 1991, \$315,000,000 on October 1, 1991, and \$250,000,000 on October 1, 1992, all such sums to remain available until expended for use in conjunction with a separate general request for proposals, and \$600,000,000 shall be made available as follows: \$150,000,000 on October 1, 1991, \$225,000,000 on October 1, 1992, and \$225,000,000 on October 1, 1993, all such sums to remain available until expended for use in conjunction with a separate general request for proposals": *Provided*, That these actions are taken pursuant to section 202(b)(1) of Public Law 100-119 (2 U.S.C. 909): *Provided further*, That a fourth general request for proposals shall be issued not later than February 1, 1991, and a fifth general request for proposals shall be issued not later than March 1, 1992: *Provided further*, That project proposals resulting from such solicitations shall be selected not later than eight months after the date of the general request for proposals: *Provided further*, That for clean coal solicitations required herein, provisions included for the repayment of government contributions to individual projects shall be identical to those included in the Program Opportunity Notice (PON) for Clean Coal Technology III (CCT-III) Demonstration Projects (solicitation number DE-PS01-89 FE 61825), issued by the Department of Energy on May 1, 1989: *Provided further*, That funds provided under this head in this or any other appropriations Act shall be expended only in accordance with the provisions governing the use of such funds contained under this head in this or any other appropriations Act.

With regard to funds made available under this head in this and previous appropriations Acts, unobligated balances excess to the needs of the procurement for which they originally were made available may be applied to other procurements for use on projects for which cooperative agreements are in place, within the limitations and proportions of Government financing increases currently allowed by law: *Provided*, That the Department of Energy, for a period of up to five (5) years after completion of the operations phase of a cooperative agreement may provide appropriate protections, including exemptions from subchapter II of chapter 5 of title 5, United States Code, against the dissemination of information that results from demonstration activities conducted under the Clean Coal Technology Program and that would be a trade secret or commercial or financial information that is privileged or confidential if the information had been obtained from and first produced by a non-Federal party participating in a Clean Coal Technology project: *Provided further*, That, in addition to the full-time permanent Federal employees specified in section 303 of Public Law 97-257, as amended, no less than 90 full-time Federal employees shall

be assigned to the Assistant Secretary for Fossil Energy for carrying out the programs under this head using funds available under this head in this and any other appropriations Act and of which 35 shall be for PETC and 30 shall be for METC: *Provided further*, That reports on projects selected by the Secretary of Energy pursuant to authority granted under this heading which are received by the Speaker of the House of Representatives and the President of the Senate less than 30 legislative days prior to the end of the second session of the 101st Congress shall be deemed to have met the criteria in the third proviso of the fourth paragraph under the heading "Administrative provisions, Department of Energy" in the Department of the Interior and Related Agencies Appropriations Act, 1986, as contained in Public Law 99-190, upon expiration of 30 calendar days from receipt of the report by the Speaker of the House of Representatives and the President of the Senate or at the end of the session, whichever occurs later.

Conference Report (H. Rep. 101-971)

CLEAN COAL TECHNOLOGY

Amendment No. 142: Provides \$35,000,000 for clean coal technology on September 1, 1991 as proposed by the House instead of \$100,000,000 as proposed by the Senate. This amendment and Amendment No. 143 shift the availability of \$65,000,000 from fiscal year 1991 to fiscal year 1992.

Amendment No. 143: Provides \$315,000,000 for clean coal technology on October 1, 1991 as proposed by the House instead of \$250,000,000 as proposed by the Senate. This amendment and Amendment No. 142 shift the availability of \$65,000,000 from fiscal year 1991 to fiscal year 1992.

Amendment No. 144: Provides dates for two solicitations for clean coal technology as proposed by the Senate. The date for CCT-IV is amended to February 1, 1991 from January 1, 1991. The date for CCT-V is not changed from the Senate date of March 1, 1992.

The managers have agreed to a February 1, 1991 date for the next solicitation to enable the Department to publish a draft solicitation for comment by interested parties. It is expected that there will be changes to evaluation criteria and other factors that make it imperative that potential proposers have an opportunity to comment on the content of the solicitation.

The managers urge the Department to include potential benefits to remote, import-dependent sites as a program policy factor in evaluating proposals. The Department should also consider projects which can provide multiple fuel resource options for regions which

are more than seventy-five percent dependent on one fuel form for total energy requirements.

Amendment No. 145: Requires selection of projects within eight months of the requests for proposals required by Amendment No. 144 as proposed by the Senate. The House had no such provision.

Amendment No. 146: Requires repayment of government contributions to projects under conditions identical to the most recent clean coal solicitation as proposed by the Senate. The House had no such provision.

Amendment No. 147: Provides that funds for clean coal technology may be expended only under conditions contained in appropriations Acts. The Senate language had prohibited geographic restrictions on the expenditure of funds. The House had no such provision. The managers direct that no preferential consideration be given to any project referenced explicitly or implicitly in other legislation.

The managers agree to delete bill language dealing with geographic restrictions based on such restrictions being deleted from clean air legislation.

Amendment No. 148: Earmarks employees to two fossil energy technology centers as proposed by the Senate. The House had no such provision. The managers agree that the earmarks for PETC and METC are minimum levels and may be increased as necessary.

The managers agree that no more than the current 30 fulltime equivalent positions from fossil energy research and development may be used in the clean coal program in fiscal year 1991.

Public Law 102-154

CLEAN COAL TECHNOLOGY

The first paragraph under this head in Public Law 101-512 is amended by striking the phrase "\$150,000,000 on October 1, 1991, \$225,000,000 on October 1, 1992" and inserting "\$100,000,000 on October 1, 1991, \$275,000,000 on October 1, 1992".

Notwithstanding the issuance date for the fifth general request for proposals under this head in Public Law 101-512, such request for proposals shall be issued not later than July 6, 1992, and notwithstanding the proviso under this head in Public Law 101-512 regarding the time interval for selection of proposals resulting from such solicitation, project proposals resulting from the fifth general request for proposals shall be selected not later than ten months after the issuance date of the fifth general request for proposals:

Provided, That hereafter the fifth general request for proposals shall be subject to all provisos contained under this head in previous appropriations Acts unless amended by this Act.

Notwithstanding the provisos under this head in previous appropriations Acts, projects selected pursuant to the fifth general request for proposals shall advance significantly the efficiency and environmental performance of coal-using technologies and be applicable to either new or existing facilities: *Provided*, That budget periods may be used in lieu of design, construction, and operating phases for cost-sharing calculations: *Provided further*, That the Secretary shall not finance more than 50 per centum of the total costs of any budget period: *Provided further*, That project specific development activities for process performance definition, component design verification, materials selection, and evaluation of alternative designs may be funded on a cost-shared basis up to a limit of 10 per centum of the Government's share of project cost: *Provided further*, That development activities eligible for cost-sharing may include limited modifications to existing facilities for project related testing but do not include construction of new facilities.

With regard to funds made available under this head in this and previous appropriations Acts, unobligated balances excess to the needs of the procurement for which they originally were made available may be applied to other procurements for use on projects for which cooperative agreements are in place, within the limitations and proportions of Government financing increases currently allowed by law: *Provided*, That hereafter, the Department of Energy, for a period of up to five years after completion of the operations phase of a cooperative agreement may provide appropriate protections, including exemptions from subchapter II of chapter 5 of title 5, United States Code, against the dissemination of information that results from demonstration activities conducted under the Clean Coal Technology Program and that would be a trade secret or commercial or financial information that is privileged or confidential if the information had been obtained from and first produced by a non-Federal party participating in a Clean Coal Technology project: *Provided further*, That hereafter, in addition to the full-time permanent Federal employees specified in section 303 of Public Law 97-257, as amended, no less than 90 full-time Federal employees shall be assigned to the Assistant Secretary for Fossil Energy for carrying out the programs under this head using funds available under this head in this and any other appropriations Act and of which not less than 35 shall be for PETC and not less than 30 shall be for METC: *Provided further*, That hereafter reports on projects selected by the Secretary of Energy pursuant to authority granted under this heading which are received by the Speaker of the House of Representatives and the President of the Senate less than

30 legislative days prior to the end of each session of Congress shall be deemed to have met the criteria in the third proviso of the fourth paragraph under the heading "Administrative provisions, Department of Energy" in the Department of the Interior and Related Agencies Appropriations Act, 1986, as contained in Public Law 99-190, upon expiration of 30 calendar days from receipt of the report by the Speaker of the House of Representatives and the President of the Senate or at the end of the session, whichever occurs later.

Conference Report (H. Rep. 102-256)

CLEAN COAL TECHNOLOGY

Amendment No. 165: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate with an amendment as follows:

In lieu of the matter stricken and inserted by said amendment insert:

Notwithstanding the issuance date for the fifth general request for proposals under this head in Public Law 101-512, such request for proposals shall be issued not later than July 6, 1992, and notwithstanding the proviso under this head in Public Law 101-512 regarding the time interval for selection of proposals resulting from such solicitation, project proposals resulting from the fifth general request for proposals shall be selected not later than ten months after the issuance date of the fifth general request for proposals: Provided, That hereafter the fifth general request for proposals

The managers on the part of the Senate will move to concur in the amendment of the House to the amendment of the Senate.

The amendment changes the issuance date for the fifth general request for proposals to July 6, 1992 instead of March 1, 1992 as proposed by the House and August 10, 1992 as proposed by the Senate and changes the allowable length of time from issuance of the request for proposals to selection of projects to ten months. The amendment also deletes Senate proposed bill language pertaining to a sixth general request for proposals as discussed below.

The managers agree that the additional two months in the procurement process for the fifth round of proposals should include an additional month to allow for the preparation of proposals by the private sector, and up to an additional month for Department of Energy review and evaluation of proposals when compared to the process for the fourth round.

The managers have agreed to delete bill language regarding a sixth round of proposals, but agree that funding will be provided for a sixth round based on unobligated and unneeded amounts that

may become available from the first five rounds. The report from the Secretary on available funds, which was originally in the Senate amendment, is still a requirement and such report should be submitted to the House and Senate Committees on Appropriations not later than May 1, 1994. Based on that report, the funding, dates and conditions for the sixth round will be included in the fiscal year 1995 appropriation.

The managers expect that the fifth solicitation will be conducted under the same general types of criteria as the fourth solicitation principally modified only (1) to include the wider range of eligible technologies or applications; (2) to adjust technical criteria to consider allowable development activities, to strengthen criteria for non-utility demonstrations, and to adjust commercial performance criteria for additional facilities and technologies with regard to aspects of general energy efficiency and environmental performance; and (3) to clarify and strengthen cost and finance criteria, particularly with regard to development activities.

Amendment No. 166: Restores House language deleted by the Senate which refers to a fifth general request for proposals. The Senate proposed language dealing with both a fifth and a sixth round.

Amendment No. 167: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate which directs the Secretary of Energy to reobligate up to \$44,000,000 from the fourth round of Clean Coal Technology proposals to a proposal ranked highest in its specific technology category by the Source Evaluation Board if other than the highest ranking project in that category was selected originally by the Secretary, and if such funds become unobligated and are sufficient to fund such project. This amendment would earmark such funds, if they become available, to a specific project not chosen in the Department of Energy selection process for the fourth round of Clean Coal Technology.

Amendment No. 168: Technical amendment which deletes House proposed punctuation and numbering as proposed by the Senate.

Amendment No. 169: Deletes House proposed language which made unobligated funds available for procurements for which requests for proposals have not yet been issued.

Amendment No. 170: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate which adds "not less than" to employment floor language for PETC as proposed by the Senate. The House had no such language.

Amendment No. 171: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate which adds "not less

than" to employment floor language for METC as proposed by the Senate. The House had no such language.

Public Law 102-381

CLEAN COAL TECHNOLOGY

The first paragraph under this head in Public Law 101-512, as amended, is further amended by striking the phrase "and \$250,000,000 on October 1, 1992" and inserting "\$150,000,000 on October 1, 1993, and \$100,000,000 on October 1, 1994" and by striking the phrase "\$275,000,000 on October 1, 1992, and \$225,000,000 on October 1, 1993" and inserting "\$250,000,000 on October 1, 1993, and \$250,000,000 on October 1, 1994".

Public Law 103-138

CLEAN COAL TECHNOLOGY

The first paragraph under this head in Public Law 101-512, as amended, is further amended by striking the phrase "\$150,000,000 on October 1, 1993, and \$100,000,000 on October 1, 1994" and inserting "\$100,000,000 on October 1, 1993, \$100,000,000 on October 1, 1994, and \$50,000,000 on October 1, 1995" and by striking the phrase "\$250,000,000 on October 1, 1993, and \$250,000,000 on October 1, 1994" and inserting "\$125,000,000 on October 1, 1993, \$275,000,000 on October 1, 1994, and \$100,000,000 on October 1, 1995".

Appendix B: Selection and Negotiation History

July 1986

9 projects were selected under CCT-I (14 alternate projects selected if negotiations for original 9 unsuccessful).

March 1987

DOE signed cooperative agreements with two CCT-I sponsors, Coal Tech Corporation (Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control) and The Ohio Power Company (Tidd PFBC Demonstration Project).

June 1987

DOE signed a cooperative agreement with CCT-I sponsor, The Babcock & Wilcox Company (LIMB Demonstration Project Extension and Coolside Demonstration).

July 1987

DOE signed a cooperative agreement with CCT-I sponsor, Energy and Environmental Research Corporation (Enhancing the Use of Coals by Gas Reburning and Sorbent Injection).

September 1987

General Electric Company withdrew its proposal (Integrated Coal Gasification Steam Injection Gas Turbine Demonstration Plants with Hot Gas Cleanup).

October 1987

Weirton Steel Corporation withdrew its proposal (Direct Iron Ore Reduction to Replace Coke Oven/Blast Furnace for Steelmaking) from further consideration.

4 more CCT-I projects were selected: Colorado-Ute Electric Association, Inc. (Nucla CFB Demonstration Project); TRW, Inc. (Advanced Slagging Coal Combustor Utility Demonstration Project); Minnesota Department of Natural Resources (COREX Ironmaking Demonstration Project); and Foster Wheeler Power Systems, Inc. (Clean Energy IGCC Demonstration Project).

December 1987

DOE signed cooperative agreements with two more CCT-I sponsors, Ohio Ontario Clean Fuels, Inc., (Prototype Commercial Coal/Oil Coprocessing Project) and Energy International, Inc. (Underground Coal Gasification Demonstration Project).

January 1988

DOE signed a cooperative agreement with The M.W. Kellogg Company and Bechtel Development Company for a CCT-I project (The Appalachian IGCC Demonstration Project).

September 1988

16 projects were selected under CCT-II.

October 1988

DOE signed a cooperative agreement with CCT-I sponsor, Colorado-Ute Electric Association, Inc. (Nucla CFB Demonstration Project).

November 1988

DOE signed a cooperative agreement with CCT-I sponsor, TRW, Inc. (Direct Iron Ore Reduction to Replace Coke Oven/Blast Furnace for Steelmaking).

December 1988

Negotiations terminated with Minnesota Department of Natural Resources under CCT-I.

DOE selected three more CCT-I projects: ABB Combustion Engineering, Inc., and CQ, Inc. (Development of the Coal Quality Expert); Western Energy Company (Advanced Coal Conversion Process Demonstration); and United Coal Company (Coal Waste Recovery Advanced Technology Demonstration).

June 1989

The City of Tallahassee CCT-I project (ACFB repowering) on alternate list was selected.

The M.W. Kellogg Company and Bechtel Development Company withdrew their CCT-I project (Clean Energy IGCC Demonstration Project).

September 1989

United Coal Company withdrew its CCT-I project (Coal Waste Recovery Advanced Technology Demonstration).

November 1989

DOE signed a cooperative agreement with CCT-II sponsor, Bethlehem Steel Corporation (Innovative Coke Oven Gas Cleaning System for Retrofit Applications).

Combustion Engineering, Inc., (CCT-II) withdrew its Postcombustion Sorbent Injection Demonstration Project.

December 1989

13 projects were selected under CCT-III.

DOE signed cooperative agreements with five CCT-II sponsors: ABB Combustion Engineering, Inc. (SNOX™ Flue Gas Cleaning Demonstration Project); The Babcock & Wilcox Company (SOx-NOx-Rox-Box™ Flue Gas Cleanup Demonstration Project); Passamaquoddy Tribe (Cement Kiln Flue Gas Recovery Scrubber); Pure Air on the Lake, L.P. (Advanced Flue Gas Desulfurization Demonstration Project); and Southern Company Services, Inc. (Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler).

Energy International, Inc., withdrew its CCT-I project (Underground Coal Gasification Demonstration Project).

February 1990

Foster Wheeler Power Systems, Inc., withdrew its CCT-I proposal (Clean Energy IGCC Demonstration Project).

April 1990

DOE signed cooperative agreements with three CCT-II sponsors: The Appalachian Power Company (PFBC Utility Demonstration Project); The Babcock & Wilcox Company (Demonstration of Coal Reburning for Cyclone Boiler NO_x Control); and Southern Company Services, Inc. (Demonstration of Innovative Applications of Technology for the CT-121 FGD Process).

June 1990

DOE signed cooperative agreements with the co-sponsors of one CCT-I project, ABB Combustion Engineering, Inc., and CQ, Inc., (Development of the Coal Quality Expert) and with two CCT-II sponsors: Southern Company Services, Inc. (Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers) and TransAlta Resources Investment Corporation (LNS Burner for Cyclone-Fired Boilers Demonstration Project).

September 1990

DOE signed cooperative agreements with one CCT-I sponsor, Rosebud SynCoal Partnership (formerly Western Energy Company; Advanced Coal Conversion Process Demonstration); one CCT-II sponsor, Southern Company Services, Inc. (180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers); and one CCT-III sponsor, ENCOAL Corporation (ENCOAL Mild Coal Gasification Project).

Negotiations terminated with CCT-II sponsor, Southwestern Public Service Company (Nichols CFB Repowering Project).

October 1990

DOE signed cooperative agreements with four CCT-III sponsors: AirPol, Inc. (10-MW Demonstration of Gas Suspension Absorption); The Babcock & Wilcox Company (Full-Scale Demonstration of Low-NO_x Cell™ Burner Retrofit); Bechtel Corporation (Confined Zone Dispersion Flue Gas Desulfurization Demonstration); and Energy and Environment's Research Corporation (Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler).

November 1990

DOE signed cooperative agreements with one CCT-I sponsor, The City of Tallahassee (Arvah B. Hopkins Circulating Fluidized-Bed Repowering Project); one CCT-II sponsor, ABB Combustion Engineering, Inc. (Combustion Engineering IGCC Repowering Project); and two CCT-III sponsors, Bethlehem Steel Corporation (Blast Furnace Granulated-Coal Injection System Demonstration Project) and LIFAC-North America (LIFAC Sorbent Injection Desulfurization Demonstration Project).

December 1990

Negotiations terminated with CCT-II sponsor, Otisca Industries, Ltd. (Otisca Fuel Demonstration Project).

March 1991

DOE signed cooperative agreements with three CCT-III sponsors: MK-Ferguson Company (Commercial Demonstration of the NOXSO SO₂/NO_x Removal Flue Gas Cleanup System); Public Service Company of Colorado (Integrated Dry NO_x/SO₂ Emissions Control System); and Tampa Electric Company (formerly Clean Power Cogeneration Limited Partnership; Tampa Electric Integrated Gasification Combined-Cycle Project).

TRW, Inc., withdrew its CCT-I project (Advanced Slagging Coal Combustion Utility Demonstration Project).

April 1991

DOE signed a cooperative agreement with CCT-III sponsor, Alaska Industrial Development and Export Authority (Healy Clean Coal Project).

June 1991

DOE withdrew its sponsorship of the Ohio Ontario Clean Fuels, Inc., CCT-I project (Prototype Commercial Coal/Oil Coprocessing Plant).

August 1991

DOE signed a cooperative agreement with CCT-III sponsor, DMEC-1 Limited Partnership (formerly Dairyland Power Cooperative; PCFB Repowering Project).

TransAlta Resources Investment Corporation withdrew its CCT-II project (LNS Burner for Cyclone-Fired Boilers Demonstration Project).

September 1991

9 projects were selected under CCT-IV.

Coal Tech Corporation's CCT-I project, Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control, was completed.

April 1992

Tri-State Generation and Transmission Association, Inc., (formerly Colorado-Ute Electric Association, Inc.) completed its CCT-I project, Nucla CFB Demonstration Project.

June 1992

The City of Tallahassee project (CCT-I) was restructured and transferred to York County Energy Partners, L.P. (York County Energy Partners Cogeneration Project).

July 1992

DOE signed cooperative agreements with two CCT-IV sponsors: Tennessee Valley Authority (Micronized Coal Reburning Demonstration for NO_x Control on a 175-MWe Wall-Fired Unit) and Wabash River Coal Gasification Repowering Project Joint Venture (Wabash River Coal Gasification Repowering Project).

August 1992

DOE signed a cooperative agreement with CCT-IV sponsor, Sierra Pacific Power Company (Piñon Pine IGCC Power Project).

Cordero Mining Company withdrew from negotiations its CCT-IV project, Cordero Coal-Upgrading Demonstration Project.

At the sponsor's request, Union Carbide Chemicals and Plastics Company Inc. (CCT-IV) was granted an extension of 1-year to the DOE deadline for completing negotiations of its Demonstration of the Union Carbide CANSOLV™ System at the ALCOA Generating Corporation Warrick Power Plant.

October 1992

DOE signed cooperative agreements with one CCT-III sponsor, Air Products and Chemicals, Inc. (Commercial-Scale Demonstration of the Liquid-Phase Methanol [LPMEOH™] Process) and with four CCT-IV sponsors: Custom Coals International (Self-Scrubbing Coal™: An Integrated Approach to Clean Air); New York State Electric & Gas Corporation (Milliken Clean Coal Technology Demonstration Project); TAMCO Power Partners (Toms Creek IGCC Demonstration Project); and ThermoChem, Inc. (Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal).

November 1992

The Babcock & Wilcox Company's CCT-I project, LIMB Demonstration Project Extension and Coolside Demonstration, was completed.

May 1993

5 projects were selected under CCT-V: Four Rivers Energy Partners, L.P. (Four Rivers Energy Modernization Project; previously, Calvert City Advanced Energy Project); Duke Energy Corp. (Camden Clean Energy Demonstration Project); Centerior Energy Corporation, on behalf of CPICOR Management Company (Clean Power from Integrated Coal/Ore Reduction [COREX®]); Arthur D. Little, Inc. (Clean Coal Combined-Cycle Project; previously Demonstration of Coal Diesel Technology at Easton Utilities); and Pennsylvania Electric Company (Warren Station Externally Fired Combined-Cycle Demonstration Project).

July 1993

Union Carbide Chemicals and Plastics Company, Inc., withdrew its CCT-IV proposal, Demonstration of the Union Carbide CANSOLV™ System at the ALCOA Generating Corporation Warrick Power Plant.

December 1993

The Babcock & Wilcox Company's CCT-II project, SO_x-NO_x-Rox-Box™ Flue Gas Cleanup Demonstration Project, was completed.

The Babcock & Wilcox Company's CCT-II project, Demonstration of Coal Reburning for Cyclone Boiler NO_x Control, was completed.

The Babcock & Wilcox Company's CCT-II project, Full-Scale Demonstration of Low-NO_x Cell™ Burner Retrofit, was completed.

The Passamaquoddy Tribe's CCT-III project, Cement Kiln Flue Gas Recovery Scrubber, was completed.

Appendix C: CCT Program Publications

Numerous publications are available on the major activities of the Clean Coal Technology Demonstration Program. The most comprehensive report is the annual *Program Update*. Project status and accomplishments are reported in the quarterly newsletter, *Clean Coal Today*. Detailed information about each project selected for award of a cooperative agreement may be found in the project's *Comprehensive Report to Congress on the Clean Coal Technology Program*. When a project is completed, the technical, environmental, and economic performance as well as other key results are reported and disseminated by the sponsor and the CCT Program. Key CCT Program publications available at year-end 1993 are listed below. Project-specific reports and newsletter articles are listed by application category and, within each category, by project.

Program Updates

Clean Coal Technology Demonstration Program: Program Update 1992 (As of December 31, 1992). Report No. DOE/FE-0272. U.S. Department of Energy. February 1993. (Available from NTIS as DE 9301-1403.)

Clean Coal Technology Demonstration Program: Program Update 1991 (As of December 31, 1991). Report No. DOE/FE-0247P. U.S. Department of Energy. February 1992.

Clean Coal Technology Demonstration Program: Project Status (As of June 30, 1991). Report No. DOE/FE-0221P. U.S. Department of Energy. June 1991.

Clean Coal Technology Demonstration Program: Program Update 1990 (As of December 31, 1990). Report No. DOE/FE-0219P. U.S. Department of Energy. February 1991.

Clean Coal Technology Demonstration Program: Annual Report to Congress (As of December 31, 1989). Report No. DOE/FE-0195P. U.S. Department of Energy. March 1990.

Clean Coal Technology Demonstration Program: Annual Report to Congress (As of December 31, 1988). Report No. DOE/FE-0125. U.S. Department of Energy. February 1989.

Clean Coal Technology Demonstration Program: Annual Report to Congress (As of December 31, 1987). Report No. DOE/FE-0107. U.S. Department of Energy. 1988.

Advanced Electric Power Generation/ Fluidized-Bed Combustion

The Appalachian Power Company—PFBC Utility Demonstration Project

Clean Coal II—PFBC Utility Demonstration Project: 1992 Annual Report. Report No.

DOE/MC/26304-3497. The Appalachian Power Company. December 1992. (Available from NTIS as DE 9400-0029.)

PFBC Utility Demonstration Project: 1991 Annual Report. Report No. DOE/MC/26304-3194. The Appalachian Power Company. November 1992. (Available from NTIS as DE 9300-0233.)

Comprehensive Report to Congress on the Clean Coal Technology Program: PFBC Utility Demonstration Project. (The Appalachian Power Company and The Ohio Power Company). Report No. DOE/FE-0159. U.S. Department of Energy. February 1990.

DMEC-1 Limited Partnership—PCFB Repowering Project

Pressurized Circulating Fluidized Bed (PCFB) Repowering Project: Annual Report/August 1991–December 1992. Report No. DOE/MC/27364-3468. DMEC-1 Limited Partnership. (Available from NTIS as DE 9400-0007.)

“Des Moines, Iowa Greet New Clean Coal Plant.” *Clean Coal Today*. Report No. DOE/FE-0215P-4. Winter 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: Pressurized Circulating Fluidized Bed Demonstration Project. (Dairyland Power Cooperative and Iowa Power Inc.). Report No. DOE/FE-0236P. U.S. Department of Energy. June 1991.

Four Rivers Energy Partners, L.P.—Four Rivers Energy Modernization Project

This CCT-V project is in negotiations.

The Ohio Power Company—Tidd PFBC Demonstration Project

“Tidd Extended Runs Verify Design Basis.” *Clean Coal Today*. Report No. DOE/FE-0215P-7. Fall 1992.

PFBC Utility Demonstration Project 1991 Annual Report. Report No. DOE/MC/26304-3194. U.S. Department of Energy. November 1992.

Tidd PFBC Demonstration Project: Public Final Design Report. Report No. DOE/MC/24132-3195. The Ohio Power Company. October 1992. (Available from NTIS as DE 9300-0234.)

“Tidd Plant Sets New Technical Operations and Environmental Performance Records.” *Clean Coal Today*. Report No. DOE/FE-0215P-6. Summer 1992.

“Tidd Plant Resumes Operation.” *Clean Coal Today*. Report No. DOE/FE-0215P-4. Winter 1991.

“Tidd Receives 1991 Power Plant Award.” *Clean Coal Today*. Report No. DOE/FE-0215P-1. Spring 1991.

“TIDD Plant Produces Power: Operations Planned Early 1991.” *Clean Coal Today*. Report No. DOE/FE-0215P. Winter 1990.

Tidd: The Nation's First PFBC Combined-Cycle Demonstration. Topical Report No. 1. U.S. Department of Energy and American Electric Power Service Corporation. March 1990.

Comprehensive Report to Congress on the Clean Coal Technology Program: Tidd PFBC Demonstration Project. (The Ohio Power Company). Report No. DOE/FE-0078. U.S. Department of Energy. February 1987.

Tri-State Generation and Transmission Association, Inc.—Nucla CFB Demonstration Project

Clean Coal Reference Plants: Atmospheric CFB (Topical Report, Task 1). Report No. DOE/MC/25177-3307. Gilbert/Commonwealth, Inc. June 1992. (Available from NTIS as DE 9300-0251.)

Demonstration Program Performance Test: Summary Reports. Report No. DOE/MC/25137-3104. Colorado-Ute Electric Association, Inc. March 1992. (Available from NTIS as DE 9200-1299.)

Economic Evaluation Report. Report No. DOE/MC/25137-3127. Colorado-Ute Electric Association, Inc. March 1992. (Available from NTIS as DE 9200-0212.)

Nucla Circulating Atmospheric Fluidized Bed Demonstration Project: 1990 Annual Report. Colorado-Ute Electric Association, Inc. Report No. DOE/MC/25137-3089. February 1992. (Available from NTIS as DE 9200-1275.)

Nucla Circulating Atmospheric Fluidized Bed Demonstration Project: Final Technical Report for the Period February 1987 through January 1991. Report No. DOE/MC/25137-3046. Colorado-Ute Electric Association, Inc. October 1991. (Available from NTIS as DE 9200-1122.)

“Colorado Fluid Bed Project Yields Both Power and Data.” *Clean Coal Today*. Report No. DOE/FE-0215P. Winter 1990.

Nucla CFB Demonstration Project: Detailed Public Design Report. Report No. DOE/MC/25137-2999. Colorado-Ute Electric Association, Inc. December 1990. (Available from NTIS as DE 9100-2081.)

Comprehensive Report to Congress on the Clean Coal Technology Program: Nucla CFB Demonstration Project. (Colorado-Ute Electric Association, Inc.). Report No. DOE/FE-0106. U.S. Department of Energy. July 1988.

York County Energy Partners—York County Energy Partners Cogeneration Project

Comprehensive Report to Congress on the Clean Coal Technology Program: Arvah B. Hopkins Circulating Fluidized-Bed Repowering Project. (The City of Tallahassee). Report No. DOE/FE-0208P. U.S. Department of Energy. October 1990.

Advanced Electric Power Generation/Integrated Gasification Combined Cycle

“Advanced Power Generation Future Bright with Coal Gasification—Combined Cycle—Six Major Projects in DOE's CCT Program.” *Clean Coal Today*. Report No. DOE/FE-0215P-5. Spring 1992.

ABB Combustion Engineering, Inc.—Combustion Engineering IGCC Repowering Project

Comprehensive Report to Congress on the Clean Coal Technology Program: Combustion Engineering

IGCC Repowering Project. (ABB Combustion Engineering, Inc.). Report No. DOE/FE-0201P. October 1990.

Duke Energy Corp.—Camden Clean Energy Demonstration Project

This CCT-V project is in negotiations.

Sierra Pacific Power Company—Piñon Pine IGCC Power Project

Comprehensive Report to Congress on the Clean Coal Technology Program: Piñon Pine IGCC Power Project. (Sierra Pacific Power Company). Report No. DOE/FE-0255P. U.S. Department of Energy. June 1992.

TAMCO Power Partners—Toms Creek IGCC Demonstration Project

Comprehensive Report to Congress on the Clean Coal Technology Program: Toms Creek IGCC Demonstration Project. (TAMCO Power Partners). Report No. DOE/FE-0264P. U.S. Department of Energy. September 1992.

Tampa Electric Company—Tampa Electric Integrated Gasification Combined-Cycle Project

“Florida Project Demonstrates Key Technologies.” *Clean Coal Today.* Report No. DOE/FE-0215P-9. Spring 1993.

Comprehensive Report to Congress on the Clean Coal Technology Program: Air-Blown Integrated Gasification Combined-Cycle Demonstration Project. (Clean Power Cogeneration Limited

Partnership). Report No. DOE/FE-0216P. U.S. Department of Energy. January 1991.

Wabash River Coal Gasification Project Joint Venture—Wabash River Coal Gasification Repowering Project

“Promise of Coal Gasification Power Draws 400 Representatives to Wabash River Site.” *Clean Coal Today.* Report No. DOE/FE-0215P-10. Summer 1993.

Comprehensive Report to Congress on the Clean Coal Technology Program: Wabash River Coal Gasification Repowering Project. (Wabash River Coal Gasification Repowering Project Joint Venture). Report No. DOE/FE-0257P. U.S. Department of Energy. June 1992.

**Advanced Electric Power Generation/
Advanced Combustion/Heat Engines**

Alaska Industrial Development and Export Authority—Healy Clean Coal Project

Healy Clean Coal Project, Design Verification and Cold-Flow Modeling Test Report. Report No. DE-FC22-91PC905443. U.S. Department of Energy. July 1993.

Healy Clean Coal Project: Healy FCM Testing at Niro Air Pollution Pilot Facility. Report No. DOE/PC/90544-T6. U.S. Department of Energy. October 1992.

Healy Clean Coal Project: Healy Coal Firing at TRW Cleveland Test Facility. TRW Space and

Technology Group, TRW, Inc. Report No. DOE/PC/90544-T2. August 1991. (Topical project report available from NTIS as DE 9200-7602.)

Comprehensive Report to Congress on the Clean Coal Technology Program: Healy Clean Coal Project. (Alaska Industrial Development and Export Authority). Report No. DOE/FE-0211P. U.S. Department of Energy. January 1991.

Arthur D. Little, Inc.—Coal Diesel Combined-Cycle Project

This CCT-V project is in negotiations.

Pennsylvania Electric Company—Warren Station Externally Fired Combined-Cycle Demonstration Project

This CCT-V project is in negotiations.

Environmental Control Devices/NO_x Control Technologies

“Clean Coal Program Marks First Commercial Success with Sale of Low NO_x Technology.” *Clean Coal Today.* Report No. DOE/FE-0215P-10. Summer 1993.

The Babcock & Wilcox Company—Demonstration of Coal Reburning for Cyclone Boiler NO_x Control

“Coal Reburn Exceeds Expected NO_x Reductions.” *Clean Coal Today.* Report No. DOE/FE-0215P-9. Spring 1993.

"Cyclone Boiler Coal Reburn Technology Cuts NO_x by more than 50 Percent." *Clean Coal Today*. Report No. DOE/FE-0215P-5. Spring 1992.

Public Design Report: Coal Reburning for Cyclone Boiler NO_x Control. The Babcock & Wilcox Company. August 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: Demonstration of Coal Reburning for Cyclone Boiler NO_x Control. (The Babcock & Wilcox Company). Report No. DOE/FE-0157. U.S. Department of Energy. February 1990.

The Babcock & Wilcox Company—Full-Scale Demonstration of Low-NO_x Cell™ Burner Retrofit

"B&W Low-NO_x Cell Burner Tests under Way." *Clean Coal Today*. Report No. DOE/FE-0215P-6. Summer 1992.

"Two CCT Projects 'Get the Word Out'." *Clean Coal Today*. Report No. DOE/FE-0215P-9. Spring 1993.

"B&W Low NO_x Cell Burners Fabricated." *Clean Coal Today*. Report No. DOE/FE-0215P-1. Spring 1991.

Public Design Report: Full-Scale Demonstration of Low-NO_x Cell™ Burner Retrofit. The Babcock & Wilcox Company. August 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: Full-Scale Demonstration of Low-NO_x Cell-Burner Retrofit. (The Babcock

& Wilcox Company). Report No. DOE/FE-0197P. U.S. Department of Energy. July 1990.

Energy and Environmental Research Corporation—Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler

"Reburning for NO_x Reduction—Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler." *PETC Review*. Issue 9. Fall 1993.

"EER's Gas Reburning—Low-NO_x Burner Technologies Reducing NO_x Emissions." *Clean Coal Today*. Report No. DOE/FE-0215P-8. Winter 1992.

"Gas Reburning Emerging as Cost-Effective Nitrogen Oxide Reduction Technique." *Clean Coal Today*. Report No. DOE/FE-0215P-5. Spring 1992.

"Gas Reburning Tests Begin at Illinois Power Plant—Early Tests Exceed Expectations." *Clean Coal Today*. Report No. DOE/FE-0215P-4. Winter 1991.

"Wall-Fired Boiler Low NO_x Overfire Air Tests Complete." *Clean Coal Today*. Report No. DOE/FE-0215P-1. Spring 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler. (Energy and Environmental Research Corporation). Report No. DOE/FE-0204P. U.S. Department of Energy. September 1990.

Southern Company Services, Inc.—Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler

"Georgia Power's Plant Hammond Previews Clean Air Act's NO_x Challenges—Project Generating Data that will Help Utilities Face New Law's 'Sleeping Giant'." *Clean Coal Today*. Report No. DOE/FE-0215P-4. Winter 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler. (Southern Company Services, Inc.). Report No. DOE/FE-0146. U.S. Department of Energy. November 1989.

Southern Company Services, Inc.—180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for Reduction of NO_x Emissions from Coal-Fired Boilers

180-MW Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers: Final Report and Key Project Findings. Southern Company Services, Inc. December 1993.

180-MW Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers: Chemical Emissions Report. Southern Company Services, Inc. October 1993. (Draft Report.)

180-MW Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of

Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers: Public Design Report. Southern Company Services, Inc. September 1993.

Comprehensive Report to Congress on the Clean Coal Technology Program: 180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions for Coal-Fired Boilers. (Southern Company Services, Inc.). Report No. DOE/FE-0191P. U.S. Department of Energy. July 1990.

Southern Company Services, Inc.—Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers

“SCR Tests Progress at Gulf’s Plant Crist.” *Clean Coal Today.* Report No. DOE/FE-0215P-10. Summer 1993.

“SCR Holds Promise for Effective NO_x Control—CCT Projects Address Higher Costs, Limited U.S. Experience.” *Clean Coal Today.* Report No. DOE/FE-0215P-6. Summer 1992.

“Catalyst Suppliers Selected in Southern Company’s SCR Project.” *Clean Coal Today.* Report No. DOE/FE-0215P-2. Summer 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: Demonstration of Selective Catalytic Reduction (SCR) Technology for the Control of Nitrogen Oxide (NO_x) Emissions from High-Sulfur-Coal-Fired Boilers. (Southern Company Services, Inc.). Report No. DOE/FE-0161P. U.S. Department of Energy. April 1990.

Tennessee Valley Authority—Micronized Coal Reburning Demonstration of NO_x Control on a 175-MWe Wall-Fired Unit

“Reburning for NO_x Reduction—Micronized Coal Reburning for NO_x Control.” *PETC Review.* Issue 9. Fall 1993.

Comprehensive Report to Congress on the Clean Coal Technology Program: Micronized Coal Reburning Demonstration for NO_x Control on a 175-MWe Wall-Fired Unit. (Tennessee Valley Authority). Report No. DOE/FE-0256P. U.S. Department of Energy. June 1992.

Environmental Control Devices/SO₂ Control Technologies

AirPol, Inc.—10-MW Demonstration of Gas Suspension Absorption

“AirPol Plant Runs Smoothly.” *Clean Coal Today.* Report No. DOE/FE-0215P-8. Winter 1992.

Comprehensive Report to Congress on the Clean Coal Technology Program: 10-MW Demonstration of Gas Suspension Absorption. (AirPol, Inc.). Report No. DOE/FE-0198P. U.S. Department of Energy. July 1990.

Bechtel Corporation—Confined Zone Dispersion Flue Gas Desulfurization Demonstration

Comprehensive Report to Congress on the Clean Coal Technology Program: Confined Zone Dispersion Flue Gas Desulfurization Demonstration. (Bechtel Corporation). Report No. DOE/FE-0203P. U.S. Department of Energy. September 1990.

LIFAC—North America—LIFAC Sorbent Injection Desulfurization Demonstration Project

“LIFAC Process Tests Now Underway.” *Clean Coal Today.* Report No. DOE/FE-0215P-8. Winter 1992.

Comprehensive Report to Congress on the Clean Coal Technology Program: LIFAC Sorbent Injection Desulfurization Demonstration Project. (LIFAC—North America). Report No. DOE/FE-0207P. U.S. Department of Energy. October 1990.

Pure Air on the Lake, L.P.—Advanced Flue Gas Desulfurization Demonstration Project

“Clean Coal Project Wins Outstanding Achievement Award.” *Clean Coal Today.* Report No. DOE/FE-0215P-8. Winter 1992.

“Pure Air Project Helps Hurricane Relief Efforts.” *Clean Coal Today.* Report No. DOE/FE-0215P-8. Winter 1992.

“Pure Air FGD Scrubber Begins Operation—Indiana Utility Leads Nation in Clean Air Act Compliance.” *Clean Coal Today.* Report No. DOE/FE-0215P-6. Summer 1992.

“Pure Air Flue Gas Project Construction Well Advanced.” *Clean Coal Today.* Report No. DOE/FE-0215P-1. Spring 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: Advanced Flue Gas Desulfurization (AFGD) Demonstration Project. (Pure Air on the Lake, L.P.). Report No. DOE/FE-0150. U.S. Department of Energy. November 1989.

Southern Company Services, Inc.—Demonstration of Innovative Applications of Technology for the CT-121 FGD Process

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“Fiberglass Reinforced Plastic Highlights CT-121 ‘Second Generation’ Wet Scrubber.” *Clean Coal Today*. Report No. DOE/FE-0215P-2. Summer 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: Demonstration of Innovative Applications of Technology for the CT-121 FGD Process. (Southern Company Services, Inc.). Report No. DOE/FE-0158. U.S. Department of Energy. February 1990.

Environmental Control Devices/Combined SO₂/NO_x Control Technologies

ABB Environmental Systems—SNOX™ Flue Gas Cleaning Demonstration Project

“Two CCT Projects ‘Get the Word Out’.” *Clean Coal Today*. Report No. DOE/FE-0215P-9. Spring 1993.

“SNOX Demonstration on Line.” *Clean Coal Today*. Report No. DOE/FE-0215P-4. Winter 1991.

“WSA-SNOX Offers Multiple Pollutant Capture, Efficiency, Salable Byproducts.” *Clean Coal Today*. Report No. DOE/FE-0215P-4. Winter 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: WSA-SNOX Flue Gas Cleaning Demonstration Project. (ABB Combustion Engineering, Inc.). Report No. DOE/FE-0151. U.S. Department of Energy. November 1989.

The Babcock & Wilcox Company—LIMB Demonstration Project Extension and Coolside Demonstration

T.R. Goots, M.J. DePero, and P.S. Nolan. *LIMB Demonstration Project Extension and Coolside Demonstration: Final Report.* The Babcock & Wilcox Company. Report No. DOE/PC/79798-T27. November 1992. (Available from NTIS as DE 9300-5979.)

D.C. McCoy et al. *The Edgewater Coolside Process Demonstration: A Topical Report.* CONSOL Inc. Report No. DOE/PC/79798-T26. February 1992. (Available from NTIS as DE 9300-1722.)

“B&W’s LIMB Operating: Coolside Tests Complete.” *Clean Coal Today*. Report No. DOE/FE-0215P. Winter 1990.

Coolside and LIMB: Sorbent Injection Demonstrations Nearing Completion. Topical Report No. 2. U.S. Department of Energy and The Babcock & Wilcox Company. September 1990.

Public Design Report. The Babcock & Wilcox Company. December 1988. (LIMB/Coolside)

Comprehensive Report to Congress on the Clean Coal Technology Program: LIMB Demonstration Project Extension. (The Babcock & Wilcox

Company). Report No. DOE/FE-0085. U.S. Department of Energy. April 1987.

The Babcock & Wilcox Company—SO_x-NO_x-Rox-Box™ Flue Gas Cleanup Demonstration Project

“Progressive Technology Exceeds Expectations.” *Clean Coal Today*. Report No. DOE/FE-0215P-10. Summer 1993.

5 MWe SNRB Demonstration Facility: Detailed Design Report. 1B. The Babcock & Wilcox Company. November 1992.

“Success is in the Ceramic Bag—B&W’s SO_x-NO_x-Rox Box Starts Up.” *Clean Coal Today*. Report No. DOE/FE-0215P-5. Spring 1992.

Comprehensive Report to Congress on the Clean Coal Technology Program: SO_x-NO_x-ROX Box Flue Gas Cleanup Demonstration Project. (The Babcock & Wilcox Company). Report No. DOE/FE-0145. U.S. Department of Energy. November 1989.

Energy and Environmental Research Corporation—Enhancing the Use of Coals by Gas Reburning and Sorbent Injection

“Reburning for NO_x Reduction—Enhancing the Use of Coals by Gas Reburning and Sorbent Injection.” *PETC Review*. Issue 9. Fall 1993.

Comprehensive Report to Congress on the Clean Coal Technology Program: Enhancing the Use of Coals by Gas Reburning and Sorbent Injection.

(Energy and Environmental Research Corporation). Report No. DOE/FE-0087. U.S. Department of Energy. May 1987.

**New York State Electric & Gas Corporation—
Milliken Clean Coal Technology Demonstration
Project**

Comprehensive Report to Congress on the Clean Coal Technology Program: Milliken Clean Coal Technology Demonstration project. (New York State Electric & Gas Corporation). Report No. DOE/FE-0265P. U.S. Department of Energy. September 1992.

**NOXSO Corporation and MK-Ferguson
Company—Commercial Demonstration of the
NOXSO SO₂/NO_x Removal Flue Gas Cleanup
System**

Comprehensive Report to Congress on the Clean Coal Technology Program: Commercial Demonstration of the NOXSO SO₂/NO_x Removal Flue Gas Cleanup System. (MK-Ferguson Company). Report No. DOE/FE-0213P. U.S. Department of Energy. January 1991.

**Public Service Company of Colorado—Integrated
Dry NO_x/SO₂ Emissions Control System**

“Second Colorado Project Also Operating.” *Clean Coal Today*. Report No. DOE/FE-0215P-8. Winter 1992.

Comprehensive Report to Congress on the Clean Coal Technology Program: Integrated Dry NO_x/SO₂ Emission Control System. (Public Service Company

of Colorado). Report No. DOE/FE-0212P. U.S. Department of Energy. January 1991.

**Coal Processing for Clean Fuels/Coal
Preparation Technologies**

**ABB Combustion Engineering, Inc., and CQ,
Inc.—Development of the Coal Quality Expert**

“Clean Coal Project will Develop Expert Computer Software Program.” *Clean Coal Today*. Report No. DOE/FE-0215P-4. Winter 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: Development of the Coal Quality Expert. (ABB Combustion Engineering, Inc., and CQ, Inc.). Report No. DOE/FE-0174P. U.S. Department of Energy. May 1990.

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Centerior Energy Corporation—Clean Power from Integrated Coal/Ore Reduction (COREX®)

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Coal Tech Corporation—Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control

The Coal Tech. Advanced Cyclone Combustor Demonstration Project—A DOE Assessment. Report No. DOE/PC 79799-TL. U.S. Department of Energy. May 1993.

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Comprehensive Report to Congress on the Clean Coal Technology Program: Low-NO_x/SO₂ Burner Retrofit for Utility Cyclone Boilers. (TransAlta Resources Investment Corporation). Report No. DOE/FE-0160P. U.S. Department of Energy. April 1990.

Comprehensive Report to Congress on the Clean Coal Technology Program: UCG/Clean Fuels Proof-of-Concept Project. (Energy International, Inc.). Report No. DOE/FE-0093. U.S. Department of Energy. November 1987.

Comprehensive Report to Congress on the Clean Coal Technology Program: Prototype Commercial Coal/Oil Co-Processing Plant. (Ohio Clean Fuels, Inc.). Report No. DOE/FE-0092. U.S. Department of Energy. October 1987.

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Second Report to Congress on Emerging Clean Coal Technologies Capable of Retrofitting, Repowering, or Modernizing Existing Facilities. Report No. DOE/FE-0086. U.S. Department of Energy. May 1987.

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Report to Congress on Emerging Clean Coal Technologies. Report No. DOE/S-0034. U.S. Department of Energy. May 1985.

CCT-I Solicitation

Report to Congress on the Relationships between Projects Selected for the Clean Coal Technology Program and the Recommendations of the Joint Report of the Special Envoys on Acid Rain. Report

No. DOE/FE-0072. U.S. Department of Energy. October 1986.

Comprehensive Report to Congress on Proposals Received in Response to the Clean Coal Technology Program Opportunity Notice. Report No. DOE/FE-0070. U.S. Department of Energy. August 1986.

CCT-II Solicitation

Comprehensive Report to Congress: Proposals Received in Response to the Innovative Clean Coal Technology Program Opportunity Notice. Report No. DOE/FE-0114. U.S. Department of Energy. October 1988.

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CCT-III Solicitation

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CCT-IV Solicitation

"Nine New Clean Coal Technology Projects Selected in Fourth Round of Competition." *Clean Coal Today.* Report No. DOE/FE-0215P-4. Winter 1991.

Comprehensive Report to Congress: Proposals Received in Response to Clean Coal Technology IV Program Opportunity Notice. Report No. DOE/FE-0242P. U.S. Department of Energy. December 1991.

Summary Proceedings: Public Meetings for Views and Comments on the Conduct of the 1990 Clean Coal Technology Solicitation. Report No. DOE/FE-0171. U.S. Department of Energy. April 1990.

Background Information: Public Meetings for Views and Comments on the Conduct of the 1990 Clean Coal Technology Solicitation. Report No. DOE/FE-0157. U.S. Department of Energy. February 1990.

CCT-V Solicitation

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"Five New Clean Coal Projects." *Clean Coal Today.* Report No. DOE/FE-0215P-9. Spring 1993.

Summary Proceedings: Public Meetings for Views and Comments on the Conduct of the 1992 Clean Coal Technology Solicitation. Report No. DOE/FE-0246P. U.S. Department of Energy. December 1991.

Background Information Public Meetings for Views and Comments on the Conduct of the 1992 Clean Coal Technology Solicitation. U.S. Department of Energy. October 1991.

Other Reports and Clean Coal Today Articles

Clean Coal Technologies: Research, Development, and Demonstration Program Plan. Report No. DOE/FE-0284. U.S. Department of Energy. November 1993.

Fossil Energy Review. Report No. DOE/FE-0223P-4. U.S. Department of Energy. January-June 1992. (Available from NTIS as DE 9201-8656.)

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"Notable First Annual Clean Coal Conference—Technology Developers Linked with Wide Range of Users." *Clean Coal Today.* Report No. DOE/FE-0215P-7. Fall 1992.

"Clean Coal Projects Join Integrated Effort to Obtain Toxic Air Pollution Data." *Clean Coal Today.* Report No. DOE/FE-0215P-4. Winter 1991.

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Innovative Clean Coal Technology Program: Programmatic Environmental Impact Analysis (PEIA). Report No. DOE/PEIA-0002. U.S. Department of Energy. September 1988.

Appendix D: Papers and Presentations on the CCT Program

As design, construction, and operational data are generated by the various CCT projects, the information is being reported in a number of ways. One of the most available and up-to-date is through papers presented at technical conferences held at various locations throughout the United States and abroad.

Several annual conferences at which papers on clean coal technologies are usually presented follow:

- Annual American Power Conference
- Annual Clean Coal Technology Conference (U.S. Department of Energy)
- Annual Conference on Gasification Power Plants
- Annual International Pittsburgh Coal Conference (Pittsburgh Energy Technology Center)
- Annual METC Gasification and Gas Stream Cleanup Contractors Reiveiw Meeting (Morgantown Energy Technology Center)
- International Conference on Fluidized-Bed Combustion
- International Joint Power Generation Conference
- PowerGen: International Power Generation Industries Conference and Exhibition

Because conference papers are generally available through the authors and may report data well in advance of the release of a formal project report, selected recent papers are listed below as an additional source of information on the CCT Program. Copies can be obtained from the authors or, in most cases, through the resources of a technical library.

Advanced Electric Power Generation/ Fluidized-Bed Combustion

DMEC-1 Limited Partnership—PCFB Repowering Project

G.E. Kruempel (Midwest Power) et al. "DMEC-1 Pressurized Circulating Fluidized Bed Demonstration Project." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

K.M. Sellakumar, J. Isaksson, and J. Tiensuu (Midwest Power). "Process Performance of Ahlstrom Pyroflow PCFB Pilot Plant." Presented at the Twelfth International Conference on Fluidized-Bed Combustion. May 1993.

S.J. Ambrose (Midwest Power) and C.L. Green et al (Pyropower Inc.). "The Midwest Power PCFB Demonstration Projects/AHLSTROM PYROFLOW First and Second Generation Pressurized Circulating Fluidized Bed (PCFB) Technology." *Proceedings of the American Power Conference*. April 1993.

S.J. Provol and R.J. Dryden (Pyropower Corp.). "Pilot Plant Test Results and Demonstration of the Ahlstrom Pyropower Pressurized CFB Technology." Presented at the Power Generation Utility Conference. September 1992.

The Ohio Power Company—Tidd PFBC Demonstration Project

M. Marrocco (American Electric Power). "American Electric Power Pressurized Fluidized Bed Combustion Technology Status." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

M. Mudd, D. Hafer, and M. Zando (American Electric Power Service Corporation). "Test Results from the 70 MW Tidd PFBC Demonstration Plant." Presented at the Twelfth International Conference on Fluidized-Bed Combustion. May 1993.

D.R. Hafer and D.A. Bauer (American Electric Power). "AEP's Program for Enhanced Environmental Performance of PFBC Plants." *Proceedings of the American Power Conference*. April 1993.

M. Marrocco and D.R. Hafer (American Electric Power Service Corporation). "Tidd PFBC Demonstration Plant Operation and Testing." Presented at the Symposium on Energy and Environmental Management. March 1993.

Tri-State Generation and Transmission Association, Inc.—Nucla CFB Demonstration Project

J. Buck, S. Bush (Tri-State Generation and Transmission Association, Inc.), and N. Rekos (U.S. Department of Energy). "Operating Costs for the 110 MWe Nucla CFB." Presented at the Twelfth International Conference on Fluidized-Bed Combustion. May 1993.

York County Energy Partners—York County Energy Partners Cogeneration Project

S.I. Wang and F.T. Bolinsky (Air Products and Chemicals, Inc.). "York County Energy Partners ACFB Demonstration Project Status." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

Advanced Electric Power Generation/Integrated Gasification Combined Cycle

ABB Combustion Engineering, Inc.—Combustion Engineering IGCC Repowering Project

R.W. Glamuzina, R.J. Allen, and J. Peletz (ABB Combustion Engineering Systems). "IGCC Demonstration Project Status: Combustion Engineering IGCC Repowering Project." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

L.J. Peletz, P.R. Thibeault, and H. Andrus, Jr. (ABB Combustion Engineering). "ABB Combustion Engineering's Coal Gasification System for Combined Cycle Power Generation." *Proceedings of the American Power Conference*. April 1993.

Sierra Pacific Power Company—Piñon Pine IGCC Power Project

E.B. Higginbotham (Sierra Pacific Power Company), L.J. Lamarre (Foster Wheeler USA Corporation), and M. Glazer (The M.K. Kellogg Company). "Piñon Pine IGCC Project Status." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

J.W. Motter (Sierra Pacific Power Company), J.D. Pitcher (Foster Wheeler USA Corporation), and W.M. Campbell (The M.W. Kellogg Company). "The Piñon Pine IGCC Project/Design and Permitting Issues." *Proceedings of the American Power Conference*. April 1993.

TAMCO Power Partners—Toms Creek IGCC Demonstration Project

M.R. Schmid (TAMCO Power Partners). "Clean Coal Power at Toms Creek." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

Tampa Electric Company—Tampa Electric Integrated Gasification Combined-Cycle Project

D.E. Pless (TECO Power Services, Inc.). "Tampa Electric Company: Integrated Gasification Combined-Cycle System." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

D.E. Pless (TECO Power Services, Inc.) and G.J. Starheim (GE Power Generation). "Application of an Advanced Power System in the Tampa Electric Polk Power IGCC Project." Presented at the PowerGen '93 Conference. May 1993.

S.D. Jenkins (TECO Power Services). "Tampa Electric Company Polk Power Station Unit #1 IGCC Project." *Proceedings of the American Power Conference*. April 1993.

C.R. Black (Tampa Electric Company). "A Utility's Perspective on the Commercialization of Gasification Power Plants." Presented at the Eleventh EPRI Conference on Gasification Power Plants. October 1992.

J.M. Brady. "Tampa Electric Opts for IGCC in Florida." *Modern Power Systems* (August 1992).

Wabash River Coal Gasification Project Joint Venture—Wabash River Coal Gasification Repowering Project

P. Amick (Destec Energy, Inc.) and J. Cook (PSI Energy, Inc.). "The Wabash River Coal Gasification Repowering Project: Program Update." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

P. Amick (Destec Energy, Inc.), D.M. Zupan (PSI Energy), and R.E. Herbst (Sargent & Lundy). "Integration of Coal Gasification and Combined Cycle Facilities on the Wabash River Coal Gasification Repowering Project." *Proceedings of the American Power Conference*. April 1993.

W.S. Lessig (Destec Energy, Inc.) and M. Judd (PSI Energy). "Environmental Considerations of Coal Gasification Technology and the Wabash River Repowering Project." *Proceedings of the American Power Conference*. April 1993.

R.E. Maurer, M.W. Roll, and N.W. Janway (Destec Energy, Inc.). "PSI Energy Uses Coal Gasification for Repowering." *Power Engineering* (April 1993).

Advanced Electric Power Generation/Advanced Combustion/Heat Engines

Alaska Industrial Development and Export Authority—Healy Clean Coal Project

S.K. Ubhayakar (TRW Applied Technology Division) et al. "The Healy Clean Coal Project: Design Verification Tests." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

V.V. Bland, S.M. Rosendahl, and D.M. Shattuck (Stone & Webster Engineering Corp.). "The Healy Clean Coal Project Air Quality Control System." EPRI Distribution Center. Report No. CONF-911226-Vol. 3.

S. Rosendahl (Stone and Webster Engineering Corporation) and D.V. McCrohan (Alaska Industrial Development and Export Authority). "The Healy Clean Coal Project." Presented at the Twelfth Annual METC Gasification and Gas Stream Cleanup Contractors Review Meeting. September 1992.

Environmental Control Devices/NO_x Control Technologies

The Babcock & Wilcox Company—Demonstration of Coal Reburning for Cyclone Boiler NO_x Control

A.S. Yagiela (The Babcock & Wilcox Company) et al. "Results of Babcock & Wilcox's Clean Coal Combustion Modification Projects: Coal Reburning

for Cyclone Boiler NO_x Control and Low NO_x Cell™ Burner Demonstrations." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

The Babcock & Wilcox Company—Full-Scale Demonstration of Low-NO_x Cell™ Burner Retrofit

J.M. Piepho (The Babcock and Wilcox Company). "Preliminary Results from the Cyclone Coal Reburn and the Low-NO_x Cell™ Burner Clean Coal Demonstrations." *Proceedings: Coal—Energy and the Environment*. Ninth Annual International Pittsburgh Coal Conference. October 1992.

Energy and Environmental Research Corporation—Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler

H.M. Moser (Energy and Environmental Research Corporation) et al. "Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

J.J. Catasus-Servia et al. "Test for an Optimization Method Applied to Controlling NO_x Emissions in a PC-Fired Boiler." Presented at the 3rd International Joint ISA/POWID EPRI Controls and Instrumentation Conference. June 1993.

B. Folson et al. "Reducing Stack Emissions by Gas Firing in Coal-Designed Boilers—Field Evaluation Results." EPRI/EPA Joint Symposium on Stationary Combustion NO_x Control. May 1993.

J.N. Sorge et al. "The Effects of Low NO_x Combustion on Unburned Carbon Levels in Wall-Fired Boilers." Presented at the Engineering Foundation Conference on Coal Utilization. February 1993.

Southern Company Services, Inc.—Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler

J.N. Sorge (Southern Company Services, Inc.), A.L. Baldwin, and L.L. Smith. "Advanced Wall-Fired Boiler Combustion Techniques for the Reduction of Nitrogen Oxides (NO_x)—Low NO_x Burner Test Phase Results." Presented at the International Congress on Technology and Technology Exchange Conference. May 1992.

R.R. Hardman and J.N. Sorge (Southern Company Services). "Reduction of Nitrogen Oxide (NO_x) Emissions From Coal-Fired Boilers Using Advanced Wall- and Tangentially-Fired Combustion Techniques." *Proceedings of the American Power Conference*. April 1992.

Southern Company Services, Inc.—180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for Reduction of NO_x Emissions from Coal-Fired Boilers

E.B. Dismukes (Southern Research Institute) et al. "Measurement of Air Toxic Emissions from a Coal-Fired Boiler Equipped with a Tangentially Fired Low

NO_x Combustion System." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

Southern Company Services, Inc.—Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers

W.S. Hinton, C.A. Powell, and J.D. Maxwell (Southern Company Services). "Demonstration of Selective Catalytic Reduction Technology for the Control of Nitrogen Oxide Emission from High-Sulfur, Coal-Fired Boilers." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

Tennessee Valley Authority—Micronized Coal Reburning Demonstration of NO_x Control on a 175-MWe Wall-Fired Unit

T.C. Kosvic (Radian Corporation) et al. "Design Methodology for a Micronized Coal Reburn System Using Modeling." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

Environmental Control Devices/SO₂ Control Technologies

AirPol, Inc.—10-MW Demonstration of Gas Suspension Absorption

F.E. Hsu (Airpol, Inc.) et al. "The Clean Coal Technology Program: 10 MWe Demonstration of Gas Suspension Absorption for Flue Gas Desulfurization." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

W.L. Goss. "Flue Gas Desulfurization as High Sulfur Coals Retrofit Costs, Lime Consumption and Removal Efficiencies 10 MWe DOE Demonstration Plant." Presented at the Coal Utilization & Fuel Systems Conference. April 1993.

Bechtel Corporation—Confined Zone Dispersion Flue Gas Desulfurization Demonstration

J.J. Batista (Pennsylvania Electric Company) et al. "Demonstration of Bechtel's Confined Zone Dispersion Process at Pennsylvania Electric Company's Seward Station: Project Status." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

LIFAC—North America—LIFAC Sorbent Injection Desulfurization Demonstration Project

J. Viiala (Tampella Power Corporation) et al. "LIFAC Sorbent Injection for Flue Gas Desulfurization

tion." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

Pure Air on the Lake, L.P.—Advanced Flue Gas Desulfurization Demonstration Project

J. Henderson (Pure Air) et al. "Project Update: Advanced FGD Design for Northern Indiana Public Service Company's Bailly Generating Station." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

G. Campbell. "Pure Air's FGD Facility at Northern Indiana's Bailly Generating Station Cited as an Outstanding 1992 U.S. Engineering Achievement." Presented to the National Society of Professional Engineers, 27th Annual Outstanding Engineering Achievement Awards Competition. January 1993.

Southern Company Services, Inc.—Demonstration of Innovative Applications of Technology for the CT-121 FGD Process

D.P. Burford (Southern Company Services, Inc.), I.G. Pearl (Radian Corporation), and H.J. Ritz (Pittsburgh Energy Technology Center, U.S. Department of Energy). "Chiyoda Thoroughbred 121 Innovative Clean Coal Technology Demonstration Project." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

Environmental Control Devices/Combined SO₂/NO_x Control Technologies

ABB Environmental Systems—SNOX™ Flue Gas Cleaning Demonstration Project

D.C. Borio, D.J. Collins, and T.D. Cassell (ABB Environmental Systems). "Performance Results from the 35 MW SNOX Demonstration at Ohio Edison's Niles Station." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

W.H. Kingston, R.E. Bolli, and M.J. Hyland. "Economic Analysis of the SNOX Process." Presented at the International Joint Power Generation Conference. October 1992.

D.C. Borio and D.J. Collins. "Conversion of SO₂ in Flue Gas to Sulfuric Acid Via the SNOX Process." Presented at the American Chemical Society Fertilizer Division. August 1992.

The Babcock & Wilcox Company—LIMB Demonstration Project Extension and Coolside Demonstration

T.R. Goots, P.S. Nolan, and M.J. DePero (The Babcock and Wilcox Company). "Economic Evaluation of the LIMB and Coolside Processes." *Proceedings: Coal—Energy and the Environment*. Ninth Annual International Pittsburgh Coal Conference. October 1992.

The Babcock & Wilcox Company—SO_x-NO_x-Rox-Box™ Flue Gas Cleanup Demonstration Project

K.E. Rødinger (The Babcock and Wilcox Company) and R.W. Corbett (Pittsburgh Energy Technology Center, U.S. Department of Energy). "SO_x-NO_x-Rox-Box™ Demonstration Project Review." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

Energy and Environmental Research Corporation—Enhancing the Use of Coals by Gas Reburning and Sorbent Injection

J.C. Opatrny (Energy and Environmental Research Corporation) et al. "Enhancing the Use of Coal by Gas Reburning and Sorbent Injection." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

New York State Electric & Gas Corporation—Milliken Clean Coal Technology Demonstration Project

C.M. Ellis, W.J. Savichky (New York State Electric & Gas Corporation), and G.G. Elia (Pittsburgh Energy Technology Corporation, U.S. Department of Energy). "The Milliken Station Clean Coal Demonstration Project: There's More To It Than Concrete and Steel." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No.

Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993..

NOXSO Corporation and MK-Ferguson Company—Commercial Demonstration of the NOXSO SO₂/NO_x Removal Flue Gas Cleanup System

J.B. Black (NOXSO Corporation) et al. "The NOXSO Combined SO₂/NO_x Removal Flue Gas Cleanup System Commercial Demonstration." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

J.L. Haslbeck and W.T. Ma (NOXSO Corporation). "NOXSO SO₂/NO_x Flue Gas Treatment Process Proof-of-Concept Test." *Proceedings: Coal—Energy and the Environment*. Presented at the Ninth Annual International Pittsburgh Coal Conference. October 1992.

Public Service Company of Colorado—Integrated Dry NO_x/SO₂ Emissions Control System

T. Hunt (Public Service Company of Colorado) et al. "Preliminary Performance and Operating Results from the Integrated Dry NO_x/SO₂ Emissions Control System." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

T. Hunt and R. Smith. "Combining Low-NO_x Burners, Overfire Air, and SNCR for High Efficiency NO_x Removal." Presented at the Air & Waste

Management Association's 86th Annual Meeting & Exhibition. June 1993.

T. Hunt et al. "Low-NO_x Combustion Modifications for Top-Fired Boilers." Presented at the 1993 Joint Symposium on Stationary Combustion NO_x Control. May 1993.

T. Hunt et al. "Selective Non-Catalytic Operating Experience Using Both Urea and Ammonia." Presented at the 1993 Joint Symposium on Stationary Combustion NO_x Control. May 1993.

E. Mail et al. "Low-NO_x Combustion Modifications for Down-Fired Pulverized Coal Boilers." *Proceedings of the American Power Conference*. April 1993.

Coal Processing for Clean Fuels/Coal Preparation Technologies

ABB Combustion Engineering, Inc., and CQ, Inc.—Development of the Coal Quality Expert

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R.W. Sheldon (Western SynCoal Company) and S.J. Heintz (Pittsburgh Energy Technology Center, U.S. Department of Energy). "Rosebud SynCoal Partnership: Advanced Coal Conversion Process Demonstration Project." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

Coal Processing for Clean Fuels/Mild Gasification

ENCOAL Corporation—ENCOAL Mild Coal Gasification Project

J.P. Frederick (ENCOAL Corporation), T.G. McCord (Franklin Coal Sales), and W.F. Farmayan (Shell Development Corporation). "Start-Up and Operation of the ENCOAL Mild Coal Gasification Project." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

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Industrial Applications

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D. Kwasnoski and L.L. Walter (Bethlehem Steel Corporation). "Blast Furnace Granular Coal Injection." *Proceedings—Second Annual Clean Coal Technology Conference*. Report No. Conf-9309152. U.S. Department of Energy and the Southern States Energy Board. September 1993.

Coal Tech Corporation—Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control

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R.D. Conley (Pure Air). "A Future Exists for CCTs." *Clean Coal/Synfuels Letter* (January 1993): 2–4.

Appendix E: CCT Project Contacts

In this section are listed contacts for obtaining further information about specific CCT Program demonstration projects. Each listing provides the name, title, phone number, and mailing address of the contact person. In those instances where the project sponsor consists of more than one company, a partnership, or joint venture, the mailing address listed is that of the contact person.

Advanced Electric Power Generation/ Fluidized-Bed Combustion

PFBC Utility Demonstration Project

Sponsor:
The Appalachian Power Company

Contacts:
Mario Marrocco, Manager, PFBC Programs
(614) 223-1740

American Electric Power Service Corporation
1 Riverside Plaza
Columbus, OH 43215

Jeffrey Summers, DOE/HQ, (301) 903-4412
Larry K. Carpenter, METC, (304) 291-4161

PCFB Demonstration Project

Sponsor:
DMEC-1 Limited Partnership

Contacts:
Gary E. Kruempel, Project Manager
(515) 281-2459

Midwest Power Systems, Inc.
907 Walnut
P.O. Box 657
Des Moines, IA 50303

John Geffken, DOE/HQ, (301) 903-9430
Larry K. Carpenter, METC, (304) 291-4161

Four Rivers Energy Modernization Project

Sponsor:
Four Rivers Energy Partners, L.P.

Contacts:
Edward Holley, Senior Project Manager
(215) 481-8568

Air Products and Chemicals, Inc.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

George Lynch, DOE/HQ, (301) 903-9449
Larry K. Carpenter, METC, (304) 291-4161

Tidd PFBC Demonstration Project

Sponsor:
American Electric Power Service Corporation as
agent for The Ohio Power Company

Contacts:
Mario Marrocco, Manager, PFBC Programs
(614) 223-1740

American Electric Power Service Corporation
1 Riverside Plaza
Columbus, OH 43215

Jeffrey Summers, DOE/HQ, (301) 903-4412
Larry K. Carpenter, METC, (304) 291-4161

Nucla CFB Demonstration Project

Sponsor:
Tri-State Generation and Transmission
Association, Inc.

Contacts:
Marshall L. Pendergraff, Assistant General Manager
(303) 249-4501

Tri-State Generation and Transmission
Association, Inc.
P.O. Box 1149
Montrose, CO 81402

John Geffken, DOE/HQ, (301) 903-9430
Nelson F. Rekos, METC, (304) 291-4066

**York County Circulating Fluidized-Bed
Cogeneration Project**

Sponsor:

York County Energy Partners, L.P.

Contacts:

Bradley F. Hahn, Project Manager
(717) 225-6601

York County Energy Partners, L.P.
25 South Main Street
Spring Grove, PA 17362

John Geffken, DOE/HQ, (301) 903-9430
Nelson F. Rekos, METC, (304) 291-4066

**Advanced Electric Power Generation/
Integrated Gasification Combined Cycle**

**Combustion Engineering IGCC Repowering
Project**

Sponsor:

ABB Combustion Engineering, Inc.

Contacts:

Robert W. Glamuzina, Project Director
(203) 285-5904

ABB Combustion Engineering, Inc.
P.O. Box 500
Windsor, CT 06095-0500

Jeffrey Summers, DOE/HQ, (301) 903-4412
R. Daniel Brdar, METC, (304) 291-4666

Camden Clean Energy Demonstration Project

Sponsor:

Duke Energy Corp.

Contacts:

Victor Shellhorse, Vice President
(704) 373-2474

Duke Energy Corp.
400 S. Tryon Street
Charlotte, NC 28202

George Lynch, DOE/HQ, (301) 903-9449
R. Daniel Brdar, METC, (304) 291-4666

Piñon Pine IGCC Power Project

Sponsor:

Sierra Pacific Power Company

Contacts:

John W. (Jack) Motter, Project Manager
(702) 689-4013

Sierra Pacific Power Company
6100 Neil Road
P.O. Box 10100
Reno, NV 89520-0400

John Geffken, DOE/HQ, (301) 903-9430
Douglas M. Jewell, METC, (304) 291-4720

Toms Creek IGCC Demonstration Project

Sponsor:

TAMCO Power Partners

Contacts:

Michael Schmid, Project Director
(717) 327-4457

TAMCO Power Partners
2600 Reach Road
P.O. Box 3308
Williamsport, PA 17701-0308

John Geffken, DOE/HQ, (301) 903-9430
Robert B. Reuther, METC, (304) 291-4578

**Tampa Electric Integrated Gasification
Combined-Cycle Project**

Sponsor:

Tampa Electric Company

Contacts:

Donald E. Pless, Director, Advanced Technology
(813) 228-1332

TECO Power Services Corporation
P.O. Box 111
Tampa, FL 33601-0111

John Geffken, DOE/HQ, (301) 903-9430
Nelson F. Rekos, METC, (304) 291-4066

Wabash River Coal Gasification Repowering Project

Sponsor:
Wabash River Coal Gasification Repowering Project
Joint Venture

Contacts:
W. Paul Ruwe, Jr., Joint Venture Manager
(713) 735-4138

Destec Energy, Inc.
2500 City West Boulevard, Suite 1700
Houston, TX 77042

Jeffrey Summers, DOE/HQ, (301) 903-4412
R. Daniel Brdar, METC, (304) 291-4666

**Advanced Electric Power Generation/
Advanced Combustion/Heat Engines**

Healy Clean Coal Project

Sponsor:
Alaska Industrial Development and Export Authority

Contacts:
John Olson, Project Manager
(907) 561-8050

Alaska Industrial Development and Export
Authority
480 West Tudor
Anchorage, AK 99503-6690

Stan Roberts, DOE/HQ, (301) 903-9431
Steven J. Heintz, PETC, (412) 892-4466

Coal Diesel Combined-Cycle Project

Sponsor:
Arthur D. Little, Inc.

Contacts:
Robert P. Wilson, Vice President
(617) 498-5806

Arthur D. Little, Inc.
200 Acorn Park
Cambridge, MA 02140

George Lynch, DOE/HQ, (301) 903-9449
Nelson F. Rekos, METC, (304) 291-4066

**Warren Station Externally Fired Combined-Cycle
Demonstration Project**

Sponsor:
Pennsylvania Electric Company

Contacts:
Thomas J. Bradish, Manager, Research and
Development
(814) 533-8593

Pennsylvania Electric Company
1001 Broad Street
Johnsontown, PA 15907

George Lynch, DOE/HQ, (301) 903-9449
Robert B. Reuther, METC, (304) 291-4578

**Environmental Control Devices/NO_x Control
Technologies**

**Demonstration of Coal Reburning for Cyclone
Boiler NO_x Control**

Sponsor:
The Babcock & Wilcox Company

Contacts:
Todd Johnson, Senior Marketing Specialist
(216) 829-7355

The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601

William Fernald, DOE/HQ, (301) 903-9448
Ronald W. Corbett, PETC, (412) 892-6141

**Full-Scale Demonstration of Low-NO_x Cell™
Burner Retrofit**

Sponsor:
The Babcock & Wilcox Company

Contacts:
Todd Johnson, Senior Marketing Specialist
(216) 829-7355

The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601

William Fernald, DOE/HQ, (301) 903-9448
Ronald W. Corbett, PETC, (412) 892-6141

Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler

Sponsor:

Energy and Environmental Research Corporation

Contacts:

Blair A. Folsom, Senior Vice President
(714) 859-8851

Energy and Environmental Research
Corporation
18 Mason
Irvine, CA 92718

William Fernald, DOE/HQ, (301) 903-9448
Harry J. Ritz, PETC, (412) 892-6137

Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler

Sponsor:

Southern Company Services, Inc.

Contacts:

John N. Sorge, ICCT Project Manager
(205) 877-7426

Southern Company Services, Inc.
P.O. Box 2625
Birmingham, AL 35202-2625

William Fernald, DOE/HQ, (301) 903-9448
Arthur L. Baldwin, PETC, (412) 892-6011

180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers

Sponsor:

Southern Company Services, Inc.

Contacts:

Robert R. Hardman, Project Manager
(205) 877-7772

Southern Company Services, Inc.
P.O. Box 2625
Birmingham, AL 35202-2625

William Fernald, DOE/HQ, (301) 903-9448
Gerard G. Elia, PETC, (412) 892-5862

Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers

Sponsor:

Southern Company Services, Inc.

Contacts:

J.D. (Doug) Maxwell, Project Manager
(205) 877-7614

Southern Company Services, Inc.
P.O. Box 2625
Birmingham, AL 35202-2625

William Fernald, DOE/HQ, (301) 903-9448
Arthur L. Baldwin, PETC, (412) 892-6011

Micronized Coal Reburning Demonstration of NO_x Control on a 175-MWe Wall-Fired Unit

Sponsor:

Tennessee Valley Authority

Contacts:

Tom Butler, Mechanical Engineer
(615) 751-6120

Tennessee Valley Authority
1101 Market Street, ATTN: MR-3A
Chattanooga, TN 37402

William Fernald, DOE/HQ, (301) 903-9448
James U. Watts, PETC, (412) 892-5991

Environmental Control Devices/SO₂ Control Technologies

10-MW Demonstration of Gas Suspension Absorption

Sponsor:

AirPol, Inc.

Contacts:

Frank E. Hsu, Project Manager
(201) 288-7070

AirPol, Inc.
32 Henry Street
Teterboro, NJ 07608

Stan Roberts, DOE/HQ, (301) 903-9431
Sharon K. Marchant, PETC, (412) 892-6008

**Confined Zone Dispersion Flue Gas
Desulfurization Demonstration**

Sponsor:
Bechtel Corporation

Contacts:
Joseph T. Newman, Project Manager
(415) 768-6514

Bechtel Corporation
P.O. Box 3965
San Francisco, CA 94119-3965

William Fernald, DOE/HQ, (301) 903-9448
Arthur L. Baldwin, PETC, (412) 892-6011

**LIFAC Sorbent Injection Desulfurization
Demonstration Project**

Sponsor:
LIFAC-North America

Contacts:
Jim Hervol, Project Manager
(412) 497-2735

ICF Kaiser Engineers, Inc.
4 Gateway Center
Pittsburgh, PA 15222-1207

William Fernald, DOE/HQ, (301) 903-9448
Robert J. Evans, PETC, (412) 892-5988

**Advanced Flue Gas Desulfurization
Demonstration Project**

Sponsor:
Pure Air on the Lake, L.P.

Contacts:
Don Vymazal, Manager, Contract Administration
(215) 481-3687

Pure Air on the Lake, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

Stan Roberts, DOE/HQ, (301) 903-9431
Thomas A. Sarkus, PETC, (412) 892-5981

**Demonstration of Innovative Applications of
Technology for the CT-121 FGD Process**

Sponsor:
Southern Company Services, Inc.

Contacts:
David P. Burford, Project Manager
(205) 870-6329

Southern Company Services, Inc.
P.O. Box 2625
Birmingham, AL 35202-2625

Stan Roberts, DOE/HQ, (301) 903-9431
Harry J. Ritz, PETC, (412) 892-6137

**Environmental Control Devices/Combined
SO₂/NO_x Control Technologies**

SNOX Flue Gas Cleaning Demonstration Project

Sponsor:
ABB Environmental Systems

Contacts:
Bill Kingston, Project Manager
(205) 995-5368

Environmental Systems Division
ABB Combustion Engineering, Inc.
P.O. Box 43030
Birmingham, AL 35243

Stan Roberts, DOE/HQ, (301) 903-9431
Robert J. Evans, PETC, (412) 892-5988

**LIMB Demonstration Project Extension and
Cookside Demonstration**

Sponsor:
The Babcock & Wilcox Company

Contacts:
Todd Johnson, Senior Marketing Specialist
(216) 829-7355

The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601

William Fernald, DOE/HQ, (301) 903-9448
Thomas W. Arrigoni, PETC, (412) 892-6258

**SOx-NOx-Rox-Box™ Flue Gas Cleanup
Demonstration Project**

Sponsor:

The Babcock & Wilcox Company

Contacts:

Todd Johnson, Senior Marketing Specialist
(216) 829-7355

The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601

Stan Roberts, DOE/HQ, (301) 903-9431
Ronald W. Corbett, PETC, (412) 892-6141

**Enhancing the Use of Coals by Gas Reburning and
Sorbent Injection**

Sponsor:

Energy and Environmental Research Corporation

Contacts:

Blair A. Folsom, Senior Vice President
(714) 859-8851

Energy and Environmental Research
Corporation
18 Mason
Irvine, CA 92718

William Fernald, DOE/HQ, (301) 903-9448
Harry J. Ritz, PETC, (412) 892-6137

**Milliken Clean Coal Technology Demonstration
Project**

Sponsor:

New York State Electric & Gas Corporation

Contacts:

Dennis O'Dea, Project Manager
(607) 729-2551

New York State Electric & Gas Corporation
120 Chenango Street
Binghamton, NY 13902

Stan Roberts, DOE/HQ, (301) 903-9431
Gerard G. Elia, PETC, (412) 892-5862

**Commercial Demonstration of the NOXSO
SO₂/NO_x Removal Flue Gas Cleanup System**

Sponsor:

NOXSO Corporation and MK-Ferguson Company

Contacts:

Eugene R. Recher, Program Manager
(216) 523-5923

MK-Ferguson Company
1500 West 3d Street
Cleveland, OH 44114

Stan Roberts, DOE/HQ, (301) 903-9431
Gerard G. Elia, PETC, (412) 892-5862

Integrated Dry NO_x/SO₂ Emissions Control System

Sponsor:

Public Service Company of Colorado

Contacts:

Gordon A. Schott, Project Manager
(303) 329-1702

Public Service Company of Colorado
5900 East 39th Avenue
Denver, CO 80207

William Fernald, DOE/HQ, (301) 903-9448
Thomas W. Arrigoni, PETC, (412) 892-6258

**Coal Processing for Clean Fuels/Coal
Preparation Technologies**

Development of the Coal Quality Expert

Sponsors:

ABB Combustion Engineering, Inc., and CQ, Inc.

Contacts:

Clark Harrison, President
(412) 479-6016

CQ, Inc.
One Quality Center
P.O. Box 280
Homer City, PA 15748-0280

Douglas Archer, DOE/HQ, (301) 903-9443
Stan Roberts, DOE/HQ, (301) 903-9431
Robert J. Evans, PETC, (412) 892-5988

Self-Scrubbing Coal™: An Integrated Approach to Clean Air

Sponsor:
Custom Coals International

Contacts:
Robin Godfrey, Project Manager
(412) 642-2625

Custom Coals International
100 First Avenue, Suite 500
Pittsburgh, PA 15222

Douglas Archer, DOE/HQ, (301) 903-9443
Robert J. Evans, PETC, (412) 892-5988

Advanced Coal Conversion Process Demonstration

Sponsor:
Rosebud SynCoal Partnership

Contacts:
Ray W. Sheldon, Project Manager
(406) 748-2366 and/or (406) 252-2277

Rosebud SynCoal Partnership
P.O. Box 7137
Billings, MT 59103-7137

Douglas Archer, DOE/HQ, (301) 903-9443
Steven J. Heintz, PETC, (412) 892-4466

Coal Processing for Clean Fuels/Mild Gasification

ENCOAL Mild Coal Gasification Project

Sponsor:
ENCOAL Corporation

Contacts:
J.P. (Jim) Frederick, Project Manager
(307) 686-5493

ENCOAL Corporation
P.O. Box 3038
Gillette, WY 82717

Douglas Archer, DOE/HQ, (301) 903-9443
Douglas M. Jewell, METC, (304) 291-4720

Coal Processing for Clean Fuels/Indirect Liquefaction

Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process

Sponsor:
Air Products and Chemicals, Inc.

Contacts:
William R. Brown, Project Manager
(215) 481-7584

Air Products and Chemicals, Inc.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

Douglas Archer, DOE/HQ, (301) 903-9443
Robert M. Kornosky, PETC, (412) 892-4521

Industrial Applications

Blast Furnace Granulated-Coal Injection System Demonstration Project

Sponsor:
Bethlehem Steel Corporation

Contacts:
Daniel Kwasnoski, Program Manager
(215) 694-6478

Bethlehem Steel Corporation
Homer Research Laboratory
Building C, Room 229
Bethlehem, PA 18016

Jeffrey Summers, DOE/HQ, (301) 903-4412
Douglas M. Jewell, METC, (304) 291-4720

Innovative Coke Oven Gas Cleaning System for Retrofit Applications

Sponsor:
Bethlehem Steel Corporation

Contacts:
Daniel Kwasnoski, Project Manager
(215) 694-6478

Bethlehem Steel Corporation
Homer Research Laboratory
Building C, Room 229
Bethlehem, PA 18016

Jeffrey Summers, DOE/HQ, (301) 903-4412
Robert M. Kornosky, PETC, (412) 892-4521

**Clean Power from Integrated Coal/Ore Reduction
(COREX®)**

Sponsor:

Centerior Energy Corporation

Contacts:

J. Lee Bailey, Manager, Corporate Communications
(216) 447-3235

Centerior Energy Corporation
6200 Oak Tree Boulevard
Independence, OH 44131

George Lynch, DOE/HQ, (301) 903-9449
Robert B. Reuther, METC, (304) 291-4578

**Advanced Cyclone Combustor with Internal
Sulfur, Nitrogen, and Ash Control**

Sponsor:

Coal Tech Corporation

Contacts:

Bert Zauderer, President
(215) 667-0442

Coal Tech Corporation
P.O. Box 154
Merion, PA 19066

Stan Roberts, DOE/HQ, (301) 903-9431
Arthur L. Baldwin, PETC, (412) 892-6011

Cement Kiln Flue Gas Recovery Scrubber

Sponsor:

Passamaquoddy Tribe

Contacts:

Garrett Morrison, Project Manager
(207) 594-5555

Passamaquoddy Technology, L.P.
P.O. Box 350
Thomaston, ME 04861-0350

Jeffrey Summers, DOE/HQ, (301) 903-4412
John C. McDowell, PETC, (412) 892-6237

**Demonstration of Pulse Combustion in an
Application for Steam Gasification of Coal**

Sponsor:

ThermoChem, Inc.

Contacts:

William Steedman, Program Manager
(410) 997-9671

ThermoChem, Inc.
5570 Sterrett Place, Suite 210
Columbia, MD 21044

William Fernald, DOE/HQ, (301) 903-9448
Steven J. Heintz, PETC, (412) 892-4466

Appendix F: Acronyms and Abbreviations

Acronyms					
ABB CE	ABB Combustion Engineering, Inc.	CZD	confined zone dispersion	JBR	jet-bubbling reactor
ABB ES	ABB Environmental Systems	DME	dimethyl ether	LHV	lower heating value
ACFB	atmospheric circulating fluidized bed	DOE	U.S. Department of Energy	LIMB	limestone injection multistage burner
AFBC	atmospheric fluidized-bed combustion	DOE/HQ	U.S. Department of Energy Headquarters	LNB	low-NO _x burner
AFGD	advanced flue gas desulfurization	EA	environmental assessment	LNCFS	low-NO _x concentric-firing system
AIDEA	Alaska Industrial Development and Export Authority	EER	Energy and Environmental Research Corporation	LSFO	limestone forced oxidation
AOFA	advanced over-fire air	EFCC	externally fired combined cycle	METC	Morgantown Energy Technology Center
BFGCI	blast furnace granulated-coal injection	EIA	Energy Information Administration	MTCI	Manufacturing and Technology Conversion International
BG	British Gas	EIS	environmental impact statement	MTF	memorandum(memoranda)-to-file
BG/L	British Gas/Lurgi	EMP	environmental monitoring plan	NEPA	National Environmental Policy Act
B&W	The Babcock & Wilcox Company	EPA	U.S. Environmental Protection Agency	NSPS	New Source Performance Standards
CAAA of 1990	Clean Air Act Amendments of 1990	EPACT	Energy Policy Act of 1992	NTIS	National Technical Information Service
CCOFA	close-coupled over-fire air	EPRI	Electric Power Research Institute	NYS Electric & Gas Corporation	New York State Electric & Gas Corporation
CCT	clean coal technology	ESP	electrostatic precipitator	PCFB	pressurized circulating fluidized bed
CCT Program	Clean Coal Technology Demonstration Program	EWG	exempt wholesale generator	PEIS	programmatic environmental impact statement
CDCC	coal-fueled diesel engine combined cycle	FBC	fluidized-bed combustion	PETC	Pittsburgh Energy Technology Center
CEQ	Council on Environmental Quality	FGD	flue gas desulfurization	PFBC	pressurized fluidized-bed combustion
CFB	circulating fluidized bed	FONSI	finding of no significant impact	PON	program opportunity notice
COG	coke oven gas	FRP	fiberglass-reinforced plastic	PSC of Colorado	Public Service Company of Colorado
CPICOR	clean power from integrated coal/ore reduction	FY	fiscal year	PURPA	Public Utility Regulatory Policies Act of 1972
CQE	Coal Quality Expert	GE	General Electric	R&D	research and development
CX	categorical exclusion	GR-LNB	gas reburning and low-NO _x burner		
		GSA	gas suspension absorption		
		HAP, HAPs	hazardous air pollutant(s)		
		HHV	higher heating value		
		HRSG	heat recovery steam generator		
		IGCC	integrated gasification combined cycle		

RD&D	research, development, and demonstration
SBIR	Small Business Innovative Research
SCR	selective catalytic reduction
SCS	Southern Company Services, Inc.
SNCR	selective noncatalytic reduction
SOFA	separated over-fire air
TVA	Tennessee Valley Authority
UBCL	unburned carbon boiler efficiency losses

Abbreviations

States are abbreviated using two-letter postal codes.

atm	atmosphere(s)
avg	average
Btu	British thermal unit
CaCO ₃	calcium carbonate (calcitic limestone)
CaO	calcium oxide (lime)
Ca(OH) ₂	calcium hydroxide (calcitic hydrated lime)
Ca(OH) ₂ •MgO	dolomitic hydrated lime
Ca/S	molar ratio of calcium to sulfur
CaSO ₃	calcium sulfite
CO	carbon monoxide
CO ₂	carbon dioxide
ft, ft ² , ft ³	foot (feet), square feet, cubic feet
GWe	gigawatt(s)-electric
H ₂ S	hydrogen sulfide
HCl	hydrogen chloride
HF	hydrogen fluoride
hr, hrs	hour, hours
in, in ² , in ³	inch(es), square inches, cubic inches
kW	kilowatt
kWh	kilowatt-hour
lb, lbs	pound, pounds
mo, mos	month, months
MgCO ₃	magnesium carbonate
MgO	magnesium oxide
MW	megawatt(s)
MWe	megawatt(s)-electric
N ₂	atmospheric nitrogen

Na/Ca	molar ratio of sodium to calcium
Na ₂ /S	molar ratio of sodium to sulfur
NaOH	sodium hydroxide
Na ₂ CO ₃	sodium carbonate
NH ₃	ammonia
NO ₂	nitrogen dioxide
NO _x	nitrogen oxides
O ₂	oxygen
ppm	parts per million (mass)
ppmv	parts per million by volume
rpm	revolutions per minute
S	sulfur
SO ₂	sulfur dioxide
std ft ³	standard cubic feet
yr, yrs	year, years

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