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CLEAN COAL TECHNOLOGY

DOE/FE-0330

Clean Coal Technology Demonstration Program

Program Update 1994

U.S. Department of Energy
Assistant Secretary for Fossil Energy
Washington, DC 20585

April 1995

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Role of the Program

The Clean Coal Technology Demonstration Program (also referred to as the CCT Program) is a $7.14 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 one-quarter of the primary energy consumed. Nearly 53 percent of all electricity generated in 1993 came from coal. 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, with the most promising moving into the marketplace.

The CCT Program has been committed to commercial realization since its inception. The emphasis on commercialization reflects the strategic importance of coal to the U.S. economy and the commitment to sound environmental policies. The CCT Program plays a major role in advancing the U.S. Department of Energy's (DOE) vision of the future by being a major contributor in ensuring that the United States leads the world in developing, applying, and exporting sustainable, clean, and economically competitive coal utilization technologies. As such, the CCT Program has a key role in advancing three goals of the DOE Strategic Plan under the Energy Resource business line:

- Reduce adverse environmental impacts associated with energy production, delivery, and use
- Ensure reliable energy services with reduced vulnerability to energy price and supply volatility
- Enhance energy productivity to strengthen the U.S. economy and improve living standards

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 equal to or greater than 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 systems
- Environmental control devices
- Coal processing equipment for clean fuels
- Industrial technologies

Approximately 78 percent, or about $5.5 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 systems 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 $4.8 billion. There are 19 environmental control device projects valued at more than $686 million. These projects include NO_x controls, SO_2 controls, and combined SO_2/NO_x controls.

Participation in these projects involve over 55 investor-owned utilities, nonutility power generators, municipals, 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 $521 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 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 technologies. Encompassing the iron, steel, and cement industries and industrial boilers, there are six projects in this category valued at over $1.12 billion.

The contribution of the $7.14 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 an average of 29,000 jobs for the years 1995 through 1999 (direct and indirect) 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 in-depth 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 CCT I–V 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 energy supply and demand situation with SO_2 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.

The completion of the original plans for five solicitations provided the framework to examine the lessons learned from the planning and implementation of the program and to analyze its future needs. In June 1994, DOE published the report, *Clean Coal Technology Program Lessons Learned.* This report summarized the programmatic and procedural lessons learned in conducting the program. Comments from the industrial participants are quoted to highlight the important aspects of the program from their viewpoint.

In planning for the future, two additional reports were issued in 1994. In February 1994, the National Coal Council released a report requested by the Secretary of Energy on the future directions for the CCT Program. The thrust of the report, *Clean Coal Technology for Sustainable Development,* was recommendations to enhance commercial deployment of demonstrated technologies. The second report, *Clean Coal Technology Program Completing the Mission,* was issued by DOE in May 1994 in response to a congressional request that the Secretary report on available funds appropriated but not used in the solicitations. The report stated "the highest priority for DOE is the completion of the 45 projects currently in the program."

Critical factors in implementing the CCT Program involve complying 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 NEPA through a process which includes (1)preparation in 1989 of a programmatic environmental impact statement (PEIS); (2)preparation of preselection, project-specific environmental reviews; and (3)preparation of postselection, site-specific NEPA documents.

By the end of 1994, NEPA reviews had been completed for 33 of the 45 projects. Additionally,

during 1994, four public meetings were held on draft environmental impact statements for two projects.

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 1994, EMPs had been completed for 30 projects.

The CAAA of 1990 calls for the eventual establishment of HAPs emission standards for various source categories. The CCT 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 25 active projects and has been completed on 10 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 a federal budget for the CCT Program. These funds have been committed to demonstration projects through five competitive solicitations. Cooperative agreement awards have been negotiated for each project selected in the five solicitations with the exception of one project which is in negotiation.

The five solicitations have resulted in a combined commitment by the federal government and the private sector of about $7.14 billion. DOE's share of the project cost is $2.42 billion, or approximately 34 percent of the total. The project participants (i.e., the non-federal government participants) are providing the remainder—nearly $4.72 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 fourth solicitation ($566 million) were apportioned for FY 1991 through FY 1997. The $564 million for projects selected in the fifth solicitation are apportioned for FY 1992 through FY 1997.

In 1994, repayments to the government were received from the Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.), Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit (The Babcock & Wilcox Company), and the Development of the Coal Quality Expert (ABB Combustion Engineering, Inc., and CQ, Inc.).

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

Commercial Realization

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 1994, 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 Third Annual Clean Coal Technology Conference attended by about 400 persons from 23 nations. The theme of the conference was "The Investment Pays Off." The conference participants reviewed the status and success of the program, the role of the program in meeting domestic and global energy and environmental needs, the opportunities for commercialization in the United States and abroad, and the challenges which are being encountered. Highlights included the Eastern Europe/NIS and the Asia/Pacific Rim Reverse Trade Missions. These reverse trade missions provided the

opportunity for U.S. industry to gain an understanding of the business opportunities for clean coal technologies in the countries represented. Three issues of the *Clean Coal Today* newsletter were prepared for distribution to 3,700 domestic and international readers. The CCT Program staff participated in 12 major domestic and international events involving users and vendors of the technology, state institutions, state regulators, and environmental groups.

International activities centered on developing a summary of the potential markets in developing countries for exporting clean coal technologies and the financing mechanisms and/or levels of government support necessary to assist U.S. industry participation in these markets. A report to the United States Congress, *Clean Coal Technology Export Markets and Financing Mechanism*, was distributed in May 1994. In November 1994, DOE solicited statements of interest in commercial projects employing CCTs in foreign countries projected to have significant growth in greenhouse gas emissions. DOE's report to Congress on the results of the informational solicitation will be issued by April 15, 1995. This report also will identify the extent to which various types of federal incentives would accelerate the commercial availability of CCTs in an international context.

At this point in the CCT Program, there are 45 projects, with 16 in operation and construction, 15 in design and project definition, and 1 CCT-V project in negotiation. A total of 13 projects have completed operation. A number of commercial successes have been realized, including the following:

- The Babcock & Wilcox Company has installed the LNCB® technology on more than 2,500 MWe of capacity in the United States—each installation achieving more than 50% NO_x reduction. In addition LNCB® retrofits have been ordered for an additional 3,250 MWe.
- Babcock & Wilcox has sold 85 contracts (61 domestic and 24 international) for the DRB-XCL® low-NO_x burners demonstrated by Pubic Service Company of Colorado.
- Foster Wheeler has had about $20 million in sales of the low-NO_x burners demonstrated on Georgia Power Company's Plant Hammond.
- Successful testing of the AirPol demonstration project resulted in the city of Hamilton, Ohio, receiving a $5-million grant from the Ohio Coal Development Office to install the GSA technology on a 50-MWe coal-fired boiler at the city's municipal power plant.
- In April 1994, Pure Air of Manatee, L.P., entered into a contract to provide 1,600 MWe of SO_2 scrubbing capacity at Florida Power & Light's Manatee power plant.
- Ohio Edison Company has retained ABB Environmental Systems' SNOX™ system at its Niles Station as part of its CAAA of 1990 compliance strategy. Commercial SNOX™ plants have been started up in Denmark and Sicily.
- The flue gas recovery system for SO_2 reduction, demonstrated by the Passamaquoddy Tribe, has been incorporated as a permanent part of a 1,450-ton-per-day cement plant.
- Pyropower Corporation has cut 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.
- A commercial version of Babcock & Wilcox's successfully demonstrated limestone injection multistage burner (LIMB) is being installed in an independent power production project in Canada.
- The first commercial sale of the Coal Quality Expert Acid Rain Advisor software package was made in 1993.
- Liquid and solid products from ENCOAL Corporation's demonstration project have been sold for commercial applications.
- Custom Coals is leading an international consortium that plans to build a fine-coal-cleaning plant, a 500-mile coal slurry pipeline, and port facility in the People's Republic of China.
- Rosebud SynCoal Partnership is working on three potential semi-commercial projects located in Wyoming, North Dakota, and Montana and ranging in size from 500,000 to 5 million tons per year. The Wyoming project is a stand alone mine-mouth design. The North Dakota project is integrated into a mine-mouth power plant with project sales offsite to regional markets. The Montana project is designed as either an integration into a power plant and fuel user or a regional market.

Exhibit ES-1
Summary of Results of Completed CCT Projects

Project and Participant	Key Environmental Results	Capital Cost
Advanced Electric Power Generation		
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)
Environmental Control Devices		
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 (LNCFS) Level III, which includes both separated over-fire air and close-coupled over-fire air	LNCFS I—$8–10/kW LNCFS II/III—$15–20/kW
10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.)	Gas suspension absorption (GSA)/electrostatic precipitator SO_2 removal efficiency 60–91%; GSA/pulse jet baghouse, 96%	$149/kW for GSA; $216/kW for wet limestone forced oxidation
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
LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC–North America)	SO_2 removal efficiency 70+% at Ca/S ratio 2.0	$66/kW for two reactors (300 MWe); $76/kW for one reactor (150 MWe)
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	NO_x reduction with SCR over 94%; SO_2 removal efficiency over 95%; produces sulfuric acid	$250/kW
LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)	SO_2 removal efficiency: LIMB—61% (3.8% sulfur coal; ligno lime) Coolside—70% (hydrated lime)	LIMB—$31–102/kW Coolside—$69–160/kW

Exhibit ES-1
Summary of Results of Completed CCT Projects (continued)

Project and Participant	Key Environmental Results	Capital Cost
SOx-NOx-Rox-Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)	SO_2 reductions of 80–90% using 3.4% sulfur bituminous coal, depending on sorbent and conditions NO_x reduction of 90% with 0.9 NH_3/NO_x	$260/kW at 250 MWe
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)	Hennepin—NO_x reduction averaged 67% with 18% gas input, SO_2 removal efficiency 52% at Ca/S ratio 1.76 Lakeside—NO_x reductions of 64–66% and SO_2 reductions of 60–63% during extended continuous combined (GR–SI) runs at 29 MWe, about 22% gas input, and Ca/S of 1.67–1.75 NO_x reduction averaged 67% during long-term testing of gas reburn only	Ranges $979–1,318/ton of NO_x removed Ranges $425–514/ton of SO_2 removed
Industrial Applications		
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 at 2.0 Ca/S NO_x emissions of 160–184 ppm (75% reduction) Slag/sorbent retention of 55–90% in combustor; inert slag	Not available
Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)	SO_2 reduction of 90–95% (3% sulfur bituminous coal); 98% maximum reduction NO_x reductions of 5–15%	$25/ton of annual cement capacity

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 SO_2 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

Four projects completed operations in 1994, bringing to 13 the total number of projects that have been successfully completed under the CCT Program. These four projects demonstrated the following technologies:

- Two SO_2 control technologies
  - 10-MWe demonstration of gas suspension absorption (AirPol, Inc.)
  - LIFAC sorbent injection desulfurization (LIFAC–North America)
- Two combined SO_2/NO_x control technologies
  - SNOX™ flue gas cleaning (ABB Environmental Systems)
  - Gas reburning and sorbent injection (Energy and Environmental Research Corporation)

This portfolio of completed projects is providing valuable data for addressing the pressing environmental and energy issues associated with the utility and industrial use of coal. Exhibit ES-1 summarizes the results of these projects. Section 5 presents further information about project results and lists available reports and project contacts. Exhibit ES-2 shows the allocation of completed projects by application category.

Results and Accomplishments from Ongoing Projects

By the end of 1994, the CCT Program consisted of 45 projects. A total of 13 projects have successfully completed operations. An additional 10 projects are in the operations phase, 6 are in the construction phase, 15 are in the design and project definition phase, and 1 CCT-V project is currently in negotiation.

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.

Exhibit ES-2
Completed Projects, by Application Category

Application Category	Number Completed
Advanced Electric Power Generation	
Atmospheric fluidized bed combustion	1
Environmental Control Devices	
NO_x control technology	3
SO_2 control technology	3
Combined SO_2/NO_x control technology	4
Industrial Applications	2

Project Fact Sheets

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

- Advanced electric power generation systems
- Environmental control devices
- Coal processing equipment for clean fuels
- Industrial technologies

Project information provided in the fact sheets includes the participant, 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, negotiations of cooperative agreements, and completion of projects 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. Appendix E lists contacts for obtaining further information about specific CCT Program demonstration projects. Appendix F provides a key to the acronyms and abbreviations used in the *Program Update*.

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 38 of the 50 states, with production contributing to the economies of 26 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. Nearly 53 percent of all electricity generated in 1993 came from coal; of the 3,204 billion kilowatt-hours generated by utilities, nonutility generators, and cogenerators, 1,693 billion kilowatt-hours were generated from coal. 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) when generation by coal technologies is projected to increase to 1,929 billion kilowatt-hours and account for approximately 50 percent of all electricity generation. Although EIA forecasts show that coal-fired utility generation is expected to grow at only 0.6 percent annually and coal-fired cogeneration at 1.3 percent annually through 2010, nonutility generators are expected to increase their coal-fired generation at an annual rate of over 13 percent.

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 contributions
- $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 are shipped 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 cost-shared partnership 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 judgments 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. The CCT Program plays a major role in advancing the U.S. Department of Energy's (DOE) vision of the future by being a major contributor in ensuring that the United States leads the world in developing, applying, and exporting sustainable, clean, and economically competitive energy technologies. As such, the CCT Program has a key role in achieving three goals of the DOE Strategic Plan under the Energy Resource business line:

- Reduce adverse environmental impacts associated with energy production, delivery, and use
- Ensure reliable energy services with reduced vulnerability to energy price and supply volatility
- Enhance energy productivity to strengthen the U.S. economy and improve living standards

Reduce Adverse Environmental Impacts

The CCT Program is pursuing the goal of reducing adverse environmental impacts through a three-part strategy. The first part is to reduce regional and local impacts of U.S. energy-related emissions and discharges through the development and deployment of lower emissions energy conversion technologies. The second part is to reduce energy-related greenhouse gases below 1990 levels by the year 2000 through the development and deployment of efficiency-enhancing technologies. The third part is to improve the global environment through policy leadership and programs for the export of advanced energy and environmental technologies. The CCT Program is pursuing its strategy through the demonstration of technologies that reduce emissions of sulfur dioxide (SO_2), nitrogen oxide (NO_x), hazardous air pollutants, and solid and liquid wastes through significant improvements in pre-utilization, in-situ, and post-utilization emissions control technologies. High-efficiency technologies are being demonstrated which result not only in efficient and cost-effective use of resources but also in reduction of greenhouse gas emissions. An initiative has been taken, at congressional direction, to solicit statements of interest in commercial projects employing CCTs in countries projected to have significant growth in greenhouse gas emissions.

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*. 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.

On November 15, 1990, Congress enacted the Clean Air Act Amendments (CAAA) of 1990. Title IV, Acid Deposition Control, established emissions reduction targets for SO_2 and directed the establishment of allowable emissions limitations for NO_x.

The acid rain provision of the CAAA of 1990 sets emission reduction requirements on SO_2 to be met in two phases. Evidence to date suggests that compliance with the Phase I targets established for 1995 will be achieved largely 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 more reliance on 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 SO_2 emissions beyond the year 2000.

The CAAA of 1990 required the U.S. Environmental Protection Agency (EPA) to establish annual allowable emissions limitations for NO_x in two phases. Phase I limitations were to be effective January 1, 1995, and address allowable emissions for tangentially fired and dry-bottom wall-fired boilers. Phase II limits will require wet-bottom wall-fired boilers, cyclone burners, cell burners, and all other types of utility boilers to reduce their NO_x emissions starting in 2000.

Phase I limitations were published in the *Federal Register* on March 22, 1994. Emission limitations for NO_x have been set at 0.45 pound per million Btu for tangentially fired units and 0.50 pound per million Btu for wall-fired boilers. The Phase I NO_x limitations involve 170 boilers. An option for NO_x control is available for an owner or operator of two or more units subject to NO_x emission limitations. The option allows the owner or operator to average emissions among its units in lieu of complying on a unit-specific basis. The actual Btu-weighted annual emissions rate averaged over the units must be no greater than the Btu-weighted annual emissions rate for the same units had they been operated in compliance with the applicable emission limitation. The remaining 637 tangentially fired and wall-fired boilers must meet the applicable NO_x emission limits by January 1, 2000.

The CAAA of 1990 provides that EPA, no later than 1997, may revise the performance standard to reflect improvements in methods for reducing emissions for NO_x. EPA plans to propose a rule regarding the January 2000 limits for the remaining tangentially fired and wall-fired boilers, should the limits be revised.

EPA is required to propose NO_x control standards for cell, cyclone, wet-bottom, bubbling fluidized-bed, stoker, and other coal-fired units by

January 1, 2000. The standards are to reflect emissions reductions achievable by retrofit applications of the best of continuous emission reduction technology available considering cost, energy, and environmental impact.

In the published Phase I rule, EPA included over-fire air systems in its definition of low-NO_x burner technology on the basis that both low-NO_x burners and over-fire air reduces NO_x by altering oxygen-to-fuel mix during combustion and therefore should be considered a common technology. A lawsuit was filed in the U.S. Court of Appeals for the District of Columbia arguing that the CAAA of 1990 prevents EPA from requiring installation of any equipment in addition to low-NO_x burners. On November 29, 1994, the court agreed with industry and vacated the rule upon finding that EPA had overstepped its statutory authority.

As of year-end 1994, EPA was working closely with industry groups in an effort to incorporate the court's decision into a revised rule. EPA is proceeding independently with development of the Phase II NO_x emission limitations, which also may require more stringent emissions levels for some Phase I boilers. Publication of Phase II limitations is anticipated by late 1996.

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 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–V projects, DOE has sought to include HAPs monitoring, and 20 projects are monitoring HAPs. HAPs monitoring has been completed for 10 projects. Two objectives of HAPs monitoring, which have been met, were to improve the quality of HAPs data being gathered and to monitor a broader range of plant configurations and emissions control equipment.

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; three of these plants are sites of CCT projects. Data collected at nine of the plants have been 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

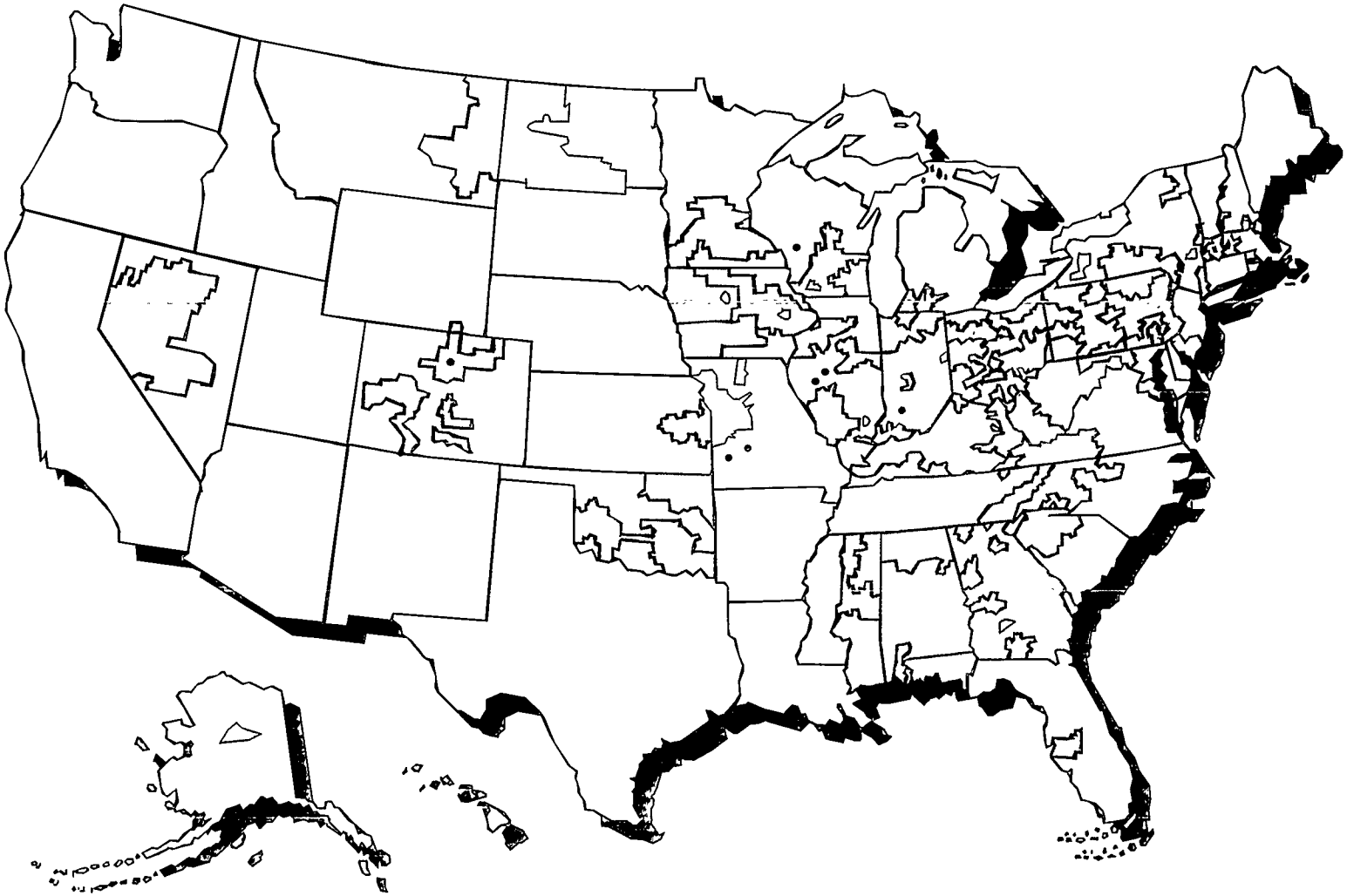
Current SO_2 emissions control technologies typically result in conversion of an air emission to an emission of a "solid" waste, in most cases a scrubber sludge which must be carefully handled and disposed of in sludge ponds. Estimates are that by 2010 approximately 4,320 acres per year would be required to dispose of flue gas desulfurization (FGD) 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.

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. The elements also are contained in the initial U.S. communication under the Framework Convention on Climate Change in September 1994.

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

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



increased efficiency of energy supply technologies. In more efficient systems, less carbon dioxide (CO_2) is produced per unit of power generated. Many clean coal technologies now being demonstrated are effective in reducing CO_2 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 CO_2 emissions by 17–27 percent. Clean coal technologies yet to be demonstrated, such as gasifier/fuel cell combinations and advanced turbines, could lower CO_2 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" CO_2 emissions; improvement of U.S. balance 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 SO_2 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.

Ensure Reliable, Secure Energy Services

The CCT Program is fostering the demonstration of a portfolio of advanced coal-based technologies which will meet the diverse requirements of the competitive marketplace for energy technologies well into the next century. These technologies make use of the most secure and abundant fossil energy resource base in the United States and will play a major role in ensuring reliability and security of energy sources at stable costs. The CCT Program addresses the diversity of the energy marketplace by demonstrating technologies in four market sectors:

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

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 $5.5 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 generators 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 advanced electric power generation systems or conventional power generation technology with environmental control devices. The Energy Information Administration forecasted 0.7 percent overall annual growth in electric utility generation between 1993 and 2010 while projecting growth in utility generation from coal at 0.6 percent annually. Increases in coal-fired generation are expected to come from a combination of increased utilization of existing generating capacity and additions of new capacity. The average utilization rate for existing coal-fired units is expected to increase from 63 percent in 1993 to

68 percent in 2010. Together, utilities, nonutilities, and cogenerators are expected to increase net coal-fired capacity by 14 gigawatts over the forecast period. There are, however, uncertainties which affect the projected need for new capacity, including the following:

- Considerable uncertainty exists about the projected savings from demand-side management and whether these savings will have a significant impact on reduction of power generation needs.
- Economic growth rates may be higher than projected. If efforts to continue to stimulate the economy are successful, the current integrated resource planning assumptions and lower growth projections may need to be revised again.
- The existing inventory of nuclear units, which accounts for about 20 percent of the electric power generation in the United States, starts to come up for relicensing in about 10 years. It is doubtful that life extension for all these nuclear units will take place. Further, a recent study by DOE indicated that several nuclear units may retire before their licenses come up for renewal. The Energy Information Agency is projecting a decrease of 14 billion kilowatt-hours in nuclear generation between 1993 and 2010.
- Utility industry restructuring and new institutional arrangements to enhance competitiveness in power marketing may tend to drive short-term considerations, which may lead to lower near-term rates for customers at the potential expense of long-term needs, such as system reliability and the desirability of long-term price stability. Further, the utility industry's approach to life extension, repowering, or replacement of aging fossil plants may be reexamined in light of a more competitive marketplace and the risk of "stranded capacity."

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 $4.81 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 5 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 (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

Exhibit 1-2
CCT Demonstration Projects, by Application Category

Application Category	Participant	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
	Clean Energy Partners Limited Partnership	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-MWe 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	SOx-NOx-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	Participant	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	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 Liquid Phase Conversion Company, L.P.	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

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 1996. Almost all NO_x control projects will complete testing by the end of 1995. Further, data from two of the NO_x control technologies being demonstrated by Southern Company Services, the tangentially fired and wall-fired boilers, were 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, 15 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.

There are five coal processing for clean fuels projects, valued at over $521 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 $1.12 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 or more 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.

Enhance Energy Productivity and United States Economy

The CCT Program strategy in pursuit of increased productivity and economic growth is to enhance the efficient use of technology and the United States' major energy resource, coal, in a cost-effective manner and thus, assuring reasonable and stable energy costs to individuals and energy intensive industries which compete in the global marketplace.

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 $7.14-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 an average of 29,000 direct and indirect jobs between 1995 and 1999, up to 2,000 permanent operating jobs, and 500 jobs in coal mining and related industries.

In addition to domestic opportunities, the international marketplace also 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 over the next 10 years could be as high as $750 billion. Of this, $200 billion could be U.S. content. If this level of penetration is achieved, the export of clean coal technologies could result in 200,000 high-quality U.S. jobs over this period. 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.

The Clean Coal Research, Development and Demonstration Program (referred to as the Clean Coal RD&D Program) implements Title XIII of Public Law 102-486 (Energy Policy Act of 1992) which states that DOE shall "conduct programs for research, development, demonstration, and commercial application in coal-based technologies." The Clean Coal RD&D program is designed to accelerate the progress of clean coal technologies from the laboratory to the marketplace and is focused on the development of new technologies that will help fill the energy needs of the post-2000 world. The current Clean Coal RD&D Program is balanced to deal with the continuum of near-term to long-term problems. The program consists of the CCT, Coal R&D, and the Advanced Research and Technology Development (AR&TD) Programs.

The CCT Program is showing, at commercial scale, that coal technologies can meet the most stringent current environmental standards as well as those projected for the next decade. The emphasis of the program has evolved from demonstrating technologies that lead to a reduction in acid rain emissions to those promising improved efficiency and environmental performance. The 66 percent level of cost sharing from nonfederal sources has provided a strong market orientation to these efforts.

The Coal R&D Program is focusing on the next round of expected tightening of emission standards after the year 2000 and consists of two components:

- *Advanced power systems* directed toward acceleration of the commercial realization of affordable high-efficiency, low-emissions, coal-fueled electricity generating technologies
- *Coal-base fuel systems* which are the focus of the development and commercial realization of clean, cost-effective coal processing technologies for production of coal-derived fuels, chemicals, and other products for the transportation, utility, commercial, and residential sectors

The specific R&D goals for the advanced power systems are outlined in Exhibit 1-3.

The R&D goal for the coal-based fuel system is to demonstrate, by the year 2010, advanced concepts for clean and safe production of coal-based transportation fuels, chemicals, and other products that can compete with petroleum-derived products, at a cost of less than $25 per barrel-of-oil equivalent in 1991 dollars.

The AR&TD component of the Clean Coal RD&D Program is directed to pursuit of applied research and technology transfer in critical enabling science and technology areas that crosscut multiple fossil energy technologies and include advanced materials research and coal bioprocessing research. Another element of AR&TD is university coal research which is focused on improving the knowledge base in fundamental and innovative coal science and technology research and on training fossil fuel scientists and engineers in relevant disciplines.

During 1994, 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.

Exhibit 1-3
R&D Goals of Advanced Power Systems

	2000	2005	2010	2015
Efficiency	42%	47%	55%	60%
SO_2, NO_x, particulates	33% of NSPS	25% of NSPS	10% of NSPS	10% of NSPS
CO_2 reduction	24%	32%	42%	47%
Cost of energy	10–20% lower			

(NSPS—New Source Performance Standards)

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 CO_2 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 SO_2 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 SO_2 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.

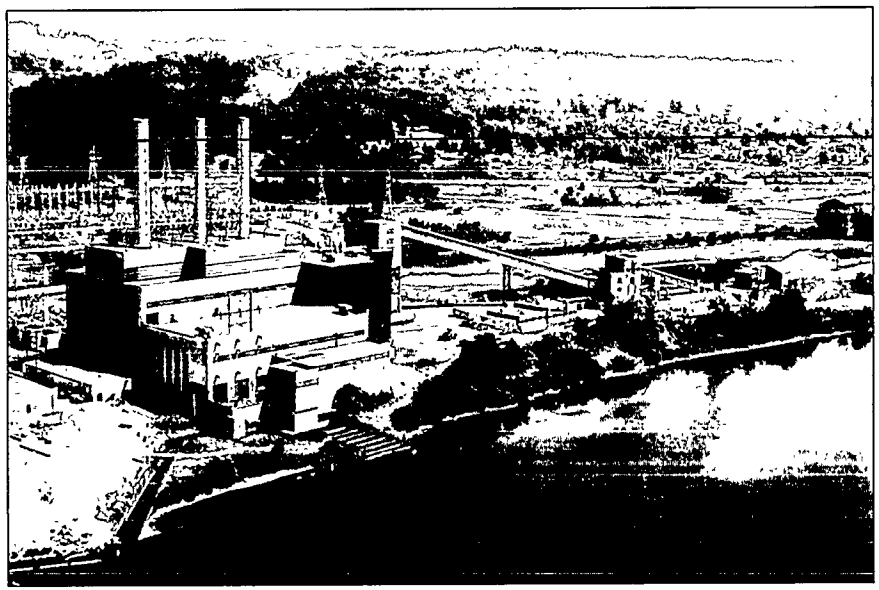
Fluidized-bed combustion can be either atmospheric (AFBC) or pressurized (PFBC). The atmospheric type operates at normal atmospheric pressure while the pressurized type operates at pressure 6–16 times higher than normal atmospheric pressure. The pressurized fluidized-bed boiler offers potentially higher 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 these earlier classifications 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 follow:

- 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 SO_2.
- 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.

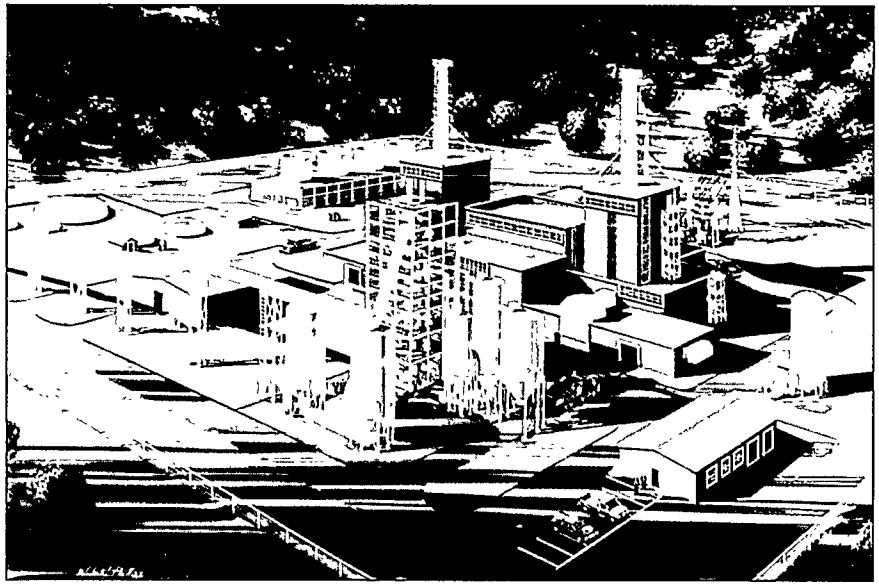


◄ The pressurized fluidized-bed technology is an advanced electric power generation technology which delivers improved combustion efficiency, and reduces SO_2 emissions by over 90% and NO_x emissions by 70%. The 70-MWe Tidd PFBC project, shown here, is demonstrating this promising technology.

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 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



◄ Depicted is an artist's concept of the 99-MWe (net) integrated gasification combined-cycle unit being built at Sierra Pacific Power Company's Tracy Station. Construction will start in 1995 and operations in 1997.

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, 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.

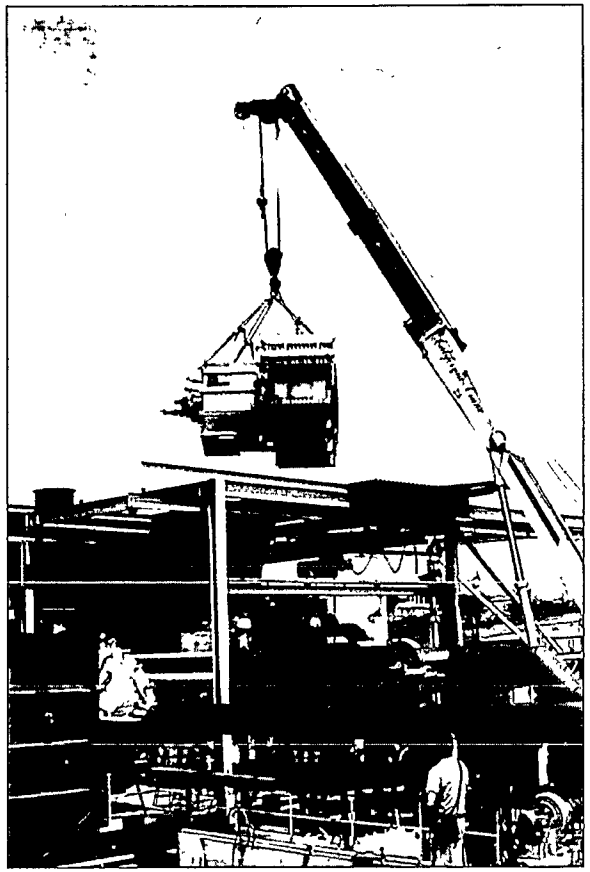
Indirectly Fired Cycle. An indirectly fired closed-cycle gas turbine uses a nonreacting gas (such as helium) as a working fluid. The gaseous working fluid is compressed, heated by means of a high-temperature air heater, expanded in a turbine, and cooled in a waste heat exchanger. Because the closed cycle 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



▲ The full-size precombustion module is being mounted into place at TRW's San Juan Capistrano test facility for design verification testing of the slagging combustor to be used in the 50-MWe Healy Clean Coal Project planned for Alaska.

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 has the potential to reduce sulfur emissions by 90percent.

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.

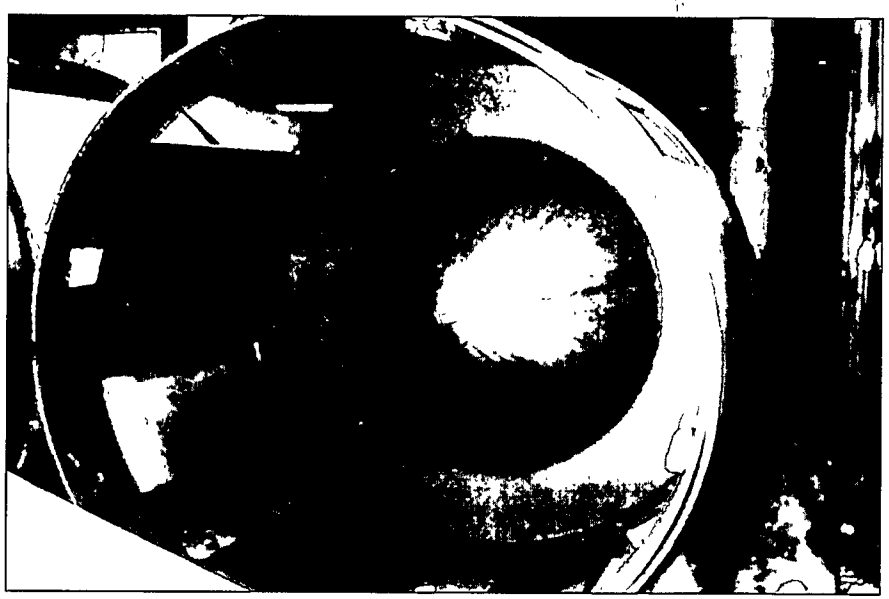
Environmental Control Devices

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.

Technologies that 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 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 NO_x control technology being demonstrated by Southern Company Services at Plant Hammond consists of advanced over-fire air, second generation low-NO_x burners, and an advanced low-NO_x digital control system. NO_x reductions of approximately 69% have been achieved. The demonstration is scheduled for completion in the spring of 1995.

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 is 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.

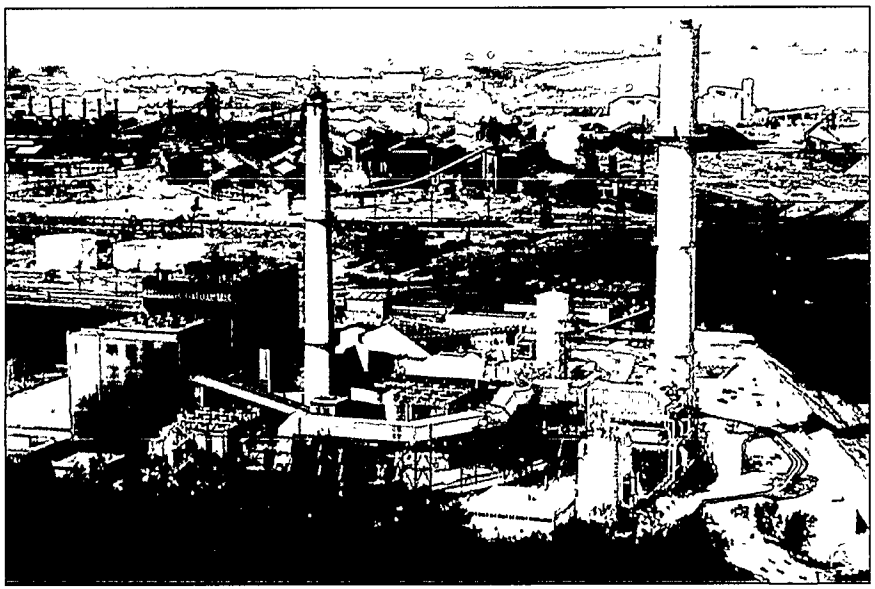
SO_2 Control Technology. Advanced combustion or postcombustion flue gas cleaning techniques are approaches for removal of sulfur and particulates from flue gas. Examples of advanced combustion techniques are discussed in the above subsection, Advanced Electric Power Generation. These techniques involve 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

➤ 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 commercial gypsum by-product. In the background is Bethlehem Steel's Burns Harbor Plant, the site of the blast furnace granulated-coal injection system demonstration project.



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.

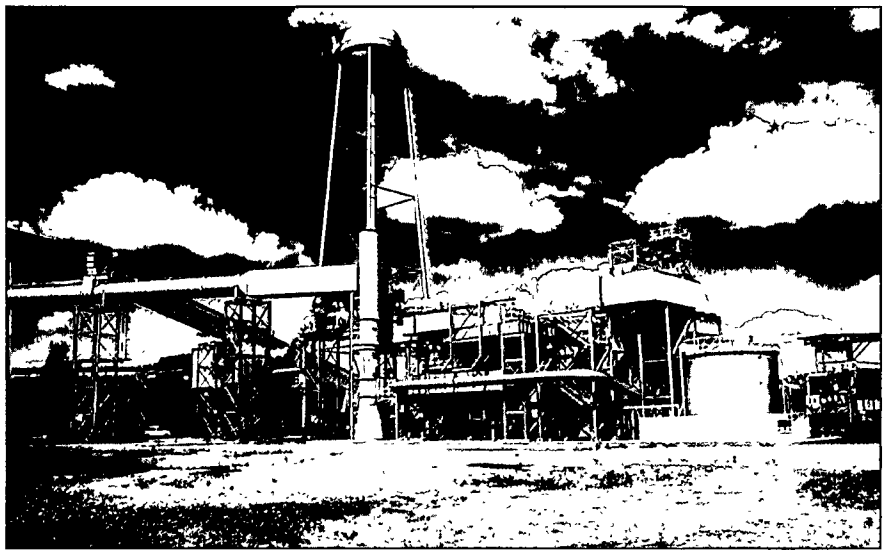
Depending upon process selection, advanced postcombustion cleaning technologies offer several advantages over the old conventional scrubber systems, including the following:

- 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 SNOX™ demonstration at Ohio Edison's Niles Station Unit No. 2 achieved SO_2 removal efficiency in excess of 95% and NO_x reduction effectiveness averaging 94%. The demonstration was completed in 1994, and Ohio Edison is retaining the SNOX™ technology as part of its environmental control system.



- 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.

➤ The Rosebud SynCoal Partnership is demonstrating an advanced thermal coal conversion process for upgrading low-rank subbituminous and lignite coals. The 45-ton/hr unit is located in Colstrip, MT, and produces a product for utility and industrial use.

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.

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 the 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.

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

➤ The ENCOAL mild gasification plant near Gillette, WY, processes about 500 tons/day of coal and produces upgraded solid fuel for use in electric power generation and liquid product for use in industrial boilers.

2. Direct liquefaction, which is the conversion of the organic solid structures in coal directly into liquid fuels

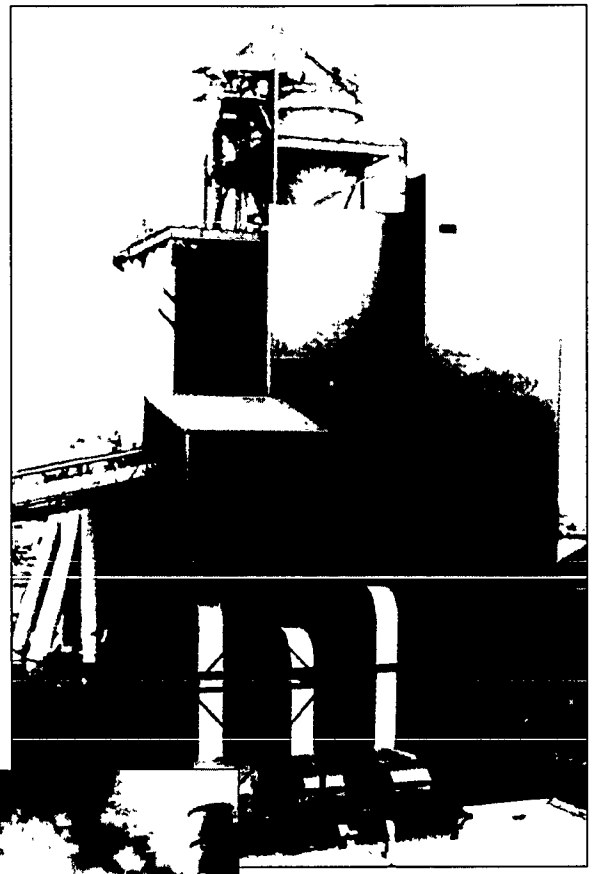
Liquefaction of coal involves the addition of hydrogen to coal by various techniques so that the fuel's ratio of hydrogen to carbon is increased to a level comparable to petroleum-based fuels.

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

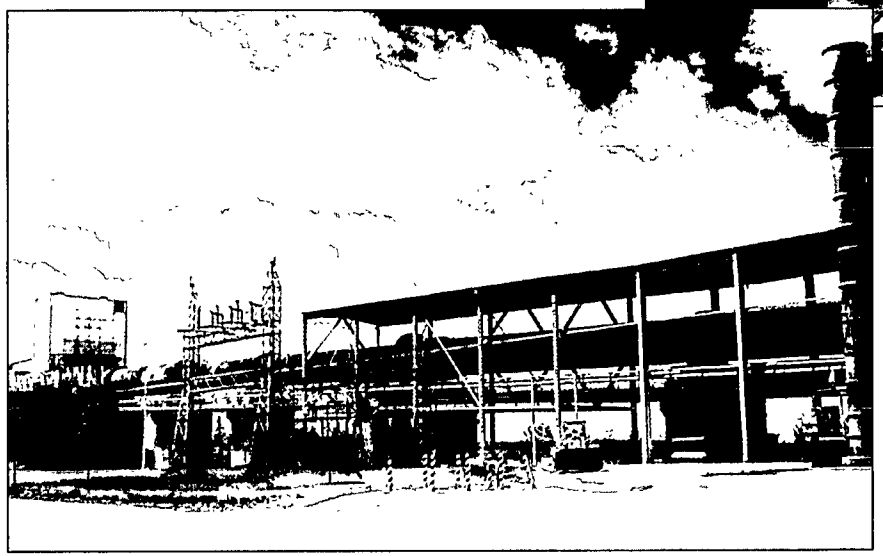
The potential advantages of direct liquefaction include relatively high thermal efficiency (in the range of 60–70 percent), high product yield, and the potential to make products such as high-quality gasoline. Principal disadvantages stem from the severe operating conditions (temperature and pressure) 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.

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.



▼►There are six industrial application projects totaling over $1.16 billion. Shown on the right is the recently completed Bethlehem Steel Corporation's facility to demonstrate the injection of granulated coal directly into two blast furnaces at Burns Harbor, IN. Below is the Passamaquoddy Tribe's cement kiln flue gas scrubber project which successfully demonstrated greater than 90% sulfur reduction and the production of usable by-products.



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 $7.14 billion and located in 21 states, are either already complete or moving forward. Government funding for the projects is approximately $2.42 billion; the private sector is providing more than $4.72 billion, or 66 percent of the projects' total value—far in excess of the congressionally mandated minimum of 50 percent.

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 $5.375 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, the President 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, and Public Law 103-332, enacted September 30, 1994, 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 when 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 1994, there were 8 CCT-I projects in the CCT Program: 4 were completed; 3 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 SO_2 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 1994, 12 CCT-II projects remained in the CCT Program: 5 were completed; 4 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 SO_2 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, 1994, all 13 projects remained in the CCT Program: 4 were completed; 3 were in operation; 2 were in construction; and 4 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 SO_2 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, 1994, 3 were in construction, and the remaining 4 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

Exhibit 2-1
CCT Program Selection Process Summary

Solicitation	PON Issued	Proposals Submitted	Projects Selected	Projects in CCT Program as of December 31, 1994
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
		211	60	45

Exhibit 2-2
Clean Coal Technology Demonstration Projects, by Solicitation

Project and Participant	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 Codorus, 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 Liquid Phase Conversion Company, L.P.)	Kingsport, TN
10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.)	West Paducah, KY

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

Project and Participant	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)	Newburgh, IN
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)	Central City and Springdale, PA Richmond, IN Ashtabula, OH
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)	To be determined
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)	Vineyard, UT
Clean Energy Demonstration Project (Clean Energy Partners Limited Partnership)	Eastern U.S.
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

facilities. In response to the solicitation, DOE received proposals for 24 projects and selected 5 projects. At year-end 1994, 4 CCT-V projects were in design and 1 was in negotiations. Selected projects included 4 demonstrating advanced electric power generation and 1, an industrial application.

The locations 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.

Next Steps

In November 1994, DOE solicited statements of interest in commercial projects employing CCTs in countries projected to have significant growth in greenhouse gas emissions. Submittals were due no later than January 13, 1995. DOE's report to Congress on the results of this informational solicitation will be issued by April 15, 1995. This report also will identify the extent to which various types of federal incentives would accelerate the commercial availability of CCTs in an international context.

This informational solicitation was issued pursuant to Conference Report 103-740 to accompany the Department of the Interior and Related Agencies Appropriations Act for FY 1995 (Public Law 103-332) and the guidance contained in the corresponding Senate and House Reports 103-294 and 103-551, respectively. The solicitation was conducted, as requested by the congressional guidance, so that Congress may have the information it requires to consider the technical, economic, and environmental aspects of various incentives to support CCTs, and their merits for potential future support.

Respondents to this informational solicitation were asked to propose an international (nondomestic) project that would employ at least one CCT and that, at a minimum, has the following characteristics:

1. Sponsorship by a U.S.-based company or consortium
2. Location in a developing country, or in a country making the transition from a centrally planned to a market economy, projected to have signficant growth in greenhouse gas emissions
3. Capability of reducing greenhouse gas emissions, particularly CO_2, as compared to technologies in common use in the proposed locale
4. Versatility with regard to effective usage of various globally available coal types and characteristics
5. Likelihood of utilization on a broad commercial scale subsequent to successful demonstration

Among the information that respondents were asked to provide were comments on or discussions of two key questions:

1. What are the greatest opportunities for commercializing U.S. CCTs abroad (short and long term)?
2. What role can DOE best play to facilitate commercialization of these technologies?

The need for the informational solicitation was based partly on the findings and recommendations of two reports issued in 1994. In February 1994, the National Coal Council released the results of its study for the Secretary of Energy of future directions for the CCT Program. In its report, *Clean Coal Technology for Sustainable Development,* the National Coal Council recommended that

1. The Secretary of Energy not engage in any further solicitations under the existing CCT Program. Where unused funds exist, the continuation of operating demonstrations should be pursued as a means of facilitating commercial deployment through expanded operating experience.
2. The Secretary of Energy promote the role of CCTs in the environmental technology programs of the Administration; that CCTs can improve the global environment as well as prevent pollution.
3. The Secretary of Energy establish a new Federal Clean Coal Technology Incentive Program of approximately $1.5 billion over 15 years to stimulate commercial deployment.
4. The Secretary of Energy ensure that future governmental policy continues to be monitored from the standpoint of the competitive position of and the ability to deploy CCTs.

The second report, *Clean Coal Technology Program Completing the Mission,* was issued by DOE in May 1994. It contains DOE's response to a congressional request that the Secretary of Energy report on available funds appropriated but not used in

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

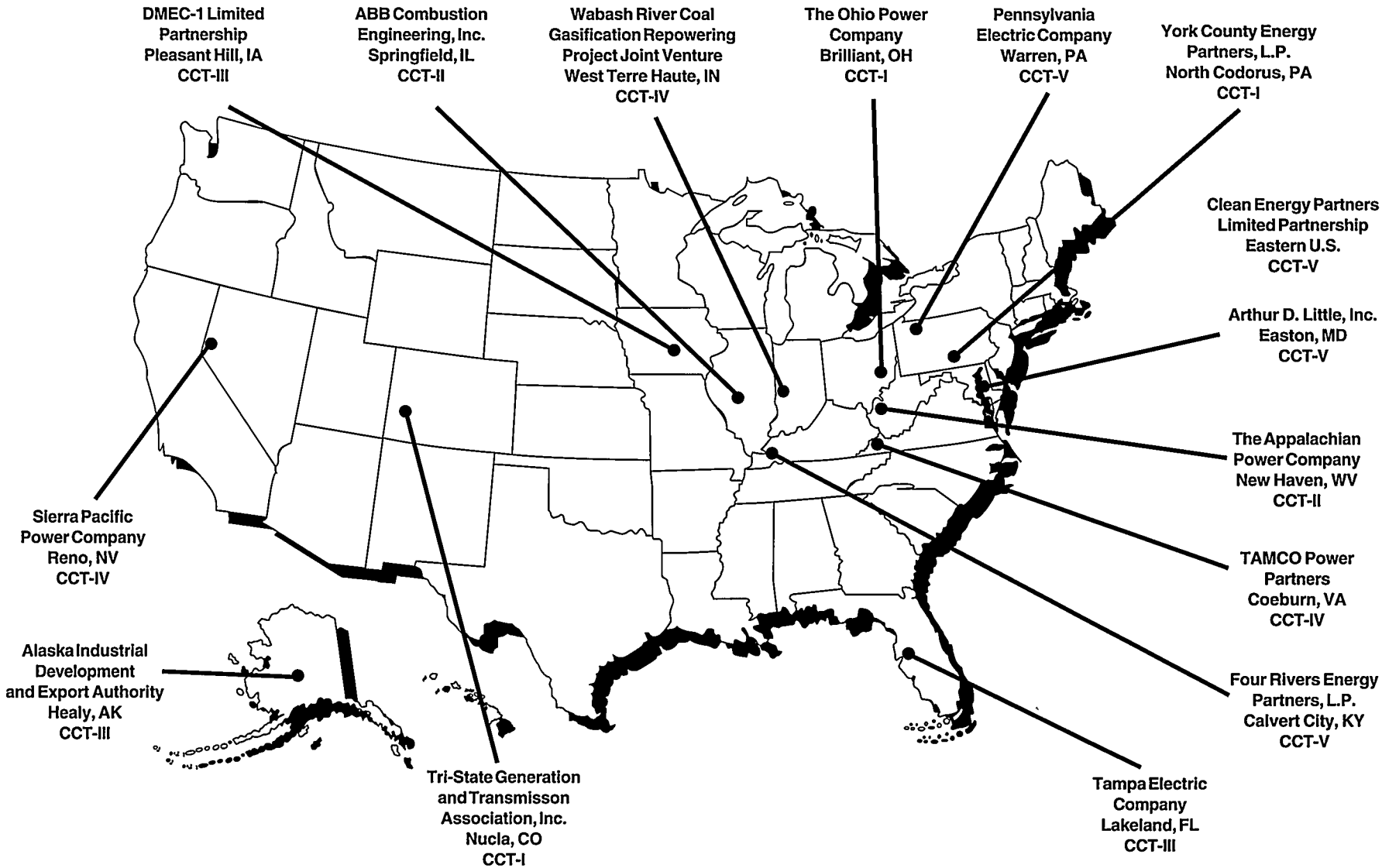


Exhibit 2-4
Geographic Locations of CCT Projects—Environmental Control Devices

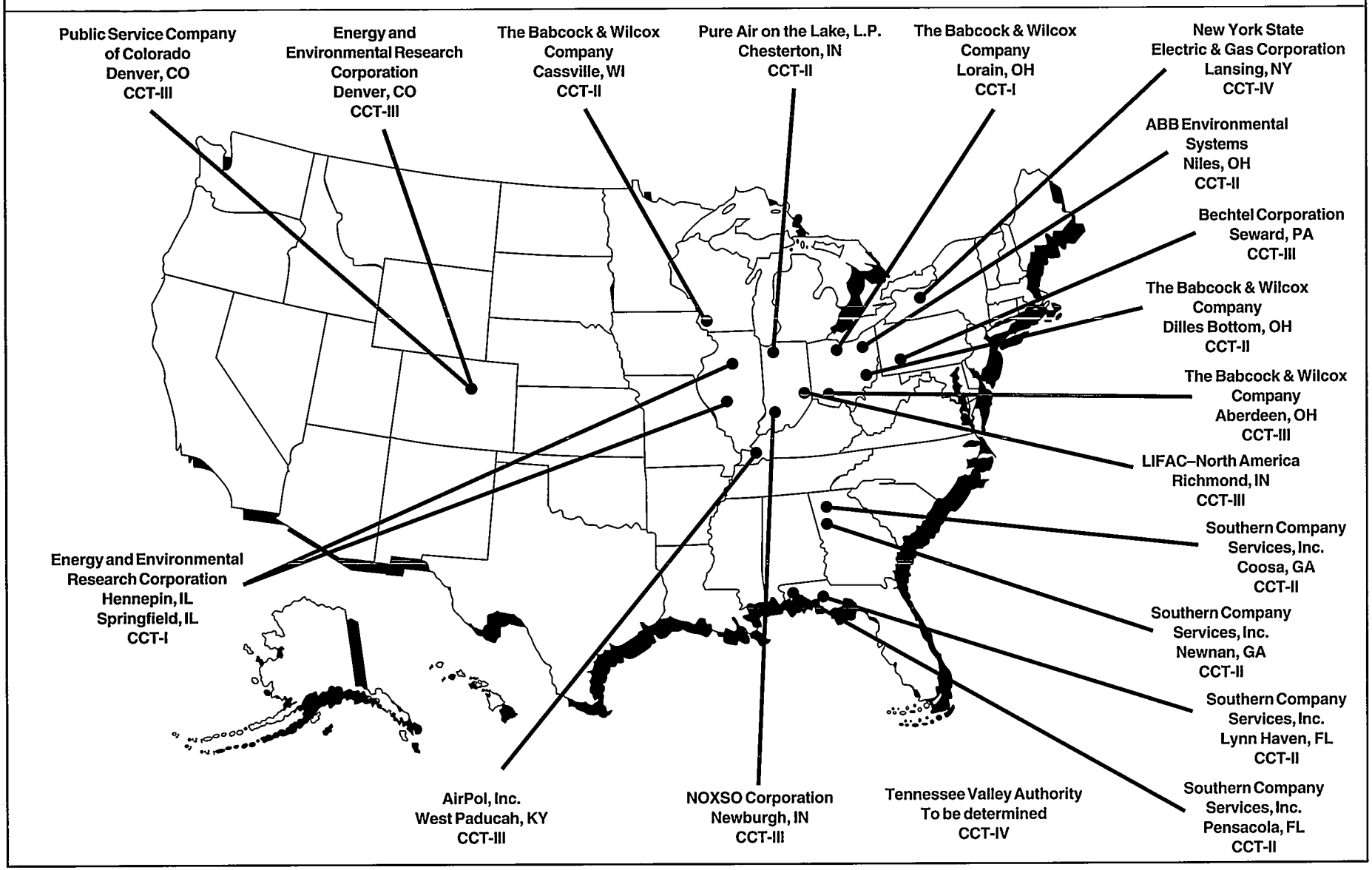


Exhibit 2-5
Geographic Locations of CCT Projects—Coal Processing for Clean Fuels

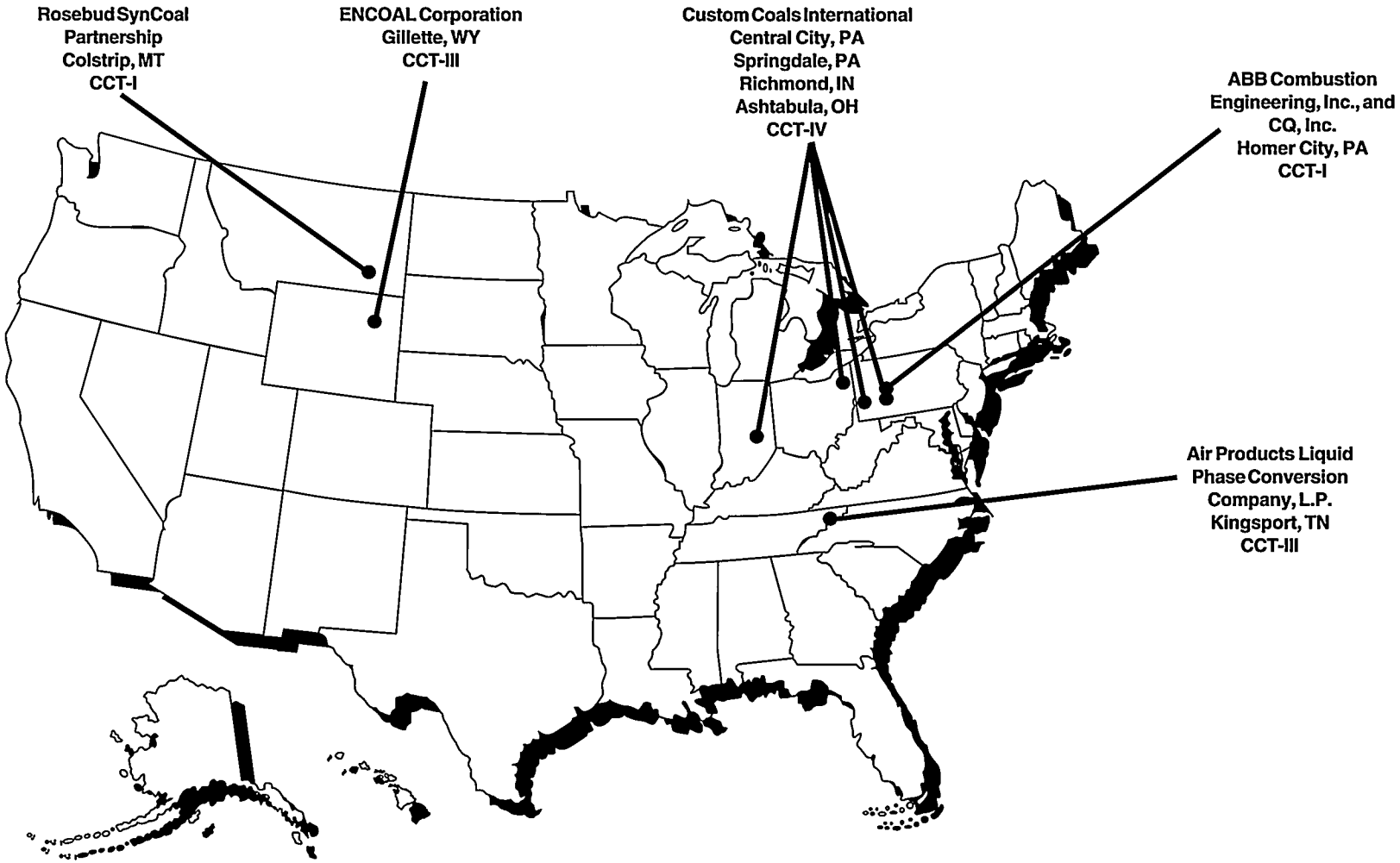
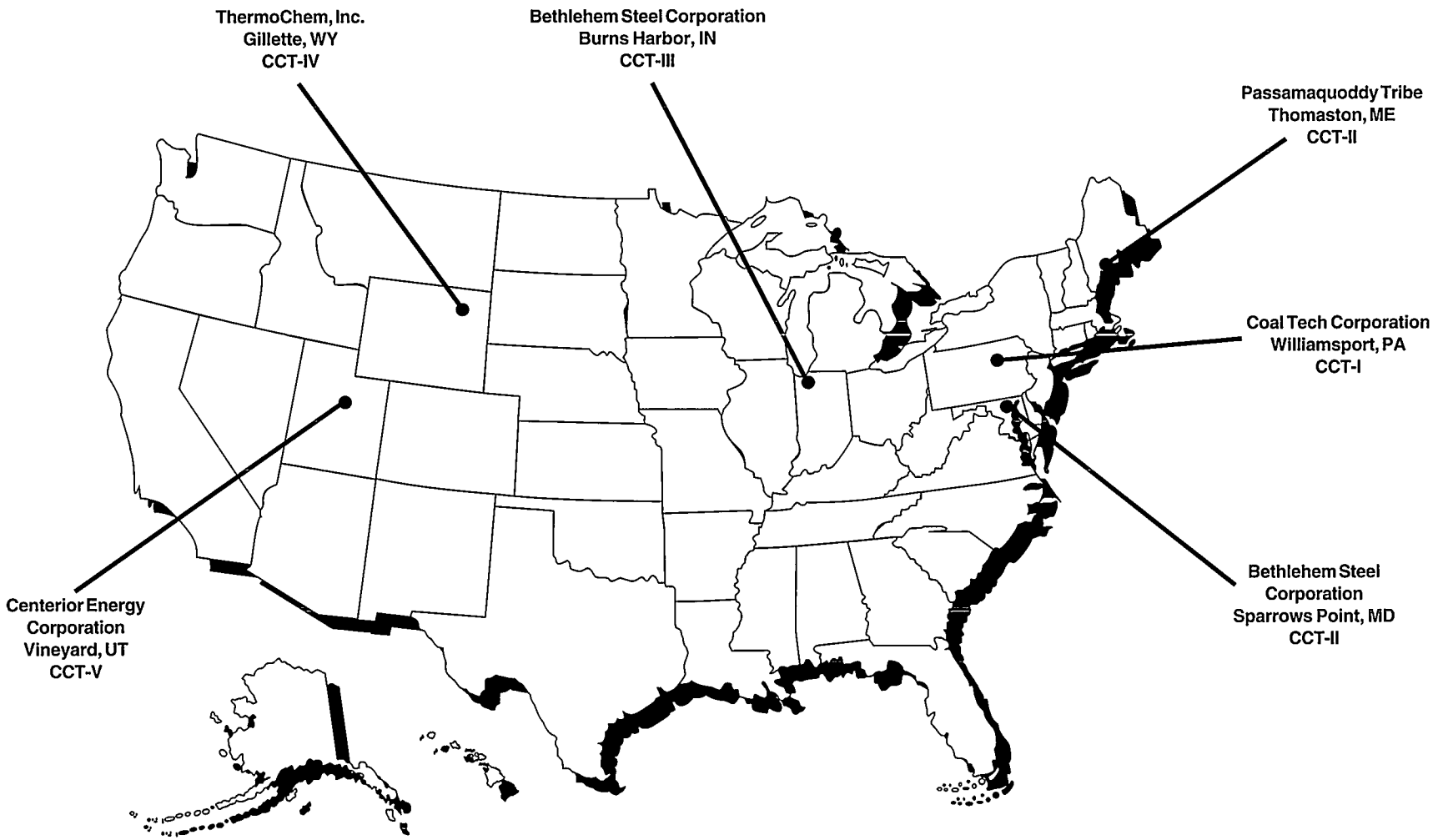


Exhibit 2-6
Geographic Locations of CCT Projects—Industrial Applications



CCT-I–V. DOE found that "an expansion of the current demonstration program in the form of an additional round of competition is not recommended." However, the report conjectured a likelihood that, by virtue of possible termination of one or two CCT projects prior to completion, "$150 million would be available both to fund new initiatives and provide program direction in the out years." Thus, DOE recommended "that Congress initially establish an International Technology Transfer Program."

In response to these proposals and recommendations, Senate Report 103-294 explained that "the highest priority for this program is to complete the existing projects as promptly as possible, but with reasonable assurance that sufficient data are generated to support subsequent commercialization activity." The report added: "The Committee does, however, support efforts by DOE in promoting exports of CCTs, particularly to countries experiencing rapid economic development. . . . Accordingly, DOE is directed to make the dissemination of CCTs overseas an integral part of its policy to reduce greenhouse gas emissions in developing countries." Further, the report directed DOE to conduct the informational solicitation.

In early 1994, simultaneously with the preparation of the two clean coal reports discussed above, the CCT Program undertook an effort to outline and document the many "lessons learned" in shaping and implementing this highly successful program. The report, *The Clean Coal Technology Program Lessons Learned,* published in July 1994, documents the knowledge acquired over the course of the program through the completion of the five planned solicitations. The report's preparation was based on the belief that it is of mutual advantage to the government and the private sector to identify those factors thought to contribute to the program's success and to point out where pitfalls were encountered and corrective actions taken.

To ensure that the document incorporated the private sector's perspective, project participants (i.e., cooperating organizations other than federal government agencies) were asked to review and comment on a draft of the report. Responses were received from many of the industrial participants leading demonstration projects funded under the program as well as from participating utilities and state offices. Their comments and additional insights were incorporated into the body of the report. Further, portions of these responses were extracted and used as quotes in the margins of the report to highlight particularly important points from the participants' view.

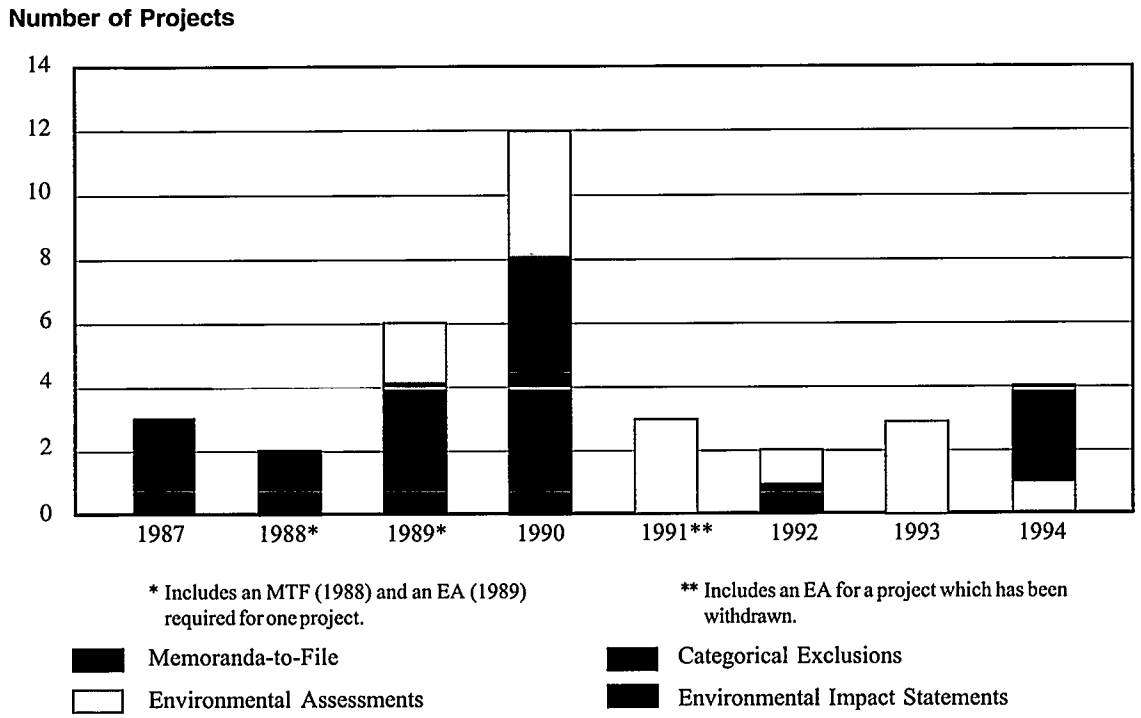
The lessons-learned effort was aimed, in part, at providing a framework for considering possible next steps for the CCT Program so that future efforts may benefit from lessons learned and continue to build on past successes. Additionally, the lessons-learned report (1) explains the CCT Program as a model for successful joint government/industry partnership for selecting and demonstrating technologies that have promise for adaptation to the energy marketplace, (2) sets forth the process by which the program has been implemented and the changes that have been made to improve that process, (3) outlines efforts employed to inform potential users and other interested parties about the technologies being developed, and (4) explains some of the questions which must be considered in determining if the CCT Program model can be applied to other programs.

During implementation of the CCT Program, many precedent-setting actions were taken and many innovations were used by both the public and private sectors to overcome procedural problems, create new management systems and controls, and move toward accomplishing shared objectives. The result has been the development of a model program for government/industry cooperation in technology development. A sound foundation has been established for application of CCT Program principles to other programs with the development of the tools for execution, a model cooperative agreement, control documents, an environmental compliance approach, and attendant procedures. Although some of the provisions cannot be adopted verbatim by other programs, the precepts are transferable and concepts underlying the CCT Program can be molded to fit. The experience developed in dealing with complex business arrangements of CCT projects is a significant asset that has contributed greatly to the CCT Program's success—an asset that can be used advantageously in framing the next steps for the CCT Program.

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)preparation in 1989 of a programmatic

Exhibit 2-7
NEPA Reviews Completed



environmental impact statement (PEIS); (2)preparation of preselection, project-specific environmental reviews; and (3)preparation of postselection, site-specific NEPA 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 1994 to complete NEPA reviews of projects in the CCT Program. By year-end 1994, NEPA reviews were completed for 34 projects (two NEPA reviews were completed for one project, Enhancing the Use of Coals by Gas Reburning and Sorbent Injection—an MTF was completed for the Hennepin site and an EA for the Lakeside site). From 1987 through 1994, NEPA requirements were satisfied with a CX for 1 project, MTFs for 17 projects, EAs for 14 projects (including a project which was subsequently withdrawn from the CCT Program), and EISs for 3 proposed projects.

For each project cofunded by DOE under the CCT Program, the participant 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 significantly 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 promulgated regulations that ensure compliance with the act.

Compliance with NEPA

In November 1989, a PEIS was distributed for the entire CCT Program. This PEIS addressed issues such as potential 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 technologies 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 participants 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 Exclusions

"Subpart D—Typical Classes of Actions" of the 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 (NEPA review was completed August 13, 1992).

Memoranda-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's 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.

If an agency determines, on the basis of an EA, that it 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.

Exhibit 2-8
Memoranda-to-File Completed

Project and Participant	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.; now Tri-State Generation and Transmission 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
SOx-NOx-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-MWe 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

CEQ and DOE regulations also provide for notification of the public that a FONSI has been issued. Also, DOE provides copies of the EA and FONSI to the public on request.

Exhibit 2-9 lists the 14 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/SO_2 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. In 1994, DOE issued records of decision on the EISs prepared for three CCT projects (see Exhibit 2-10).

NEPA Actions in Progress

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

Environmental Monitoring

Participants of CCT projects are required to develop and implement an environmental monitoring plan (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
- 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

Exhibit 2-9
Environmental Assessments Completed

Project and Participant	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	
Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International)	2/14/94
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 Participant	Completed
CCT-III	
Healy Clean Coal Project (Alaska Industrial Development and Export Authority)	3/10/94
Tampa Electric Company Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	8/17/94
CCT-IV	
Piñon Pine IGCC Power Project (Sierra Pacific Power Company)	11/8/94

- 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 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. A total of 25 projects 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. Exhibit 2-13 lists the 25 projects which provide for HAPs monitoring. This list includes projects selected in CCT-V.

HAPs monitoring has been completed for 10 projects. The objectives to improve the quality of HAPs data being gathered and to monitor a broader range of plant configurations and emissions control equipment have been met.

The CCT Program is coordinating with organizations such as the Electric Power Research Institute and the Ohio Coal Development Office in activities focused on HAPs monitoring and analysis. A parallel effort under DOE's Coal R&D Program is being undertaken to collect HAPs data from 16 coal-fired power plants representing a cross section of technical

configurations; three of these plants are sites of CCT projects. Data collected at nine of the plants have been 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.

Exhibit 2-11
NEPA Reviews in Progress

Project and Participant	Status
CCT-I	
York County Energy Partners Cogeneration Project (York County Energy Partners, L.P.)	EIS projected for 5/95
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 Liquid Phase Conversion Company, L.P.)	EA projected for 4/95
PCFB Demonstration Project (DMEC-1 Limited Partnership)	EIS projected for 3/96
Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System (NOXSO Corporation)	EA projected for 6/95
CCT-IV	
Toms Creek IGCC Demonstration Project (TAMCO Power Partners)	EIS projected for 12/96
Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal (ThermoChem, Inc.)	EA projected for 5/95
CCT-V	
Four Rivers Energy Modernization Project (Four Rivers Energy Partners, L.P.)	EA projected for 9/95
Clean Energy Demonstration Project (Clean Energy Partners Limited Partnership)	Projected for 6/96 (action to be determined)
Coal Diesel Combined-Cycle Project (Arthur D. Little, Inc.)	EA projected for 10/95
Warren Station Externally Fired Combined-Cycle Demonstration Project (Pennsylvania Electric Company)	EA projected for 4/95
Clean Power from Integrated Coal/Ore Reduction (COREX®) (Centerior Energy Corporation)	To be determined

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

Project and Participant	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 (Tri-State Generation and Transmission 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 5/95
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
SOx-NOx-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 Participant	Status
CCT-III	
Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process (Air Products Liquid Phase Conversion Company, L.P.)	Projected 1/96
10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.)	Completed 10/2/92
Healy Clean Coal Project (Alaska Industrial Development and Export Authority)	Projected 4/95
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)	Completed 12/23//94
PCFB Demonstration Project (DMEC-1 Limited Partnership)	Projected 5/96
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)	Projected 6/95
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 2/95
CCT-IV	
Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International)	Projected 3/95
Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Corporation)	Completed 12/1/94
Piñon Pine IGCC Power Project (Sierra Pacific Power Company)	Projected 6/95
Toms Creek IGCC Demonstration Project (TAMCO Power Partners)	Projected 6/95
Micronized Coal Reburning Demonstration for NO_x Control on a 175-MWe Wall-Fired Unit (Tennessee Valley Authority)	To be determined
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 2-12 (continued)
Status of Environmental Monitoring Plans for CCT Projects

Project and Participant	Status
CCT-V	
Four Rivers Energy Modernization Project (Four Rivers Energy Partners, L.P.)	Projected 2/96
Clean Energy Demonstration Project (Clean Energy Partners Limited Partnership)	Projected 6/96
Coal Diesel Combined-Cycle Project (Arthur D. Little, Inc.)	Projected 10/95
Warren Station Externally Fired Combined-Cycle Demonstration Project (Pennsylvania Electric Company)	Projected 2/95
Clean Power from Integrated Coal/Ore Reduction (COREX®) (Centerior Energy Corporation)	To be determined

Exhibit 2-13
CCT Projects Monitoring Hazardous Air Pollutants

Application Category	Participant	Project	Solicitation
Advanced Electric Power Generation	Alaska Industrial Development and Export Authority	Healy Clean Coal Project	CCT-III
	Arthur D. Little, Inc.	Coal Diesel Combined-Cycle Project	CCT-V
	Clean Energy Partners Limited Partnership	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
	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-MWe 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	SOx-NOx-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
	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
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	Centerior Energy Corporation	Clean Power from Integrated Coal/Ore Reduction (COREX®)	CCT-V
	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. As of December 31, 1994, the program consists of 45 active or completed projects, including one project selected under the fifth solicitation that remains in negotiation.

The five solicitations have resulted in a combined commitment by the federal government and the private sector of about $7.14 billion. The U.S. Department of Energy's (DOE's) cost share for these projects is $2.42 billion, or approximately 34 percent of the total. The project participants (i.e., the non-federal-government participants) are providing the remaining $4.72 billion.

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 participant has primary responsibility for the project. The federal government monitors project activities, provides technical advice, assesses progress by periodically reviewing project performance with the participant, 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, 103-138, and 103-332 provided the final $1.2billion 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. Additional activities funded by CCT Program appropriations are the Small Business Innovative Research (SBIR) Program, the Small Business Technology Transfer Program (STTR), 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 STTR Program implements the Small Business Technology Transfer Act of 1992 that establishes a pilot program and funding for small business concerns performing cooperative research and development efforts.

The program direction budget provides for the management and administrative costs of the program

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

Appropriation Enacted	Subprogram	Appropriated to DOE[a]	SBIR & STTR Budgets[b]	Program Direction Budget	Projects Budget[d]
P.L. 99-190	CCT-I	397,600	4,902	23,467	369,231
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	8,988	25,000	566,012
P.L. 101-121[c]	CCT-V	600,000	12,208	25,000	562,792
Total		2,747,595	39,785	128,527	2,579,283

[a] 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 (SBIR) and Small Business Technology Transfer Program (STTR).

[c] P.L. 101-121 was revised by P.L. 101-512, 102-154, 102-381, 103-138, and 103-332.

[d] Project budgets do not appear to add due to rounding.

and includes federal employees' salaries, benefits and travel, site support services, and services provided by national laboratories and private firms.

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 FY1986, when the program was initiated, through FY1997, 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. Funds can be transferred between subprogram budgets to meet project and program needs.

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 obligate 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 participant for use in performing tasks as defined in the cooperative agreement.
- **Costs.** A request for payment submitted by the project participant 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.

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

Fiscal Year	1986–87	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Total[d]
Adjusted Appropriations[a]												
P.L. 99-190	248,500	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	18,000	100,000	32,000	600,000
P.L. 101-121[b]						100,000	0	125,000	19,121	100,000	255,879	600,000
Total	248,500	199,100	190,000	554,000	390,995	415,000	0	225,000	37,121	200,000	287,879	2,747,595
Subprogram Budgets												
CCT-I Projects	241,958	145,273							(18,000)			369,231
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	98,450	17,622	97,850	31,152	566,012
CCT-V Projects						74,062	0	123,063	18,719	97,850	249,098	562,792
Projects Subtotal	241,958	176,367	173,800	524,809	361,420	385,125	0	221,513	18,341	195,700	280,250	2,579,283
Program Direction	3,479	20,500	14,000	22,548	25,000	25,000			18,000			128,527
Fossil Energy Subtotal	245,437	196,867	187,800	547,357	386,420	410,125	0	221,513	36,341	195,700	280,250	2,707,810
SBIR & STTR[c]	3,063	2,233	2,200	6,643	4,575	4,875	0	3,487	779	4,300	7,629	39,785
DOE Total[d]	248,500	199,100	190,000	554,000	390,995	415,000	0	225,000	37,121	200,000	287,879	2,747,595

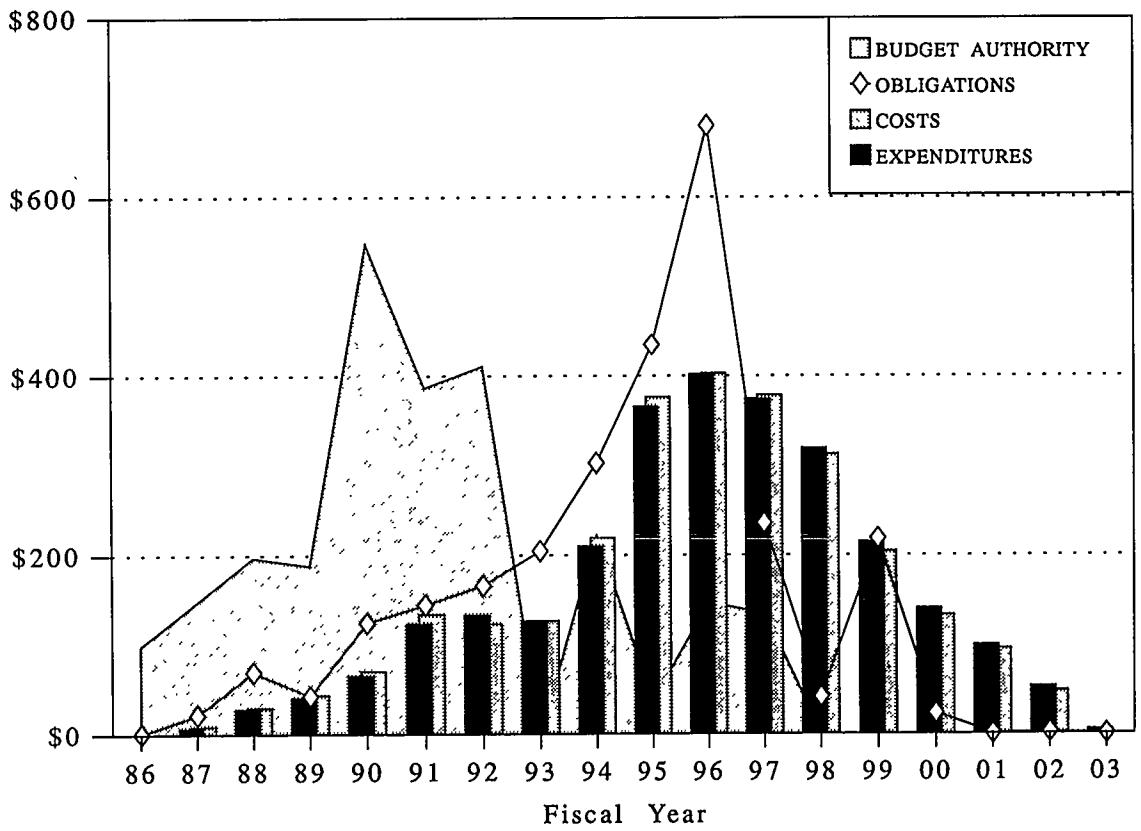
[a] Shown are appropriations less amounts sequestered under the Gramm-Rudman-Hollings Deficit Reduction Act.

[b] Shown is the fiscal year apportionment schedule of P.L. 101-121 as revised by P.L. 101-512, 102-154, 102-381, 103-138, and 103-332.

[c] Small Business Innovative Research Program (SBIR) and Small Business Technology Transfer Program (STTR).

[d] Totals do not appear to add due to rounding.

Exhibit 3-3
CCT Financial Projections as of December 31, 1994
(Dollars in Millions)



- **Expenditures.** Expenditures represent payment amounts to the project participant from checks drawn upon the U.S. Treasury. Expenditures directly affect the government's cash flow.

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 FY1986 through FY1994 and DOE estimates for FY1995 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, 1994, is presented by subprogram in Exhibit 3-4. SBIR and STTR monies

Exhibit 3-4
Financial Status of the CCT Program as of December 31, 1994
(Dollars in Thousands)

Subprogram	Appropriations Allocated to Subprograms[b]	Apportioned to Date	Committed to Date	Obligated to Date	Cost to Date
CCT-I	369,231	369,231	259,947	181,432	174,070
CCT-II	535,704	535,704	471,170	172,317	153,007
CCT-III	545,544	545,544	589,951	371,486	187,078
CCT-IV	566,012	437,010	554,317	264,119	192,076
CCT-V	562,792	215,844	567,813	22,140	3,563
Projects Subtotal	2,579,283	2,103,333	2,443,198	1,011,494	709,794
SBIR & STTR[a]	39,785	27,856	38,505	27,856	27,856
Program Direction	128,527	128,527	128,527	109,807	104,880
Total	2,747,595	2,259,716	2,610,230	1,149,157	842,530

[a] Small Business Innovative Research Program (SBIR) and Small Business Technology Transfer Program (STTR).
[b] Sums do not appear to add due to rounding.

Apportionment Sequence		
FY	Annual	Cumulative
1986	99,400	99,400
1987	149,100	248,500
1988	199,100	447,600
1989	190,000	637,600
1990	554,000	1,191,600
1991	390,995	1,582,595
1992	415,000	1,997,595
1993	0	1,997,595
1994	225,000	2,222,595
1995	37,121	2,259,716
1996	200,000	2,459,716
1997	287,879	2,747,595

are included in this exhibit to account for all funding. Exhibit 3-4 also indicates the apportionment sequence as modified by Public Law 103-332. These values represent the amount of budget authority available for the CCT Program.

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 presentedin Exhibit 3-5.

Cost Sharing

A characteristic feature of the CCT Program is the cooperative funding agreement between the participant 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, An Act Making Appropriations for the Department of the Interior and Related Agencies for the Fiscal Year Ending September 30, 1986, and for Other Purposes. 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 participants is required in each phase in design, construction, and operation.

Exhibit 3-5
CCT Project Schedules and Funding, by Application Category

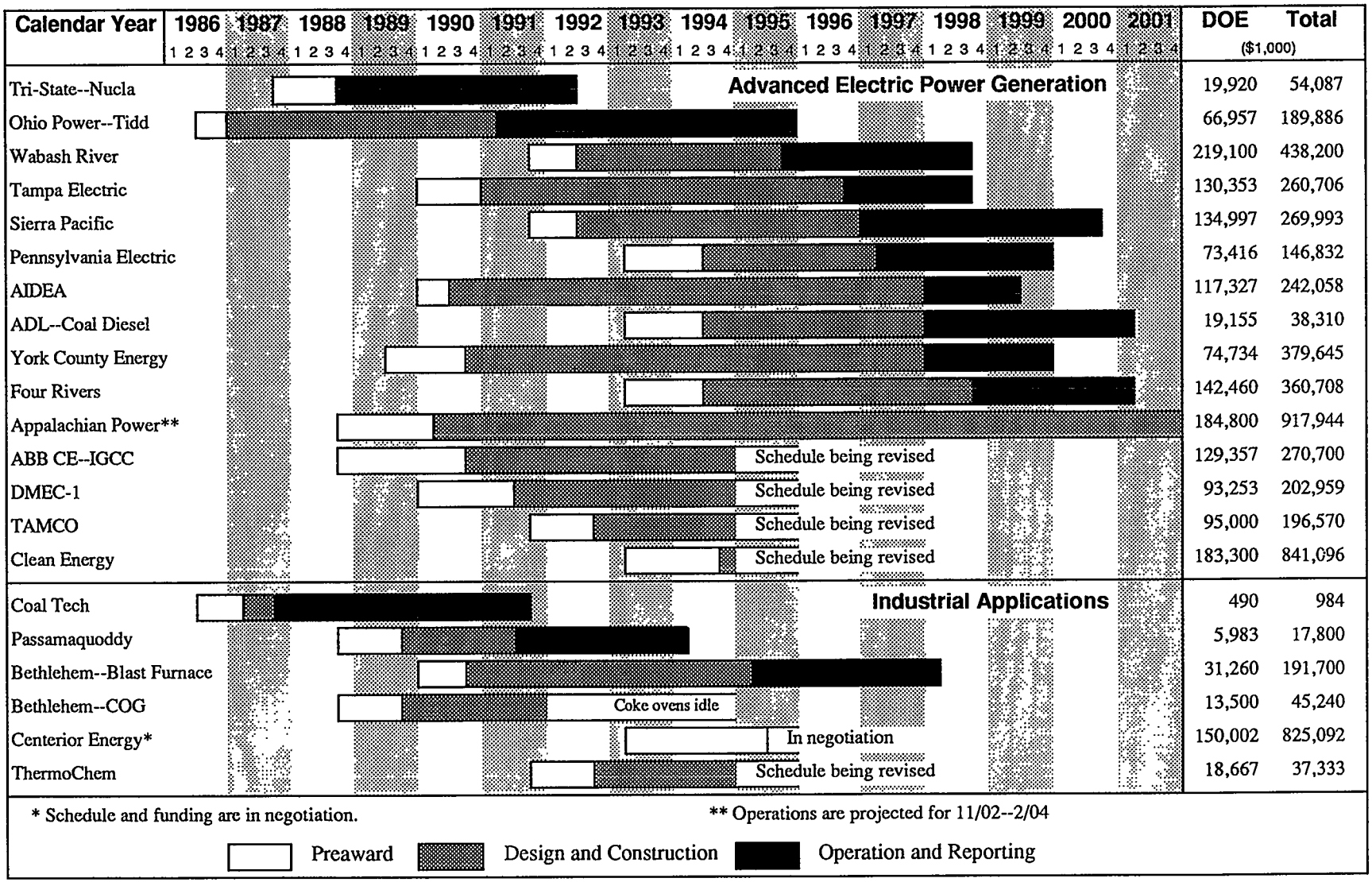
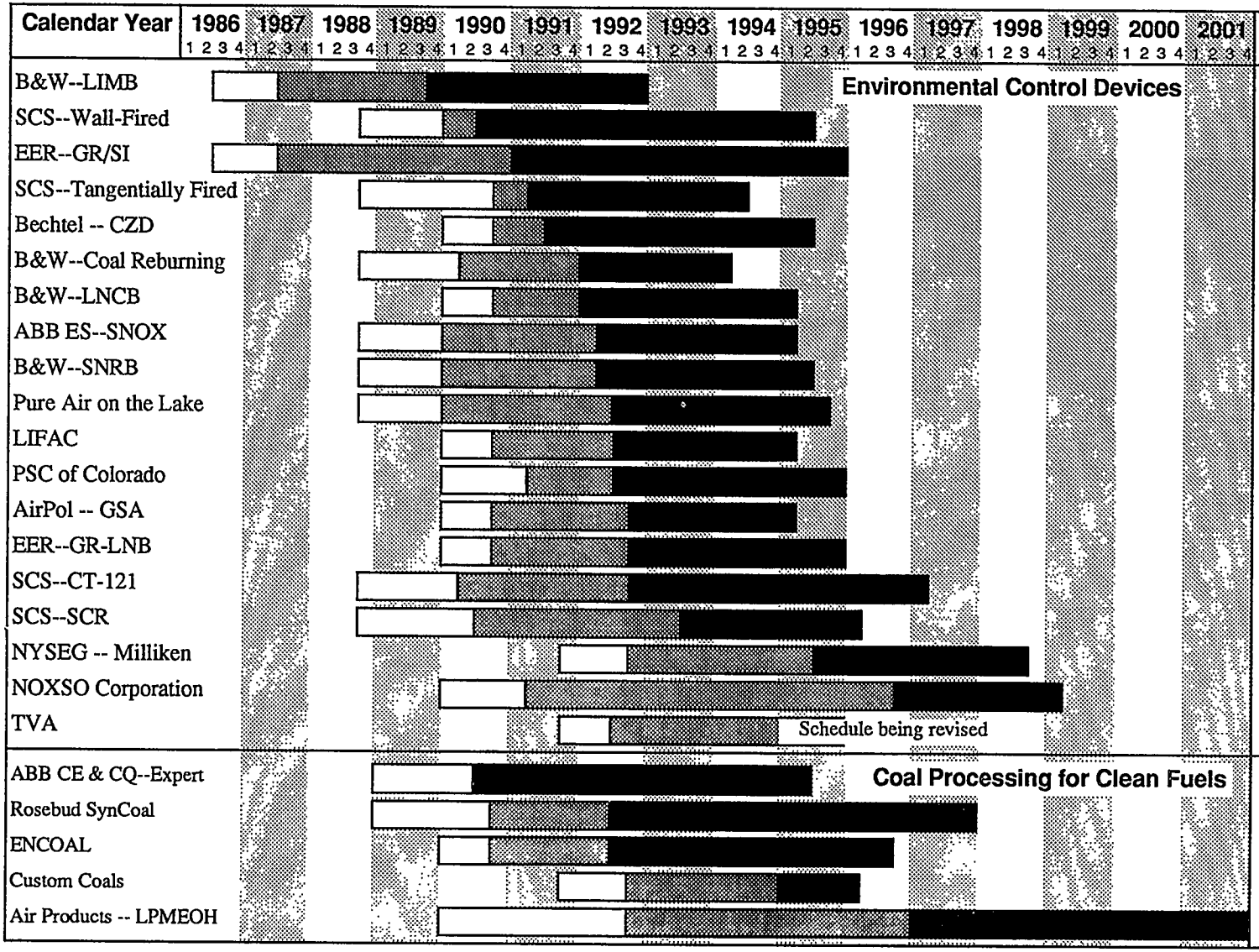


Exhibit 3-5 (continued)
CCT Project Schedules and Funding, by Application Category



	DOE ($1,000)	Total ($1,000)
Environmental Control Devices		
B&W--LIMB	7,597	19,405
SCS--Wall-Fired	6,554	14,711
EER--GR/SI	18,748	37,589
SCS--Tangentially Fired	4,440	9,153
Bechtel -- CZD	5,206	10,412
B&W--Coal Reburning	6,341	13,647
B&W--LNCB	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
LIFAC	10,637	21,394
PSC of Colorado	13,706	27,411
AirPol -- GSA	2,315	7,717
EER--GR-LNB	8,906	17,811
SCS--CT-121	21,085	43,075
SCS--SCR	9,407	23,230
NYSEG -- Milliken	45,000	158,608
NOXSO Corporation	33,506	67,181
TVA	3,515	7,330
Coal Processing for Clean Fuels		
ABB CE & CQ--Expert	10,864	21,746
Rosebud SynCoal	43,125	105,700
ENCOAL	45,332	90,664
Custom Coals	38,039	89,716
Air Products -- LPMEOH	92,708	213,700

Exhibit 3-6
Cost Sharing of Active CCT Projects
(Dollars in Thousands)

	Total Project Costs[a]	%	Cost Share DOE[b]	Cost Share Participants	Percent DOE	Percent Participants
Subprogram						
CCT-I	809,043	11	242,435	566,608	30	70
CCT-II	1,551,917	22	467,177	1,084,740	30	70
CCT-III	1,364,947	19	589,951	774,996	43	57
CCT-IV	1,197,750	17	554,317	643,434	46	54
CCT-V	2,212,037	31	567,813	1,644,224	26	74
Total	7,135,695	100	2,421,693	4,714,003	34	66
Application Category						
Advanced Electric Power Generation	4,809,695	67	1,684,129	3,125,566	35	65
Environmental Control Devices	686,325	10	288,115	398,210	42	58
Coal Processing for Clean Fuels	521,526	7	230,068	291,458	44	56
Industrial Applications	1,118,150	16	219,381	898,768	20	80
Total	7,135,695	100	2,421,693	4,714,003	34	66

[a] Numbers may not appear to add due to rounding.

[b] DOE share does not include $21,505,431 obligated for withdrawn and terminated projects.

- 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.
- The participant'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 3-6 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 67percent of total project costs and the average private-sector participant 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. Participants 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 demonstraton 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 participant 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.

In 1994, three projects made repayments to the government. These were the Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.), Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit (The Babcock & Wilcox Company), and Development of the Coal Quality Expert (ABB Combustion Engineering, Inc., and CQ, Inc.). Recoupments are anticipated in the near future from the 10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.) and the Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.) based on commercial sales.

4. The Road to Commercial Realization

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 1994, 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.

A highlight of the continuing CCT Program outreach effort was the Third Annual Clean Coal Technology Conference attended by about 400 persons from 23 nations. The theme of the conference was "The Investment Pays Off." The conference participants reviewed the status and success of the program, the role of the program in meeting domestic and global energy and environmental needs, the opportunities for commercialization in the United States and abroad, and the challenges which are being encountered. Highlights included participation of delegates in the Eastern Europe/Newly Independent States (NIS) and the Asia/Pacific Rim reverse trade missions. These reverse trade missions provided the opportunity for U.S. industry to gain an understanding of the business opportunities for clean coal technologies in the countries represented. Three 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.

International activities centered on developing a summary of the potential markets in developing countries for exporting clean coal technologies and the financing mechanisms and/or levels of government support necessary to assist U.S. industry participation in these markets. A report to the U.S. Congress, *Clean Coal Technology Export Markets and Financing Mechanism*, was distributed in May 1994. In November 1994, DOE solicited statements of interest in commercial projects employing CCTs in countries projected to have significant growth in greenhouse gas emissions. DOE's report to Congress on the results of the informational solicitation will be issued by April 15, 1995. This report also will identify the extent to which various types of federal incentives would accelerate the commercial availability of CCTs in an international context.

Commitment to Commercial Realization

The CCT Program has been committed to commercial realization since its inception. The significant environmental, efficiency, and economic benefits of the technologies being demonstrated in the program will be realized only if those technologies achieve widespread commercial success. The importance attached to commercial realization of clean coal technologies is highlighted in Senate Report 99-82 which contains recommendations for project evaluation criteria: "The project must demonstrate commercial feasibility of the technology or process and be of commercial scale of such size as to permit rapid commercial scale-up."

The commitment to commercial realization recognizes the complementary but distinctive roles of 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 and 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 are vital to efforts to commercialize the technology. 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 and to identify those meeting operational requirements. The importance of commercial realization is confirmed by the requirement in the solicitations and the cooperative agreement that the project participant must commercialize the technology after successful demonstration.

Each of the five solicitations contains requirements for the project proposals to include a discussion of the commercialization plans and approaches to be used by the participants. The proposer must discuss the following:

- The critical factors required to achieve commercial deployment, such as financing, licensing, engineering, manufacturing, and marketing
- A timetable identifying major commercialization goals and schedule for completion
- Additional requirements for demonstration of the technology at other operational scales as well as significant planned parallel efforts to the demonstration project which may affect the commercialization approach or schedule
- The priority placed by senior management on accomplishing the commercialization effort and how the project fits into the various corporation business marketing, or energy utilization strategies

The cooperative agreement contains three mechanisms to ensure the demonstrated technology can be replicated by responsible firms while protecting the proprietary commercial position of the technology owner:

- The commercialization clause requires the technology owner to meet U.S. market demand for the technology on a nondiscrimination basis. Further, this clause "flows down" from the project participant to the project team members and contractors.
- The clauses concerning rights to technical data deal with the treatment of data developed jointly in the project as well as data brought into the project.
- The patent clause affords protection for new inventions developed in the project.

In addition to ensuring the implementation of the above project-specific mechanisms, the government role also 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

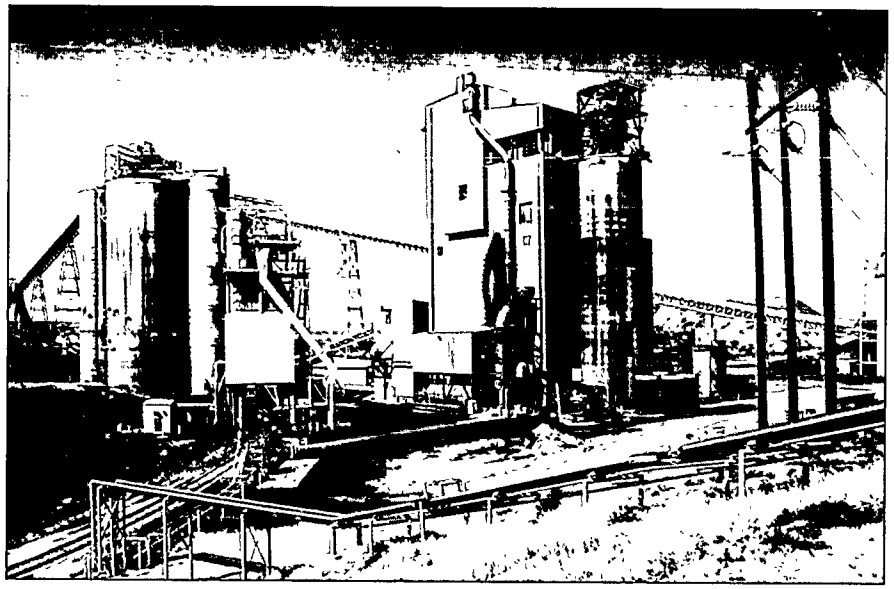
◄ Babcock & Wilcox has installed the LNCB® technology on more than 2,500 MWe of capacity in the United States—each installation achieving more than 50% NO_x reduction. The LNCB® technology was demonstrated at Dayton Power & Light Company's J.M. Stuart Plant between December 1991 and April 1994.

Even though the CCT Program is in its early stages with about 22 percent of the projects in operation and about 29 percent completed, a number of commercial successes have been realized. These successes are summarized in Exhibit 4-1.

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 Phase-I-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 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 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 R&D 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.

Numerous industry and environmental awards for excellence and outstanding achievement have been presented to CCT projects since 1991. These award-winning projects and honors earned are highlighted in Exhibit 4-2.



➤ The solid products from the ENCOAL project are being used for electricity generation in Oklahoma and Wisconsin, and the liquid products are being used in industrial boilers in the Midwest. Information from this mild gasification project is providing the basis for feasibility studies of large-scale plants in China, Indonesia, and Poland.

Understanding the Domestic Market

Since the beginning of the program in 1985, there have been a number of activities aimed at developing an understanding of the commercial market for the technologies and enhancing their entry into the commercial marketplace. As a part of the response to the recommendations of the Special Envoys on Acid Rain, the President directed the Secretary of Energy in April 1987 to establish a panel to advise him on innovative clean coal technology activities. This panel was entitled the Innovative Control Technology Advisory Panel (ICTAP). As a part of its activities, the state and federal incentive subcommittee of ICTAP prepared a report on the

Exhibit 4-1
CCT Program: Commercialization Successes

Project and Participant	Commercialization Status
Advanced Electric Power Generation	
Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.)	The Nucla CFB demonstration prompted wide dissemination of the technical progress of CFB technology and showed the viability of scaling up to the 110-MWe size. When the Nucla CFB boiler was sold, it was 44% larger than any other CFB that had been sold in the United States and 41% larger than any other CFB sold anywhere in the world. It was not until after the Nucla CFB unit was built and the first coal firing occurred that another CFB boiler of comparable size was sold. As a result of the project, Pyropower Corporation was able to save almost 3 years in establishing a commercial line of ACFB units. Pyropower's commercial units are now offered under warranty in sizes ranging up to 400 MWe. Presently, 22 CFB units larger than 100 MWe are being planned, engineered, built, or operated; 11 of these are in the United States. These 22 CFBs represent about 3,800 MWe of capacity and are estimated to be worth about $5 billion (in 1994 dollars), assuming an average total capital cost of $1,400/kW.
Environmental Control Devices	
NO_x Control Technologies	
Demonstration of Coal Reburning for Cyclone Boiler NO_x Control (The Babcock & Wilcox Company)	Babcock & Wilcox's reburning technology has been retained by Wisconsin Power and Light for commercial use at Nelson Dewey Station, Unit No. 2.
Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit (The Babcock & Wilcox Company)	Babcock & Wilcox has sold six contracts for its LNCB® technology; these contracts, which involve 144 burners, have an estimated value of $25 million and an employment impact of 25 person-years. To date, Babcock & Wilcox has installed the LNCB® technology on more than 2,500 MWe of capacity in the United States—each installation achieving more than 50% NO_x reduction. In addition LNCB® retrofits (introduced in early 1993) have been ordered for an additional 3,250 MWe.
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)	Foster Wheeler's commercial sales of its low-NO_x burners have an estimated value of $20 million and represent an employment impact of 140 person-years. Georgia Power is retaining the low-NO_x burners installed at Plant Hammond, Unit No. 4.
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	The Low-NO_x Concentric Firing System (LNCFS) is being retained by Gulf Power at its Plant Lansing Smith. The system also is being used at a number of other installations; for example, LNCFS III is in use at Milliken Station.

Exhibit 4-1 (continued)
CCT Program: Commercialization Successes

Project and Participant	Commercialization Status
SO_2 Control Technologies	
10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.)	The AirPol project is the first North American demonstration of the GSA system for coal-fired FGD. As a result of this successful project, the city of Hamilton, OH, received a $5-million grant from the Ohio Coal Development Office to install the GSA technology to control emissions from a 50-MWe coal-fired boiler at the city's municipal power plant. The GSA technology was identified as the least-cost alternative for the city to meet the 1997 CAAA compliance requirements. The estimated value of this sale is $10 million and involves an employment impact of 70 person-years. 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/yr iron ore sinter plant. Sweden's stringent sulfur emission standard requires a 90–95% removal efficiency. In Europe, where GSA was first commercially installed in 1988, there are 10 GSA units installed on municipal solid waste incinerators. Further, AirPol has received a letter of intent to purchase a GSA system for a 12-MWe oil-fired cogeneration plant located in Taiwan; this sale would have a value of $2.5 million and a U.S. employment impact of 5 person-years.
LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC–North America)	The LIFAC system is being retained by Richmond Power & Light at its Whitewater Valley Station Unit No. 2.
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	In April 1994, Pure Air of Manatee, L.P., entered into a contact to provide 1,600 MWe of SO_2 scrubbing capacity at Florida Power & Light's Manatee power plant. The estimated value of the sale is $200 million and the employment impact is about 1,400 person-years. Pure Air on the Lake, L.P., will continue to operate the AFGD unit at Northern Indiana Public Service Company's Bailly Generating Station for 17 years after the 3-year demonstration. Bailly Generating Station with the AFGD unit became the first power plant on the list of CAAA of 1990 Phase-I-affected units to meet the SO_2 standards using FGD technology.
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	Georgia Power will continue to operate the CT-121 FGD system installed at its Plant Yates, Unit No. 1, after completion of operational testing. In 1994, a tar sands oil extraction facility in Murray, Canada, purchased a CT-121 scrubber.

Exhibit 4-1 (continued)
CCT Program: Commercialization Successes

Project and Participant	Commercialization Status
Combined SO_2/NO_x Control Technologies	
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	Ohio Edison is retaining the SNOX™ technology as a permanent part of the pollution control system at Niles Station to help the utility meet its overall SO_2 and NO_x reduction goals. Commercial SNOX™ plants are operational in Denmark and Sicily. In Denmark, a 305-MWe plant has been designed and constructed; it has operated since August 1991. The boiler at this plant burns coals from Vanbus suppliers around the world, including the United States; the coals contain up to 3.0% sulfur. The plant in Sicily, operating since March 1991, has a capacity of about 30 MWe and fires petroleum coke.
LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)	A commercial version of LIMB will be used in an independent power production project in Canada. Babcock & Wilcox has sold 85 contracts (61 domestic and 24 foreign) for the DRB-XCL® low-NO_x burner. These sales involve 1,515 burners or 20,396 MWe of capacity. The sales have an estimated value of about $202 million and an employment impact of 1,414 person-years.
Integrated Dry NO_x/SO_2 Emissions Control System (Public Service Company of Colorado)	The Colorado utility plans to continue operation of the combustion modifications and the sodium-based dry sorbent injection system. A final decision on the urea injection system will be made after the test program is completed in mid-1995.
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)	Illinois Power is retaining the gas-reburning portion of the system for possible use in 1995 for NO_x control at its Hennepin Plant, Unit 1. City Water, Light and Power also is retaining the gas-reburning technology at Lakeside Station, Unit 7.
Coal Processing for Clean Fuels	
Coal Preparation Technologies	
Development of the Coal Quality Expert (ABB Combustion Engineering, Inc., and CQ, Inc.)	CQ, Inc., and Black and Veatch have signed a commercialization agreement which gives Black and Veatch nonexclusive worldwide rights to sell users' licenses and to offer consulting services that include the use of CQE software. The first commercial sale of the CQE Acid Rain Advisor software package was made in 1993.
Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International)	Custom Coals is leading an international consortium that plans to build a fine-coal-cleaning plant, a 500-mile coal slurry pipeline, and port facility in the People's Republic of China. The project's estimated value is $888.6 million and its U.S. employment impact is expected to be 1,000 person-years.

Exhibit 4-1 (continued)
CCT Program: Commercialization Successes

Project and Participant	Commercialization Status
Advanced Coal Conversion Process Demonstration (Rosebud SynCoal Partnership)	The Rosebud SynCoal Partnership is working on three potential semi-commercial projects located in Wyoming, North Dakota, and Montana. These projects would range in size from 500,000 to 5 million tons/yr. The Wyoming project is a stand-alone mine-mouth design. The North Dakota project is integrated into a mine-mouth power plant with project sales offsite to regional markets. The Montana project is designed either to be integrated into a power plant and fuel user or to expand the existing demonstration facility. In 1993, the partnership signed a letter of intent with Minnkota Power Cooperative to prepare a $2-million study to examine the merits of applying the coal processing technology to a commercial plant integrated into an existing power plant site. The study's results have been positive, but market commitments are still necessary. Commercial development efforts for the SynCoal® product and fines continue. Current industrial and utility users include Ash Grove Cement, Bentonite Corporation, Empire Sand and Gravel, and Montana Power Company. Also, the partnership is working on plans for a commercial coal-drying facility to be located in North Dakota. This project has an estimated value of $43 million and an employment impact of 1,000 person-years.
Mild Gasification	
ENCOAL Mild Coal Gasification Project (ENCOAL Corporation)	The ENCOAL Corporation has commercial contracts in place for two products resulting from the demonstration. Solid products are being used in electricity generation in Oklahoma and Wisconsin. Tank cars of liquid product are being shipped on a regular basis to several customers in the Midwest for use in industrial boilers. The Dakota Gasification Company tested the liquid products in 1992 and in 1994 purchased an additional 800,000 gallons for use in its synfuel plant in Beulah, ND. SGI International and Mitsubishi Heavy Industries are studying the feasibility of developing a 6,000-metric-ton-per-day liquids plant in Shandong province of the People's Republic of China. The Chinese became interested in the technology during a 1993 DOE-led trade mission to China. Feasibility studies using the ENCOAL process have also been proposed for projects in Indonesia and Poland. In Indonesia, small-scale candidate coal testing was completed and feasibility studies have been proposed for two 5,000-metric-ton-per-day plants in Sumatra. In Poland, small-scale candidate coal testing was completed in 1994, with positive recommendations for a plant to process high-sulfur coals from the Belchatow mine in south-central Poland.
Industrial Applications	
Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)	In 1994, a Taiwanese cement company engaged Passamaquoddy Technologies, L.P., to do a preliminary study for the installation of the Passamaquoddy Technology Recovery Scrubber™ on a new cement plant in Taiwan.

Exhibit 4-2
Award-Winning CCT Projects

Project and Participant	Award
Tidd PFBC Demonstration Project (The Ohio Power Company)	1992 National Energy Resource Organization award for demonstration of energy efficient technology. 1991 Powerplant Award presented by *Power Magazine* to American Electric Power Company's Tidd project "for demonstrating pressurized fluidized-bed-combustion combined-cycle technology." Co-recipient was The Babcock & Wilcox Company.
Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit (The Babcock & Wilcox Company)	1994 R&D 100 Award presented by *R&D Magazine* to the U.S. Department of Energy for development of the low-NO_x cell burner, selected as "one of the 100 most technologically significant new products of the year."
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	1993 Powerplant Award presented by *Power Magazine* to Northern Indiana Public Service Company's Bailly Generating Station "for demonstrating advanced wet limestone FGD technology with innovations in wastewater treatment and gypsum production reuse." 1992 Outstanding Engineering Achievement Award presented by the National Society of Professional Engineers.
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	1994 Powerplant Award presented by *Power Magazine* to Georgia Power's Plant Yates "for large-scale demonstration of an advanced scrubbing process . . . and commercial application of low-NO_x burners." Co-recipient was the U.S. Department of Energy. 1994 Outstanding Achievement Award presented by the Georgia chapter of the Air and Waste Management Association for use of an innovative technology for air quality control. 1993 Environmental Award presented by the Georgia Chamber of Commerce in recognition of the success of the scrubber.

actions that states could take to provide incentives for demonstrating and deploying clean coal technologies and their eventual commercial successes and determined that demonstration and deployment should be managed through both state and federal initiatives.

In the same time frame, the Vice President's Task Force on Regulatory Relief (later referred to as the Presidential Task Force on Regulatory Relief) was established. Among other things, the task force was asked to examine incentives and disincentives to the commercial realization of new clean coal technologies and other cost-effective emissions reduction measures that might be inhibited by various federal, state, and local regulations. An outgrowth of this activity was the recommendation that preference be given to projects located in states that offer certain regulatory incentives to encourage such technologies. This recommendation was accepted and became part of the project selection considerations beginning with the second CCT solicitation.

The framers of the CAAA of 1990 recognized the environmental benefits of widespread commercial deploying of clean coal technologies. A provision in the act allows a 4-year extension (to December 31, 2003) to comply with the requirements of Title IV if one or more units are repowered with a qualifying clean coal technology.

An effort has been under way to gain greater understanding of the potential domestic market for clean coal technologies and the organizations and

factors that will influence what and when facilities get built as well as the technologies that are used. A DOE team conducting a series of executive seminars with the CCT Program's key stakeholders. These seminars focus on the power generation market and include discussions with leaders in the utility, independent power, regulatory, and financial communities. In these meetings, DOE seeks insights from management and planners whose views and decisions will shape the future use of clean coal technologies in power generation.

Additionally, a series of regional studies of key utilities and utility systems are under way with the purpose of gaining a better understanding of the markets for clean coal technologies and the regional and state factors that have a bearing on commercial deployment. Regions selected for study account for most of the U.S. coal-fired generating capacity. Detailed data and information have been compiled on (1) regional and state energy use, coal use and resources, and electric power generation; (2) state government agencies (including public utility commissions), regulations, legislation, and policies that could have a bearing on clean coal technology commercial realization; and (3) coal-using investor-owned, rural cooperative, and municipal electric entities which are potential users of clean coal technologies. The collected information and data are analyzed for insights into environmental compliance strategies, capacity planning, and other issues facing utility and state stakeholders.

The insights contributed by these 1994 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. These insights include the following:

- 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). Coal is expected to provide about 50 percent of all electric power in 2010, with coal-fired generation increasing from 1,693 billion kilowatt-hours in 1993 to 1,929 billion kilowatt-hours in 2010. There are many uncertainties that may affect the projected need for new capacity, such as the following:
  - Considerable uncertainty exists about the projected savings from demand-side management and whether these savings will have a significant impact on reduction of power generation needs.
  - Economic growth rates may be higher than projected. While there may be a lessening of the relationship between economic activity and electric power usage, a relationship still exists. If efforts to continue to stimulate the economy are successful, the current integrated resource planning assumptions and load growth projections may need to be revised upward.
  - The existing inventory of nuclear units, which accounts for about 19 percent of all electric power generation in the United States, starts to come up for relicensing in about 10 years. It is doubtful that life extension for all these nuclear units will take place. Further, a recent study by DOE indicated that several nuclear units may retire before their licenses come up for renewal. The Energy Information Agency has projected a decrease of 14 billion kilowatt-hours in nuclear generation by 2010.
  - The utility industry is restructuring and implementing new institutional arrangements to enhance competitiveness in power marketing. These actions may tend to drive short-term considerations which may lead to lower near-term rates for customers at the potential expense of long-term needs such as system reliability and the desirability of long-term stability of fuel prices. Further, the utility industry's approach to life extension, repowering, or replacement of aging fossil plants may be reexamined in light of a more competitive marketplace and the risk of causing "stranded capacity."
- 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 timetable that will allow potential users to evaluate the technical, economic, and environmental performance of the technologies 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 SO_2-control technologies capable of removing over 90 percent of the SO_2 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 SO_2/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 considerable 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 SO_2 will be met largely by fuel switching and emissions allowance 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 SO_2 and ozone; (2)areas designated by the U.S. EPA 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, Title VII of 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 and Michigan and California have taken steps to open both wholesale and retail electricity markets. 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 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. SO_2 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 SO_2 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 SO_2 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.

An Emerging International Market

Internationally, clean coal technologies are acquiring significant increased importance in the export market, creating major opportunities for U.S. business. The potential CCT market for new facilities and retrofit installations outside the United States for the 1993–2010 period has been reported to be between $571 and $870 billion. Export of the technology to meet this demand would create a reported 69,000–109,000 person-years of employment. Aggressive action by U.S. companies to capture a share of this market with U.S. technologies from the Clean Coal RD&D Program could lead to a significant reduction in both the U.S. trade deficit and unemployment by providing high-technology engineering and manufacturing jobs.

Recognizing the importance of this export market, a number of efforts are under way to define market opportunities to promote U.S. technology and to support U.S. project development work. International activities have concentrated on providing technical support to the U.S. trade agencies, organizing trade missions, developing financial and market analysis in response to Section 1331 of the Energy Policy Act of 1992, and developing an international technology transfer program as directed by Section 1332 of that act.

In May 1994, DOE completed the report, *Clean Coal Technology Export Markets and Financing Mechanisms,* in response to the requirement of Conference Report 103-299 which accompanied Public Law 103-138, the Department of the Interior and Related Agencies Appropriations Act for FY 1994. The report provides a summary of the potential markets in developing countries for exporting clean coal technologies. The estimates are 390 gigawatts for retrofitting existing facilities and 330 gigawatts of new capacity by the year 2010. These markets represent the potential creation of 70,000 U.S. export-related jobs. The primary markets for clean coal technologies are China and India for new capacity and Eastern Europe, Russia, and Newly Independent States for facility upgrades or retrofit applications to reduce emissions. The report also contains an assessment of financing mechanisms for preliminary activities and the construction of the project itself. The primary source of financing of preliminary activities, such as prefeasibility and feasibility studies and project definition activities, are the multilateral development

banks. Financing of projects can involve general credit, which is the preferred method for utilities with excellent credit histories; official credit, which includes loans, guarantees, and grants from multilateral banks and developing country governments; and project financing, which is nonrecourse borrowing and is likely to be the method most often used for projects involving U.S. CCTs.

Clean coal technologies also were the focus of numerous international activities in Pacific Rim countries, including India and China, as well as many of the newly emerging markets of Eastern Europe. Two separate visits were made to China to continue the support of a prefeasibility study of IGCC for China, and assistance was provided to Tulane University for a workshop on clean coal technologies. The workshop was for a Chinese delegation and part of an effort being undertaken by Tulane's newly organized U.S.-China Center. The CCT project staff as well as the industrial participants played active roles in the effort to support the Secretary of Energy's visit to India. The Pacific Rim countries receive up-to-date information on the characteristics and current status of clean coal technology through DOE's participation in the Asia Pacific Economic Cooperation organization's expert group on clean coal technology. International audiences at each of two conferences held in the Czech Republic (i.e., Plzen and Prague) were introduced to the performance characteristics and development status of CCTs of particular interest to the region. Other trade missions to Hungary and Bulgaria have further extended the potential markets for CCTs.

The interest of Congress, the program, and the U.S. industrial sector in the international marketplace was further demonstrated in November 1994 when, in response to congressional direction, DOE solicited statements of interest in commercial projects employing CCTs in countries projected to have significant growth in greenhouse gas emissions.

This informational solicitation was issued pursuant to Conference Report 103-740 to accompany the Department of the Interior and Related Agencies Appropriations Act for FY 1995 (Public Law 103-332) and the guidance contained in corresponding Senate and House Reports 103-294 and 103-551, respectively. The solicitation was conducted, as requested by the congressional guidance, so that Congress may have the information it requires to consider the technical, economic, and environmental aspects of various incentives to support CCTs and their merits for potential future support.

Respondents to this informational solicitation were asked to propose an international (nondomestic) project that would employ at least one CCT and that, at a minimum, has the following characteristics:

- Sponsorship by a U.S.-based company or consortium
- Location in a developing country, or in a country making the transition from a centrally planned to a market economy, projected to have significant growth in greenhouse gas emissions
- Capability of reducing greenhouse gas emissions, particularly CO_2, as compared to technologies in common use in the proposed locale
- Versatility with regard to effective usage of various globally available coal types and characteristics
- Likelihood of utilization on a broad commercial scale after successful demonstration

Among the information respondents were asked to provide were comments on or discussions of two key questions:

- What are the greatest opportunities for commercializing U.S. CCTs abroad (short and long term)?
- What role can DOE best play to facilitate commercialization of these technologies?

Submittals are due no later than January 13, 1995. DOE's report to Congress on the results of the informational solicitation will be issued by April 15, 1995.

Market Communications

As an outgrowth of ICTAP's *Report to the Secretary of Energy Concerning Commercialization Incentives*, a clean coal technology outreach program was established. The purpose of this program is 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 to commercial realization of the technologies. Specific objectives of the outreach program 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 process
- Providing policymakers and regulators with information about the advantages of clean coal technologies
- Increasing the confidence of financial institutions that these technologies are viable options

The outreach activities conducted by DOE have been directed toward reaching targeted audiences, including users and vendors of the technology, regulators, public educators, environmental organizations, and export markets. DOE's outreach program has been implemented through the following mechanisms: publications, annual clean coal technology conferences, presentations and exhibits, and international trade missions. Additionally, project participants have been holding open houses, providing tours of demonstration facilities, and publicizing projects through groundbreaking ceremonies. They also have been presenting technical papers at professional and industry conferences to report progress and results to potential users.

DOE has been disseminating information through the distribution of published material about the program and the projects. These reports include the annual *Program Update, Comprehensive Reports to Congress* for each solicitation and successfully negotiated projects, the *New Coal Era*, and a series of project-specific topical reports to highlight project events or to capture progress at particular points driven by project-specific considerations. In 1994, as the program neared its midpoint, a number of key publications were prepared and disseminated, including the following:

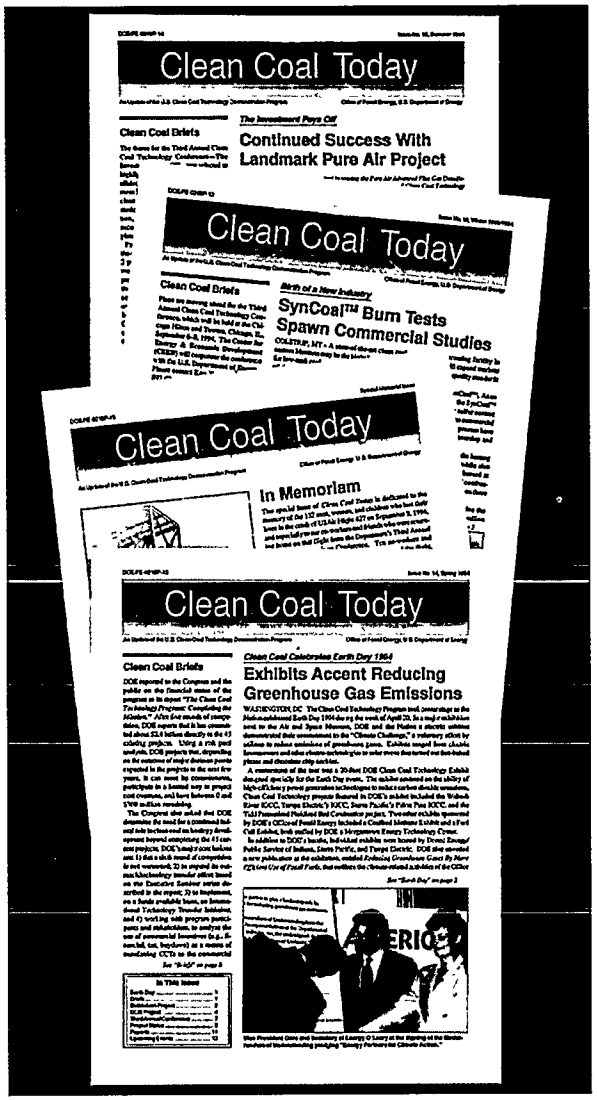
- *Clean Coal Technology: The Investment Pays Off* highlights a number of commercial successes achieved thus far in the program.
- *Comprehensive Report to Congress: Clean Coal Technology Program Completing the Mission* was prepared in response to a congressional request and presents a status of the entire CCT Program, the options available for continuing the program, and recommendations on the government's role in continuing the commercial development of the technologies being demonstrated in the program.
- *Report to the U.S. Congress: Clean Coal Technology Export Markets and Financing Mechanisms* describes the potential coal technology export markets in developing countries and the financing mechanisms and/or levels of government support necessary to assist U.S. industry participation in these markets.
- *Clean Coal Technology Demonstration Program Lessons Learned* summarizes the programmatic and procedural lessons learned in conducting this unique and highly successful industry/government cost-shared program.
- *Third Annual Clean Coal Technology Conference: Technical Papers* contains the technical papers presented at the 1984 conference.

Appendix C is a comprehensive listing of CCT Program publications, and Appendix D lists recent papers and presentations on the CCT Program.

Three issues of the newsletter, *Clean Coal Today,* were prepared in 1994. The newsletter is distributed to approximately 3,700 domestic and international readers. In 1994, feature articles covered the blast furnace granulated-coal injection project, early results from Gulf Power's selective catalytic reduction test facility, and operation updates from the Pure Air, Tidd, ENCOAL, and Milliken projects. A special memorial edition was dedicated to the DOE personnel and industry colleagues and their family members who lost their lives in the crash of US Air Flight 427 on September 8, 1994, while returning from the Third Annual Clean Coal Technology Conference.

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.

The Third Annual Clean Coal Technology Conference was held in Chicago, Illinois, in September 1994 and was cosponsored by The Center for Energy and Economic Development. The theme, "The Investment Pays Off," brought the focus of the conference to the "pay off" of public/private investment in CCTs. The objective was to review the status and successes of the program, the role of the program in meeting domestic and global energy and environmental needs, the opportunities for CCT commercialization in the United States and abroad,



Clean Coal Today

Clean Coal Briefs

The Investment Pays Off

Continued Success With Landmark Pure Air Project

Clean Coal Today

Clean Coal Briefs

Birth of a New Industry

SynCoal™ Burn Tests Spawn Commercial Studies

Clean Coal Today

In Memoriam

Clean Coal Today

Clean Coal Briefs

Clean Coal Celebrates Earth Day 1994

Exhibits Accent Reducing Greenhouse Gas Emissions

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

and the challenges being encountered. This review was accomplished within the context of emerging trade agreements and global energy, economic, and environmental challenges. The 3-day conference was attended by about 400 persons from 23 countries, including Bulgaria, Canada, the Czech Republic, Estonia, Finland, Hungary, India, Indonesia, Italy, Japan, Latvia, Lithuania, Macedonia, the Netherlands, Poland, Romania, Russia, Taiwan, Slovakia, South Korea, the Ukraine, the United Kingdom, and the United States.

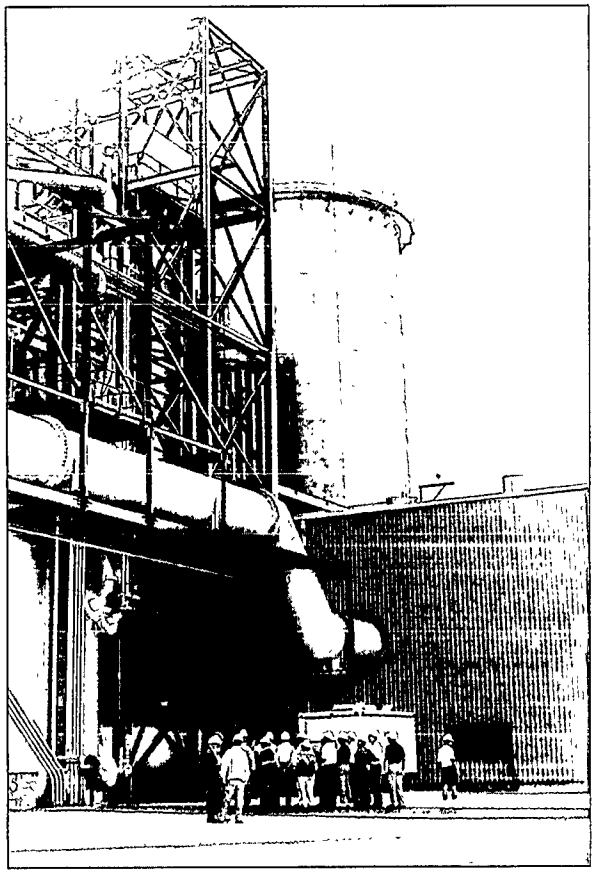
The first morning was devoted primarily to orientation of international delegations and introductory discussions between industrial representatives and the foreign visitors. The first day's highlight was Pure Air's tour of its demonstration advanced flue gas desulfurization unit at Northern Indiana Public Service Company's Bailly Generating Station.

Discussions over the next 2 days were framed by an opening plenary session entitled "Global, Energy, Environmental, and Economic Challenges" in which speakers addressed the following topics:

- Approaches to CCT deployment in the marketplace
- Evolution of domestic utility markets into the next century
- World economic and energy outlook
- Global opportunities for U.S. industries in clean coal markets
- Environmental considerations in meeting world energy needs

The first of four panel sessions addressed international business and covered topics that included understanding overseas markets, the linkage between coal exports and CCTs, and linking project needs with funding. Two subsequent sessions

▼ The Third Annual Clean Coal Technology Conference held in Chicago, IL, was attended by about 400 persons from 23 countries. One of the highlights was the site tour of the Pure Air on the Lake, L.P., advanced flue gas desulfurization unit shown here.



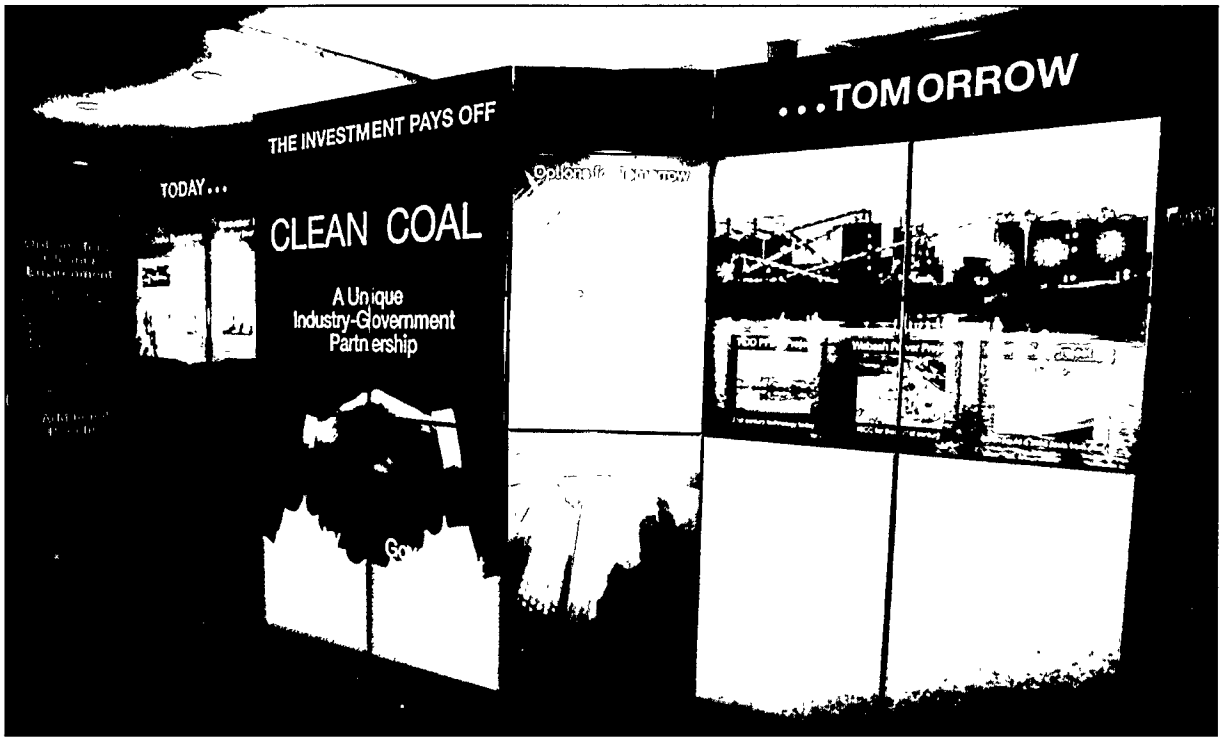
provided forums for reverse trade missions: one on Eastern Europe/NIS and the other on Asia/Pacific Rim. A final panel focused on emerging issues and the environment for the domestic CCT market.

In nine technical sessions, industrial participants presented the results and accomplishments of 36 CCT demonstration projects—12 advanced electric power generation projects, 14 environmental control devices projects, 5 coal processing projects, and 5 industrial projects.

In the closing plenary session, speakers examined the challenges to commercialization. Topics addressed included forecasts of the future role of coal, technology selection in an evolving domestic utility market, the impact of externalities on coal and CCT utilization, implications of federal and state plant siting requirements, international opportunities within the context of joint implementation, and next steps along the CCT pathway.

During 1994, DOE made use of exhibits and presentations as a means to highlight the activities and benefits of the CCT program. The exhibits were used in 12 major domestic and international events including Earth Day, World Summit on Trade and Efficiency, Power Gen '94, the Third Annual Clean Coal Technology Conference, The Energy Summit (Madras, India), and Energy & Environment: Transition in Eastern Europe (Czech Republic). During 1994, two exhibits were acquired to replace an older, outdated exhibit and to present interactive videos of the CCT projects. These exhibits form a backdrop for individual and group discussions on the efficiency and environmental merits of clean coal technologies.

▼ The theme of the Third Annual Clean Coal Technology Conference was the investment pays off and focused on the "payoff" of public/private investment in CCTs.



5. Results of Completed Projects

Summary

Four projects completed operation in 1994, bringing to 13 the total number of projects for which operations have been completed under the CCT Program. The four projects are as follows:

- Two SO_2 control technologies
  - 10-MWe demonstration of gas suspension absorption (AirPol, Inc.)
  - LIFAC sorbent injection desulfurization project (LIFAC–North America)
- Two combined SO_2/NO_x control technologies
  - SNOX™ flue gas cleaning demonstration (ABB Environmental Systems)
  - Gas reburning and sorbent injection (Energy and Environmental Research Corporation)

These projects completed in 1994 provide valuable data for addressing pressing environmental and energy issues associated with utility and industrial use of coal.

AirPol, Inc., completed the demonstration of gas suspension absorption (GSA) system for flue gas desulfurization. This demonstration was conducted at the Center for Emissions Research on a 10-MWe slipstream of flue gas from a 150-MWe coal-fired boiler at the Tennessee Valley Authority's Shawnee Fossil Plant. A western Kentucky coal with approximately 3 percent sulfur was used in the demonstration. SO_2 removal efficiency during the tests ranged from about 60 percent (approach-to-saturation temperature of 28 °F and Ca/S of 1.00) to nearly 91 percent (approach-to-saturation temperature of 8 and 18 °F and Ca/S of 1.30). The demonstration of the GSA/cyclone/pulse jet baghouse showed the SO_2 removal efficiency averaged more than 96 percent or about 3–5 percentage points higher than that achieved with GSA/electrostatic precipitator. Air toxic tests showed high removal of trace metals and particulates. Levelized cost for the 300-MWe GSA and wet limestone, forced-oxidation system were 10.4 mills per kilowatt-hour and 13.04 mills per kilowatt-hour, respectively. Successful testing of the GSA resulted in the city of Hamilton, Ohio, receiving a $5-million grant from the Ohio Coal Development Office to install the technology on a 50-MWe coal-fired boiler at the city's municipal power plant.

LIFAC–North America demonstrated its flue gas desulfurization technology at Richmond Power and Light's 60-MWe Whitewater Valley Unit No. 2. The coals used during the demonstration had sulfur contents ranging from 2.0 to 2.9 percent. Operational testing was begun in September 1992 and was completed in June 1994 and consisted of approximately 2,800 hours of operation. Long-term testing showed that SO_2 reduction of 70 percent or more could be maintained under normal boiler operating ranges and at a Ca/S of 2.0. The process proved to be highly operable because it has few moving parts and is simple to operate. The economic evaluation indicates that the capital cost of a LIFAC installation is lower than both spray dryers and wet scrubbers and range from $66 per kilowatt at 300-MWe to $76 per kilowatt at 150-MWe. Currently there are 10 full-scale LIFAC units in operation or under construction in Canada, China, Finland, Russia, and the United States.

ABB Environmental Systems completed the demonstration of the SNOX™ combined NO_x, SO_2, and particulate control process at Ohio Edison's Niles Station. The process treated a 35-MWe equivalent slipstream of flue gas from the 108-MWe No. 2 boiler. A high-sulfur (3.4 percent) Ohio coal was used to fire the boiler. Testing was initiated in March 1992 and completed in December 1994. The system was operated for more than 7,800 hours. Particulate emissions were controlled by using a high-efficiency fabric filter baghouse. Removal efficiencies of over 99 percent were achieved. NO_x reduction was achieved by use of a selective catalytic reactor (SCR) using DNX-932 catalyst. Reduction efficiencies averaged over 94 percent with inlet NO_x levels of approximately 500–700 parts per million. SO_2 control was achieved through the conversion of SO_2 to SO_3 in a catalytic converter. The SO_3 was then passed through a WSA condenser where sulfuric acid was condensed out of the gas stream. During the test program SO_2 removal efficiency was normally in excess of 95 percent for inlet concentrations which averaged about 2,000 parts per million. About 5,400 tons of

sulfuric acid were produced and sold for industrial use. The sulfuric acid concentration and composition met or exceeded the requirements of the federal specifications for Class I acids. Ohio Edison has retained the SNOX™ unit at its Niles plant. Further, a 305-MWe plant is in operation on coal in Denmark and a 30-MWe plant is in operation on petroleum coke in Sicily.

The Energy and Environmental Research Corporation completed a demonstration of gas reburning and sorbent injection (GR–SI) at the tangentially fired Illinois Power Hennepin Plant Unit 1 and the cyclone-fired Lakeside Station Unit 7 owned and operated by City Water, Light and Power of Springfield, Illinois. The GR–SI demonstration at the 71-MWe Hennepin Plant was carried out from January 1992 to October 1992. Over the long-term demonstration period, average gross power output was 62 MWe. For the long-term demonstration, the average NO_x reduction was 67.3 percent and average SO_2 removal efficiency was 52.6 percent at a Ca/S of 1.76 using Linwood hydrated lime. The GR–SI demonstration at the 33-MWe pressurized cyclone unit at Lakeside was initiated in May 1993 and completed in October 1994. The gas reburning parametric tests achieved an average NO_x reduction of approximately 67 percent. SO_2 reductions using the sorbent injection only and a Ca/S of 2.0 were 44 percent at 33 MWe, 38 percent at 25 MWe, and 32 percent at 20 MWe. Combined GR–SI operation resulted in an average SO_2 removal efficiency of 58 percent. The gas reburning technology is being retained at both Hennepin and Lakeside for use in NO_x reduction.

Exhibit 5-1 shows the number of completed projects for each application category. Notably, the technical, environmental, and economic results are available from most of the projects in the environmental control devices category—in time for potential users to have the information necessary to meet CAAA of 1990 requirements for SO_2 and NO_x reductions.

Results summaries for the 13 completed demonstration projects, as reported by the participants, follow for quick reference. Results are discussed in more detail in the project summaries provided in this section.

Exhibit 5-1
Completed Projects

Application Category	Total Projects	Completed Projects
Advanced Electric Power Generation		
Fluidized-bed combustion	6	1
Integrated gasifier combined cycle	6	0
Advanced combustion/heat engines	3	0
Environmental Control Devices		
NO_x control technologies	7	3
SO_2 control technologies	5	3
Combined SO_2/NO_x control technologies	7	4
Coal Processing for Clean Fuels	5	0
Industrial Applications	6	2
	45	13

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

Technology

Atmospheric circulating fluidized-bed (ACFB) combustion

Size

110 MWe

Demonstration Duration (8/88–1/91)

15,700 hrs

Coals

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

Sorbent

Limestone

Environmental Results

- 70% SO_2 removal efficiency with 1.5 Ca/S (<1,620 °F)
- 95% SO_2 removal efficiency with 4.0 Ca/S (<1,620 °F)
- NO_x <0.34 lb/million Btu; avg 0.18 lb/million Btu

Technical Results

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

Economic Results

Capital cost—approx $1,123/net kW (repower cost)

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 (11/91–12/92)

2,000 hrs

Coals

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

Environmental Results

	Reduction in NO_x		
	Boiler Load		
Coal	110 MWe	82 MWe	60 MWe
Lamar	52%	47%	36%
Powder River	62%	55%	53%

Technical Results

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

Economic Results

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 (12/91–4/93)

Continuous service

Coals

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

Environmental Results

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

Technical 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

Economic Results

Capital cost—$5.50–8.00/kW at 500 MWe

180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the 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 (5/91–12/92)

Continuous operation

Coals

KY, IL, and 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 or LNCFS Level I

Economic Results

- LNCFS I—$8–10/kW
- LNCFS II/III—$15–20/kW

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

Technology

- FLS miljo a/s' gas suspension absorption (GSA) system for flue gas desulfurization
- Pulse jet baghouse for particulate control

Size

10-MWe equivalent slipstream of flue gas from a 150-MWe boiler

Demonstration Duration (10/92–3/94)

- Air toxic tests, 9/93–10/93
- Factorial tests, 1/93–9/93
- Demonstration, 10/25/93–11/24/93
- Pulse jet baghouse test, 2/94–3/94

Coals

- Bituminous, 2.7–3.5% S
- Simulated high-chloride (about 0.3%) coal

Sorbents

Hydrated lime slurry

Environmental Results

- 60% SO_2 removal efficiency at 28 °F approach-to-saturation temperature, lime stoichiometry of 1.00 mole $Ca(OH)_2$/mole of inlet SO_2, coal chloride of 0.02–0.04%
- 90–91% SO_2 removal efficiency at 18 °F approach-to-saturation temperature, avg 1.40–1.45 moles of $Ca(OH)_2$/mole of inlet SO_2, coal chloride of 0.12%
- 96% SO_2 removal efficiency achieved with GSA/pulse jet baghouse system
- Particulate removal efficiency—99.9+% avg; emission rate—0.015 lbs/million Btu avg
- HCl removal rate across the GSA reactor and cyclone approximates 100%
- Trace metals, particulates, and HF removal high

Technical Results

- Demonstrated reliability of technology by remaining on-line for entire 28-day demonstration period
- Demonstrated a number of key technical attributes including
  - Simple and direct method of lime/solid recirculation
  - High acid gas absorption
  - Low lime consumption/minimum waste by-product residue
  - Low maintenance operation
  - No internal buildup
  - Reduced space requirement
- Demonstrated pulse jet baghouse system improved SO_2 removal efficiency by about 3–5 percentage points

Economic Results

- Capital cost (1990 dollars)—$149/kW for GSA as compared to $216/kW for wet limestone, forced-oxidation scrubbing system (WLFO) (300 MWe, 2.6% S coal, 90% SO_2 removal efficiency)
- Levelized cost (mills/kWh)

	GSA	WLFO
Fixed costs	2.3	2.81
Variable costs	3.1	2.93
Capital costs	5.0	7.30
Total	10.4	13.04

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 (7/91–6/93)

Approximately 5 mos of continuous testing

Coals

PA bituminous, 1.5–2.5% S

Sorbents

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

Environmental Results

50% SO_2 removal efficiency

Technical Results

- Drying and SO_2 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 required before commercial use can be achieved
- Very good system availability

Economic Results

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

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

Technology

LIFAC's sorbent injection process with sulfur capture in a unique, patented vertical activation reactor

Size

60 MWe

Demonstration Duration (9/92–8/94)

2,800 hrs

Coals

Bituminous, 2.0–2.9% S

Sorbents

- Fine limestone (80% minus 325 mesh)
- Course limestone (80% minus 200 mesh)

Environmental Results

- 70% SO_2 removal efficiency at 7–12 °F approach to saturation, 2.0–2.5 Ca/S, fine limestone (SO_2 removal about 15% less with coarse limestone)
- Solid waste is mixture of fly ash and calcium compounds; quantity equal to amount of limestone injected (4.3 tons/ton of SO_2 removed, assuming 75% capture with Ca/S of 2.0)
- ESP efficiency 99.2%; stack opacity about 10%

Technical Results

Demonstrated a number of key technical attributes including

- High operability due to few moving parts
- Ease of start-up and shutdown
- Automated programmable logic system to regulate process control loops, interlocking, start-ups, shutdowns, and data collection
- No negative impact on bottom ash and flyash removal systems

Economic Results

- Capital cost—$66/kW for two LIFAC reactors (300 MWe); $76/kW for one LIFAC reactor (150 MWe); $99/kW for one LIFAC reactor (65 MWe) (compare with $205/kW for 300-MWe wet scrubber)
- $65/ton of SO_2 removed, assuming 75% SO_2 capture, Ca/S of 2.0, limestone 95% $CaCO_3$, limestone cost of $15/ton

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

Technology

- Particulate control—fabric filter baghouse
- NO_x control—selective catalytic reactor
- SO_2 control—Haldor Topsoe's catalytic SO_2 oxidizer; WSA sulfuric acid condenser

Size

35-MWe slipstream from 108-MWe boiler

Demonstration Duration (3/92–12/94)

7,800 hrs

Coals

OH bituminous, 3.4% S

Environmental Results

- NO_x reduction—94%
- SO_2 removal efficiency—95%
- Particulate control—99+%
- Sulfuric acid purity—exceeds federal specification for Class I acid
- Air toxics—removal very high for majority of species examined

Technical Results

- No alkali reagent required for SO_2 removal
- No generation of secondary pollution streams such as solids, slurries, and liquids
- Minimal or no increase in CO_2 emissions
- Reduction of CO and hydrocarbons in the flue gas
- Synergistic coupling of NO_x and SO_2 catalysts
- Furnace integration of recovered heat

Economic Results

- Capital costs—$250/kW
- Total operating cost—1.3 mills/kWh

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

Technology

- Limestone injection multistage burner (LIMB)
- In-duct sorbent injection (Coolside)
- DRB-XCL® low-NO_x burners

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% SO_2 removal efficiency (3.8% S coal; ligno lime)
- Coolside—70% SO_2 removal efficiency (hydrated lime; 2.0 Ca/S, 0.2 Na/Ca, and 20 °F approach to saturation)
- 40–50% NO_x removal throughout LIMB and Coolside testing

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

Economic Results

- Capital cost—LIMB $31–102/kW; Coolside $69–160/kW
- Annual levelized cost—LIMB $392–791/ton of SO_2 removed; Coolside $482–943/ton of SO_2 removed

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

Project Technology

- SO_2—in-duct sorbent injection
- NO_x—injection with selective catalytic reduction (SCR) catalyst
- Particulate—high-temperature fabric bag filters

Size

5-MWe equivalent slipstream from 156-MWe boiler

Demonstration Duration (5/92–5/93)

2,300 hrs

Coals

OH 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% SO_2 removal efficiency with commercial-grade lime at 2.0 Ca/S (800–850 °F)
- 90% SO_2 removal efficiency with hydrated limes at 2.0 Ca/S (800–850 °F)
- 80% SO_2 removal efficiency with sodium bicarbonate at 1.0 Na_2/S (425 °F)
- 90% NO_x reduction with 0.9 NH_3/NO_x (800–850 °F)
- 99.89% particulate emissions removal efficiency

Technical Results

- SO_2 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

Economic Results

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

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

Technology

- Gas reburning (GR)
- Sorbent injection (SI)

Hennepin

Size

80 MWe (gross), 71 MWe (net) tangentially fired

Demonstration Duration (1/91–1/93)

- Gas reburning, 400 hrs
- Sorbent injection, 115 hrs
- Combined, 760 hrs
- Baseline, 825 hrs

Coals

IL bituminous, 3.0% S

Sorbents

- Linwood hydrated lime
- PromiSORB™ A
- PromiSORB™ B
- High-surface-area hydrated lime

Environmental Results

- 67% avg NO_x reduction with 18% gas input
- 52% avg SO_2 reduction at Ca/S of about 1.76
- CO_2, HCl, and HF emissions also reduced
- Particulate emissions reduced by flue gas humidification upstream of ESP

Technical Results

- Thermal efficiency: -0.3–1.1% latent heat loss due to hydrogen
- Carbon-in-ash: +0.5–1.7%; minimal impact on boiler efficiency
- Steam temperature: no change; controlled by attemperation
- Heat distribution—minor changes; within normal range
- No change in tube wastage, tube metallurgy, or projected boiler life

Lakeside

Size

40 MWe (gross), 33 MWe (net) cyclone-fired

Demonstration Duration (5/93–10/94)

- Parametric tests—100 gas reburning tests; 25 sorbent injection tests
- Long-term tests—gas reburning, 249 hrs; combined, 223 hrs
- Extended operating tests (4/94–5/94)—continuous gas reburning, 115 hrs; continuous combined, 38 hrs and 64 hrs

Coals

IL bituminous, 3.0% S

Sorbents

- Limestone ($CaCO_3$)
- Hydrated lime [$Ca(OH)_2$]

Environmental Results

- Over 60% NO_x reduction with optimum achieved at 22–23% gas input (gas reburn only); 67% avg NO_x reduction during GR long-term testing
- 44% SO_2 reduction at 33 MWe; 38% reduction at 25 MWe; 32% at 20 MWe (all at Ca/S of 2.0) (sorbent injection only); 58% avg SO_2 reduction during GR–SI long-term testing
- 3–5% increase in NO_x reduction (due to decrease in nozzle diameter) and 50% SO_2 reduction at Ca/S >1.5 along with gas heat inputs of 22–25% (combined operation)
- Particulate emissions averaged 0.016 lb/million Btu, well below the 0.1 lb/million Btu limit
- Extended continuous combined runs:
  - 60% SO_2 reduction, 66% NO_x reduction (38 hrs at 29 MWe, gas input 22.4%, Ca/S 1.67)
  - 63% SO_2 reduction, 64% NO_x reduction (64 hrs at 29 MWe, gas input 21.6%, Ca/S 1.75)

Technical Results

- Thermal efficiency—fell 0.8% due to higher moisture in methane
- Carbon-in-ash—gas reburn neither increased carbon-in-ash nor impacted boiler efficiency
- Flue gas temperature—rose 6 °F; sorbent deposition on back pass heat transfer surfaces
- Operated consistently and reliably

Combined Economic Results

- NO_x reduction
  - \$979/ton of NO_x removed (14% gas input; 47% NO_x reduction)
  - \$1,318/ton of NO_x removed (24% gas input; 60% NO_x reduction)
- SO_2 removal
  - \$425/ton SO_2 removed (1.0 Ca/S; 29% SO_2 removal)
  - \$514/ton SO_2 removed (2.0 Ca/S; 45% SO_2 removal)

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

Technology

Air-cooled cyclone slagging combustor

Demonstration Duration (11/87–5/90)

900 hrs

Size

23 million Btu/hr

Coals

8 different PA bituminous, 1–3.3% S

Environmental Results

- SO_2—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

Economic Results

Not yet available

Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)

Technology

Passamaquoddy Technology Recovery Scrubber™

Size

1,450 tons/day of cement; 250,000 std ft^3/min of kiln gas; up to 274 tons/day of coal

Demonstration Duration (8/91–9/93)

5,316 hrs

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% SO_2 reduction, with maximum reduction of 98%
- NO_x emissions reductions of 5–15% achieved

Technical Results

- In 5-mo period, plant produced 140,000 tons of cement while scrubber removed 70 tons of SO_2 and treated 6,000 tons of kiln dust
- Scrubber became permanent part of commercial plant operation

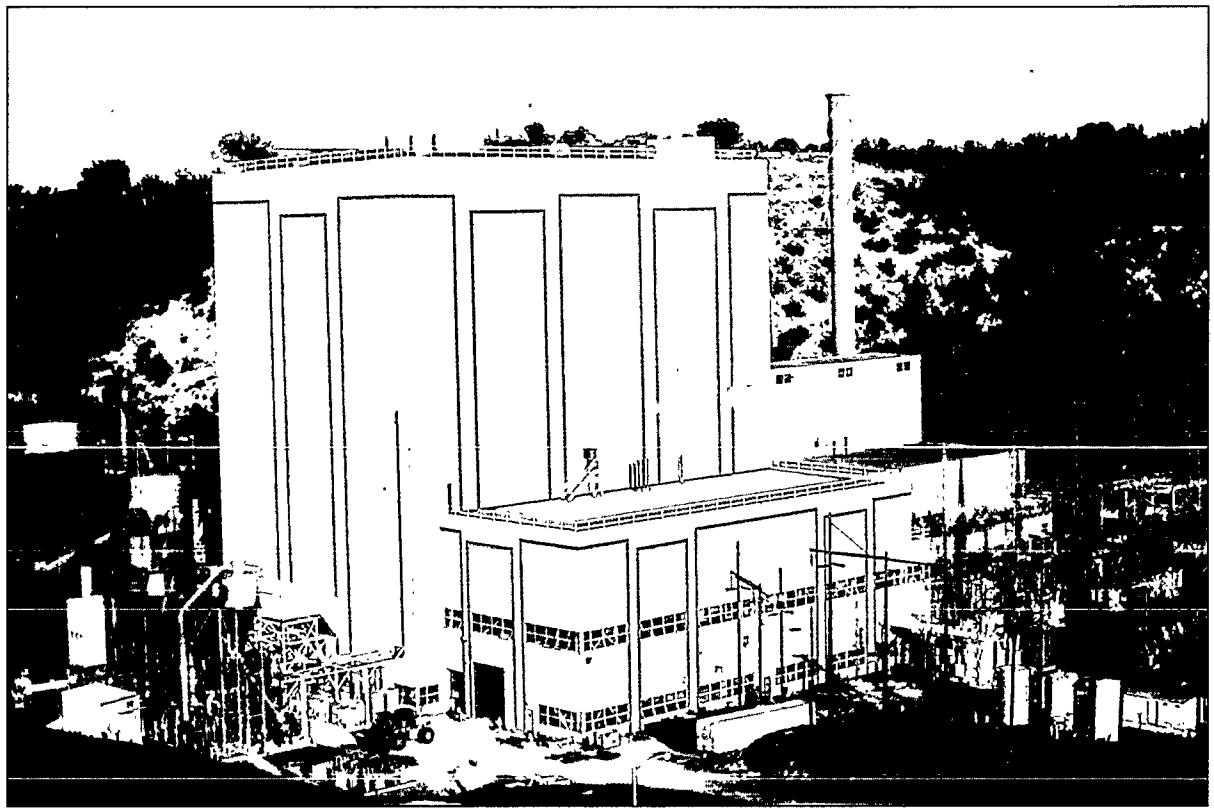
Economic Results

Capital cost—$25/ton of annual cement capacity

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.



▲ The 110-MWe Nucla demonstration enabled Pyropower Corporation to save almost 3 years in establishing a line of commercial ACFB units. Commercial units are now sold under warranty in sizes ranging up to 400 MWe.

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 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) compared 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 participant, are as follows:

- **Emissions Performance.** Results indicated strong correlations of absolute CO, SO_2, 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 CO_2. 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 SO_2 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: 1990 Annual Report.* Report No. DOE/MC/25137-3089. Colorado-Ute Electric Association, Inc. 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.)
- *Nucla CFB Demonstraton 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.)

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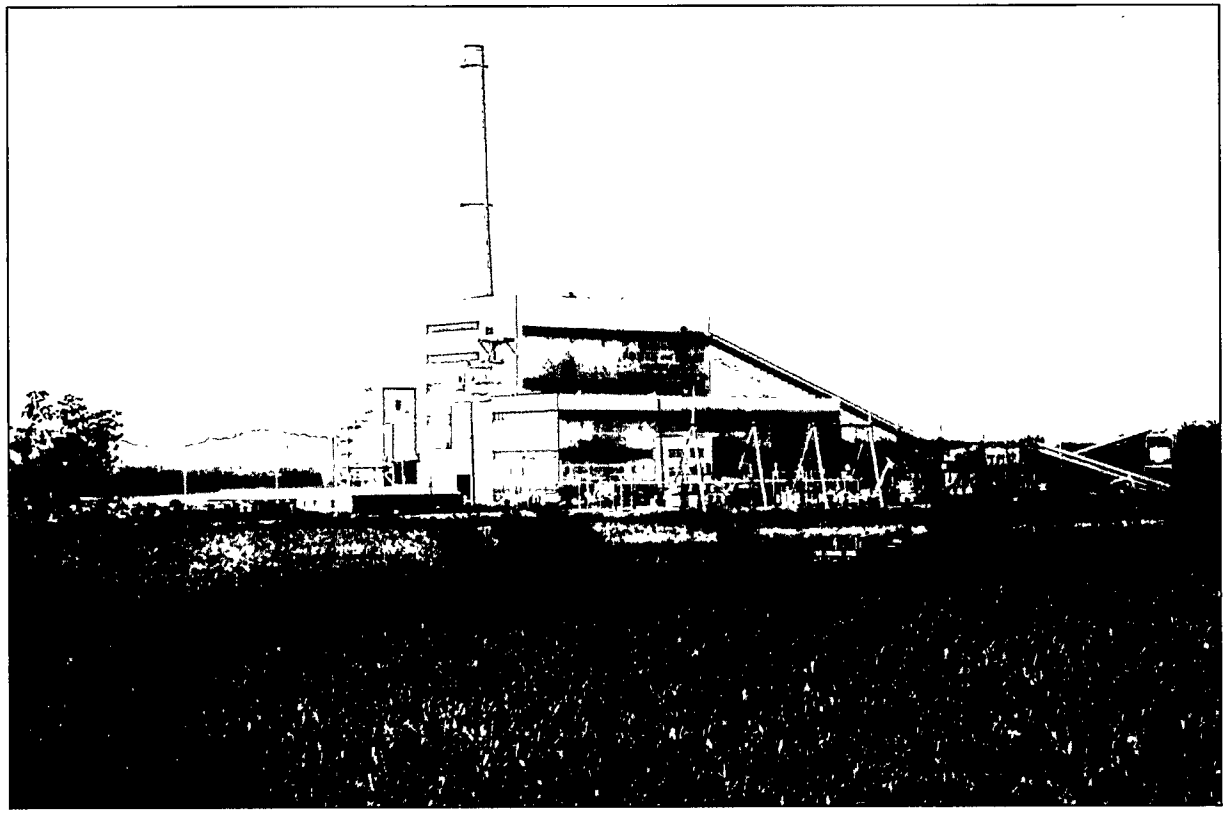
Demonstration of Coal Reburning for Cyclone Boiler NO_x Control (The Babcock & Wilcox Company)

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 NO_2).

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-deficient (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.



▲ Babcock & Wilcox's demonstration of coal reburning at the 100-MWe cyclone boiler of Nelson Dewey Station achieved NO_x reductions in excess of 50% at full load.

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 5-2 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 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 optimization 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.

Exhibit 5-2
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%

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 to consist 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

- *Demonstration of Coal Reburning for Cyclone Boiler NO_x Control.* Report No. DOE/PC/89659-T16. The Babcock & Wilcox Company. March 1994. (Available from NTIS as DE 9401-3052.)
- *Public Design Report: Coal Reburning for Cyclone Boiler NO_x Control.* The Babcock & Wilcox Company. August 1991.

The economic evaluation report is expected to be available in early 1995.

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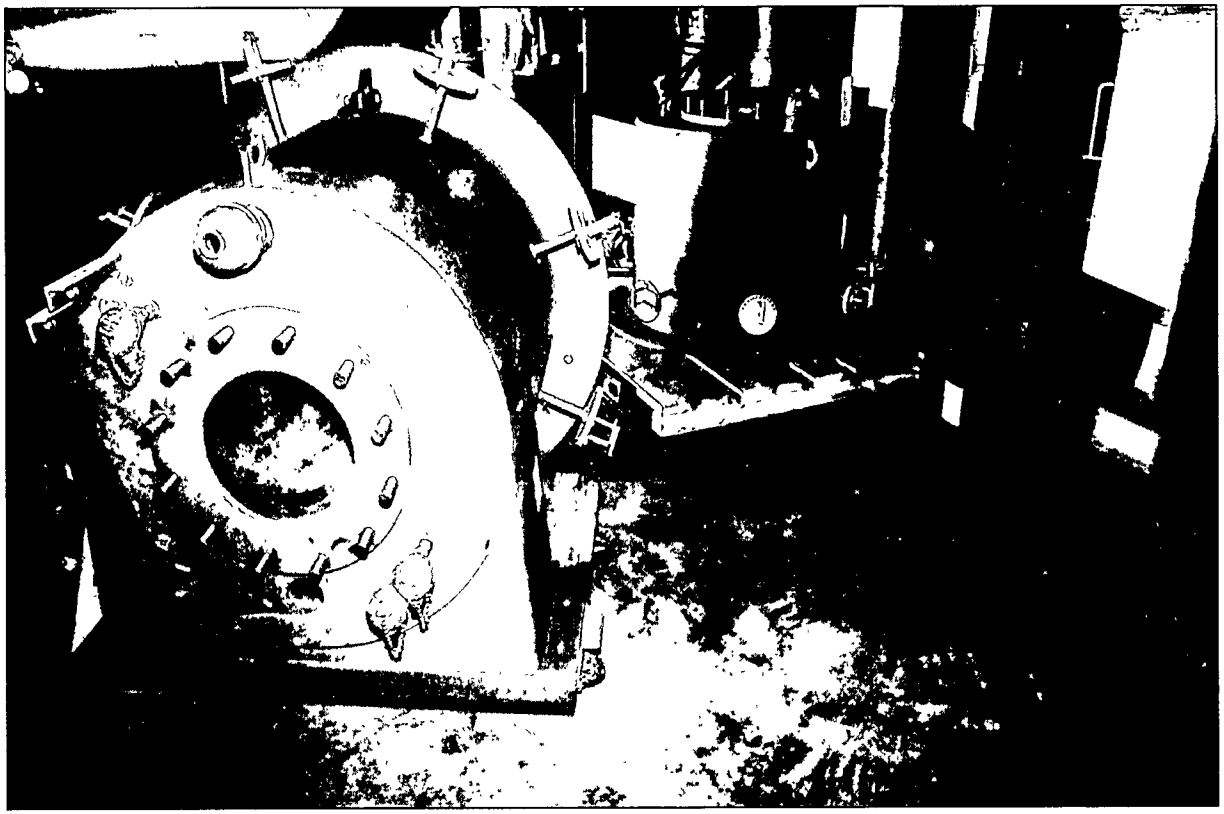
▼ The coal-reburning burners (shown here) have been retained by Wisconsin Power and Light for commercial use at Nelson Dewey Station.



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

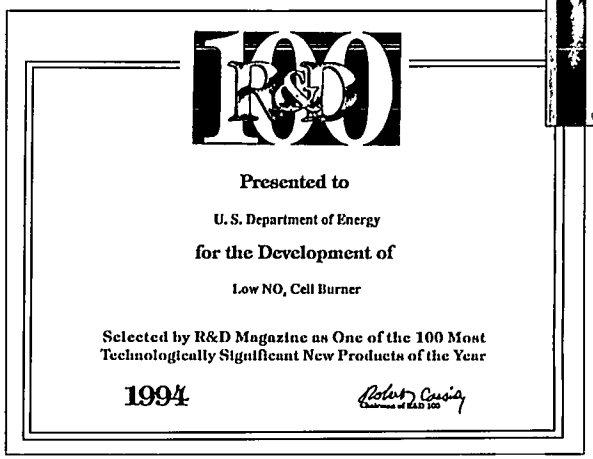
The Babcock & Wilcox Company has completed demonstration of its low-NO_x cell burner (LNCB®) technology. The objective was to demonstrate the capability of the LNCB® burner to achieve at least 50 percent NO_x reduction without degradation of boiler performance and at less cost than conventional low-NO_x 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 NO_2).

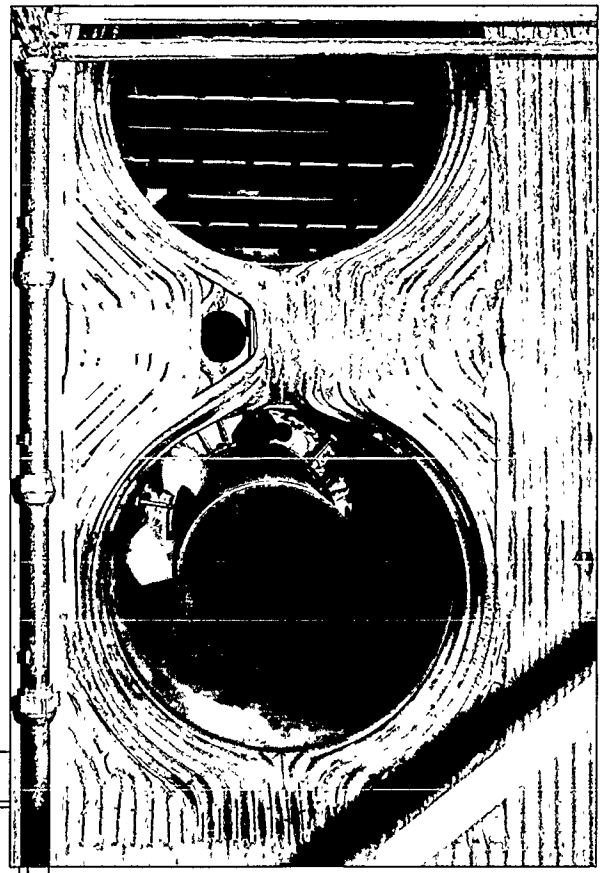
To reduce NO_x emissions, the upper burner of the standard two-burner cell was replaced with a secondary air port, and the lower burner was replaced with a larger burner having the same fuel input capacity as the standard cell. The LNCB® operates on the principle of staged combustion to reduce NO_x emissions. 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, which were arranged in an opposed-firing configuration with two rows of six cells on each side, were replaced with LNCB® burners.

The LNCB® 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 H_2S levels, ultrasonic testing of lower furnace tube wall thicknesses, and destruction examination of a corrosion test panel

▼ The LCNB® project received *R&D Magazine's* 1994 R&D 100 award for technical excellence in a new commercial product.





▲ All 24 of the two-nozzle cell burners at J.M. Stuart Plant Unit No. 4 were replaced with Babcock & Wilcox LNCB® burners. The low cost and short outage time for an LNCB® retrofit, along with NO_x reductions exceeding 50%, make the LNCB® an attractive option.

Exhibit 5-3
LNCB® 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	–	–

were mechanisms used to predict impact on remaining boiler life. NO_x, CO, CO_2, 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 LNCB® 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 5-3.

A corrosion test panel was installed when the LNCB® 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 to 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 an LNCB® retrofit make the option financially attractive. In a typical retrofit installation, the capital cost would include LNCB® 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 LNCB® is a plug-in design.

The domestic market potential for the LNCB® 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 has installed its LNCB® technology on more than 2,500 MWe of capacity in the United States—in each case achieving more than 50 percent NO_x reduction. In addition, LNCB® retrofits (introduced in early 1993) have been ordered for an additional 3,250 MWe.

The LNCB® project received *R&D Magazine's* 1994 R&D 100 award for technical excellence in a new commercial product.

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 1995.

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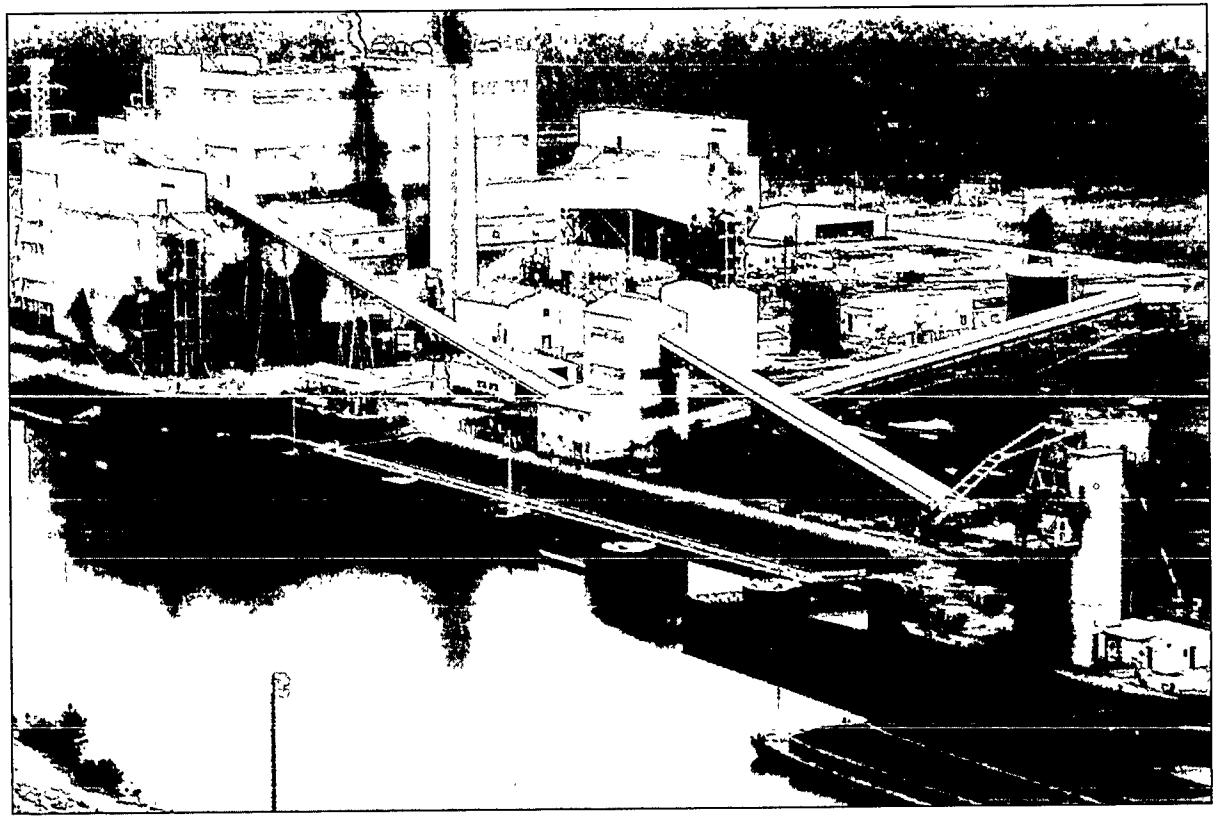
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)

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 the 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 load 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 40percent compared to baseline emissions data.



▲ Gulf Power has retained the Low-NO_x Concentric Firing System at Plant Lansing Smith Unit No. 2. The system is also in commercial use at a number of other installations.

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

tests showed that the LNCFS had little or no impact on the emissions of air toxics. The final project report was completed in early 1994.

Gulf Power has retained the LNCFS at its Plant Lansing Smith Unit No. 2. The system also is being used at a number of other installations; for example, LNCFS Level III is in use at Milliken Station.

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. The capital cost estimates for LNCFS Level I range between $8–10 per kilowatt and for LNCFS Levels II/III $15–20 per kilowatt.

Available Reports

- *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. February 1994.
- *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.* Report No. DOE/PC/89652-T12. Southern Company Services, Inc. October 1993. (Available from NTIS as DE 9400-5038.)
- *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.* Report No. DOE/PC/89652-T13. Southern Company Services, Inc. September 1993. (Available from NTIS as DE 9400-0218.)

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▼ The demonstration tested three levels of LNCFS, each using various combinations of over-fire air and clustered coal nozzle positioning to achieve NO_x reductions. Level III, which includes separated over-fire air and close-coupled over-fire air, reduced NO_x emissions by 48%.

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

The objectives of the gas suspension absorption (GSA) system for flue gas desulfurization demonstration project were as follows:

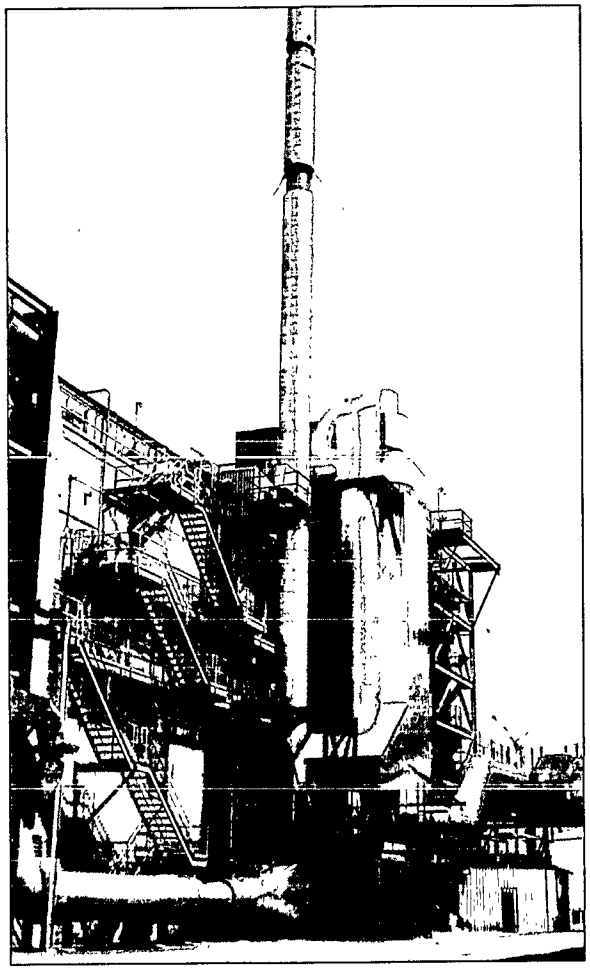
- Effectively demonstrate SO_2 removal in excess of 90 percent using high-sulfur U.S. coals
- Optimize design and operating parameters to increase the SO_2 removal efficiency and the lime utilization
- Compare the SO_2 removal efficiency of the GSA technology with existing spray dryer/ electrostatic precipitator technology

The GSA process concept was developed by AirPol's parent company, FLS miljo a/s of Copenhagen, Denmark. The process was initially developed as a cyclone preheater system for cement kiln raw material. The system provided both capital and energy savings by reducing the required length of the rotary kiln and by lowering fuel consumption. The GSA system also showed superior heat and mass transfer characteristics. The GSA system for FGD applications was developed later by injecting lime slurry and recycle solids into the bottom of the reactor to function as an acid gas absorber. In 1985, a GSA pilot plant was built in Denmark to establish design parameters for SO_2 and hydrogen chloride absorption for waste incineration applications. The first commercial GSA unit was installed at the KARA waste-to-energy plant at Roskilde, Denmark, in 1988. Currently there are 10 GSA units in Europe, all installed on municipal solid waste incinerators.

The 10-MWe demonstration project was selected under the third solicitation, initiated in October 1990, and completed in December 1994. The project was the first North American demonstration of the GSA system for coal-fired utility FGD. The project was located at the Center for Emissions Research and used 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, Kentucky. A western Kentucky coal with about 3 percent sulfur was used in the demonstration.

Approximately 26 months of operating and testing were conducted during the demonstration. A test plan was prepared to detail the procedures, locations, and analytical methods to be used in all tests. The objectives of the tests follow:

- Optimization of operating variables
- Determination of Ca/S stoichiometric ratios for various SO_2 removal efficiencies
- Evaluation of erosion and corrosion at various locations in the system
- Demonstration of 90 percent or greater SO_2 removal efficiency when the boiler is fired with high-sulfur coal
- Determination of the air toxics removal performance



▲ AirPol successfully demonstrated the GSA system using a 10-MWe slipstream from TVA's Shawnee Unit 9. The first full-scale commercial GSA unit in the United States as well as the world's first GSA unit on a coal-fired boiler is being installed on a 50-MWe boiler at a Hamilton, OH, municipal power plant.

- Evaluation of the pulse jet baghouse performance in conjunction with the GSA process

Several general relationships affecting SO_2 removal efficiency became apparent. A significant positive effect on SO_2 removal efficiency came from increasing the lime stoichiometry and other factors, such as increasing the coal chloride level or decreasing the approach-to-saturation temperature. Increasing the recycle rate resulted in higher SO_2 removal, but the benefit appeared to reach an optimum level above which further increases in the recycle rate did not seem to have a significant effect on SO_2 removal. Increasing the flue gas flow rate had a negative effect on SO_2 removal.

The SO_2 removal efficiency during the tests ranged from about 60 percent to nearly 95 percent, depending on the specific test conditions.

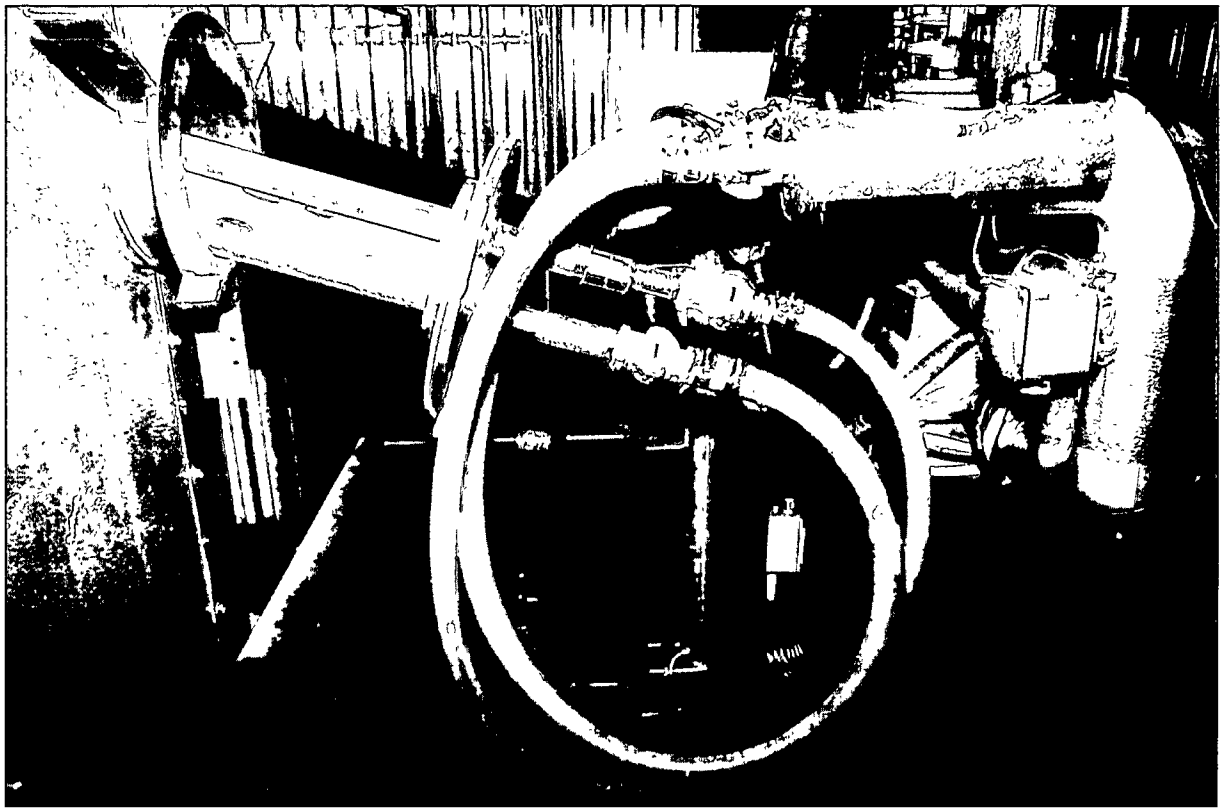
The lower SO_2 removal efficiency levels were achieved at the higher approach-to-saturation temperature (28 °F), the lower lime stoichiometry level (Ca/S of 1.00), and lower coal chloride level (0.02–0.04 percent). The higher SO_2 removal efficiency levels were achieved at the lower approach-to-saturation temperatures (8 and 18 °F), the higher lime stoichiometry level (Ca/S of 1.30), and higher coal chloride level (0.12 percent). Most of the SO_2 removal in the GSA system occurred in the reactor/cyclone, with only about 2–5 percent of the overall removal occurring in the ESP.

An evaluation of ESP performance was also conducted as part of the tests. The results from the particulate testing showed that the emission rate from the ESP was substantially below the New Source Performance Standard for particulates (0.03 pound per million Btu) at all test conditions evaluated. The typical emission rate was 0.010 pound per million Btu. The particulate removal efficiency was above 99.9 percent for nearly all tests and the outlet grain loading was below 0.005 grain per cubic foot.

Although not part of the original GSA demonstration, TVA and EPRI cofunded the installation of a 1-MWe pulse jet baghouse (PJBH) pilot plant to be operated in conjunction with the existing GSA demonstration. Later, AirPol and DOE joined in the operation and testing of the PJBH pilot plant program. The resulting SO_2 removal efficiency in the GSA reactor/cyclone/PJHB system was typically about 3–5 percentage points higher than that achieved in the reactor/cyclone/ESP system at the same test conditions. The particulate removal efficiency in the PJBH was 99.9+ percent for all tests completed with full dust loading from GSA reactor/cyclone.

A total of six air toxic tests were conducted: four with the GSA reactor operating and two with the GSA system not operating. All tests were completed

▼ The GSA reactor fluidizing nozzles and feed tubes (shown here) were inserted into the bottom of the reactor.



while the boiler was burning high-sulfur (2.7 percent), low-chloride coal and were run at the high flue gas flow rate (20,000 standard cubic feet per minute) and high flyash loading (2.0 grains per cubic foot) test conditions. Preliminary results suggest that the GSA system is capable of removing HCl, particulate, and trace metals. The removal rate of the HCl across the reactor and cyclone appears to be 100 percent. Removal rates for trace metals, particulate, and HF also appear to be high during the six tests.

A continuous 4-week demonstration run of the GSA system in conjunction with only the ESP demonstrated an SO_2 removal efficiency of 90 percent or better using a high-sulfur (2.7 percent), low-chloride coal and a higher sulfur (3.5 percent) coal. The CA/S ratio averaged 1.40–1.45 moles of $Ca(OH)_2$ per mole of inlet SO_2 during the demonstration run.

The project demonstrated a number of key technical attributes including a direct and simple method of lime/solid recirculation, high acid gas adsorption, low lime consumption with minimal waste by-product residue, low maintenance operation, no internal buildup, and reduced space requirements.

The relative process economics for the GSA system were evaluated for a moderately difficult retrofit to a 300-MWe boiler burning a coal containing 2.6 percent sulfur. The design SO_2 removal efficiency was 90 percent. The resulting capital cost estimate (in 1990 dollars) is $149 per kilowatt for GSA as compared to $216 per kilowatt for the wet limestone, forced-oxidation (WLFO) scrubbing system. The levelized annual revenue requirement for the GSA process is lower than that for the WLFO system, but the difference is only about 20 percent (which is not considered to be significant given the limitations on the accuracy of estimates used in the analysis). The principal annual operating cost for the GSA process is the cost of the pebble lime. The 15-year levelized costs in mills per kilowatt-hour for the two systems are listed below:

	GSA	WLFO
Fixed costs	2.3	2.81
Variable costs	3.1	2.93
Capital costs	5.0	7.30
Total	10.4	13.04

The GSA should fulfill the need of the utility industry to meet the new SO_2 emission standards set forth in the CAAA of 1990. There is a particular need for a simple and economic FGD process, such as GSA, by plants in the 50–250-MWe range where wet FGD systems are not feasible.

Successful testing of the AirPol demonstration project has resulted in a commercial application in Ohio. The city of Hamilton, Ohio, has received a $5-million grant from the Ohio Coal Development Office to install the GSA technology to control emissions from a 50-MWe coal-fired boiler at the city's municipal power plant. The new system is scheduled to be operational in August 1996 and will be the first full-scale commercial GSA unit in the United States as well as the world's first GSA unit for a coal-fired boiler. The GSA technology was identified as the least-cost alternative for the city to meet the 1997 compliance requirements under the CAAA of 1990.

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-per-year iron ore sinter plant. Sweden has stringent sulfur emission standards which require a removal efficiency of 90–95 percent.

Available Reports

The final technical report and public design report are expected to be available in early 1995.

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Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)

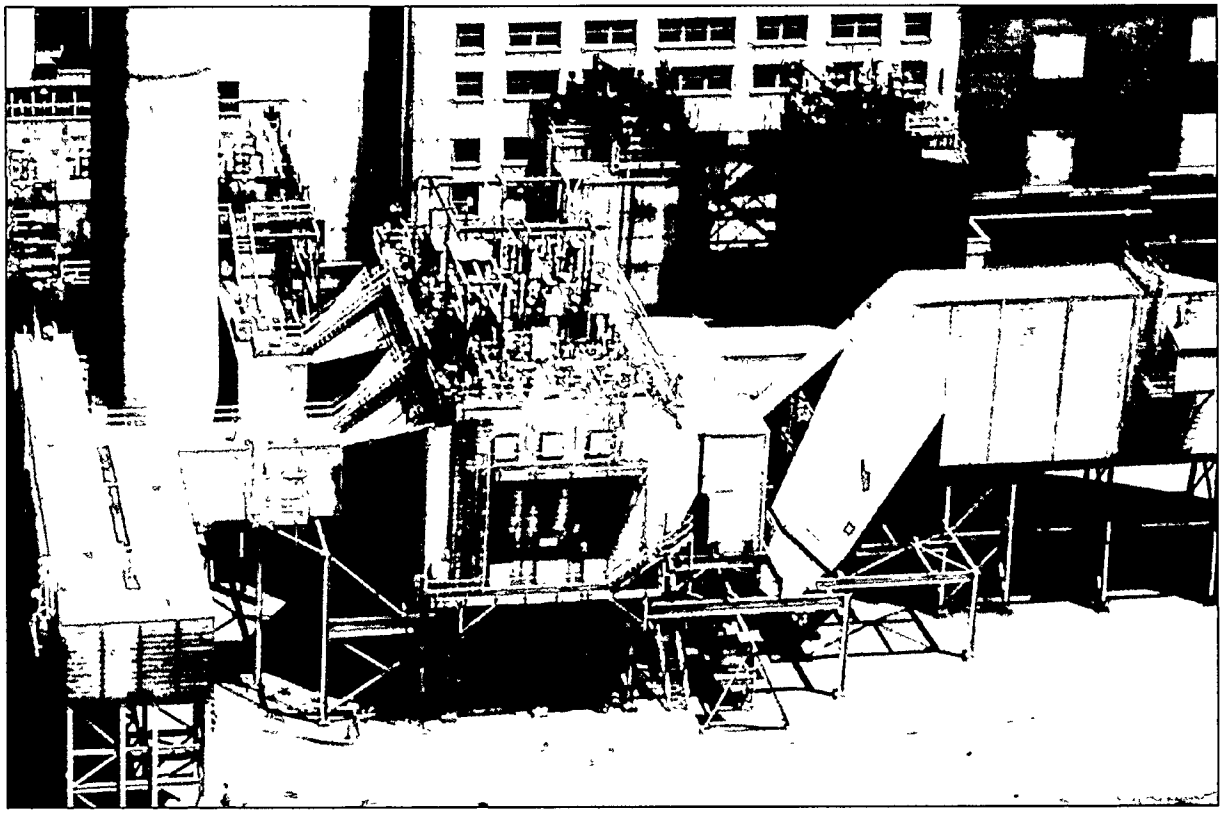
The objective of Bechtel Corporation's project was to demonstrate SO_2 removal capabilities of in-duct CZD/FGD technology; specifically to define the optimum process operating parameters and to determine CZD/FGD's operability, reliability, and cost-effectiveness during long-term testing and its impact 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 SO_2 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 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.

▼ Bechtel demonstrated CZD/FGD technology at Pennsylvania Electric's Seward Station Unit No. 5. One-half of the 147-MWe unit's flue gas capacity was routed through a modified, longer duct between the first and second electrostatic precipitator. The demonstration showed that a 50% SO_2 removal efficiency is possible and that the CZD/FGD system responds well to automated control operation.



The primary objectives of the project follow:

- Achieve an SO_2 removal rate of 50 percent
- Realize SO_2 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 SO_2 from the flue gas but require different concentrations in the lime slurry for the same percentage of SO_2 removed. The most efficient and easiest to operate was the pressure-hydrated dolomitic lime. These parametric tests indicated that SO_2 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 SO_2 removed. An analysis of the continuous operational data indicates that the percentage of lime utilization is directly dependent on two key factors:

- Percentage of SO_2 removed
- Lime slurry concentration

For operating conditions at Steward Station, data indicate that, for 40–50 percent SO_2 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 SO_2 removed; or assuming 92 percent lime purity, 1.9–2.4 tons of lime are required for every ton of SO_2 removed. In summary, the demonstration showed the following:

- A 50 percent SO_2 removal efficiency with CZD/FGD is possible.
- The process requires that drying and SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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

- *Confined Zone Dispersion Project: Public Design Report.* Bechtel Corporation. April 1993.

The final technical report is expected to be available in mid-1995.

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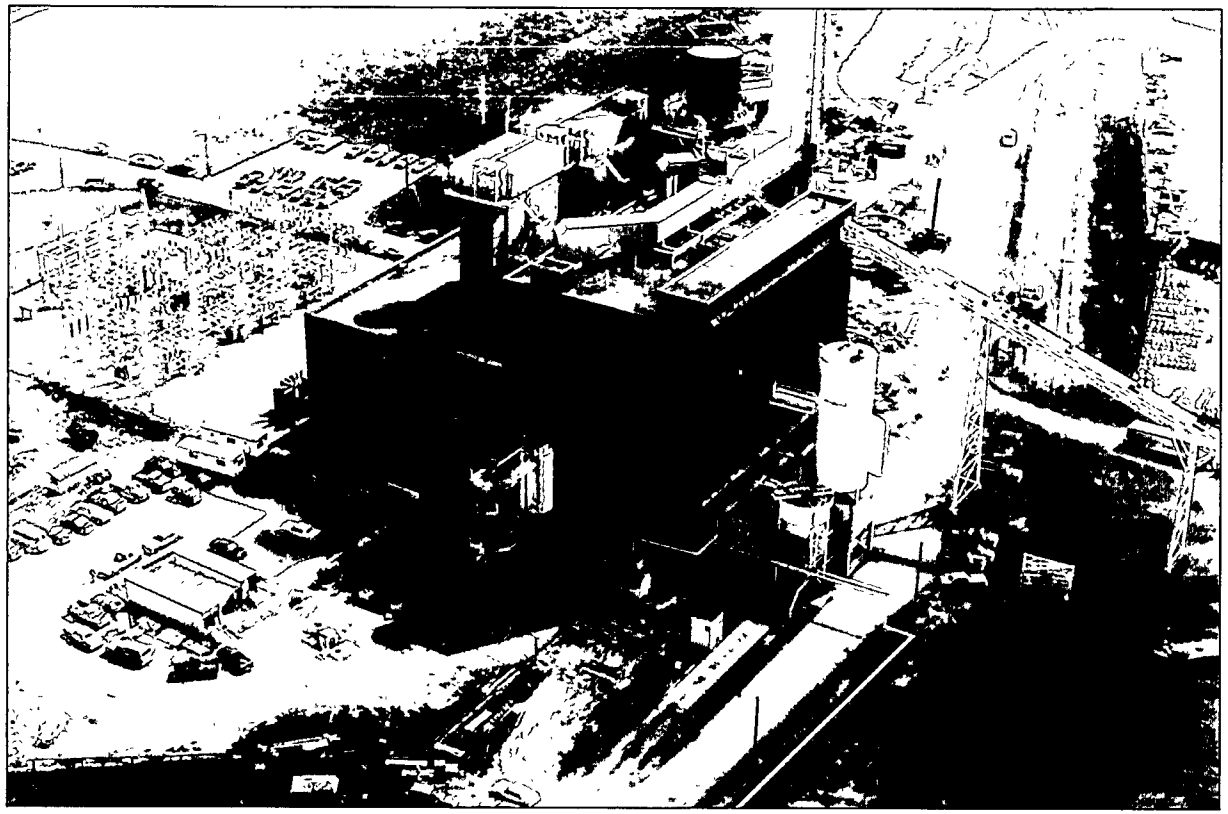
LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC–North America)

LIFAC–North America, a joint venture partnership between Tampella Power Corporation and ICF Kaiser Engineers, have demonstrated the LIFAC flue gas desulfurization technology developed by Tampella Power. The technology provides SO_2 control for coal-fired power plants, especially where tight space limitations exist. SO_2 emissions are reduced over 75 percent by using limestone as a sorbent.

The LIFAC technology was developed in response to Finland's acid rain legislation which applied limits on SO_2 emissions sufficient to require that FGD systems have the capability to remove approximately 80 percent of the SO_2 from the flue gas. Tampella Power began developing an economical, alternative sorbent injection system. Process development first involved laboratory and pilot-plant tests, then full-scale tests of sorbent injection of limestone. Subsequent research and development by Tampella led to the addition of a humidification section after the boiler. In 1986, the first major full-scale test was performed at Imatron Vaimu's Inkee power plant in Finland using a 70-MWe side-stream from a 250-MWe boiler burning 1.5 percent sulfur coal. A second LIFAC reactor was constructed to treat an additional 125-MWe side-stream. The initial demonstration installations were capable of achieving removal rates of 70–80 percent using Ca/S molar ratios of 2–2.5. In 1988, the first tests with high-sulfur U.S. coals were performed at Tampella's pilot plant. A Pittsburgh No. 8 coal containing 3 percent sulfur was evaluated and an SO_2 removal rate of over 70 percent was achieved at 2.0 Ca/S.

The LIFAC project was selected in the third solicitation and the cooperative agreement was awarded in November 1990. The demonstration was conducted at Whitewater Valley Station Unit No. 2, a 60-MWe coal-fired power plant owned and operated by Richmond Power & Light and located in Richmond, Indiana. Operational testing was begun in



▲ The LIFAC system successfully demonstrated at Whitewater Valley Station Unit No. 2 is being retained by Richmond Power & Light for commercial use with high-sulfur coal. There are 10 full-scale LIFAC units in operation or under construction in Canada, China, Finland, and the United States.

September 1992 and completed in June 1994 and consisted of 2,800 hours of operation. The demonstration had the following four objectives:

- Sustained high SO_2 removal efficiency
- Ability to retrofit the LIFAC system under tight construction conditions
- Compatibility of the LIFAC system with existing equipment and operation
- Demonstration of LIFAC's competitiveness on a cost-per-ton of SO_2 removed

The process evaluation test plan was composed of five distinct phases each having its own objectives. These tests were as follows:

- **Baseline Tests.** Baseline measurements were taken to characterize the operation of the host boiler and associated subsystems prior to LIFAC operations.
- **Parametric Tests.** Parametric tests were designed to evaluate the many possible combinations of LIFAC process parameters and their effect on SO_2 removal.
- **Optimization Tests.** Optimization tests were performed after the parametric tests to evaluate the reliability and operability of the LIFAC process over short, continuous operating periods.
- **Long-Term Tests.** Long-term tests were performed to demonstrate LIFAC's performance under commercial operating conditions.
- **Post-LIFAC Tests.** Post-LIFAC tests involved repeating the baseline test to identify any changes caused by the LIFAC system.

The coals used during the demonstration were high in sulfur, with a sulfur content ranging from 2.0 to 2.9 percent.

During the parametric testing phase the numerous LIFAC process values and their effects on sulfur removal efficiency were evaluated. The four major parameters having the greatest influence on sulfur removal efficiency were limestone quality, Ca/S molar ratio, reactor bottom temperature (approach-to-saturation), and ESP ash recycling rate. Total SO_2 capture was about 15 percentage points better when injecting fine limestone (80 percent minus 325 mesh) than it was with coarse limestone (80 percent minus 200 mesh).

While injecting the fine limestone, the soot blowing frequency had to be increased from 6- to 4.5-hour cycle periods. The coarse-quality limestone did not affect soot blowing but was found to be more abrasive on the feed and transport hoses.

Parametric tests indicated that a 70 percent SO_2 reduction was achievable with a Ca/S molar ratio of 2.0. ESP ash containing unspent sorbent and fly ash was recycled from the ESP hoppers back into the reactor inlet duct work. Ash recycling is essential for efficient SO_2 capture. The large quantity of ash removed from the LIFAC reactor bottom and the small size of the ESP hoppers limited the ESP ash recycling rate. As a result, the amount of material recycled from the ESP was approximately 70 percent less than had been anticipated. However, this low recycling rate contributed an additional 15 percentage points to total SO_2 capture. During a brief test, it was found that increasing the recycle rate by 50 percent resulted in a 5 percentage point increase in SO_2 removal efficiency. It is anticipated that if the reactor bottom ash is recycled along with ESP ash, while sustaining a reactor temperature of 5 °F above saturation temperature, an SO_2 reduction of 85 percent could be maintained.

Optimization testing began in March 1994 and was followed by long-term testing in June 1994. The boiler was operated at an average load of 60 MWe during long-term testing, although it fluctuated according to power demand. The LIFAC process automatically adjusted to boiler load changes. A 2.0 Ca/S was selected to attain SO_2 reductions above 70 percent. Reactor bottom temperature was about 5 °F higher than optimum to avoid ash buildup on the steam reheaters. Atomized water droplet size was smaller than optimum for the same reason. Other key process parameters held constant during the long-term tests included the degree of humidification, the grind size of the high-calcium-content limestone, and recycle of spent sorbent from the ESP.

Long-term testing showed that SO_2 reductions of 70 percent or more can be maintained under normal boiler operating ranges. Stack opacity was low (about 10 percent) and ESP efficiency was high (99.2 percent). The amount of boiler bottom ash increased slightly during testing, but there was no negative impact on the power plant's bottom and flyash removal system. The quantity of solid waste, which is a mixture of fly ash and calcium compounds, equals the amount of limestone injected. ESP and LIFAC fly ash were readily disposed of at the same local landfill.

The LIFAC system proved to be highly operable because it has few moving parts and is simple to operate. The process can be easily shut down and restarted. The process is automated by a programmable logic system, which regulates process control loops, interlocking, start-up, shutdowns, and data collection. The entire LIFAC process was easily managed via two IBM-compatible personal computers located in the host utility's control room.

The economic evaluation indicated that the capital cost of a LIFAC installation is lower than both spray dryers and wet scrubbers. Capital costs for LIFAC technology vary depending on unit size and the quantity of reactors needed:

- $99 per kilowatt for one LIFAC reactor at Whitewater Valley Station (65 MWe)
- $76 per kilowatt for one LIFAC reactor at Shand Station (150 MWe)
- $66 per kilowatt for two LIFAC reactors at Shand Station (300 MWe)

Crushed limestone accounts for about one half of LIFAC's operating costs. LIFAC requires 4.3 tons of limestone to remove 1 ton of SO_2, assuming 75 percent SO_2 capture, a Ca/S of 2.0, and limestone containing 95 percent $CaCO_3$. If limestone costs $15 per ton, then LIFAC's operating cost would be $65 per ton of SO_2 removed.

Currently there are 10 full-scale LIFAC units in operation or under construction in Canada, China, Finland, Russia, and the United States. The LIFAC system at Richmond Power & Light is the first to be applied to a power plant using high-sulfur (2.0–2.9 percent) coal. The LIFAC system is being retained by Richmond Power & Light at Whitewater Valley Station, Unit No. 2. The other LIFAC installations on power plants using bituminous and lignite coals have lower sulfur contents (0.6–1.5 percent).

Available Reports

Final reports are scheduled for completion in mid-1995.

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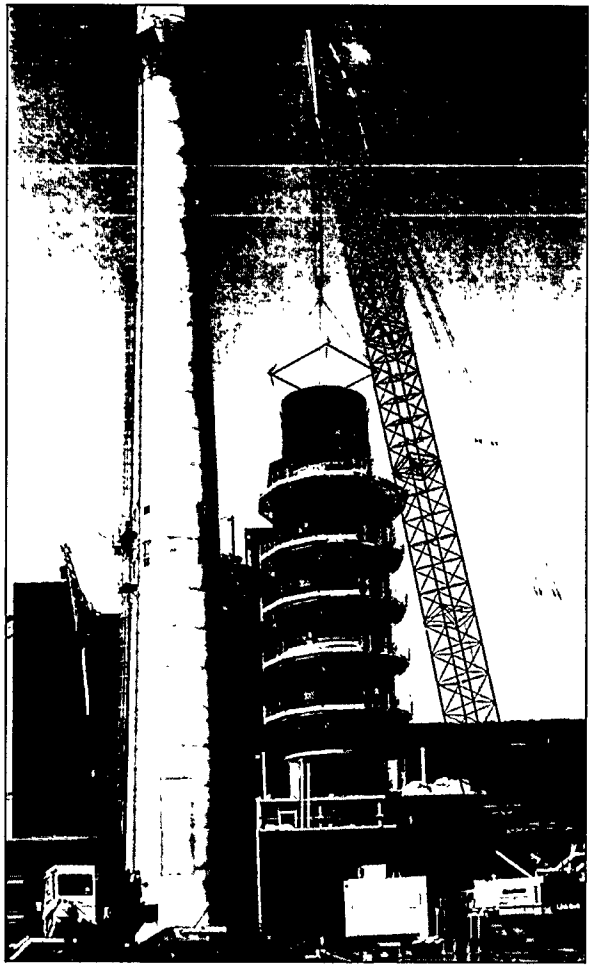
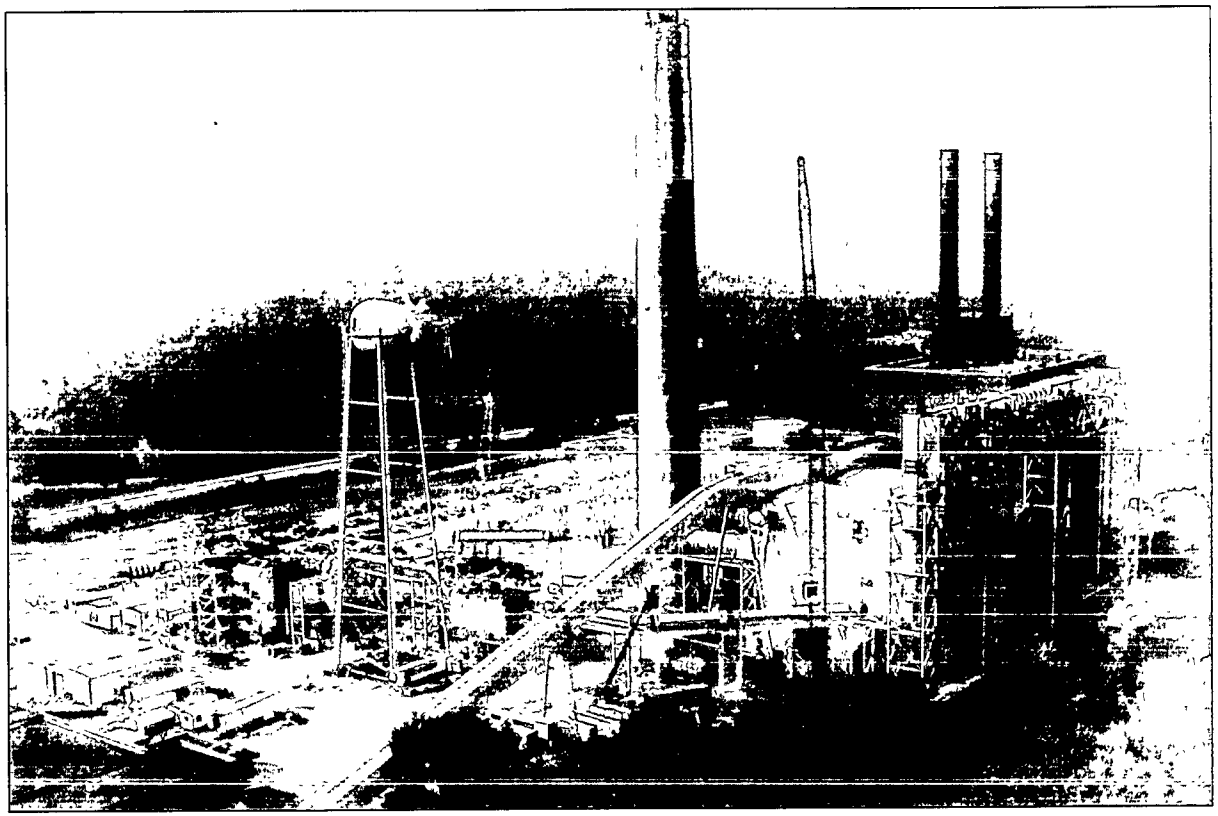


▲ The LIFAC reactor is shown after the top section was lifted into place. Long-term testing showed that SO_2 reductions of 70% or more can be maintained under normal boiler operating ranges. The system also proved to be highly operable.

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

ABB Environmental Systems has demonstrated the SNOX™ process developed by Haldor Topsoe a/s. SNOX™ is a totally catalytic process for the reduction of SO_2 and NO_x in gaseous streams. The SO_2 is converted to commercial grade sulfuric acid and the NO_x is decomposed to elemental nitrogen and water vapor. The objective of the project was to (1) demonstrate the feasibility of the SNOX™ process as applied to coal-fired power plants, (2) achieve 95 percent SO_2 removal and at least 90 percent NO_x reduction at various loads, (3) demonstrate commercial quality of the sulfuric acid produced, (4) satisfy all environmental monitoring plan requirements, and (5) perform a technical and economic characterization of the technology. The demonstration unit is installed at the Ohio Edison's Niles Station. The process is treating a 35-MWe equivalent slipstream of flue gas from the 108-MWe Unit No. 2 boiler. A high-sulfur (3.4 percent) Ohio coal is used to fire the boiler. The project was selected under the second solicitation and the cooperative agreement was awarded in December 1989. Testing was initiated in March 1992 and completed in December 1994.

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 SO_2 converter. The ash-free gas is reheated through the primary side of a gas/gas heat exchanger. An ammonia and air mixture is then added to the gas prior to the SCR where NO_x is reduced to elemental nitrogen and water. The DNX-932 catalyst used in the SCR is a high activity, titanium-oxide-based monolithic type which operates in a temperature range of 650–800 °F. The flue gas leaves the SCR, its temperature is raised slightly by an in-line burner, and enters the SO_2 converter containing Haldor Topsoe VL-WSA sulfuric acid catalyst which oxidizes SO_2 to sulfur trioxide (SO_3). The SO_3 laden gas is passed through the secondary side of the gas/gas heat exchanger where it is cooled as the incoming flue gas is heated.



A ABB Environmental Systems has successfully demonstrated the SNOX™ process at Niles Station Unit No. 2, where the process achieved 94% NO_x reduction and 95% SO_2 removal efficiency. Ohio Edison is retaining the SNOX™ plant; commercial SNOX™ plants also are in operation in Denmark and Sicily.

The processed flue gas is then passed through a falling film condenser (the WSA condenser) where it is further cooled with ambient air to below the sulfuric acid dewpoint. Acid condenses out of the gas phase on the interior of borosilicate glass tubes and is subsequently collected, cooled, and stored. The flue gas is discharged from the process at about 210 °F and cooling air leaves the WSA condenser at approximately 400 °F. In a full-scale integrated SNOX™ system, the hot air is used for process support and as boiler combustion air after increasing the temperature through the air preheater.

In order to demonstrate and evaluate the performance of the SNOX™ process, general operating data was collected and parametric tests conducted to characterize the process and equipment. The system has operated for over 7,800 hours and produced more than 5,400 tons of commercial-grade sulfuric acid.

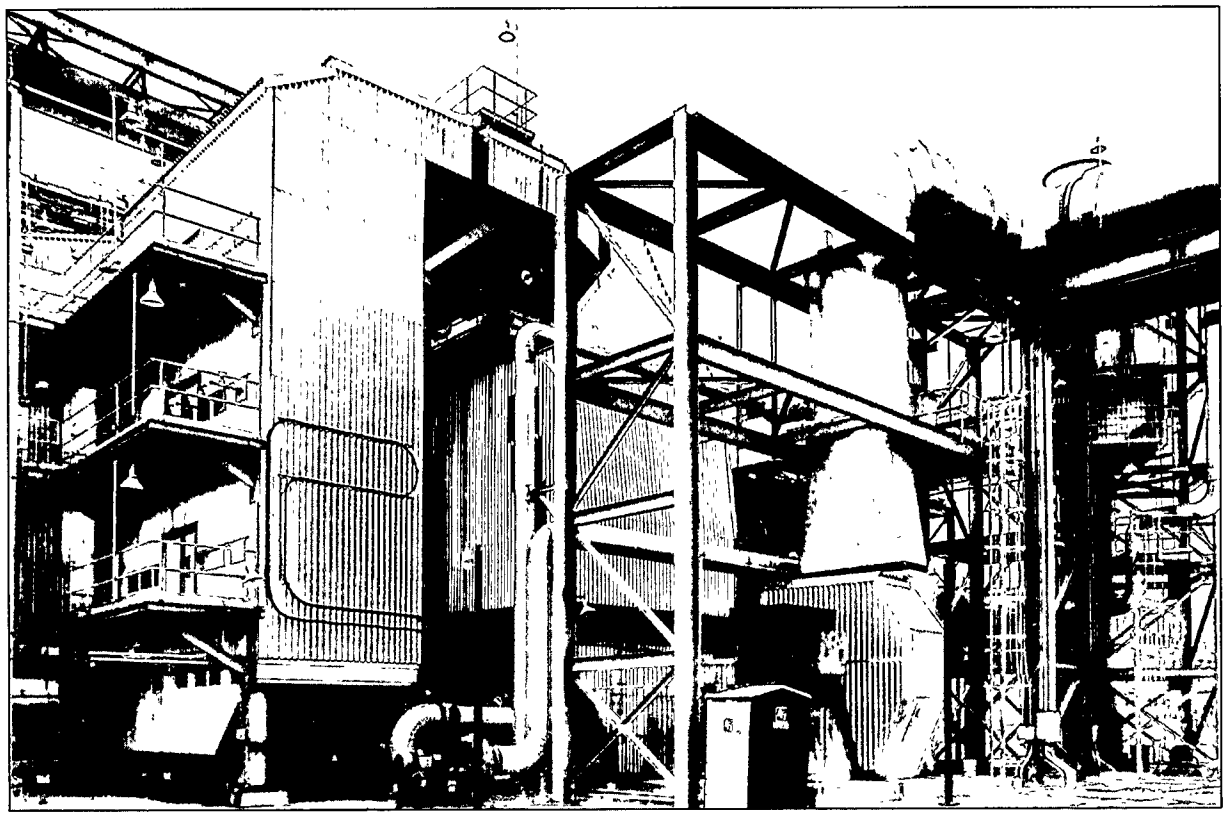
Many tests for the SNOX™ system were conducted at three loads—75 percent, 100 percent, and 110 percent of design capacity.

Sulfur dioxide removal in the SNOX™ process is controlled by the efficiency of the SO_2-to-SO_3 oxidation which occurs as the flue gas passes through the oxidation catalyst beds. The efficiency is controlled by two factors—space velocity and bed temperature. Space velocity governs the amount of catalyst which is necessary at design flue gas flow conditions, and gas and bed temperature must be high enough to activate the SO_2 oxidation reaction. During the test program, SO_2 removal efficiency was normally in excess of 95 percent for inlet concentrations averaging about 2,000 parts per million.

The SCR portion of the SNOX™ process can operate at higher than typical ammonia stoichiometrics due to its location ahead of the SO_2 catalyst beds. The excess ammonia is oxidized to nitrogen, water vapor, and a small amount of nitrogen oxide. Normal operating stoichiometrics for the SCR system are in the range of 1.02–1.05 and system reduction efficiencies averaged 94 percent with inlet NO_x levels of approximately 500–700 parts per million.

Sulfuric acid concentration and composition has met or exceeded the requirements of the federal specifications for Class I acid. During the design and construction of the SNOX™ demonstration, arrangements were made with a sulfuric acid supplier to purchase and distribute the acid from the plant. The acid has been sold to the agriculture industry for the production of diammonium phosphate fertilizer and to the steel industry for pickling. Ohio Edison has also used a significant amount in boiler water demineralizer systems throughout its plants.

▼ The SCR portion of the SNOX™ process used 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.



Air toxic testing conducted at the Niles SNOX™ plant measured the following substances:

- Five major and 16 trace elements including mercury, chromium, cadmium, lead, selenium, arsenic, beryllium, and nickel
- Acids and corresponding anions (HCL, HF, chloride, fluoride, phosphate, sulfate)
- Ammonia and cyanide
- Elemental carbon
- Radionuclides
- Volatile organic compounds
- Semi-volatile compounds including polynuclear aromatic hydrocarbons
- Aldehydes

For the majority of the species examined, especially those that exit primarily as particulates at the SNOX™ fabric filter or SNOX™ outlet, removal is very high. Because of the mechanism of sulfuric acid condensation in the WSA condenser, any particulates remaining at this point act as a nuclei for H_2SO_4 and are captured in the acid. For volatile species, the WSA condenser outlet temperature (200 °F) is lower than conventional boiler outlet temperatures (about 300 °F) and should condense and capture more of the volatile species than a plant with only an ESP or fabric filter.

The economic evaluation of the SNOX™ process shows a capital cost of approximately $250 per kilowatt and a total operating cost of approximately 1.3 mills per kilowatt-hour.

During 1993 Ohio Edison announced that it would retain the plant, and funds that were designated for dismantling were reapportioned into the operating phase of the program for testing and system modifications in addition to the Niles demonstration.

Commercial SNOX™ plants are in operation in Denmark and Sicily. In Denmark, a 305-MWe plant has been designed amd constructed and has been in operation since August 1991. The boilers at this plant burn coals from various suppliers around the world including the United States, with sulfur contents varying from 0.5 to 3.0 percent. The plant in Sicily, operating since March 1991, has a capacity of approximately 30 MWe and fires petroleum coke.

Available Reports

Final reports are scheduled to be available in March 1995.

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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.

During both LIMB and Coolside testing, Babcock & Wilcox's DRB-XCL® low-NO_x burners achieved 40–50 percent NO_x removal.

LIMB Extension

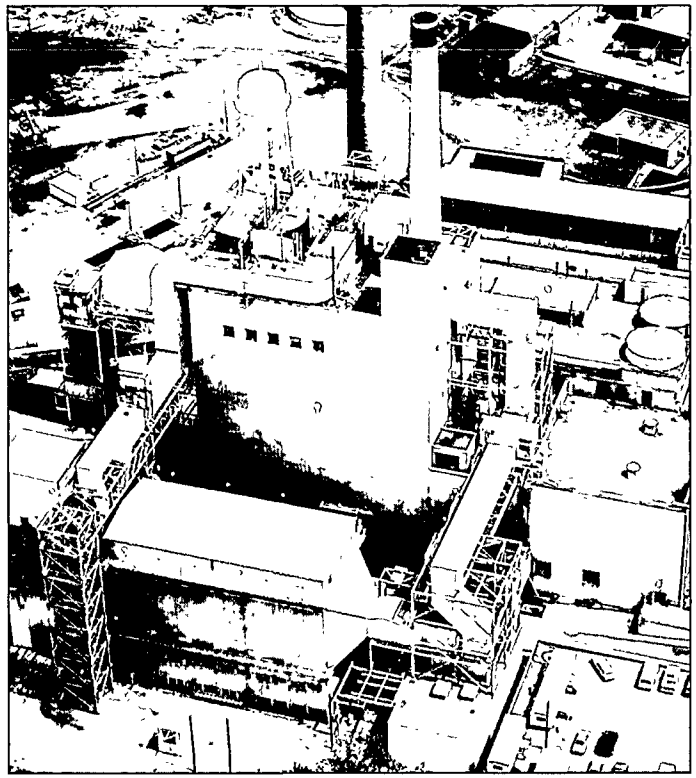
The primary purpose of the extension testing under the CCT Program was to demonstrate the generic applicability of LIMB technology. The LIMB process reduces SO_2 by injecting dry sorbent into the boiler at a point above the burners. The sorbent then travels through the boiler and is removed along with the fly ash.

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

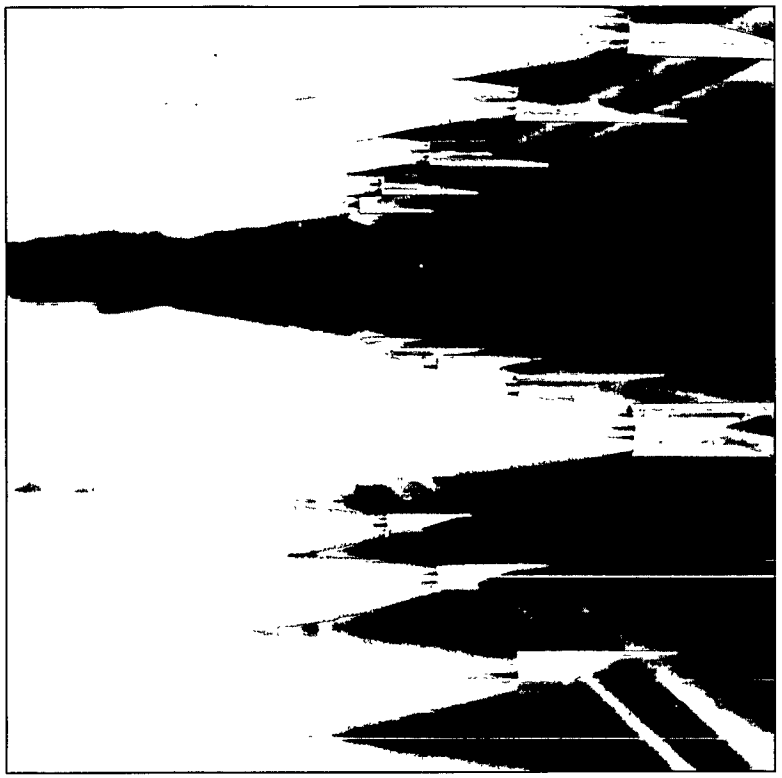
- Calcitic limestone ($CaCO_3$)
- Type-N atmospherically hydrated dolomitic lime [$Ca(OH)_2 \cdot MgO$]
- Calcitic hydrated lime [$Ca(OH)_2$]
- Calcitic hydrated lime [$Ca(OH)_2$] with added calcium lignosulfonate (ligno lime)

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.

- **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



▲ Babcock & Wilcox demonstrated LIMB and Coolside processes on Ohio Edison's Edgewater Station. LIMB achieved 61% SO_2 removal efficiency and Coolside, 70%. 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%.

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 stoichio-metry 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 levelized 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 falls 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

- T.R. Goots, M.J. DePero, and P.S. Nolan. *LIMB Demonstration Project Extension and Coolside Demonstration: Final Report.* Report No. DOE/PC/79798-T27. The Babcock & Wilcox Company. November 1992. (Available from NTIS as DE 9300-5979.)
- D.C. McCoy et al. *The Edgewater Coolside Process Demonstration: A Topical Report.* Report No. DOE/PC/79798-T26. CONSOL, Inc. February 1992. (Available from NTIS as DE 9300-1722.)
- *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.)

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

The Babcock & Wilcox Company completed the demonstration of the SOx-NOx-Rox-Box™ (SNRB™) process for the combined removal of SO_2, NO_x, and particulates in one piece of the equipment—a high-temperature baghouse. SNRB™ incorporates dry sorbent injection for SO_2 emissions control, selective catalytic reduction 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 SO_2 removal and 90 percent or higher reduction in NO_x emissions while maintaining particulate emissions below 0.03 pound per million Btu.

Four different sorbents were tested for SO_2 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 SO_2

▲ Babcock & Wilcox successfully demonstrated the SNRB™ process at Ohio Edison's R.E. Burger Plant Unit No. 5. The project achieved SO_2 removal efficiencies exceeding 80% and NO_x reductions of 90%.

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 and above resulted in SO_2 removals of over 80 percent.
- At a Ca/S of 2.0, 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 calcium 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 using sodium bicarbonate was 80 percent at 1.0 Na_2/S and 98 percent at 2.0 Na_2/S 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 as low as 1.5 and Na_2/S less than 1.0.

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 SO_2 sorbent for a system designed for 85–90 percent SO_2 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 was delivered in August 1994. The economic evaluation report is expected in March 1995.

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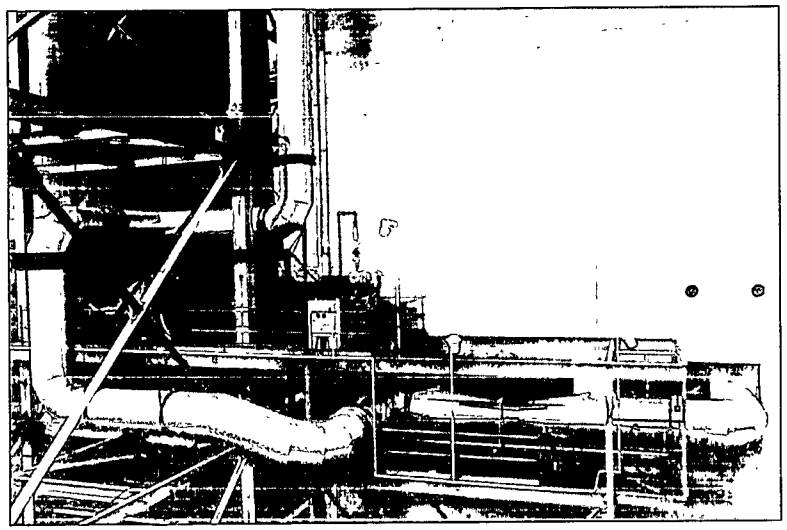
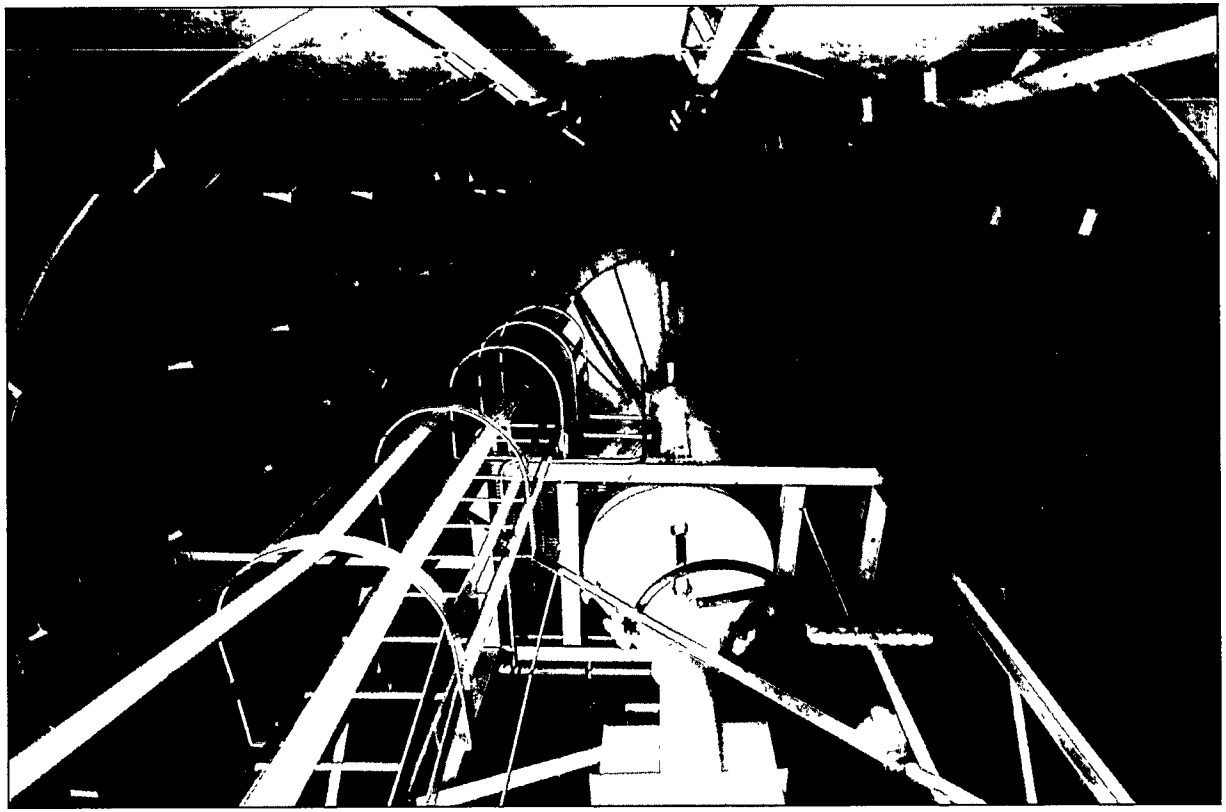
▼ Shown here are SNRB™ duct work, tie-in, and propane heater.



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

The Energy and Environmental Research Corporation (EER) has conducted a demonstration of gas reburning and sorbent injection (GR–SI) at the tangentially fired Illinois Power Hennepin Plant Unit 1 and the cyclone-fired Lakeside Station Unit 7 of City Water, Light and Power. The gas reburning (GR) process consists of injection of natural gas corresponding to 15–25 percent of the heat input at a location above the coal burners to create a fuel-rich zone which will allow the reduction of NO_x formed in the coal zone to molecular nitrogen. Over-fire air is injected at a higher elevation to burn out the fuel combustibles under fuel-lean conditions. In the sorbent injection (SI) process, a calcium-based sorbent such as calcium hydroxide [$Ca(OH_2)$] is injected into the upper furnace to react with flue gas SO_2 resulting in the formation of calcium sulfate ($CaSO_4$) and calcium sulfite ($CaSO_3$). These solids are carried from the boiler and captured with the fly ash in the particulate collection device.

The GR–SI project was selected in the first solicitation and the cooperative agreement was awarded in July 1987. The following summary of results addresses the Hennepin and Lakeside demonstrations separately.



▲ The GR–SI was demonstrated at Illinois Power's Hennepin Station and City Water, Light and Power's Lakeside Station. SO_2 removal efficiency ranged from about 52% to over 80%, depending on the type and amount of sorbent used. This photograph shows the inside of the sorbent silo.

Hennepin Plant Unit 1

Hennepin Plant Unit 1 is a 71-MWe (net) or 80-MWe (gross) tangentially fired unit designed by Combustion Engineering. The unit was retrofitted with a GR–SI system designed by EER. Operational testing, which included optimization testing, and long-term testing were conducted between January 1991 and January 1993. The project goal was a reduction in NO_x emission by 60 percent, from a baseline of 0.75 pound per million Btu and SO_2 emissions from a baseline of 5.30 pounds per million Btu.

The GR–SI long-term demonstration tests were carried out from January 1992 to October 1992 to verify the system performance over an extended

period. The unit was operated at constant loads and with the system under dispatch operation where load was varied to meet plant power output requirements. With the system under dispatch, the load fluctuated over a wide range from 40 MWe to a maximum load of 75 MWe. Over the long-term demonstration period, the average gross power output was 62 MWe.

For the long-term demonstration testing, the average NO_x reduction was approximately 67 percent. The average SO_2 removal efficiency was over 52 percent at a Ca/S molar ratio of 1.76. (Linwood hydrated lime was used throughout these tests except for a few days when Marblehead lime was used.) CO emissions were below 50 parts per million in many cases but were higher during operation at low load.

A significant reduction in CO_2 was also measured. This was due to partial replacement of coal with natural gas having a lower C/H ratio. This cofiring with 18 percent natural gas results in a theoretical CO_2 emissions reduction of nearly 8 percent from coal-fired baseline level. With flue gas humidification, ESP collection efficiencies greater than 99.8 percent and particulate emissions less than 0.025 pound per million Btu were measured even with an increase in inlet particulate loading resulting from sorbent injection. These are comparable to measured baseline emissions of 0.035 pound per million Btu and a collection efficiency greater than 99.5 percent.

Following the completion of the long-term tests, three specially prepared sorbents were tested. Two were manufactured by EER and contained proprietary additives to increase their reactivity toward SO_2 and were referred to as PromiSORB™ A and B. The other sorbent was developed by the Illinois State Geological Survey. It was a high-sulfur and hydrated lime which uses alcohol to form a material that gives rise to a much higher than normal surface area per unit rate than the atmospherically hydrated limes.

The SO_2 capture, without GR, at a nominal 1.75 Ca/S molar ratio, was 54 percent for PromiSORB™ A, 66 percent for PromiSORB™ B, 59 percent for high-surface-area hydrated lime, and 42 percent for Linwood lime. At a 2.6 Ca/S the PromiSORB™ B gave 80 percent SO_2 removal efficiency.

Illinois Power, the host company has decided to retain the gas reburn system. EER states that GR, SI, and combined GR–SI are ready for commercial application.

Lakeside Station Unit 7

Lakeside Station Unit 7 is a 33-MWe (net) or 40-MWe (gross) pressurized cyclone unit fired with Illinois bituminous coal containing 3 percent sulfur. Operational testing of Lakeside was initiated in May 1993 and completed in October 1994. The operational tests included the following:

- Parametric tests involved optimization of GR–SI parameters to comply with the specific operating characteristics of a cyclone unit.
- Long-term tests involved operation of the GR–SI process throughout the unit's normal 9-month duty cycle to determine process performance during normal dispatch operation.
- Extended operation involved continuous operation of the GR–SI to determine effects of continuous operation on process performance, GR–SI equipment performance, and the unit's thermal performance.

Parametric tests were conducted in three series: GR parametric tests, SI parametric tests, and GR–SI optimization tests. A total of 100 GR parametric tests were conducted at boiler loads of 33, 25, and 20 MWe. Gas heat input varied from 5 to 26 percent. The GR parametric tests achieved a NO_x reduction of approximately 60 percent at gas heat input of 22–23 percent. Additional flow modeling and computer modeling studies indicated that smaller reburning fuel jet nozzles could increase reburning fuel mixing and consequently improve the NO_x reduction performance.

A total of 25 SI parametric tests were conducted to isolate the effects of sorbent on boiler performance and operability. Results showed that SO_2 reduction level varied with load because of the effect of temperature on the sulfation reaction. Full load, corresponding to flue gas temperatures near the 2,200 ^{0}F optimum observed at pilot scale and the full-scale Hennepin GR–SI demonstration, resulted in higher SO_2 reductions compared to the other two operating loads. At a Ca/S of 2.0, 44 percent SO_2 reduction was achieved at full load (33 MWe); 38 percent SO_2 reduction was achieved at mid-load (25 MWe); and 32 percent SO_2 reduction was achieved at low load (20 MWe).

In the GR–SI optimization tests, the two technologies were integrated. Modifications were made to the reburning fuel injection nozzles based on the results of the initial GR parametric tests and flow modeling studies. The total cross-sectional area of the reburning jets was decreased by 32 percent to increase the reburning jet's penetration characteristics. The decrease in nozzle diameter increased NO_x reduction by an additional 3–5 percent compared to the

initial parametric tests. With GR-SI, total SO_2 reductions resulted from partial replacement of coal with natural gas and sorbent injection. SO_2 reductions above the 50 percent reduction goal were achieved with Ca/S molar ratios greater than 1.5 along with gas heat inputs of 22–25 percent.

The primary goal of the long-term testing was to operate the GR–SI during normal operating cycle of the Lakeside unit. The NO_x and SO_2 reduction goals were to be achieved while maintaining the unit's operability and availability during the 9-month test period. The unit typically operated in cycling service with a very low capacity factor. The average NO_x reduction during the long-term testing was 67 percent after a total of 249 hours of GR operation. The average SO_2 reduction after 223 hours of GR–SI operation was 58 percent.

During the demonstration program, loss on ignition (LOI) for fly ash was determined only under GR operations. LOI varied from 7 percent to 14 percent with GR; the baseline LOI was in the range of 3–12 percent in 1991, before this demonstration. LOI varied somewhat with boiler load. Part of the weight loss caused by igniting a sample to determine LOI was due to the burning of carbon; the balance was made up of other materials. The LOI with GR was within the range of the baseline measurement. This indicated that GR most likely did not increase LOI and therefore did not decrease efficiency.

There were two extended GR-SI runs of 38 and 64 hours duration each. The 38-hour run was conducted at 29 MWe with a gas input of 22.4 percent and a Ca/S molar ratio of 1.67. The average NO_x emission was 0.311 pound per million Btu, a 66 percent reduction, and the average SO_2 emission was 2.338 pounds per million Btu, a 60 percent reduction. The 64-hour run was carried out at 29 MWe with a gas input of 21.6 percent and a Ca/S molar ratio of 1.75. The average NO_x emission was 0.325 pound per million Btu, a 64 percent reduction. The average SO_2 emission was 2.18 pounds per million Btu, a 63 percent reduction.

The NO_x control cost with gas reburning has been calculated to be $979 per ton removed for a 47 percent reduction achieved with a gas heat input of 14 percent. For a gas heat input of 24 percent and a 60 percent NO_x reduction, the cost is $1,318 per ton of NO_x removed. For sorbent injection, 29 percent SO_2 removal costs $425 per ton at a Ca/S molar ratio of 1.0. At the 45 percent removal level, using a Ca/S molar ratio of 2.0, SO_2 removal costs $514 per ton. The SO_2 removal costs given do not include the substitution of natural gas for coal.

Energy and Environmental Research Corporation is offering GR for NO_x control to a variety of utilities. GR in combination with agent injection, a process called advanced gas reburning (AGR), has achieved NO_x reduction in excess of 80 percent at the pilot scale. AGR and/or GR may be suitable for many power plants in the northeast which are required to meet NO_x emission limits.

Available Reports

- *Enhancing the Use of Coals by Gas Reburning and Sorbent Injection; Volume 2: Reburning—Sorbent Injection at Hennepin Unit 1, Illinois Power Company.* Energy and Environmental Research Corporation. October 1994.
- *Enhancing the Use of Coals by Gas Reburning and Sorbent Injection; Volume 3: Reburning—Sorbent Injection at Edwards Unit 1, Central Illinois Light Company.* Energy and Environmental Research Corporation. October 1994.
- *Reduction of NO_x and SO_2 Using Gas Reburning, Sorbent Injection and Integrated Technologies.* Topical Report No. 3. U.S. Department of Energy and Energy and Environmental Research Corporation. September 1993.

The final report for the Lakeside site as well as the public design and economic evaluation reports are expected to be available in mid-1995.

Contact

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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 Tampella-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.

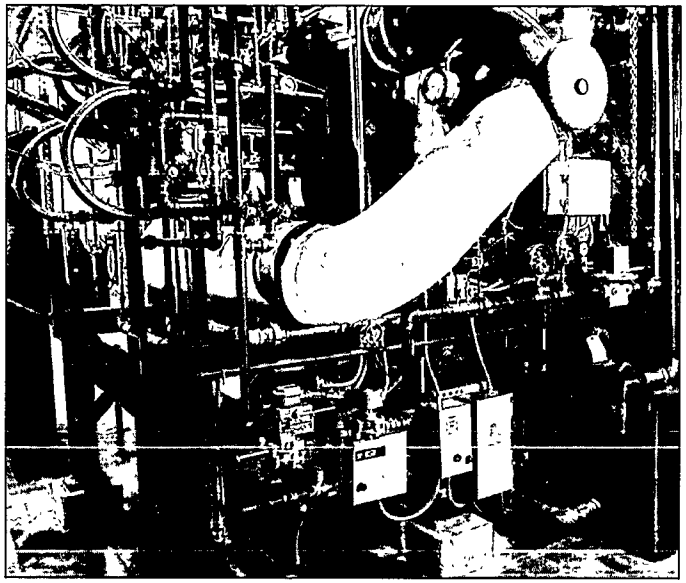
The test effort consisted of 800 hours of operation which included five individual tests, each of 4 days duration. An additional 100 hours were performed as part of separate ash vitrification tests. Pennsylvania bituminous coals with 1.1–3.1 percent sulfur content were used throughout the demonstration. 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.

- **Objective 2—To achieve 70–90 percent SO_2 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 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 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



▲ Coal Tech's advanced ceramic-lined slagging cyclone combustor was retrofitted to a package boiler at the Tampella-Keeler boiler factory. Testing resulted in SO_2 reductions over 80% and NO_x reductions of 75%.

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 through 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-T1. 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.)

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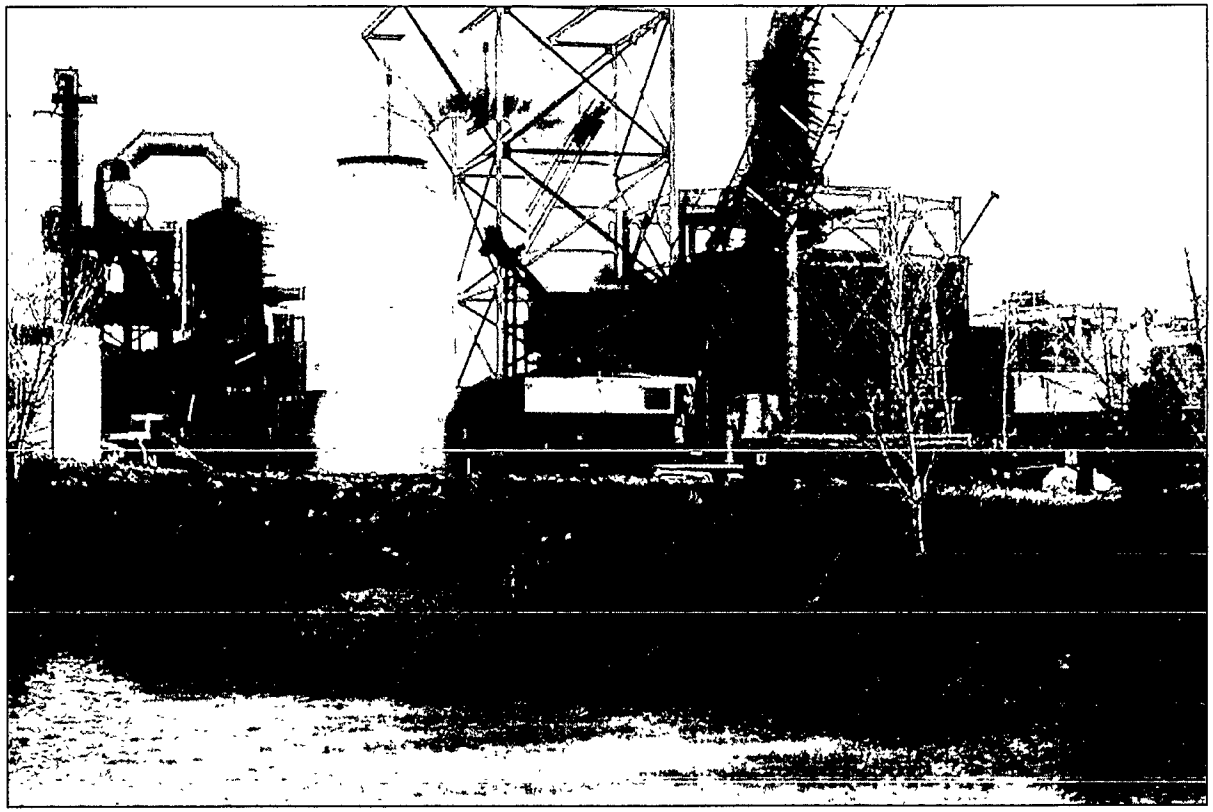
Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)

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 kiln; (2)significantly reduce emissions of SO_2 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 SO_2 and treated 6,000 tons of cement kiln dust for return to the kiln as raw feed. Long-term



▲ The Passamaquoddy Technology Recovery Scrubber™ was demonstrated by the Passamaquoddy Tribe at Dragon Products' coal-burning cement plant. The scrubber system achieved more than 90% SO_2 reduction using waste kiln dust. The scrubber has become a permanent part of the Dragon facility.

removal efficiency for SO_2 was 90–92 percent. For SO_2 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 SO_2. 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 SO_2 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™: Final Report.* Volumes 1 and 2. Passamaquoddy Tribe. February 1994. (Volume 1 available from NTIS as DE 9401-1175-T3, Volume 2 as DE 9401-1176-T3.)
- *Passamaquoddy Technology Recovery Scrubber™: Public Design Report.* Passamaquoddy Tribe. October 1993.
- *Passamaquoddy Technology Recovery Scrubber™: Topical Report.* Report No. DOE/PC/89657-T1. Passamaquoddy Tribe. March 1992. (Available from NTIS as DE 9201-9868.)

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6. Results and Accomplishments from Ongoing Projects

Introduction

By the end of 1994, the CCT Program consisted of 45 projects. A total of 13 projects have successfully completed operations and fulfilled all reporting requirements or are preparing the final project documentation. An additional 10 projects are in operations, 6 are in construction, 15 are in design and project definition, and 1 CCT-V project is currently in negotiation.

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 which are now in operation or under construction. (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 $4.8 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 about 10,300 hours of operation on coal and more than 5,000 hours of operation with hot particulate recovery filters on a slipstream of product gas. Two projects are in construction. A formal groundbreaking ceremony for the Tampa Electric Integrated Gasification Combined-Cycle Project (250 MWe) in Lakeland, Florida, was held on November 2, 1994; operations are expected to begin in late 1996. For the Wabash River Coal Gasification Repowering Project (262 MWe) in West Terre Haute, Indiana, construction is about 70 percent complete and operations are scheduled to begin in September 1995. Ten other projects are in design; one CCT-V project is in negotiation.

Advanced electric power generation technologies are characterized by high thermal efficiency, very low SO_2 and NO_x emissions, reduced CO_2 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.

Nearly 4 years of pioneering work have been accomplished at the Tidd PFBC Demonstration Project, leading to the establishment of a sound database for

Exhibit 6-1
Highlighted CCT Projects, by Application Category

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.

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)

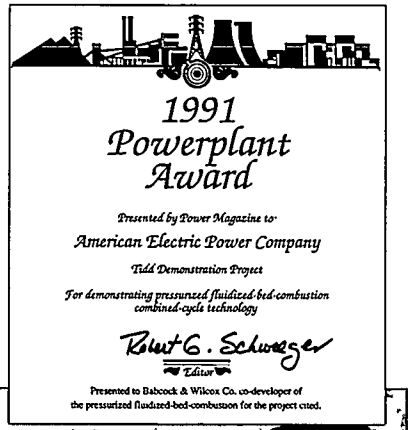
In the Tidd PFBC Demonstration Project, which is being directed by the American Electric Power Service Corporation and conducted by the Ohio Power Company, the Unit 1 boiler of Ohio Power's Tidd Plant was replaced with a 70-MWe PFBC combined-cycle system. The PFBC technology is expected to reduce SO_2 emissions by at least 95 percent and NO_x emissions by 70 percent.

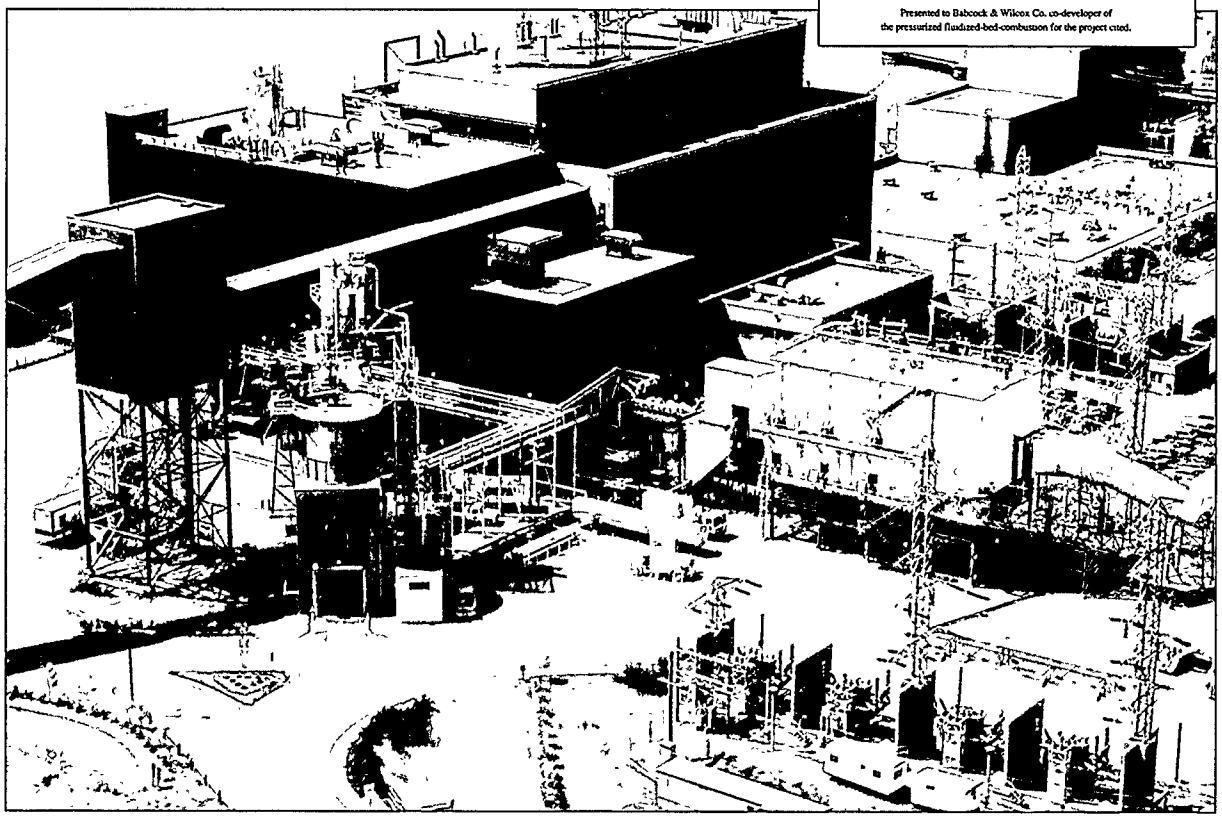
During 1994, approximately 4,800 hours of coal-fired operation were achieved, bringing the cumulative total since February 1991 to approximately 10,300 hours. During 1994, Tidd produced 219,000 megawatt-hours of gross power generation and completed 39 parametric tests. SO_2 emissions reductions of more than 90 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.

The unit has been modified to route one-seventh of its flow of hot flue gases through advanced ceramic hot-gas filtration elements. Approximately 5,000 hours of operation with hot-particulate filters have been achieved.

Operational testing has been extended into 1995 to obtain additional data on long-term gas turbine survivability, economical sulfur capture at a 95 percent level, and exposure of advanced ceramic filtration devices.

▼➤ In operation since 1991, the Tidd PFBC combined-cycle system has operated for approximately 10,300 hours. In 1994 approximately 4,800 hours of coal-fired operations were achieved and produced over 219,000 MWh of gross power generation. American Electric Power Company was awarded *Power Magazine's* 1991 Powerplant Award and in 1992 the company received a National Energy Resource Organization award for demonstration of energy efficient technology.

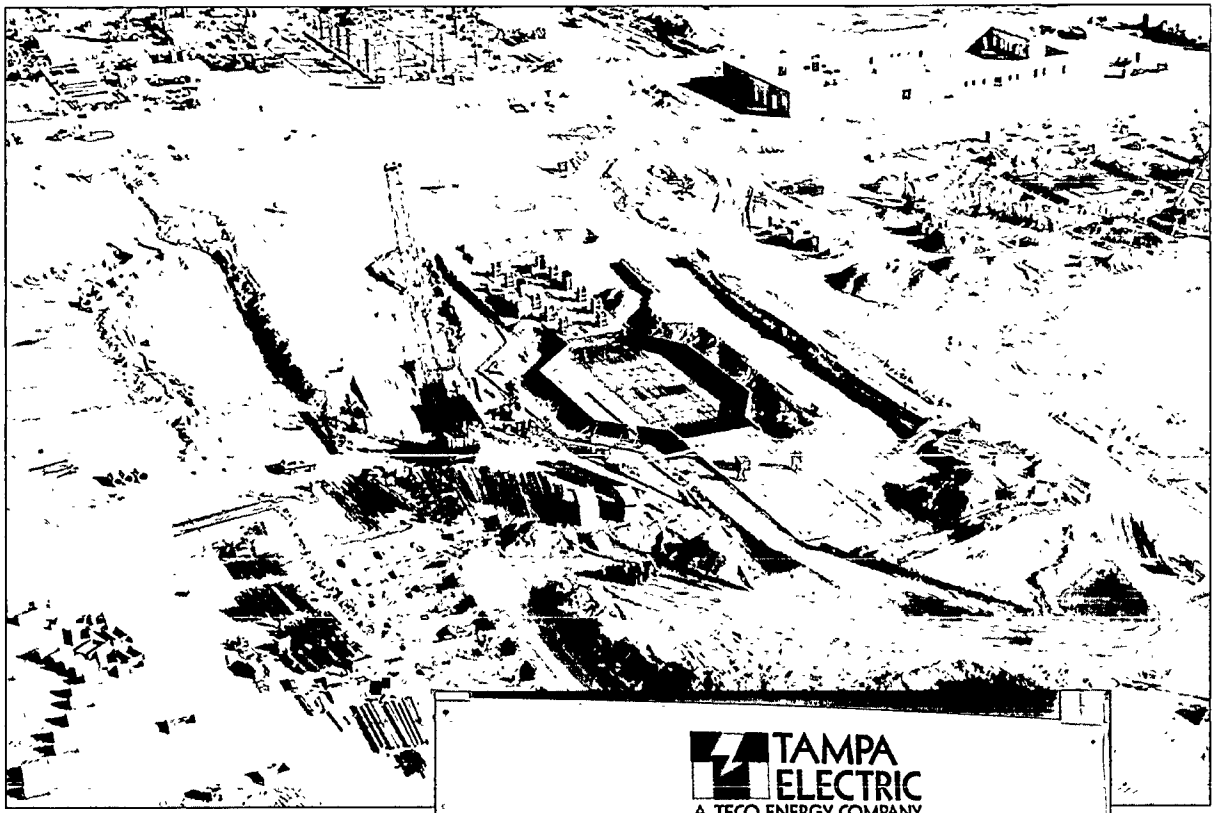


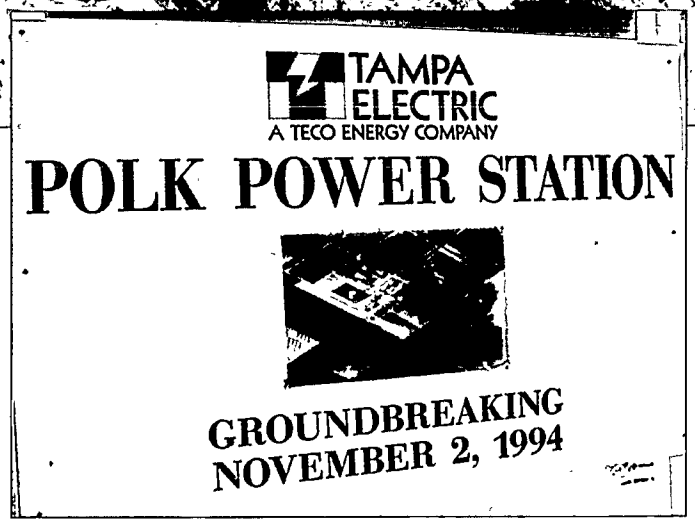


Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)

The Tampa Electric Integrated Gasification Combined-Cycle Project will demonstrate a utility application of IGCC using Texaco's pressurized, oxygen-blown, entrained-flow gasifier and the integrated performance of a metal oxide hot-gas cleanup system, conventional cold-gas cleanup, and an advanced gas turbine with nitrogen injection for power augmentation and NO_x control. The project involves only the first 250-MWe (net) IGCC portion of the planned 1,150-MWe Polk Power Station in Lakeland, Florida. The gasifier is being designed to use about 2,000 tons per day of bituminous coal containing 2.5–3.5 percent sulfur. The anticipated heat rate for the IGCC system is approximately 8,600 Btu per kilowatt-hour (40 percent thermal efficiency). SO_2 emissions are expected to be below 0.21 pound per million Btu (96 percent capture). Thermally generated NO_x is expected to be controlled to less than 0.27 pound per million Btu by injecting nitrogen as a diluent in the gas turbine's combustion section.

The final EIS was released for public comment on June 10, 1994; DOE issued a favorable record of decision on the demonstration project on August 17, 1994. A groundbreaking ceremony was held on November 2, 1994. Construction is expected to be completed by about mid-1996 and will be followed by a 2-year demonstration period.





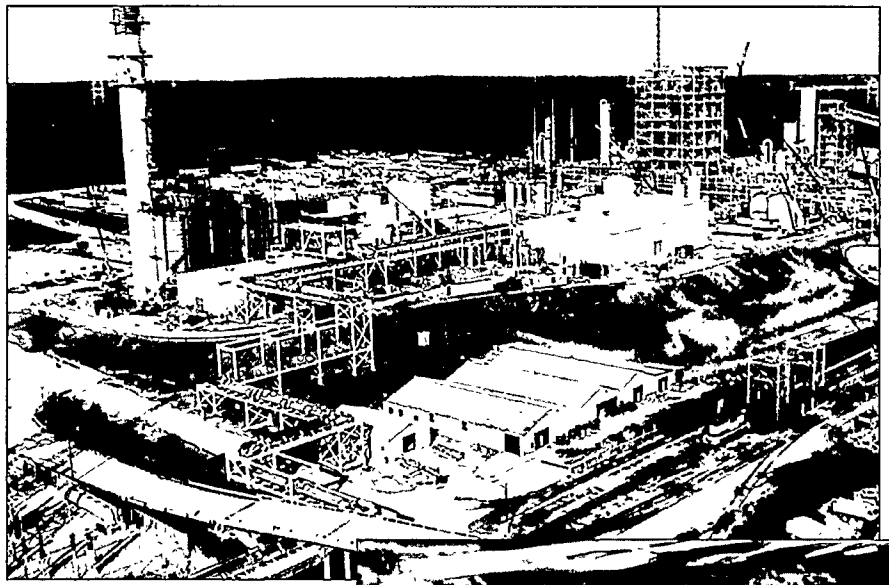
▲► On November 2, 1994, the groundbreaking ceremony was held for the 250-MWe (net) IGCC portion of the planned 1,150-MWe Polk Power Station in Lakeland, FL. Progress on the gasification tower foundation is shown in the right center of the photograph (above).

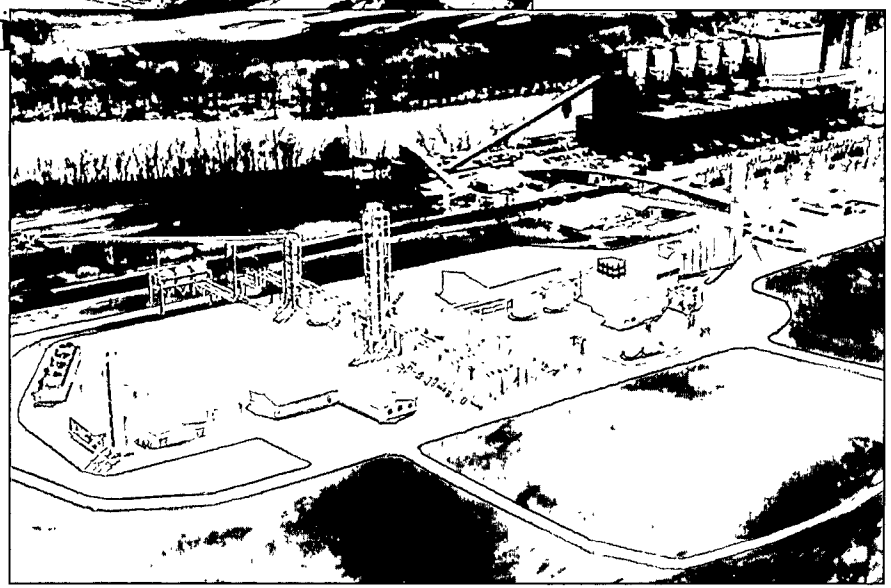
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)

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 (38 percent thermal efficiency), or a 21 percent increase in station efficiency. SO_2 emissions are expected to be less than 0.1 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).

By year-end 1994, construction was about 70 percent complete. Design specifications for several vessels have been modified to incorporate recent experience from Destec Energy's operating unit located in Plaquemine, Louisiana.





◄ ▼ By year-end 1994, construction of the Wabash River Coal Gasification Repowering Project was about 70% complete. The photograph (left) shows Destec Energy's two-stage, oxygen-blown gasifier tower at right and the IGCC heat exchanger and stack at left. The artist concept of the final plant (below) is superimposed next to the existing PSI Energy's Wabash River Generating Station.

Environmental Control Devices

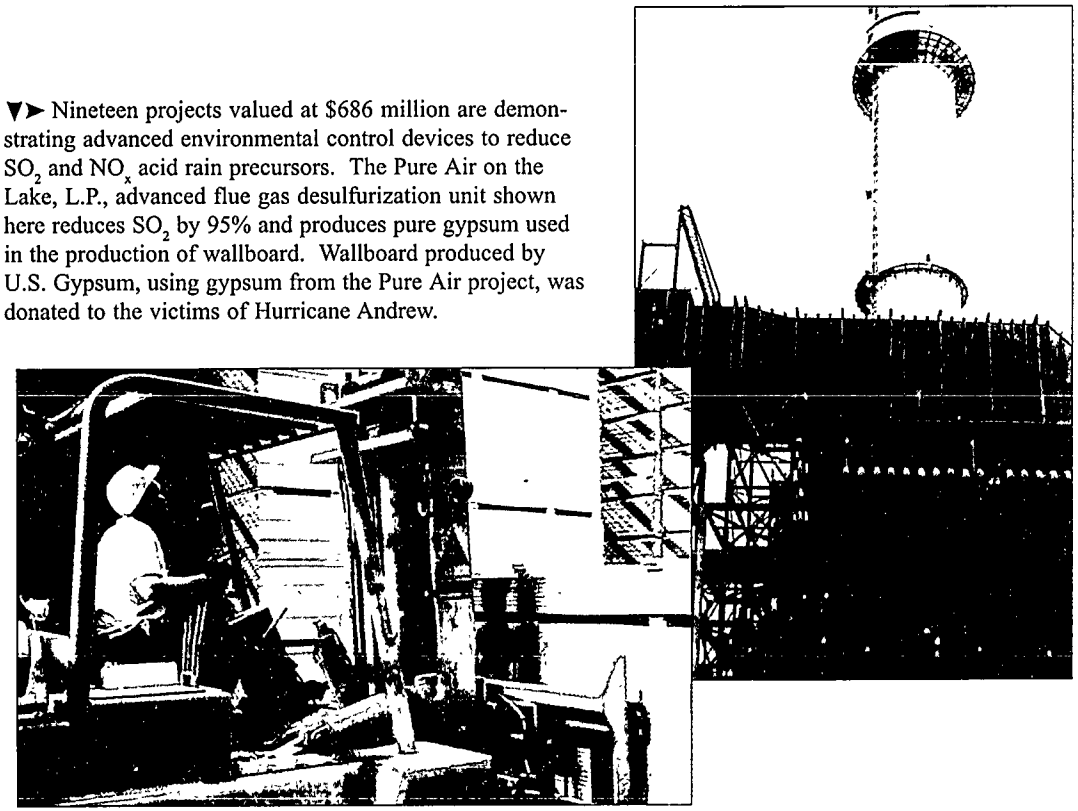
The environmental control devices category includes the largest number of projects, 19; their total value exceeds $686 million. These projects represent approximately 1,700 MWe of NO_x control, 770 MWe of SO_2 control, and 765 MWe of combined SO_2/NO_x control technology demonstrations. A total of 10 projects have completed operations (see Section 5). Six projects are operational, one is in construction, and two are in design.

The projects are demonstrating technologies for SO_2 or NO_x emissions control or for combined SO_2/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. Studies indicate that the January 1, 1995, SO_2 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 SO_2 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 SO_2 limits which will require solutions of a more technological nature. Two advanced flue gas desulfurization technologies are routinely achieving over 95 percent capture of SO_2 and producing wallboard-grade gypsum as a by-product instead of solid waste for disposal.

Almost all of the NO_x control projects have completed testing or are nearing the end of operational testing. The utility sector requires answers now on how to solve the problems of NO_x emissions control and the CCT Program along with project participants are responding. Four 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. Babcock & Wilcox has installed its LNCB® technology on more than 2,500 MWe of capacity in the United States—in each case achieving more than 50 percent NO_x reduction. In addition, LNCB® retrofits (introduced in early 1993) have been ordered for an additional 3,250 MWe.

Most of the combined SO_2/NO_x control systems have completed testing. These systems have demonstrated SO_2 removal efficiencies of over 90 percent and NO_x reduction efficiency of about 90 percent.



▼► Nineteen projects valued at $686 million are demonstrating advanced environmental control devices to reduce SO_2 and NO_x acid rain precursors. The Pure Air on the Lake, L.P., advanced flue gas desulfurization unit shown here reduces SO_2 by 95% and produces pure gypsum used in the production of wallboard. Wallboard produced by U.S. Gypsum, using gypsum from the Pure Air project, was donated to the victims of Hurricane Andrew.

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

A gas reburning system combined with low-NO_x burners (GR–LNB) was installed and evaluated on a 172-MWe (gross) wall-fired boiler. The host boiler for this project was Cherokee Station Unit 3 owned and operated by the Public Service Company of Colorado (PSCC). The boiler is a balanced-draft pulverized-coal unit supplied by Babcock & Wilcox. The gas reburn (GR) system including an over-fire air system was designed and installed by Energy and Environmental Research Corporation. The low-NO_x burner (LNB) was designed and installed by Foster Wheeler. Gas reburning involves firing natural gas (up to 20 percent of the total fuel input) above the main coal combustion zone 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.

Parametric testing was begun in October 1992 and completed in April 1993. The parametric tests were conducted by changing the process variables (such as zone stoichiometrics, percent gas input, percent over-fire air, load) and determining the effects of these variables on NO_x reduction, SO_2 reduction, CO emissions, carbon in ash, and heat rates. The tests showed that the use of LNB alone reduced NO_x emissions more than 30 percent from the baseline. For both GR and LNB, the reduction was more than 70 percent from the baseline.

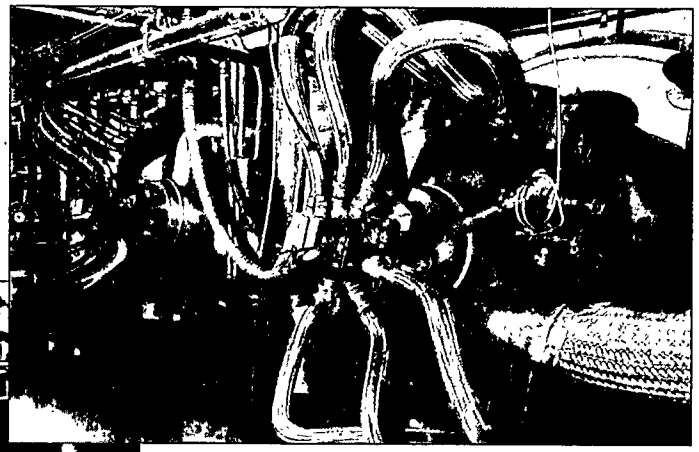
Natural gas also reduced SO_2 emissions in proportion to the gas input. At the Cherokee Station, using low-sulfur (0.4 percent) coal, the typical SO_2 emissions were 0.65 pound per million Btu. With a gas input of 20 percent, SO_2 emissions decreased by 20 percent to 0.52 pound per million Btu.

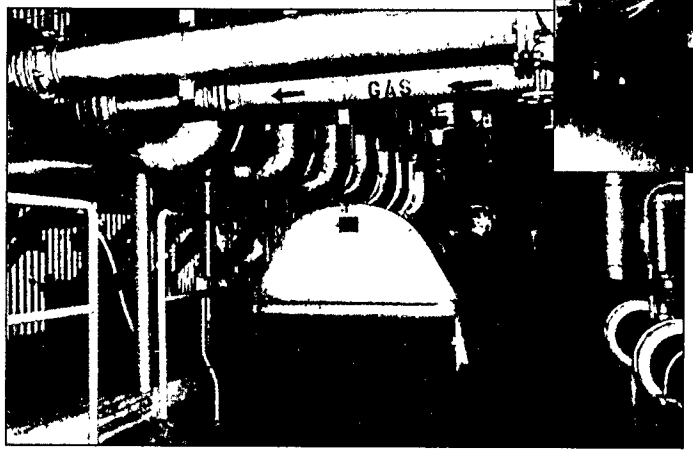
The CO_2 emissions were also reduced as a result of using natural gas, which has a lower C/H ratio than coal. At a gas heat input of 20 percent, the CO_2 emissions were reduced by 8 percent.

Long-term testing was initiated in April 1993 and is scheduled to be completed in January 1995. The long-term test results confirmed the parametric test results. The combined GR–LNB achieved NO_x reductions of 60–73 percent. NO_x reductions of 60–65 percent were achieved with gas heat input of 5–10 percent. NO_x reduction by low-NO_x burners alone was typically 30–40 percent. NO_x emissions were insensitive to a change in recirculated flue gas flow employed to inject the natural gas.

By the end of 1994, the Cherokee systems had been operated for more than 4,200 hours. This operating time was divided into two sections. The first 3,100 hours involved conventional GR–LNB where flue gas recirculation was used. The next 1,100 hours involved second generation GR without flue gas recirculation, gas–gas-reburning/cofiring, and advanced over-fire air.

The second generation GR demonstration work established that flue gas recirculation was not necessary to reduce NO_x emissions by 62 percent. This means that construction time and capital can be conserved, reducing estimated costs from $16–40 per kilowatt down to $10–20 per kilowatt.





◄▲ These low-NO_x burners, installed at the Cherokee Station, are capable of firing gas or coal. Long-term tests conducted throughout 1994 showed that combined GR–LNB achieved NO_x reductions of 60–73%. The natural gas supply lines meet the flue gas recirculating line at the points of intersection just outside of 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 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.

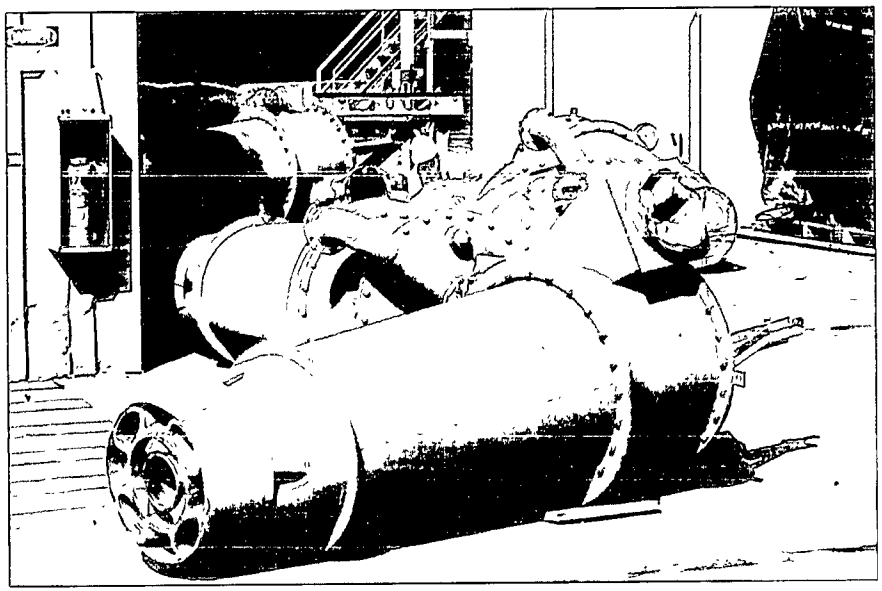
However, preliminary analysis of the emissions data suggests that the incremental NO_x reduction effectiveness of the AOFA system (above LNB alone) was approximately 17 percent, with additional reductions resulting from other operational changes.

On June 4, 1994, Plant Hammond Unit 4 resumed operation following a 9-month outage. The major activities during this outage included (1) installation of the digital control system, (2) replacement of two remaining mills, (3) replacement of the precipitator, (4) upgrade of the low-pressure turbine, and (5) burner repairs and modifications. By year-end 1994, the digital control system was operational and design of the artificial intelligence software package for optimizing NO_x reduction and boiler efficiency neared completion.

A report on the air toxics testing with the combined AOFA/LNB configuration was issued in December 1993.

Completion of the demonstration project and issuance of the final report are scheduled for April 1995.

➤ The Foster Wheeler split-flow, split-flame low-NO_x burners shown here were able to achieve a 48% reduction in NO_x. Full-load long-term NO_x emissions reductions of over 65% were achieved using the low-NO_x burners and advanced over-fire air.

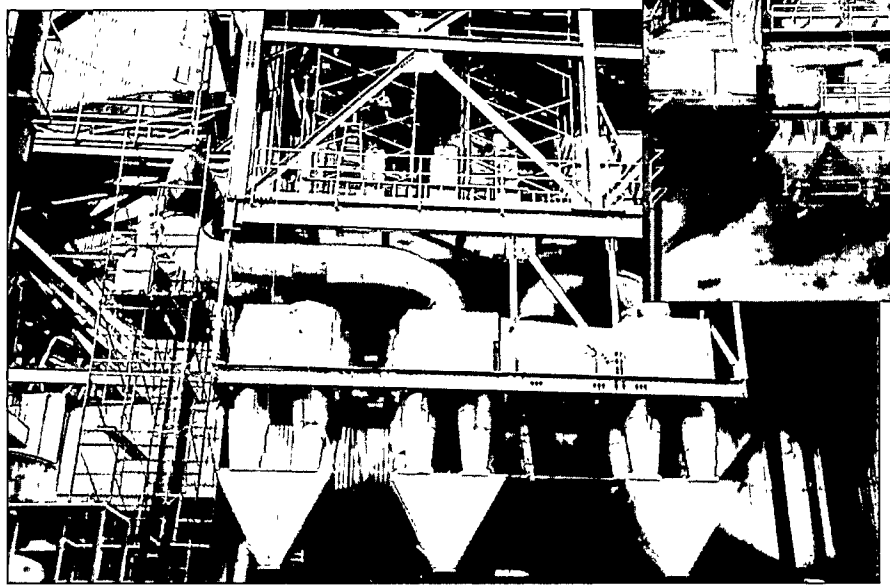


Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers (Southern Company Services, Inc.)

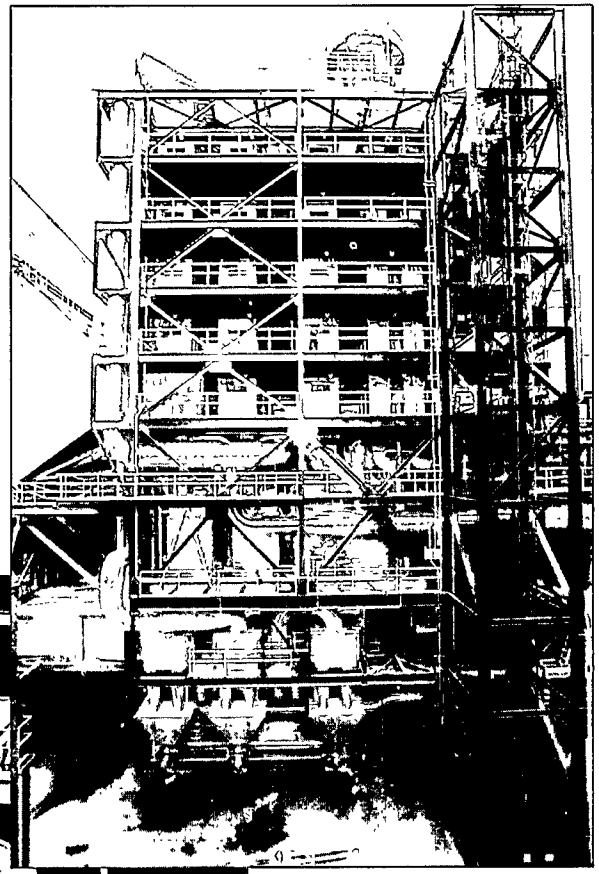
The Southern Company Services, Inc., is demonstrating selective catalytic reduction (SCR) technology which consists of injecting ammonia into boiler flue gas and passing it through a catalyst bed where NO_x and ammonia react to form nitrogen and water vapor. The demonstration facility, located at Gulf 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.

Long-term performance testing began in July 1993; operations will continue into mid-1995. The start-up and commissioning tests demonstrated that each of the SCR reactors is operating on the same basis in terms of process gas feed. Distribution measurements on the individual reactors are in good agreement with the original design requirements. The results of these tests validate the test facility and guarantee the quality of data obtained in long-term operation and parametric testing.

Early results of the parametric and long-term testing show that all the catalysts meet or exceed the specifications of ammonia slip, SO_2 oxidation, and NO_x reduction. However, the catalysts show major differences in their operating characteristics in terms of both physical operation and chemical activity. Continued aging of the catalyst will allow extrapolation of the catalyst life as well as determination of the primary poisons in the coals currently being used at the facility.



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



▲ This view of the completed SCR installation shows the large insulated reactors on the top four levels, the heat exchanges underneath, and the cyclones at the bottom.

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.

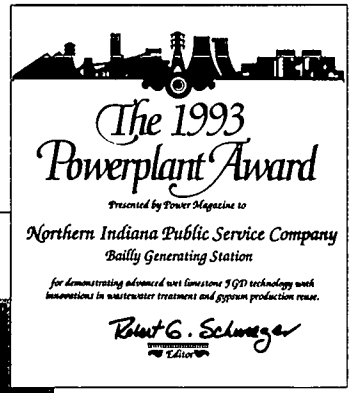
The project also is demonstrating a novel business concept whereby Pure Air on the Lake owns and operates the facility, relieving the utility of the responsibility for operations. Following successful demonstration of the process, Pure Air will continue to own and operate the facility for an additional 17-year period under contract to the utility.

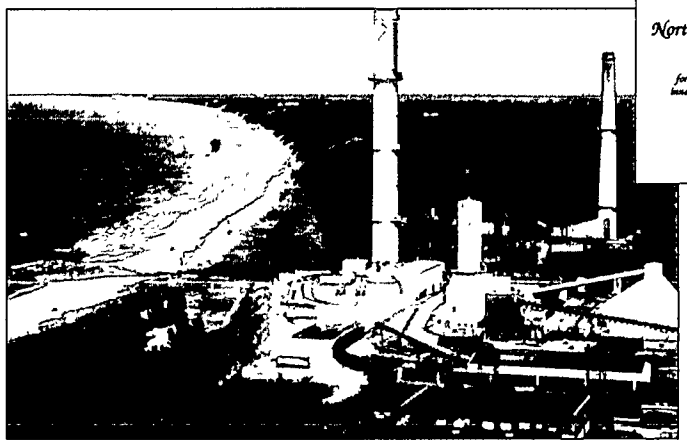
The advanced flue gas desulfurization system began operations in June 1992 and the demonstration period will continue into June 1995. During this period, six 1-month demonstration tests are being performed to assess scrubber operations with a variety of coals. By year-end 1994, five of the tests were completed; bituminous coals with sulfur contents ranging from 2.0 percent to 4.5 percent were tested. The remaining test, scheduled for spring 1995, will assess optimal conditions.

The scrubber is exceeding both its demonstration targets and all contractual requirements. The facility is removing in excess of 95 percent of the SO_2 from Bailly Units 7 and 8, has a 99 percent availability rate, and is producing a wallboard-grade gypsum that is 98 percent pure.

This project earned the Bailly Generating Station *Power Magazine's* 1993 Powerplant Award. In 1992, it was also named an Outstanding Engineering Achievement by the National Society of Professional Engineers.

In April 1994, Pure Air of Manatee, L.P., entered into a contract to provide 1,600 MWe of SO_2 scrubbing capability at Florida Power & Light Company's Manatee power plant on an own-and-operate basis. The Manatee scrubber will feature two 800-MWe absorber vessels, PowerChip™ gypsum recycle, and wastewater evaporation.





◄▲ The advanced flue gas desulfurization demonstration project has been in operation since June 1992. Tests have shown SO_2 removal efficiencies in excess of 95% using coals with sulfur content ranging from 2.0% to 4.5%. The project earned *Power Magazine's* 1993 Powerplant Award.

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 is addressing 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 are being measured, including power consumption, limestone utilization, itemized maintenance requirements, and aerodynamic design additions to the FRP chimney.

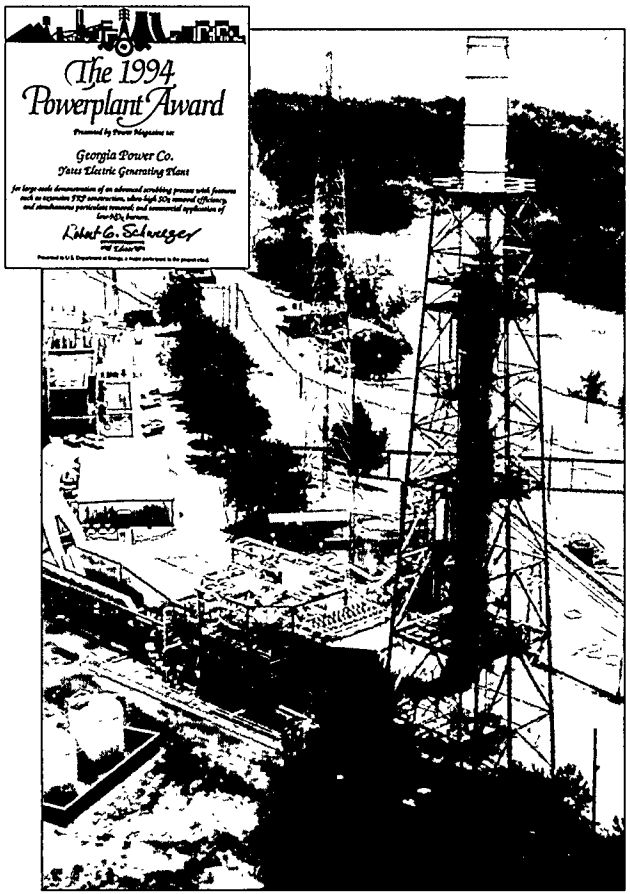
The demonstration has two operational phases. The first, between January 1993 and February 1994, was conducted with the preexisting ESP in service. The second phase, which began March 1994, is a repeat of the first phase testing, but with the ESP deenergized in stages to allow evaluation of the scrubber's performance under high particulate loading conditions. During the more recent testing, the process was stressed by burning 4.3 percent sulfur coal (which is 170 percent of design conditions) and with high particulate loading. Performance was excellent; SO_2 removal efficiency ranged from 79 to 97 percent over a range of control settings. Particulate testing with the ESP fully detuned indicated a 99.1 percent particulate removal efficiency across the scrubber. High efficiency testing has established the ability of the process to consistently remove in excess of 98 percent of the SO_2 in the flue gas at some operating conditions—while achieving parasitic power consumption levels of less than 1.8 percent of maximum capacity (100 MWe).

The demonstration established that (1) fiberglass can be used for a reactor vessel, (2) there is greater than 98 percent reliability and availability meaning that no spare absorber is needed, (3) reheat of the flue gas is not required, (4) the process can function with or without an ESP stream, (5) the gypsum produced with an ESP is suitable for other uses, (6) the system can meet New Source Performance Standards with 93–98 percent SO_2 removal, and (7) the system can operate at 180+ percent of its design capacity with respect to sulfur content of the coal. DOE-sponsored air toxics testing was done in June 1993. Removal of nonvolatile particulate metals averaged more than 98 percent across the ESP.

The project received two awards in 1994: *Power Magazine's* 1994 Powerplant Award and an Outstanding Achievement Award from the Georgia chapter of the Air and Waste Management Association for the use of an innovative technology for air quality control.

In January 1995, Georgia Power will retain and operate the CT-121 scrubber.

▼ This aerial view shows the backside of the CT-121 process area (left of stack in foreground). The CT-121 process can remove over 90% of the SO_2 over a wide load range. The project received *Power Magazine's* 1994 Powerplant Award and an Outstanding Achievement Award from the Georgia chapter of the Air and Waste Management Association.



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 SO_2 removal using Saarberg-Hölter-Umwelttechnik's formic acid enhanced wet limestone scrubber technology; NALCO Fuel Tech's NO_xOUT urea injection system for NO_x removal, in conjunction with separate combustion modifications, including installation of ABB Combustion Engineering's Low-NO_x Concentric Firing System (LNCFS) Level III; 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, Inc., 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 system is designed to achieve up to 98 percent SO_2 removal efficiency using limestone while burning high-sulfur coal. Pittsburgh, Freeport, and Kittaning coals with sulfur contents ranging from 1.5–4.0 percent are being used.

NO_x emissions have been reduced from 0.65 to 0.40 pound per million Btu (23 percent) by retrofitting the two boilers with low-NO_x burners (LNCFS Level III). NO_xOUT is expected to reduce NO_x emissions from Unit 2 by an additional 15–20 percent.

Construction started in April 1993 and has stayed 2–3 months ahead of schedule. Hydro testing of the scrubber began in November 1994, with passage of flue gas in December 1994. Equipment shakedown and start-up is expected to begin in January/February 1995. Baseline and preoperational testing is scheduled to commence in April 1995, with full-scale operation beginning in July and running for the next 3 years.

◄ In 1994, construction of the combined SO_2/NO_x demonstration project at NYSEG Milliken Station Units 1 and 2 was essentially completed. Operational testing of the formic-acid-enhanced, wet limestone scrubber, a urea injection system, and other systems is scheduled to begin in mid-1995.

Integrated Dry NO_x/SO_2 Emissions Control System (Public Service Company of Colorado)

The integrated dry NO_x/SO_2 emissions control system was installed at Public Service Company of Colorado's (PSCC) Arapahoe 4 in 1992. The 100-MWe demonstration combines low-NO_x burners, over-fire air, and selective noncatalytic reduction (SNCR) for NO_x control and dry sorbent injection (DSI) with humidification for SO_2 control. The Arapahoe 4 uses top-fired boilers fired with low-sulfur (0.4 percent) Colorado bituminous coal.

The test program involves the individual testing of the low-NO_x burners, over-fire air, urea injection, calcium duct injection, calcium economizer injection, sodium injection, and integrated system. Four tests were conducted to determine baseline and removal capabilities of the system for many air toxics.

Baseline NO_x emissions before retrofit were nearly uniform across the load range (60–110 MWe) at approximately 1.10 pounds per million Btu. The combination of low-NO_x burners (Babcock & Wilcox Dual-zone NO_x Ports) and over-fire air (Babcock & Wilcox Dual Register Burner–Axially Controlled Low-NO_x, or DRB-XCL®) greatly reduced NO_x emissions by 63–69 percent across the load range.

The urea-based SNCR supplied by Noell, Inc., reduced NO_x formation by 11–45 percent over the load range. This performance was at urea injection rates that limit NH_3 slip at the fabric filter inlet to 10 parts per million. When used with low-NO_x burners, the urea-based SNCR increases total system NO_x reduction to greater than 80 percent at full load, significantly exceeding the project goal of 70 percent. Further, higher NO_x reduction is possible using ammonia as the SNCR chemical at lower loads.

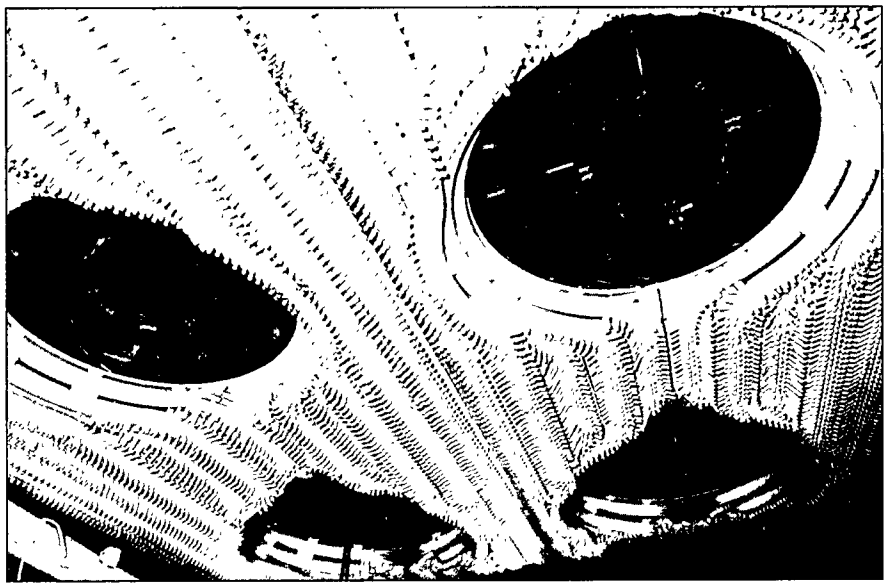
SO_2 removal with the calcium-based [$Ca(OH_2)$] dry sorbent injected into the boiler without humidification was only 5–8 percent at a stoichiometry of 2.0. Operation with the humidification system during economizer injection increased SO_2 removal by only 3–4 percent.

Sodium bicarbonate injection before the air heater was very effective with short-term SO_2 removal efficiencies of over 80 percent possible. Long-term testing with sodium bicarbonate has demonstrated removal efficiency near 70 percent at an approximate stoichiometric ratio of 1.0. Sodium sesquicarbonate injection after the air heater also obtained 70 percent SO_2 removal but at a stoichiometric ratio of approximatley 1.8.

The project includes a comprehensive investigation into many potential air toxic emissions. The fabric filter had an overall particulate removal efficiency of over 99.96 percent. Removal efficiency of all trace metals sampled averaged over 96.9 percent. Mercury removal had the lowest capture efficiency of 78 percent.

Due to the successful application of the system, PSCC plans to continue operation of the combustion modifications and sodium-based DSI system. A final decision on the SNCR system will be made after the test program is completed. All testing will be completed mid-1995, with project completion scheduled for November 1995.

▼ The combined dry NO_x/SO_2 emissions control system installed at PSCC's Arapahoe 4 plant can achieve NO_x reductions greater than 80% and SO_2 reductions of 70–80%. This photograph shows four Babcock & Wilcox low-NO_x DRB-XCL® down-fired burners mounted in the roof of the boiler.

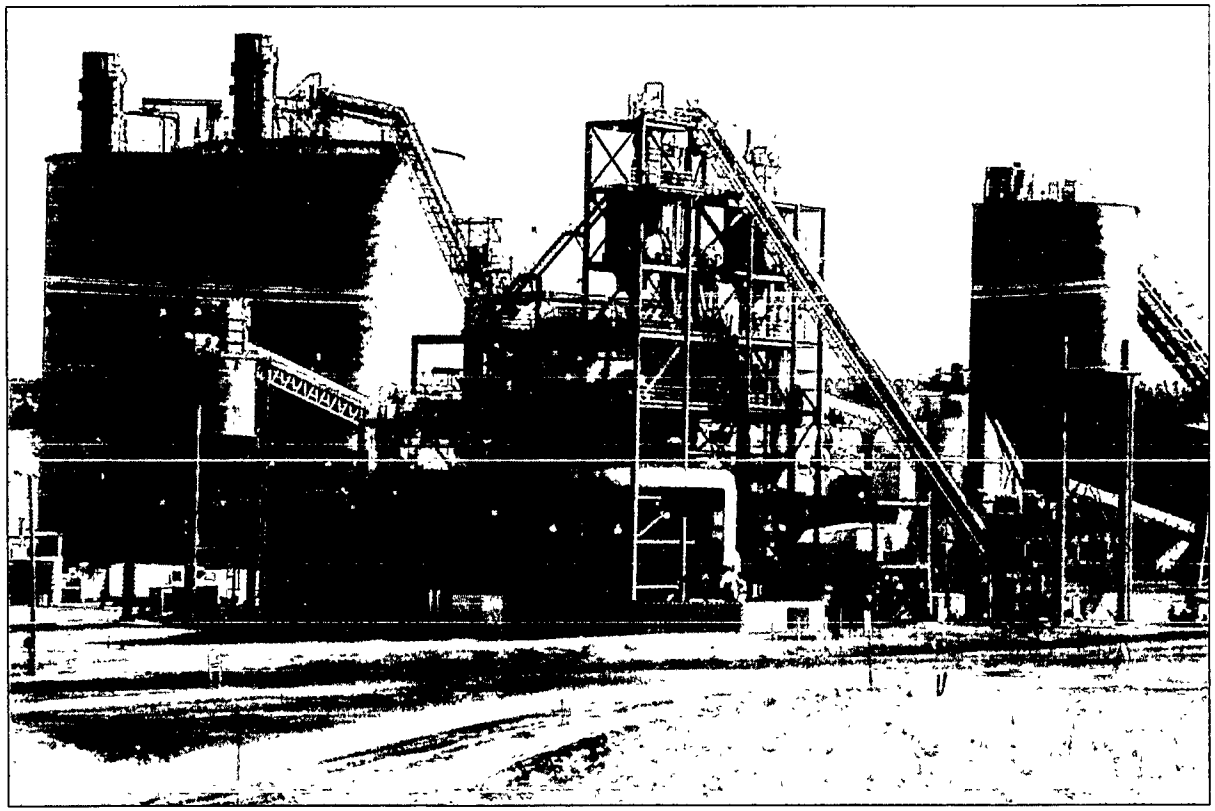


Coal Processing for Clean Fuels

There are five projects in the coal processing for clean fuels category; their combined value exceeds $521 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.

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. A CQE beta version will be released in early 1995 and the final version is expected in June 1995.

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.



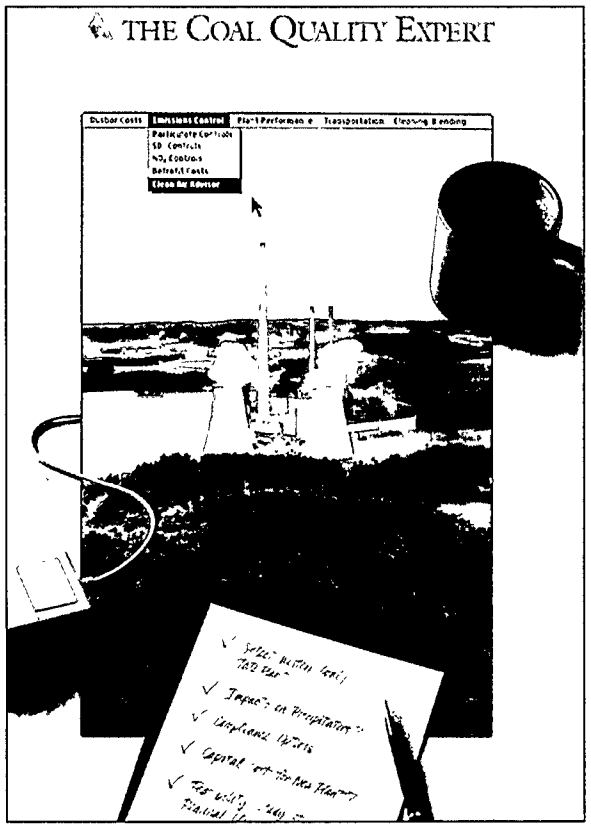
Five projects with a value of over $521 million are demonstrating technologies which produce compliance solid fuels, liquid products for use as a chemical or transportation fuel feedstock, and methanol. An example is the advanced coal conversion process demonstration which produces 1,000 tons/day of SynCoal®. Another project involved development of a system to predict operating performance of coals.

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 (CQE) prototype was showcased in September 1993. The process code for the model constructor was nearing completion at year-end 1994. A CQE beta version will be released in early 1995, and the final version is expected in June 1995.



◄ Software to enable a utility to analyze the effects of coal quality on power plant performance has been developed. A prototype of the software was released in 1993 and the final version is expected in mid-1995.

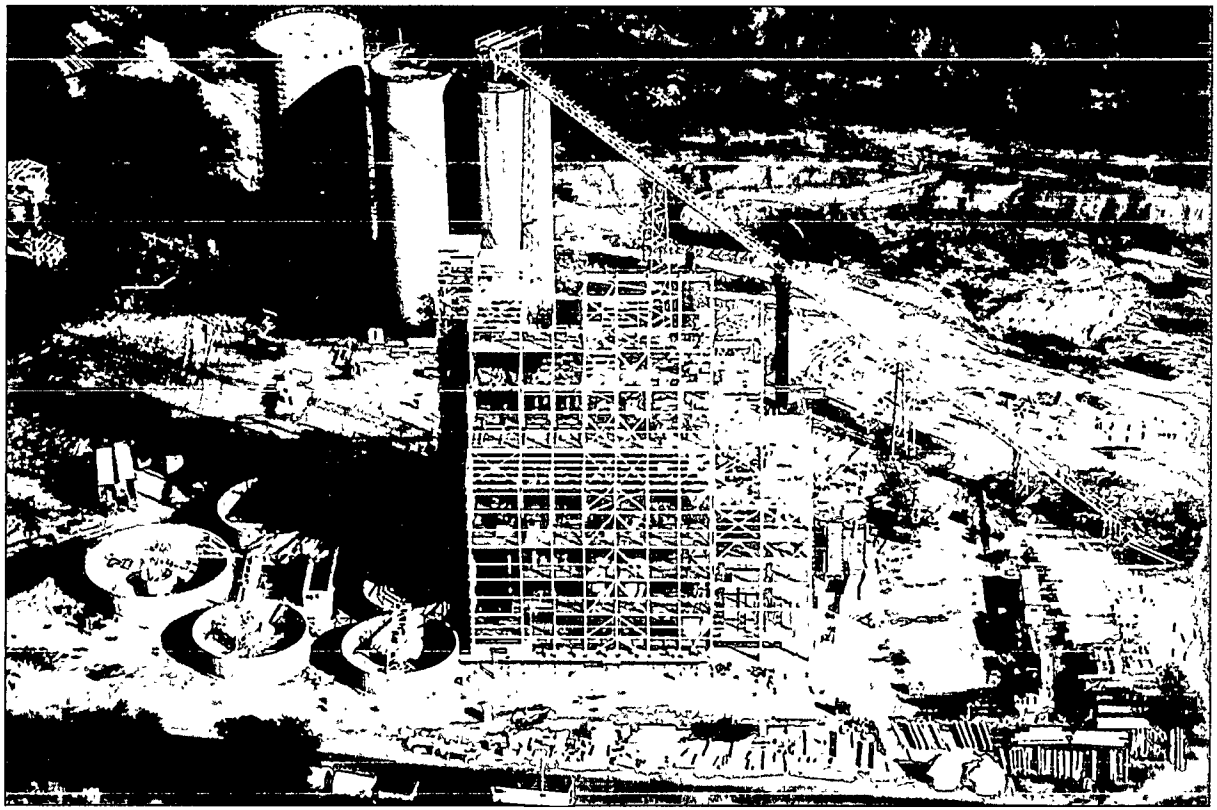
Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International)

Custom Coals International is demonstrating advanced coal-cleaning unit processes to produce low-cost compliance coals. The project is using Custom Coal's advanced physical coal cleaning and fine magnetite separation technology as well as sorbent addition technology. Construction is under way on a 500-ton-per-hour plant located near Central City, Pennsylvania. The plant will manufacture Self-Scrubbing Coal™ from Illinois No. 5 and Lower Freeport Seam coals and Carefree Coal™ using Sewickley 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 percent of the pyritic sulfur and most of the ash. When compliance coal cannot be produced by reducing pyritic sulfur, Self-Scrubbing Coal™ can be produced to achieve compliance. This coal is produced by taking Carefree Coal and adding to it sorbents, promoters, and catalysts. The coal's reduced ash content permits the addition of relatively large amounts of sorbent without exceeding the ash specifications of the boiler or overloading the ESP.

Construction was initiated in December 1993 and by year-end 1994, piping was approximately 50 percent complete and structural steel erection was entirely complete. Over 99 percent of the equipment has been installed. The raw coal burn test to provide baseline data to determine the cleaning effect is scheduled to begin in early 1995. Combustion testing of Sewickley coal will be conducted at Duquesne Light Company's Cheswick Power Station, Illinois No. 5 coal at Richmond Power & Light's Whitewater Valley Generating Station, and Lower Freeport seam coal at Centerior Energy's Ashtabula C Power Plant.

In August 1994, a U.S.-led consortium with Custom Coals International as the principal partner signed a cooperative agreement with the People's Republic of China to build a coal-cleaning plant, a 500-mile underground slurry pipeline, and port facility. The pipeline will bring coal from the Shanxi province in northwest China to the coastal province of Shandong.

▼ Construction of Custom Coals International's 500-ton/hr advanced coal-cleaning plant located near Central City, PA, is approximately 50% complete. The plant will produce two compliance fuels from high-sulfur bituminous feedstock—Carefree Coal™ and Self-Scrubbing Coal™.



Advanced Coal Conversion Process Demonstration (Rosebud SynCoal Partnership)

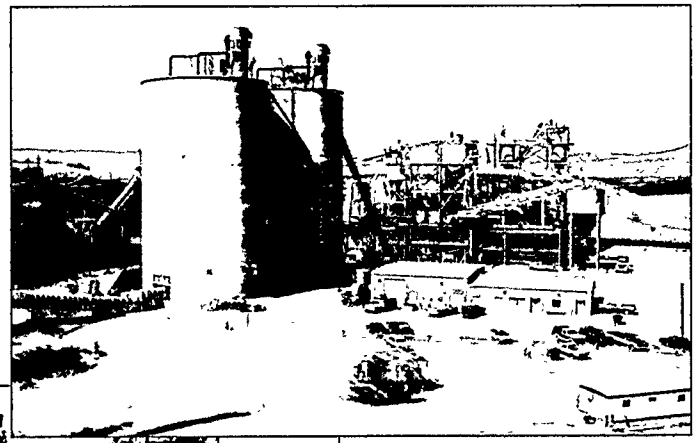
The Rosebud SynCoal Partnership project is demonstrating an advanced thermal coal-conversion process coupled with physical cleaning techniques to upgrade high-moisture, low-rank coals to produce a high-quality, reduced-ash, low-sulfur fuel called SynCoal®. The 1,000-ton-of-SynCoal-per-day demonstration unit is located at the Rosebud Mine in Colstrip, Montana. The project enhances low-rank western coal, which usually has a moisture content of 25–40 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 0.4 percent, ash content of about 9 percent, and heating value up to 12,000 Btu per pound.

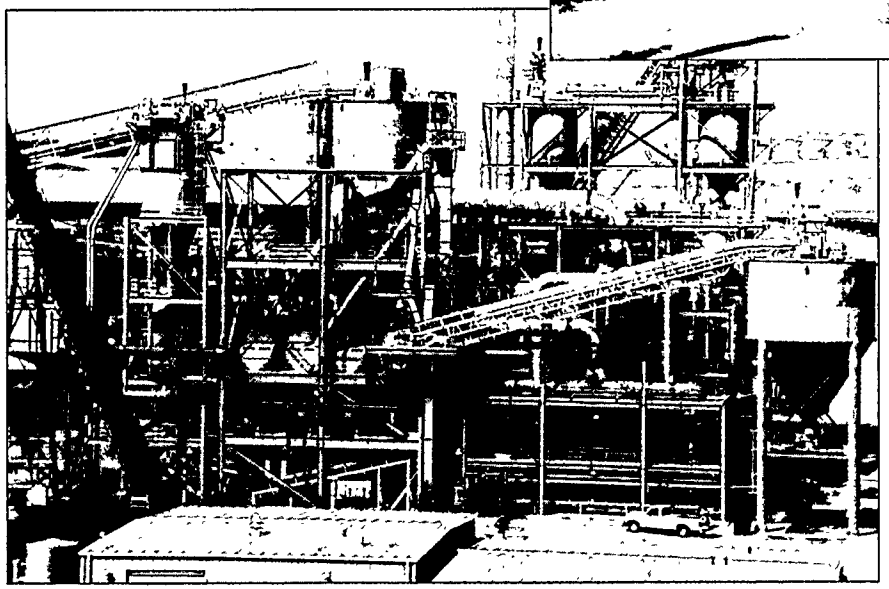
A test program was initiated in March 1994 at the J.E. Corette power plant using a 50/50 blend of raw subbituminous coal and DSE Conditioned SynCoal®. Preliminary results indicate significantly improved boiler cleanliness, efficiency, and operations capacity while the SO_2 emissions decreased with no noticeable effect on NO_x. With higher SynCoal® blends, SO_2 emissions decreased by as much as 43 percent and the plant could hold a 170-MWe load, which is well above the normal 160-MWe load. The boiler efficiency increased from 84.9 to 85.7 percent with the 50/50 blend and to 86.2 percent with a 75/25 blend. The corresponding decreases in net unit heat rate were 130 Btu per kilowatt-hour and 181 Btu per kilowatt-hour, respectively.

Project operations have been extended through mid-1997.

Rosebud SynCoal Partnership has conducted a study for Minnkota Power Cooperative to examine the merits of applying the coal processing technology to a commercial plant integrated into an existing power plant site. The study results have been positive, but market commitments are still necessary.

Total sales of SynCoal® product continued strong with a total of 5,757 tons being delivered to Ash Grove Cement, Bentonite Corporation, and Empire Sand and Gravel. Montana Power received 5,412 tons of conditioned SynCoal®.





◄▲ The Rosebud SynCoal® facility enhances low-rank western coal to a low-moisture, low-sulfur, low-ash, and enhanced-heating-value compliance fuel. Over 10,000 tons of SynCoal® has been delivered to industrial and utility customers.

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 pyrolized 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.

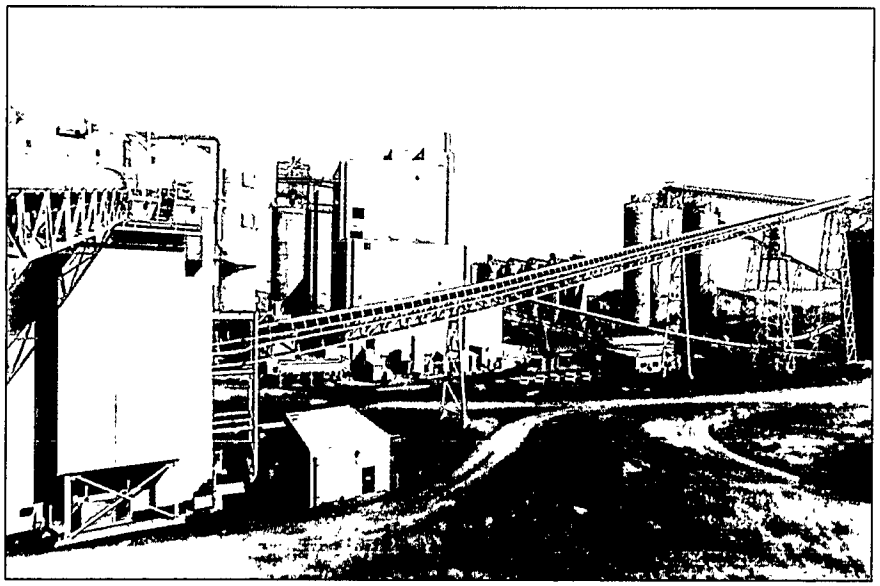
The site for this plant is Triton Coal Company's Buckskin Mine located about 10 miles north of Gillette, Wyoming.

The plant officially entered the production mode in June 1994; operation has been at a coal feed rate of 500 tons per day. By year-end 1994, 22 test runs were completed, representing more than 5,000 hours of operation on coal. Solid and liquid products being produced by the plant are being shipped to industrial and utility customers. In September 1994, approximately 8,000 tons of solid product were shipped as 15–35 percent blends of Powder River Basin coal for use in electricity generation at the Western Farmers Cooperative's Hugo plant in Oklahoma. This rural electric cooperative used the product successfully in its boilers. ENCOAL also has contracted with Wisconsin Power & Light for the sale of 30,000 tons of solid product. A contract to sell blends of up to 92 percent solid product was signed with Muscatine Power and Water in Iowa. Other major utility companies have expressed interest in purchasing solid product.

Tank cars of liquid product are being shipped on a regular basis to several customers in the Midwest for use in industrial boilers. The Dakota Gasification Company tested the liquid products in 1992 and in 1994 purchased an additional 800,000 gallons for use in its synfuel plant in Beulah, North Dakota.

SGI International and Mitsubishi Heavy Industries are studying the feasibility of developing a 6,000-metric-ton-per-day liquids-from-coal plant in the Shandong province of the People's Republic of China. Feasibility studies have also been proposed for projects in Indonesia and Poland.

▼ In 1994, the ENCOAL plant officially entered production mode and, by year-end 1994, 22 test runs representing more than 5,000 hours had been completed. The solid product is being sold to utilities, and the liquid product to several Midwest industrial customers.



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 SO_2 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 completed construction for a project to demonstrate the injection of granulated coal directly into two blast furnaces at Burns Harbor, Indiana. Preoperational testing began in December 1994 and will continue until May 1995 when operation is scheduled to begin. 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.

Another project (currently in negotiation), Clean Power from Integrated Coal/Ore Reduction, utilizes coal instead of coke in steelmaking. This CCT-V project, which integrates iron making with combined-cycle electric power production, is sited at Geneva Steel's mill in Vineyard, Utah.

Meanwhile, Bethlehem Steel's Coke Oven Gas Cleaning System for Retrofit Applications project will remain on hold until a decision is made concerning alternatives for resumption of coke production at Sparrows Point. The demonstration facility had to be mothballed because of an unrelated shutdown of the coke ovens due to their rapid deterioration.

▼ Bethlehem Steel Corporation completed construction of a project to demonstrate the injection of granulated coal into two blast furnaces at Burns Harbor, IN. The granulated coal preparation unit is shown in the center, with the blast furnace to the right.

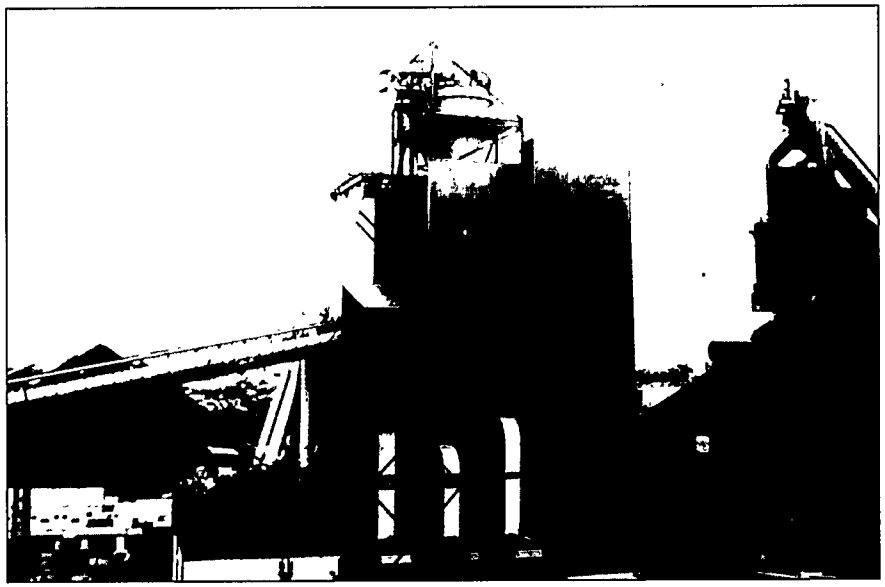


Exhibit 6-2
Status of CCT Demonstration Projects at Year-End 1994—Advanced Electric Power Generation

Project and Participant	Status
Fluidized-Bed Combustion	
PFBC Utility Demonstration Project (The Appalachian Power Company)	The participant is evaluating the results of various value engineering studies which were conducted to improve the efficiency and economic viability of the project. The utility and DOE are assessing the merits of continuing the project.
PCFB Demonstration Project (DMEC-1 Limited Partnership)	Preliminary design activities are under way. Announcement of a planned merger between Midwest Resources, Inc., and Iowa-Illinois Gas and Electric has impacted the project. An extension was granted for the participant to finalize continuation plans.
Four Rivers Energy Modernization Project (Four Rivers Energy Partners, L.P.)	The cooperative agreement was awarded July 28, 1994, with an effective date of August 1, 1994. Preliminary design activities are under way.
Tidd PFBC Demonstration Project (The Ohio Power Company)	The test program, initiated in March 1991, was extended for 1 year. Approximately 4,800 hours of coal-fired operation were achieved during 1994, bringing the cumulative total to approximately 10,300 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 is in the design stage and agreements have been finalized with all major equipment vendors and coal suppliers. Efforts were focused on completion of NEPA and state permitting process. The draft EIS was released for public review in November 1994 and a public hearing on the EIS was held in mid-December in York, PA.
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.
Clean Energy Demonstration Project (Clean Energy Partners Limited Partnership)	The cooperative agreement was awarded December 2, 1994. Project design activities are under way.
Piñon Pine IGCC Power Project (Sierra Pacific Power Company)	All permits needed for plant construction were received and the participant requested approval to continue with detailed design and construction. The EIS was completed and DOE issued a record of decision on November 8, 1994.
Toms Creek IGCC Demonstration Project (TAMCO Power Partners)	Efforts continued to secure a power sales agreement and to redefine the project.

Exhibit 6-2 (continued)
Status of CCT Demonstration Projects at Year-End 1994—Advanced Electric Power Generation

Project and Participant	Status
Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	Engineering is approximately 75% complete. DOE released a record of decision for the demonstration portion of the EIS in August 1994. Tampa Electric held a formal groundbreaking ceremony on November 2, 1994.
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	Construction is in progress and is 70% complete with all major equipment installed, including the gasifiers, air separation unit, and gas turbine.
Advanced Combustion/Heat Engines	
Healy Clean Coal Project (Alaska Industrial Development and Export Authority)	Engineering and design are complete. A final EIS was issued on December 15, 1993, and a record of decision was issued on March 10, 1994. Bids for the General Construction Contract were opened in November 1994. Construction is expected to begin in the spring of 1995.
Coal Diesel Combined-Cycle Project (Arthur D. Little, Inc.)	The cooperative agreement was awarded July 12, 1994. Design efforts are in progress and environmental information is being prepared for use in the NEPA process.
Warren Station Externally Fired Combined-Cycle Demonstration Project (Pennsylvania Electric Company)	The cooperative agreement was awarded on August 1, 1994. Design efforts are in progress. Environmental information was prepared and an EA drafted for review.

Exhibit 6-3
Status of CCT Demonstration Projects at Year-End 1994—Environmental Control Devices

Project and Participant	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 and the final report was delivered in March 1994. 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)	This project was completed in December 1994. The average NO_x emissions reduction when at full load was 58%. LNCB® has been installed on more than 2,500 MWe and ordered for more than 3,250 MWe.
Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)	Long-term testing was initiated in April 1993 and will conclude in January 1995. Combined GR–LNB achieved NO_x reductions of 60–73%. With gas heat input of 5–10%, NO_x reductions were 60–65%. With low-NO_x burners alone, NO_x reductions were typically 30–40%.
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. The digital control system was tested and the artifical intelligence software system nearly completed.
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	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 37% at full load. The project was completed as of June 30, 1994, and the LNCFS is being retained by Gulf Power at its Plant Lansing Smith.
Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers (Southern Company Services, Inc.)	Operational testing began in July 1993 and will be completed in July 1995. Parametric tests through December 1994 indicated that all catalysts are performing within design specifications, although differences have been noted in NO_x reduction activity, SO_2 oxidation, physical fouling, and pressure drop.
Micronized Coal Reburning Demonstration of NO_x Control on a 175-MWe Wall-Fired Unit (Tennessee Valley Authority)	Due to plant problems and operational and environmental strategy changes, the original host site was no longer suitable to demonstrate the technology. Other options for a host site are being investigated.

Exhibit 6-3 (continued)
Status of CCT Demonstration Projects at Year-End 1994—Environmental Control Devices

Project and Participant	Status
SO_2 Control Technologies	
10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.)	Operational testing was conducted from October 1992 to March 1994. 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%. A full scale unit will be installed at the City of Hamilton Ohio's 50 MWe municipal power station. This unit is scheduled for operation in August 1996.
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)	LIFAC test has been completed, and the unit is being retained by Richmond Power & Light. Long-term tests showed that SO_2 reductions above 70% can be maintained under normal boiler operating ranges. LIFAC had no long-term effects on normal boiler operations. Final reports are expected in the spring of 1995.
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	In 1994, tests were completed on coals with 4–4.5% sulfur and 2–2.5% sulfur. The scrubber is achieving SO_2 removals in excess of 95% while producing a 97% pure commercial gypsum by-product. As of the end of November 1994, the AFGD facility had accumulated almost 22,000 hours of operation with an availability of 98–99% and 100% reliability. About 181,500 tons of SO_2 have been removed and over 501,000 tons of gypsum produced.
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	During 1994, testing of high sulfur coal (2.5%), compliance coal (1.5%), and low-sulfur coal (1.35%) were conducted. A total of 12,000 hours had been logged by the end of 1994. It was demonstrated that New Source Performance Standards could be met with 93–98% SO_2 removal. The project was awarded *Power Magazine's* 1994 Powerplant Award. The final report of the demonstration will be produced during 1995.
Combined SO_2/NO_x Control Technologies	
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	Operational testing was completed in December 1994. The system has operated for over 7,800 hours and produced more than 5,400 tons of commercial-grade sulfuric acid. The facility has routinely operated at full capacity, achieving removal efficiencies of 95% for SO_2, 94% for NO_x, and 99.9% for particulates. The system was retained by Ohio Edison Company as part of its CAAA of 1990 compliance strategy.
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.

Exhibit 6-3 (continued)
Status of CCT Demonstration Projects at Year-End 1994—Environmental Control Devices

Project and Participant	Status
SOx-NOx-Rox-Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)	Operational testing was completed in May 1993 and the final report was delivered in August 1994. SO_2 removal efficiencies were 80% with commercial-grade lime and 90% with hydrated lime (both at 2.0 Ca/S and 800–850 °F) and 80% with sodium bicarbonate (1.0 Na/S, 425 °F). NO_x reductions consistently exceeded 90%. Particulate removal efficiency was 99.8%
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 Hennepin. 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. The average NO_x reduction during long-term testing at Lakeside was 67% and SO_2 removal was 58%.
Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Corporation)	Construction is several months ahead of schedule. Hydro testing of the scrubber began in November 1994, with passage of flue gas in December 1994. Equipment shakedown and start-up are expected to begin in January/February 1995.
Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System (NOXSO Corporation)	NOXSO Corporation has selected 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)	When used with low-NO_x burners, urea-based SNCR increased total system NO_x reduction to greater than 80% at full load (110 MWe). Long-term testing has demonstrated SO_2 removal efficiency near 70% using sodium bicarbonate (1.0 Na/S). Particulate removal was over 99.96%. Since combustion modifications were made in May 1992, the unit has operated over 20,000 hours, with an availability factor exceeding 96%.

Exhibit 6-4
Status of CCT Demonstration Projects at Year-End 1994—Coal Processing for Clean Fuels

Project and Participant	Status
Coal Preparation Technologies	
Development of the Coal Quality Expert (ABB Combustion Engineering, Inc., and CQ, Inc.)	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 with the first commercial sale being made in 1993. A CQE beta version will be released in early 1995. The final version will be available in June 1995.
Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International)	Construction was started in December 1993 with piping approximately 50% complete and structural steel erection completed by years end, 1994. Raw coal burn testing to provide baseline data is scheduled to begin in early 1995. In August 1994, a consortium lead by Custom Coal International signed a cooperative agreement with the Peoples Republic of China for a major coal cleaning and transportation facility.
Advanced Coal Conversion Process Demonstration (Rosebud SynCoal Partnership)	Total sales of SynCoal® product continued strong with a total of 5,757 tons being delivered to Ash Grove Cement, Bentonite Corporation and Empire Sand and Gravel. Montana Power Company received 5,412 tons of conditioned SynCoal®.
Mild Gasification	
ENCOAL Mild Coal Gasification Project (ENCOAL Corporation)	The plant entered production mode in June 1994. To date, the plant has completed 22 runs and logged over 5,000 hours of coal-based operation. In September 1994, approximately 8,000 tons of solid product were shipped as 15-35% blends with Powder River Basin coal for use in electric generation. Other commercial contracts for sale of solid and liquid products are in place.
Indirect Liquefaction	
Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process (Air Products Liquid Phase Conversion Company, L.P.)	A limited partnership, Air Products Liquid Phase Conversion Company, has been formed to manage and execute the project. Project definition activities were completed in September 1994 and design was initiated. Relevant environmental information for use in the NEPA process is being updated; an EA is in progress.

Exhibit 6-5
Status of CCT Demonstration Projects at Year-End 1994—Industrial Applications

Project and Participant	Status
Blast Furnace Granulated-Coal Injection System Demonstration Project (Bethlehem Steel Corporation)	Construction has been completed and preoperational tests were initiated in December 1994 and will continue until May 1995. Operational testing is scheduled to begin in May 1995.
Innovative Coke Oven Gas Cleaning System for Retrofit Applications (Bethlehem Steel Corporation)	Coke production at Sparrows Point was suspended in December 1991 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. In July 1994, Air Products and Chemicals, Centerior Energy, and Geneva Steel Company signed an agreement to site the project at Geneva Steel's mill in Vineyard, UT.
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 were delivered in March 1994.
Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal (ThermoChem, Inc.)	Design verification tests are continuing at MTCI's Baltimore Test Facility. On October 26, 1994, ThermoChem requested that DOE consider relocating the project to an alternative host site.

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 participant, 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-refererence CCT projects by participants and application categories are provided as a guide to the fact sheets included in this section.

- Exhibit 7-1 indexes project fact sheets by application category.
- Exhibit 7-2 indexes fact sheets by participant.

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	Participant	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
Clean Energy Demonstration Project	Clean Energy Partners Limited Partnership	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	Participant	Page
SO_2 Control Technologies		
10-MWe 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 SO_2/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	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 Liquid Phase Conversion Company, L.P.	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 Participant

Participant	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™ Flue Gas Cleaning Demonstration Project	II/Complete	7-64
Air Products Liquid Phase Conversion Company, L.P.	Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process	III	7-88
AirPol, Inc.	10-MWe Demonstration of Gas Suspension Absorption	III/Complete	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 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	SOx-NOx-Rox-Box™ Flue Gas Cleanup Demonstration Project	II/Complete	7-68
Bechtel Corporation	Confined Zone Dispersion Flue Gas Desulfurization Demonstration	III/Complete	7-56
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Advanced Electric Power Generation Fact Sheets

PFBC Utility Demonstration Project

Participant:
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)

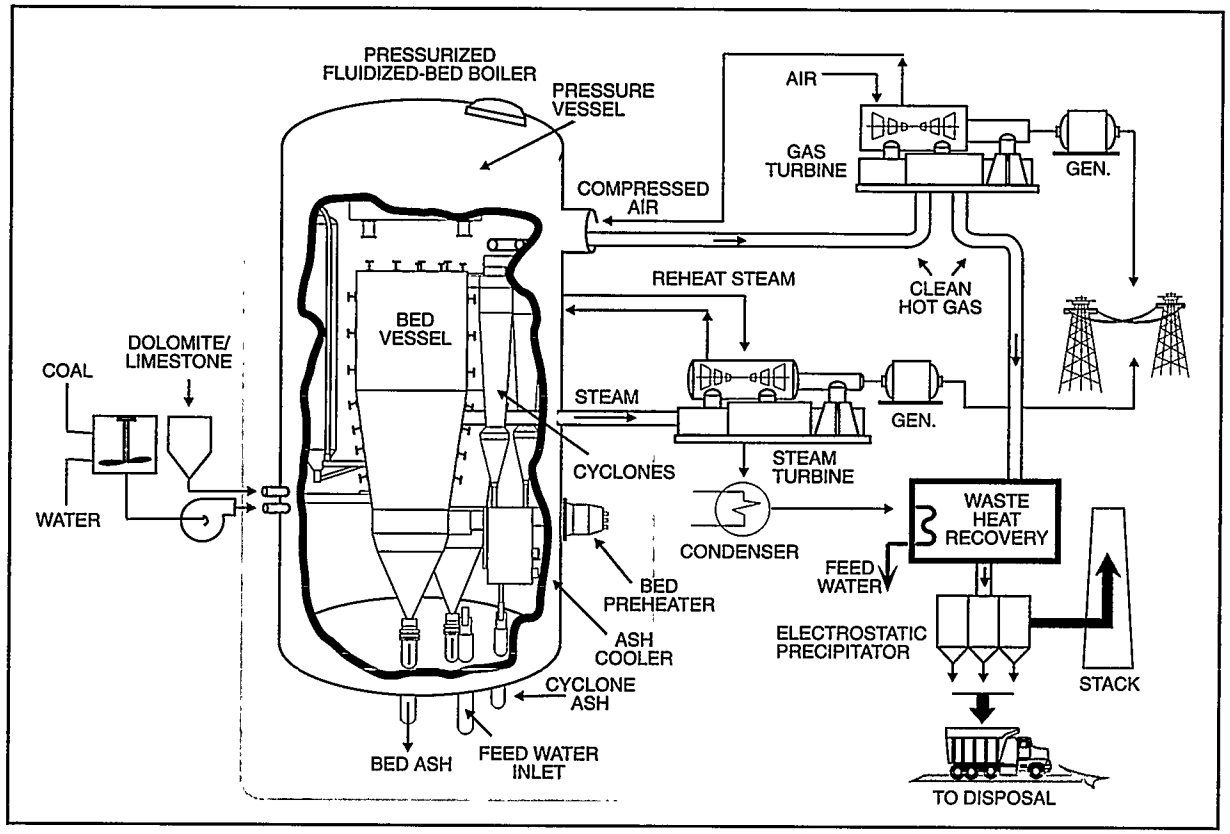
Technology:
The Babcock & Wilcox Company's pressurized fluidized-bed combustion (PFBC) system (under license from ABB Carbon) (advanced electric power generation/fluidized-bed combustion)

Plant Capacity/Production:
340 MWe (net)

Project Funding:

Total project cost	$917,944,000	100%
DOE	184,800,000	20
Participant	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.

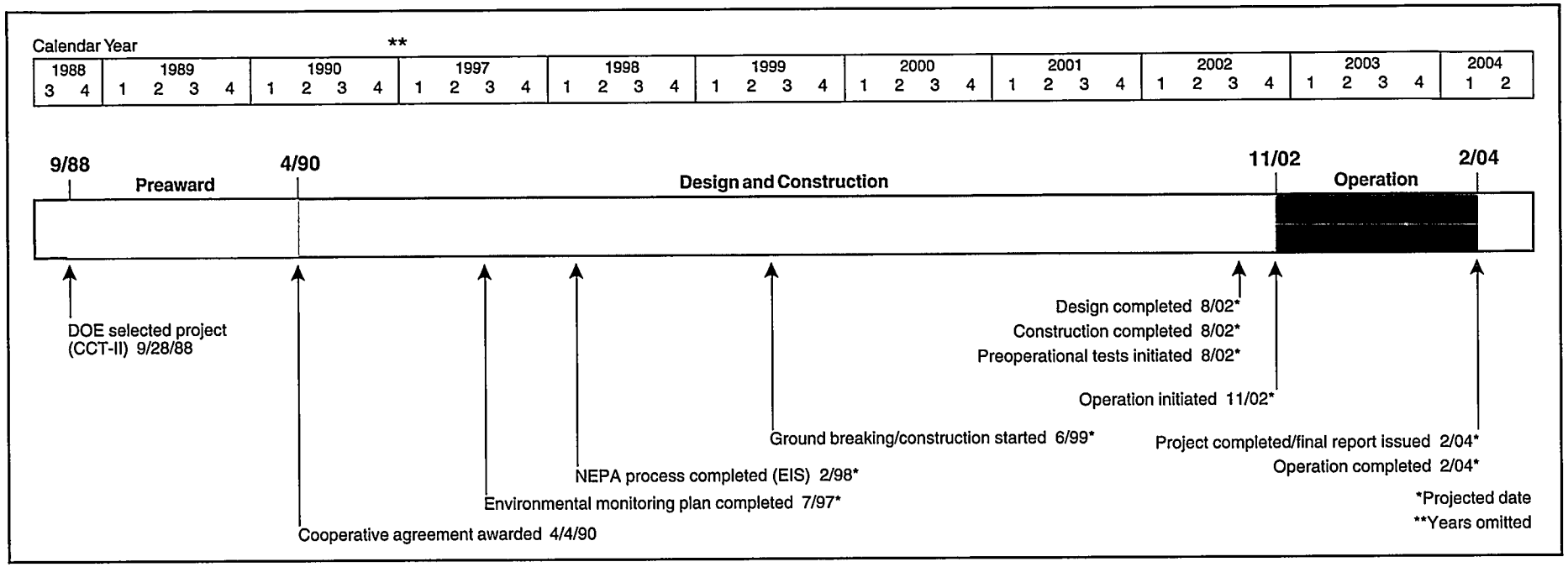


Technology/Project Description:
This project will be a greenfield facility located adjacent to the existing Mountaineer and Sporn plants. The most noticeable aspect of the unit is that the boiler, cyclones, reinjection vessel, and associated hardware are encapsulated in a pressure vessel 60 ft in diameter and 100 ft high.

The project incorporates a bubbling fluidized-bed process operating at 16 atm (235 lb/in^2 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 250MW e. 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). SO_2 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:

Appalachian Power is evaluating results from various value engineering activities, which were conducted to improve the efficiency and economic viability. 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

Participant:
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)

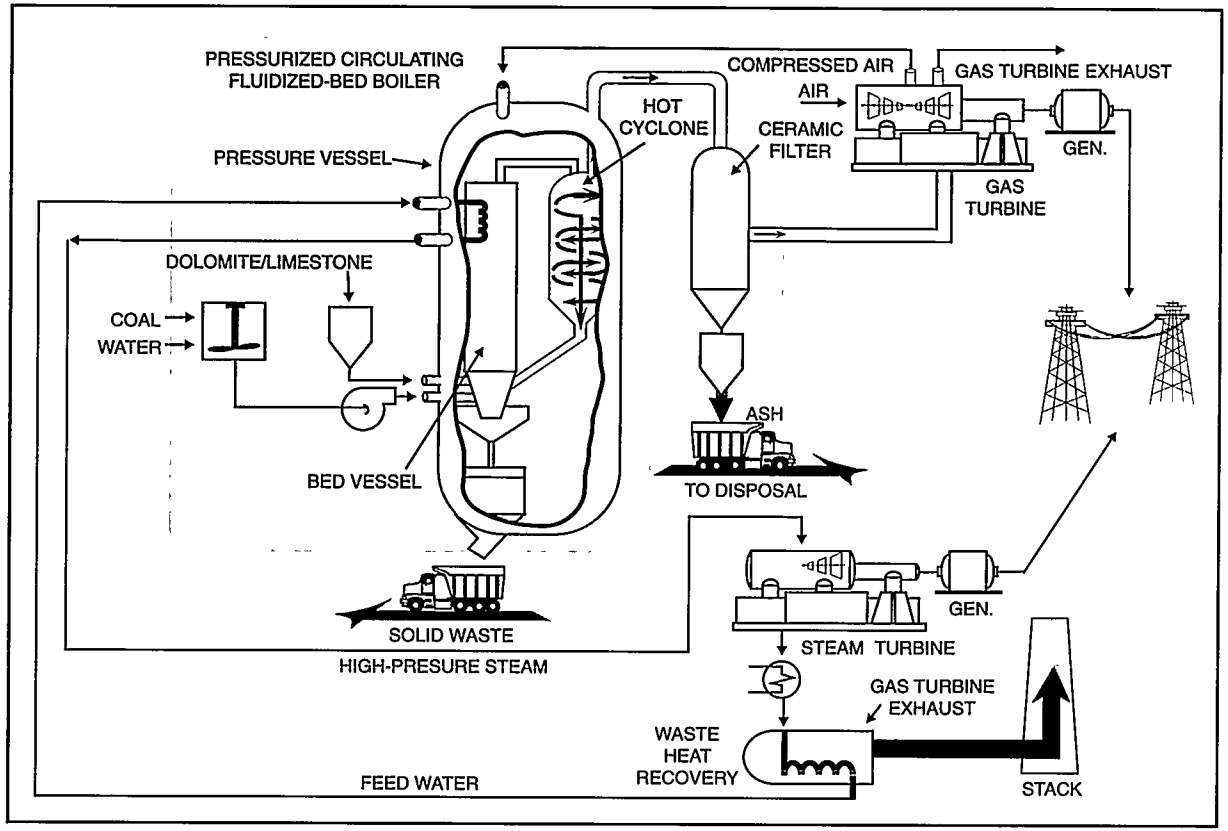
Technology:
Pyropower Corporation's PYROFLOW pressurized circulating fluidized-bed combustion (PCFB) combined-cycle system (advanced electric power generation/fluidized-bed combustion)

Plant Capacity/Production:
80 MWe

Project Funding:

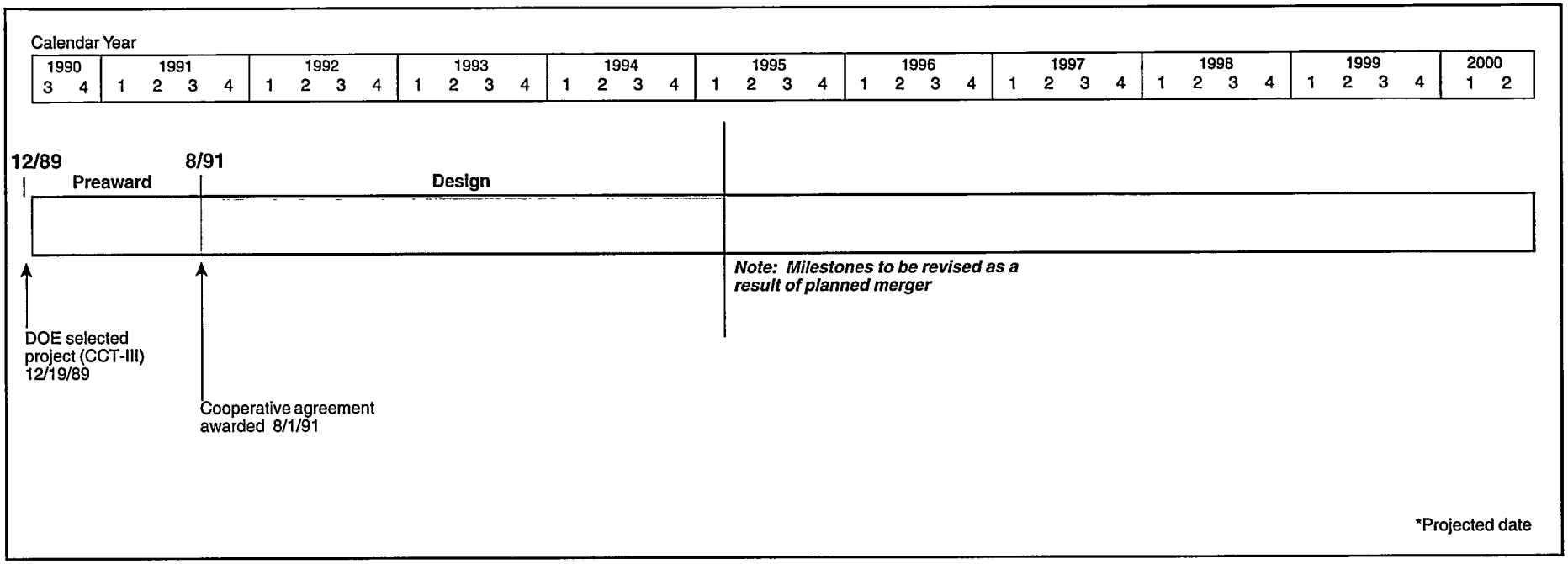
Total project cost	$202,959,000	100%
DOE	93,253,000	46
Participants	109,706,000	54

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.



Project Status/Accomplishments:

Preliminary design activities are under way. An August 1994 announcement of a planned merger between Midwest Resources, Incorporated, parent of Midwest Power, and Iowa-Illinois Gas and Electric has impacted the project structure. A 4-month extension was issued on October 31, 1994, to provide the participant with additional time to restructure the project and finalize continuation plans. Pending completion of the participant's plans, NEPA actions have been placed on hold.

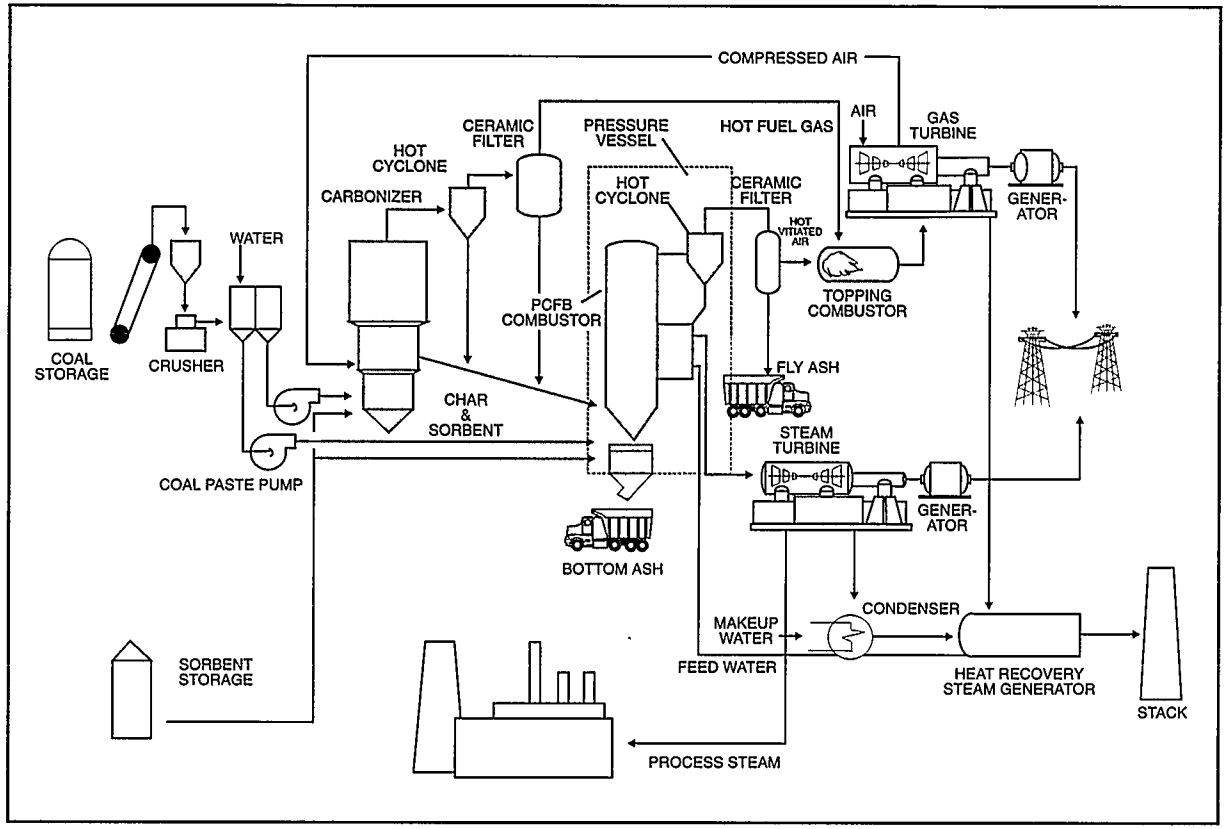
Commercial Applications:

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



Participant:

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, heat exchanger supplier; engineering

Westinghouse Electric Corporation—gas turbine, topping combustor, carbonizer filter, and alkali removal system supplier

LLB Lurgi Lentjes Babcock Energietechnick GmbH—combustor filter, slurry feed, and ash removal system supplier

Location:

Calvert City, Marshall County, KY (adjacent to Air Products and Chemicals' chemicals 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	$360,707,500	100%
DOE	142,460,000	39
Participants	218,247,500	61

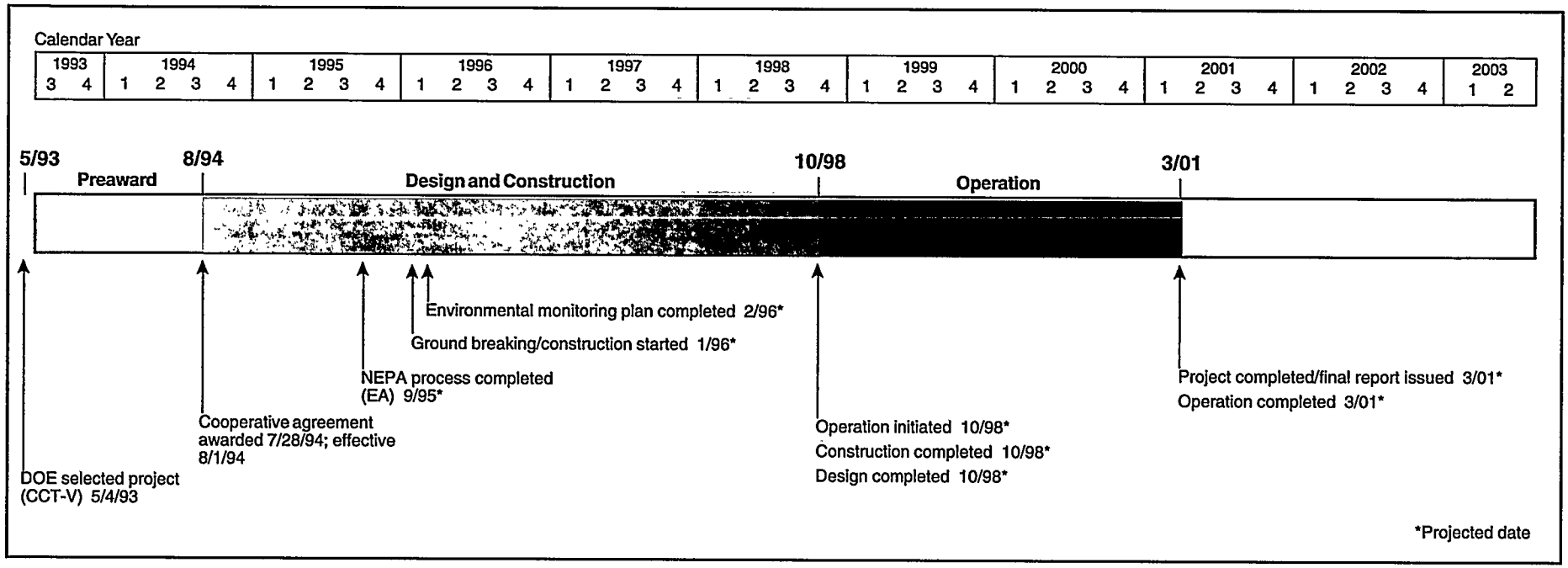
Project Objective:

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:

Coal is fed to a pressurized carbonizer that produces a low-Btu fuel gas and char. After the fuel gas is cleaned of particulates 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 passes through ceramic filtration and alkali removal units and then is mixed with the carbonizer fuel gas for combustion in the topping combustor. A steam turbine is driven by steam generated in (1) the heat recovery steam generator, which is located downstream of the gas turbine, (2) an integrated ash-cooling heat exchanger, and (3) the PCFB combustor.

At the Calvert City chemical 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. The facility will use about 870 tons/day of 2.4–3.5% sulfur bituminous coals from western Kentucky and southern Illinois.



Project Status/Accomplishments:

The cooperative agreement was awarded July 28, 1994, with an effective date of August 1, 1994. Environmental information for use in the NEPA process has been submitted to DOE. Preliminary design activities are under way.

Commercial Applications:

This project serves as a stepping stone to move the second-generation PCFB technology to readiness for widespread commercial application. 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 nonruggedized gas turbine in a pressurized fluidized-bed application.

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.

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 CO_2 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

Participant:
The Ohio Power Company

Additional Team Members:
Amercian 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, Unit 1)

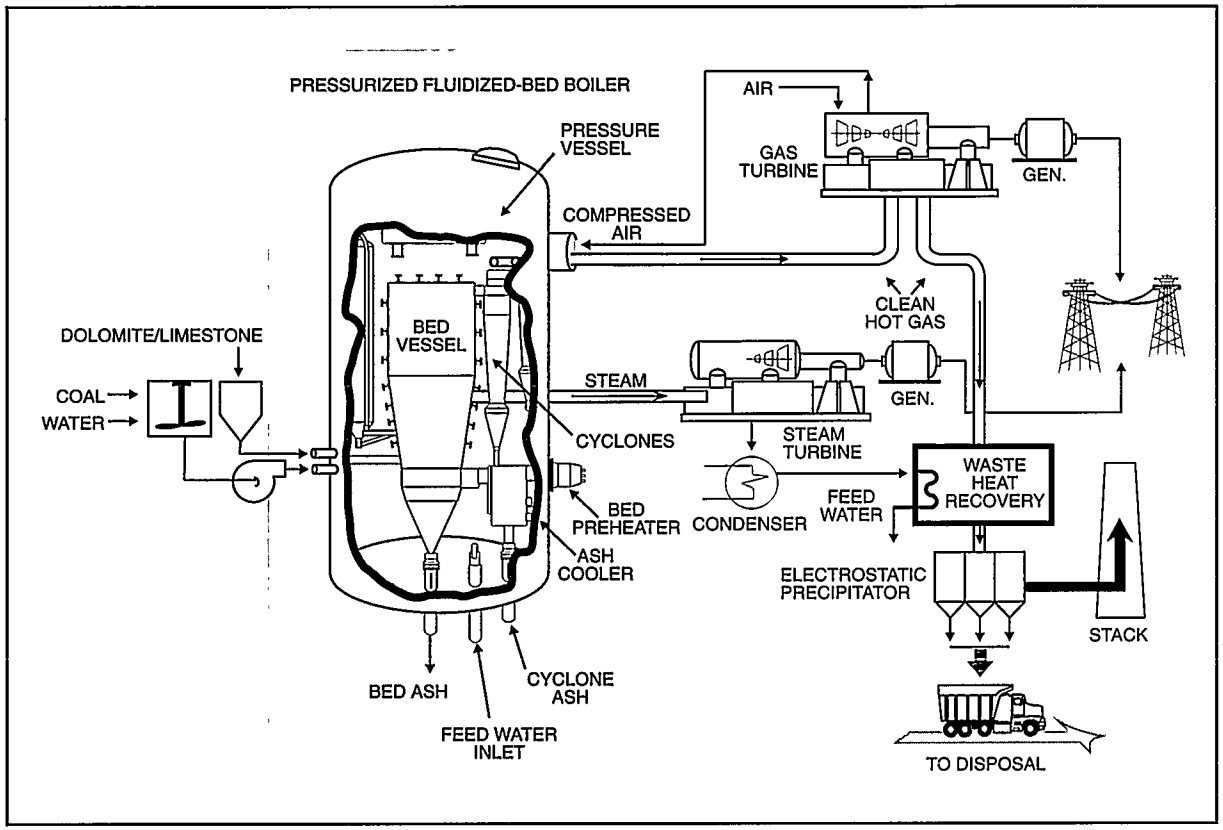
Technology:
The Babcock & Wilcox Company's pressurized fluidized-bed combustion (PFBC) system (under license from ABB Carbon) (advanced electric power generation/ fluidized-bed combustion)

Plant Capacity/Production:
70 MWe

Project Funding:

Total project cost	$189,886,339	100%
DOE	66,956,993	35
Participants	122,929,346	65

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% SO_2 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.

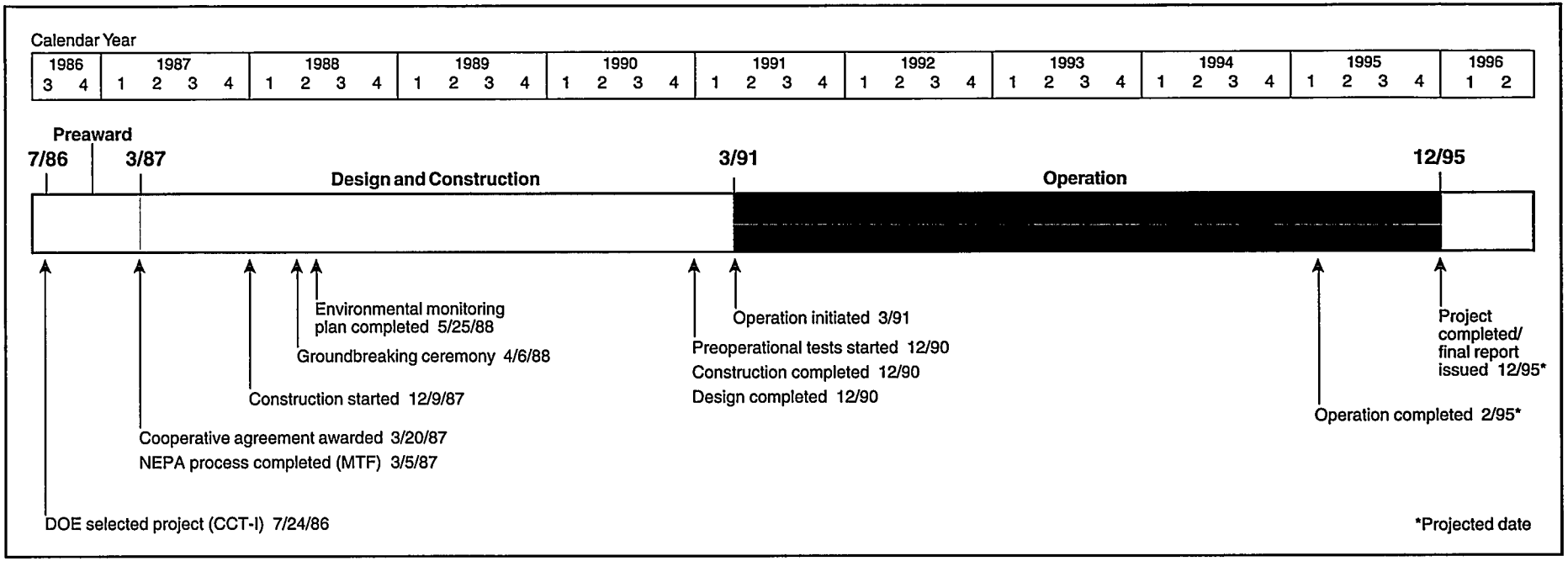


Technology/Project Description:
Tidd is the first large-scale demonstration of PFBC in the United States and one of only five worldwide. The boiler, cyclones, bed reinjection vessels, and associated hardware are encapsulated in a pressure vessel 45 ft in diameter and 70 ft high. The facility was designed 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/in^2 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/in^2 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 approximately 4,800 hours of operation during 1994. Overall, coal-fueled operation now totals approximately 10,300 hours, including continuous coal-fired runs of 28, 29, 31, and 45 days. During 1994, Tidd produced 219,011 MWh of gross generation and completed 39 parametric tests. SO_2 emissions reductions above 90% and NO_x emission levels of 0.15–0.18 lb/million Btu were routinely achieved. These levels are well below NSPS requirements.

Advanced ceramic hot-gas-filtration elements have undergone approximately 5,000 hours of exposure to one-seventh of the slipstream.

Ohio Power and DOE added a fourth year of operations to obtain additional data on long-term gas turbine survivability, economical sulfur capture at a 95% level, and exposure of advanced ceramic filtration devices. Testing is expected to conclude during the first quarter of 1995.

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 7,500Btu/kWh (45% ef ficiency).

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.

Participant:
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)

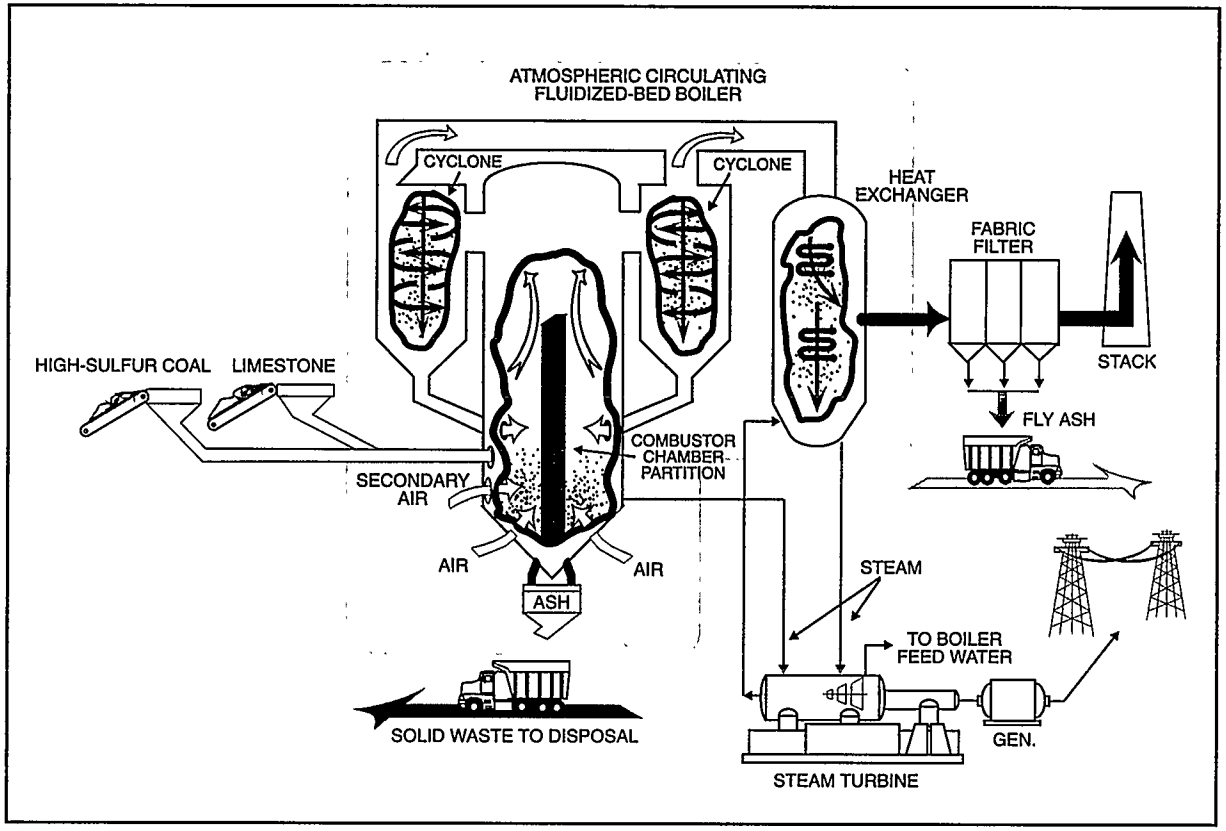
Technology:
Pyropower's atmospheric circulating fluidized-bed combustion (ACFB) system (advanced electric power generation/fluidized-bed combustion)

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% SO_2 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 SO_2 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% suflur).

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 participant, follow:

- Results indicated strong correlations of absolute CO, SO_2, 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 CO_2, 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 SO_2 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% SO_2 reduction, 60–80% NO_x reduction, and control of pollutants at lower costs than are offered by existing technologies.

As a result of the Nucla demonstration, Pyropower Corporation was able to save almost 3 years in establishing a commercial line of ACFB units. Pyropower's commercial units are now offered under warranty in sizes ranging up to 400 MWe. Under the terms of the project's repayment plan, Tri-State is required to submit to DOE semiannual payments based on a percentage of the net revenues from plant operation. This repayment obligation ends in October 2011 unless DOE's contribution is repaid before that time. In September 1994, Tri-State made its first payment of $276,141 under the plan.

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	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

Participant:
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)

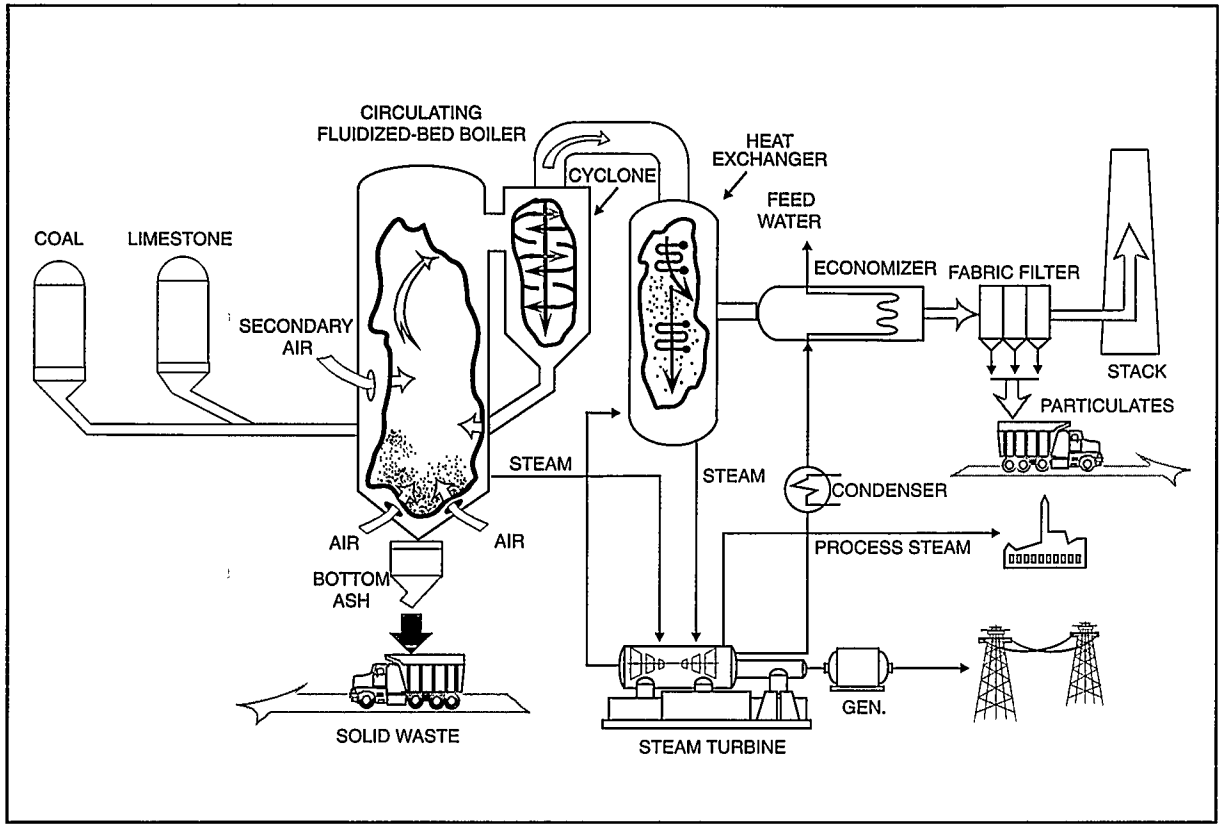
Technology:
Foster Wheeler's atmospheric circulating fluidized-bed (ACFB) combustor (advanced electric power generation/ fluidized-bed combustion)

Plant Capacity/Production:
227 MWe (net) and 400,000 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 nonutility power producers, with the data necessary for evaluating a 250-MWe ACFB as a commercial alternative to accomplish greater than 90% SO_2 removal, to reduce NO_x emissions by 60% when compared with conventional technology, and to achieve a steam efficiency of 88%.

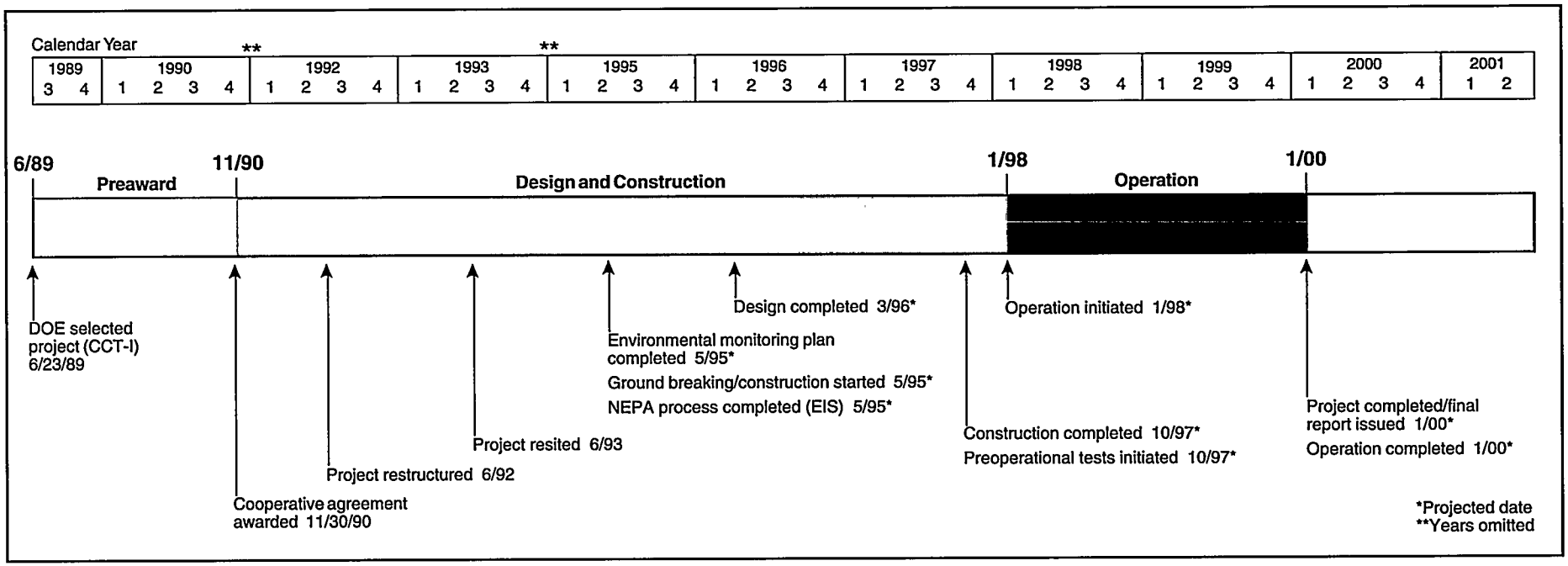


Technology/Project Description:
In this project, the circulating fluidized-bed combustor operates at atmospheric pressure. Coal, primary air, and a solid sorbent, such as limestone, are introduced into the lower portion of the combustor where initial combustion occurs. As coal particles decrease in size 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 participant 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 SO_2 emissions from this demonstration plant are below



0.24lb/million Btu (92% reduction). This technology operates at lower temperatures than conventional boilers, thus reducing NO_x production. In addition, installation of a selective noncatalytic reduction system planned for the facility is expected to reduce the NO_x emissions by an additional 50%.

Bituminous coal (2% sulfur) from western Pennsylvania will be used.

Project Status/Accomplishments:

The project is in the design stage. The participant has finalized agreements with all major equipment vendors and with coal and limestone suppliers. During 1994, the participant selected Gilbert/Commonwealth as the project's architect and engineer and later as the construction manager.

In 1993, the project was relocated 6 miles to a new site in North Codorus, PA. The 1994 efforts focused on the completion of the NEPA and state permitting processes. Environmental information for use in the NEPA process was prepared. Public scoping meetings for the North Codorus site were held in August and October 1993 to solicit public comments on preparation of the project's environmental impact statement. The draft EIS was released for public review in late November 1994. A public hearing on the draft EIS was held at York, PA, in December 1994; another is planned for January 1995.

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 SO_2 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

Participant:
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, Unit 7)

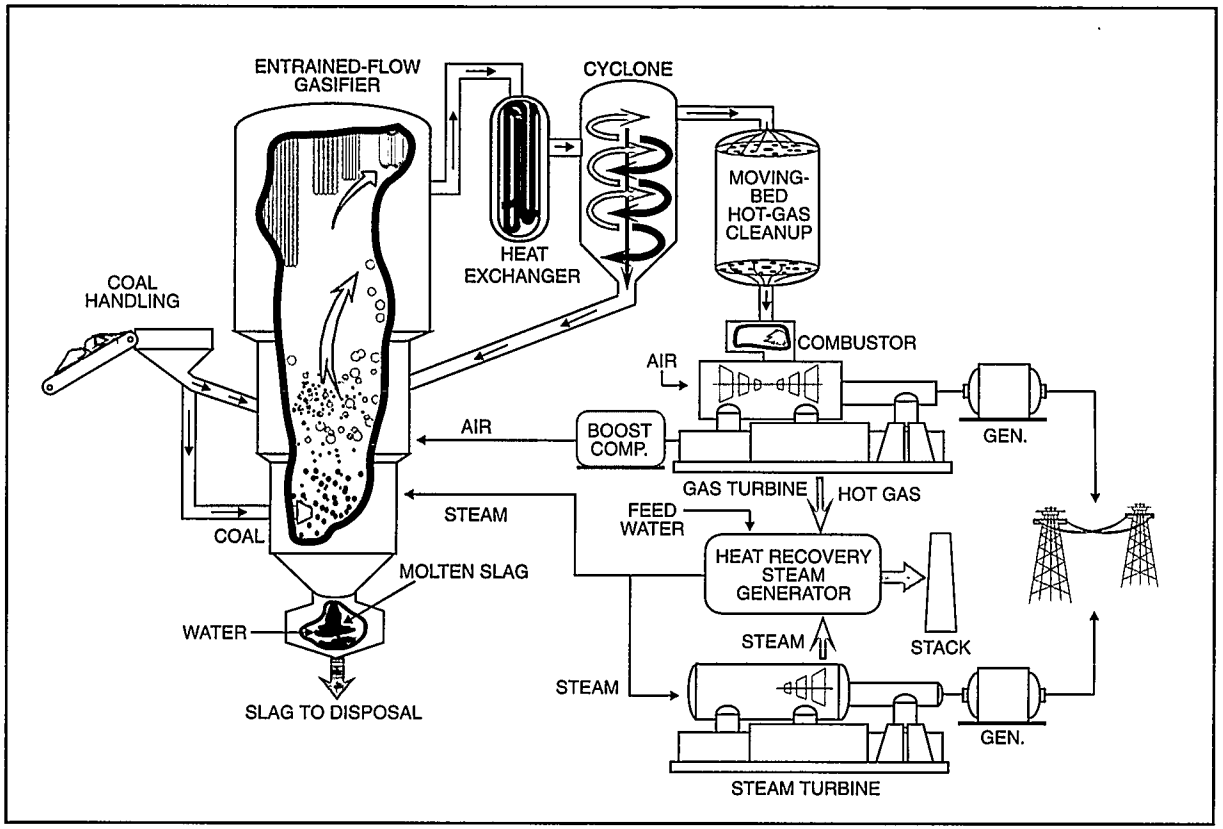
Technology:
ABB Combustion Engineering's integrated gasification combined-cycle (IGCC) system (advanced electric power generation/integrated gasification combined cycle)

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.



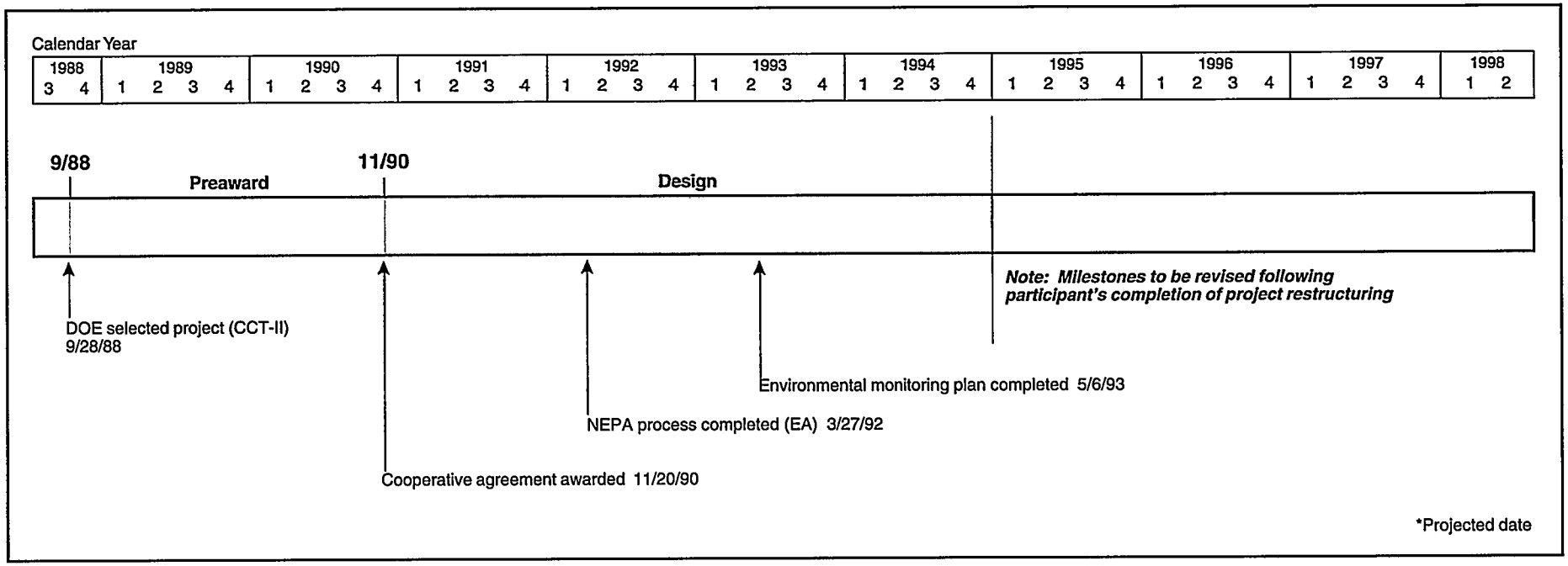
Technology/Project Description:
Pressurized pulverized coal is pneumatically transported to the gasifier. The gasifier essentially consists of a bottom combustor section and a top reductor section. Coal is fed into both sections. A slag tap at the bottom of the combustor allows molten slag to flow into 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 ahigh 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 40MW e (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 8,800Btu/kWh (an efficiency of 38.8%). SO_2 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). Illinois No. 6 bituminous coal containing 2.4% sulfur will be used.

Project Status/Accomplishments:

An environmental assessment with a finding of no significant impact was completed March 27, 1992.

Efforts to reduce the projected cost or, if necessary, restructure the project are continuing.

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 SO_2, NO_x, and CO_2. 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 8,000Btu/kWh (ef ficiency 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 CO_2 emissions.

Clean Energy Demonstration Project

Participant:

Clean Energy Partners Limited Partnership (a limited partnership consisting of Clean Energy Genco, Inc., an affiliate of Duke Energy Corp.; Makowski Clean Energy Investors, Inc.; British Gas Americas, Inc.; and an affiliate of the General Electric Company)

Additional Team Members:

Duke Engineering & Services, Inc.—engineer and constructor

General Electric Company—power island designer and supplier

British Gas Americas, Inc., affiliate in conjunction with Lurgi Energie and Umwelt GmbH—gasification island designer

Fuel Cell Engineering Corporation—molten carbonate fuel cell designer and supplier; cofunder

Electric Power Research Institute—cofunder

National Rural Electric Cooperative Association—cofunder

Deutsche Aerospace AG—cofunder

Location:

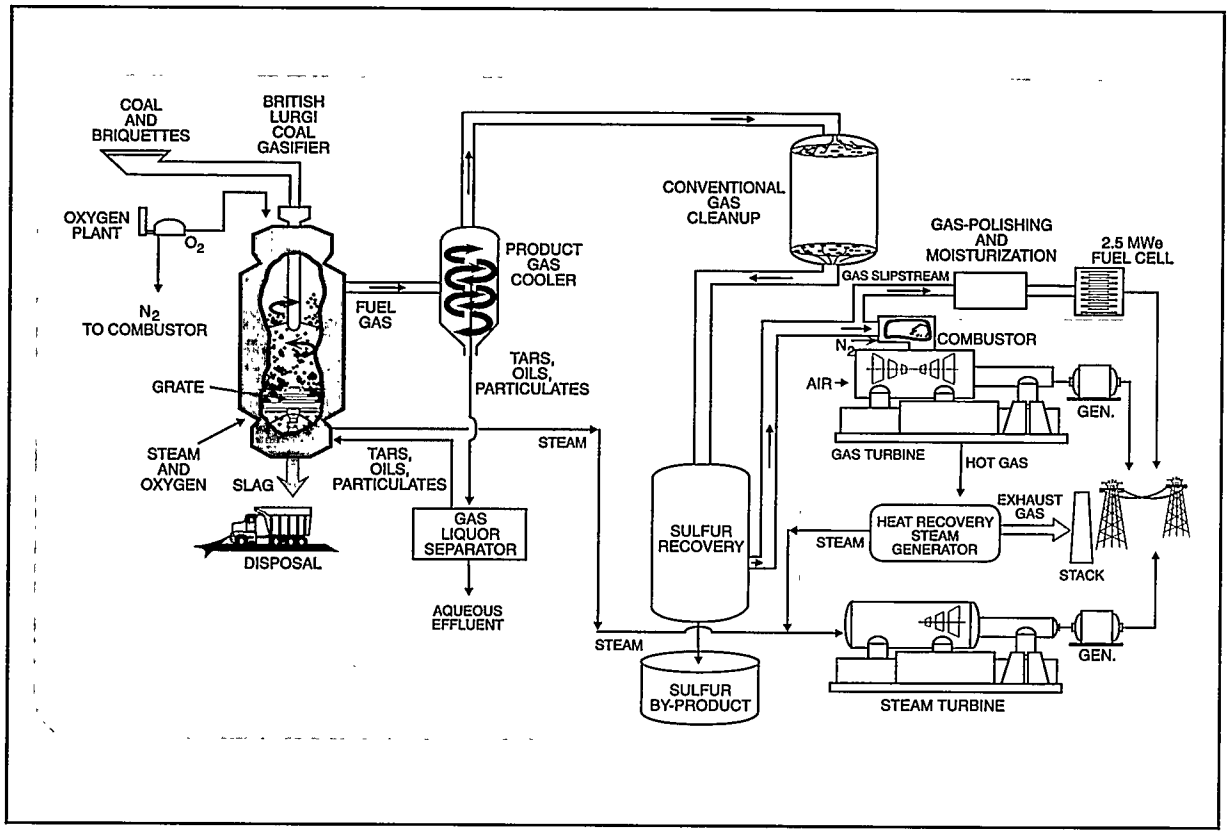
An east coast site

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 (MCFC) (advanced electric power generation/integrated gasification combined cycle)

Plant Capacity/Production:

477-MWe (net) IGCC; 1.25-MWe MCFC



Project Funding:

Total project cost	$841,096,189	100%
DOE	183,300,000	22
Participants	657,796,189	78

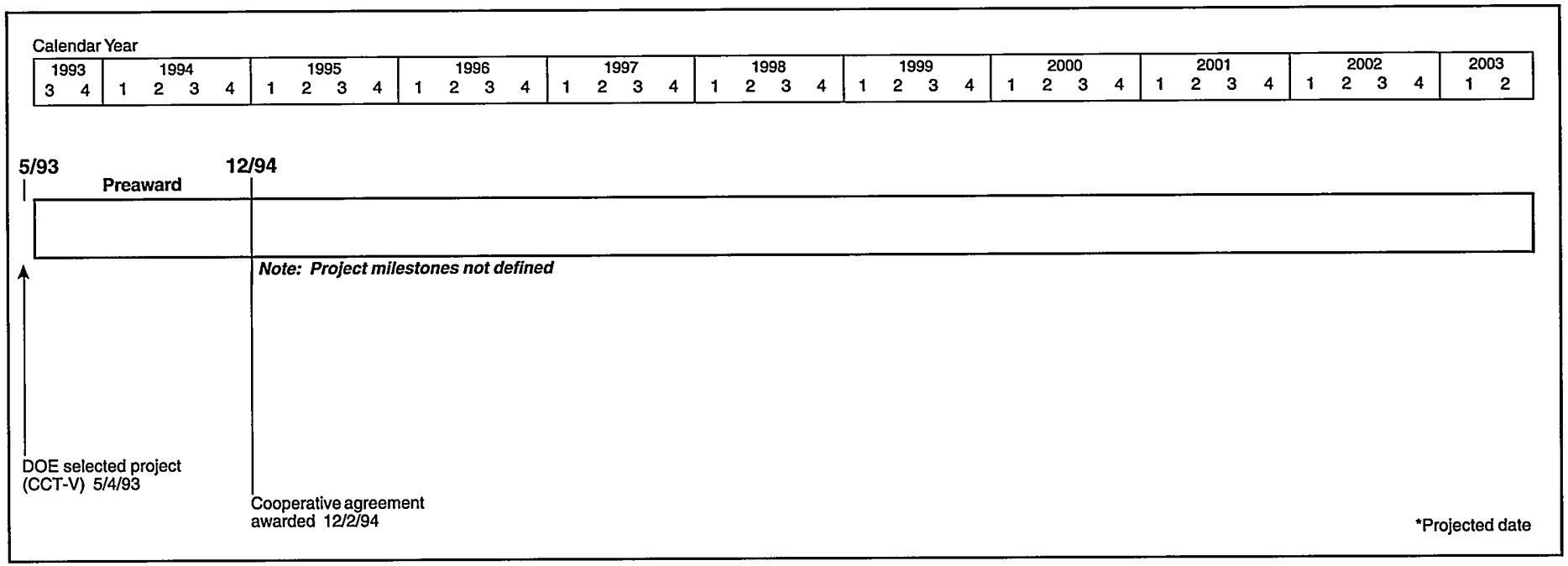
Project Objective:

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, by an independent power producer under commercial terms and conditions.

Technology/Project Description:

The BG/L gasifier is supplied with steam, oxygen, limestone flux, and coals having a high fines content. During gasification, the oxygen and steam react with the coal and limestone to produce a raw coal gas rich in hydrogen and carbon monoxide. Raw coal gas exiting the gasifier is washed and cooled. Hydrogen sulfide and other sulfur compounds are removed. Elemental sulfur is reclaimed and disposed of as a by-product. Tars, oils, and dust are recycled to extinction in the gasifier. The resulting clean, medium-Btu fuel gas is used to fuel the gas turbine in the IGCC power island. A small portion of the clean gas is used for the MCFC.

The MCFC is composed of a molten carbonate electrolyte sandwiched between porous anode and cathode plates. Fuel (desulfurized, heated medium-Btu gas) and steam are fed continuously into the cathode. Electrical reactions produce direct electric current which is converted to alternating power in an inverter.



The project is demonstrating the use of eastern U.S. bituminous coal in a commercial-scale IGCC system and integrated MCFC module.

Project Status/Accomplishments:

The cooperative agreement was awarded December 2, 1994.

Commercial Applications:

The IGCC system being demonstrated in this project is suitable for both repowering applications and new power plants. The technology is expected to be adaptable to a wide variety of potential market applications because of 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. In addition, the high efficiency and excellent environmental performance of the system are competitive with or superior to other fossil-fuel-fired power generation technologies.

The heat rate of the IGCC demonstration facility is 8,560 Btu/kWh (40% 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 CO_2 when compared to a conventional pulverized coal plant equipped with a scrubber. SO_2 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 nonleaching, glass-like slag that can be marketed as a usable by-product.

Piñon Pine IGCC Power Project

Participant:
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)

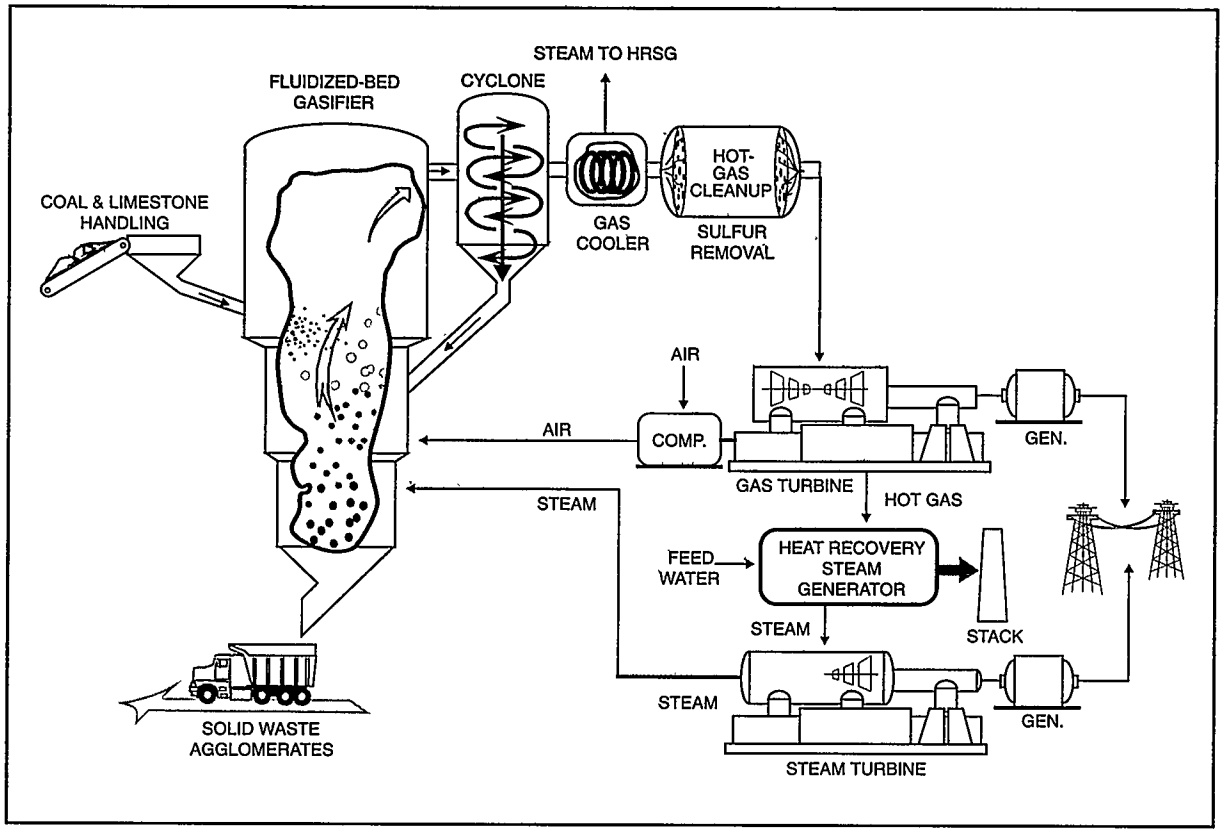
Technology:
Integrated gasification combined-cycle (IGCC) using the KRW air-blown, pressurized, fluidized-bed coal gasification system (advanced electric power generation/ integrated gasification combined cycle)

Plant Capacity/Production:
99 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.



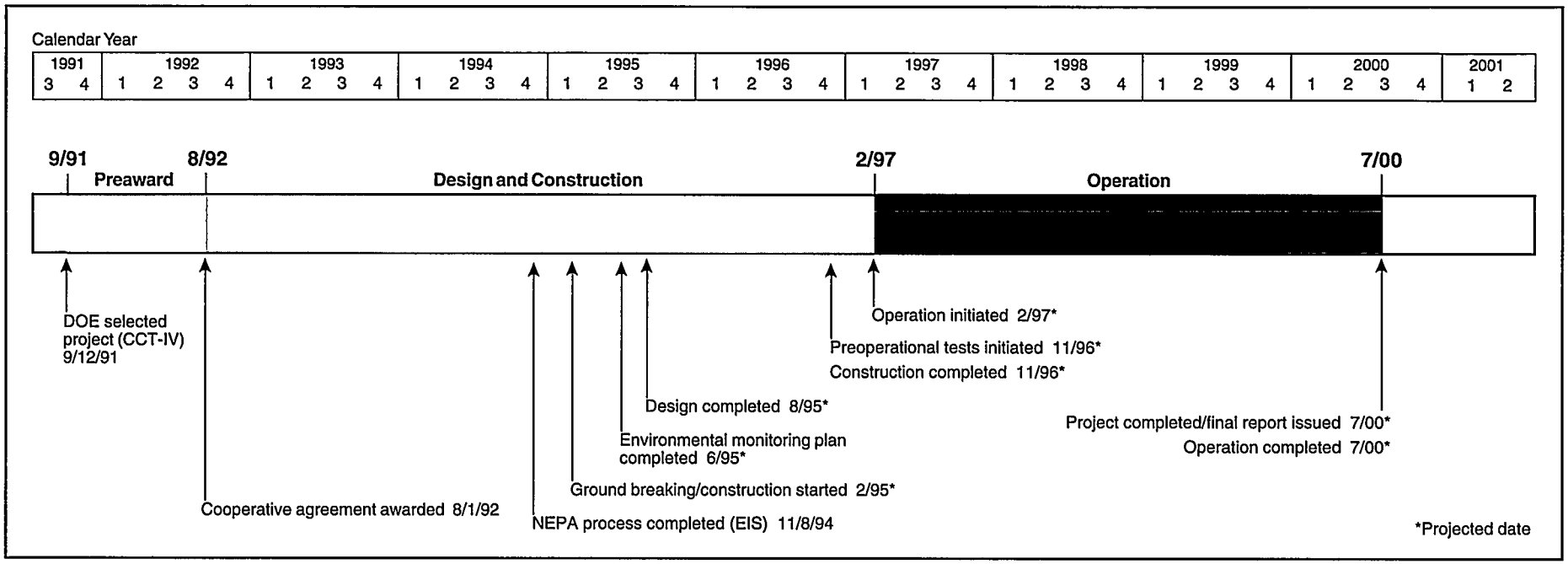
Technology/Project Description:
Dried and crushed coal is introduced into a pressurized, air-blown, fluidized-bed gasifier. Crushed limestone is added to the gasifier to capture a portion of the sulfur and to inhibit conversion of fuel nitrogen to ammonia. The sulfur reacts with the limestone to form 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 by reaction with 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 46 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, SO_2 emissions are 0.069 lb/million Btu (90% reduction).

In the demonstration project, 880 tons/day of coal are converted into 107 MWe (gross), or 99MW e (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 1994. A permit to construct the project under the provisions of Nevada's Utilty Environmental Protection Act was issued by the Public Service Commission of Nevada. In June 1994, three public hearings were conducted on the draft EIS. A final EIS was released for public comment on September 30, 1994. DOE issued a record of decision on November 8, 1994. By December 1994, all permits needed for plant construction had been received, and the participant had requested approval from DOE to continue with detailed design and construction of the plant.

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 CO_2 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-swelling 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 nonhazardous waste. SO_2 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 0.053lb/million Btu, and emissions of particulates are expected to be below 0.01 lb/million Btu.

Toms Creek IGCC Demonstration Project

Participant:
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

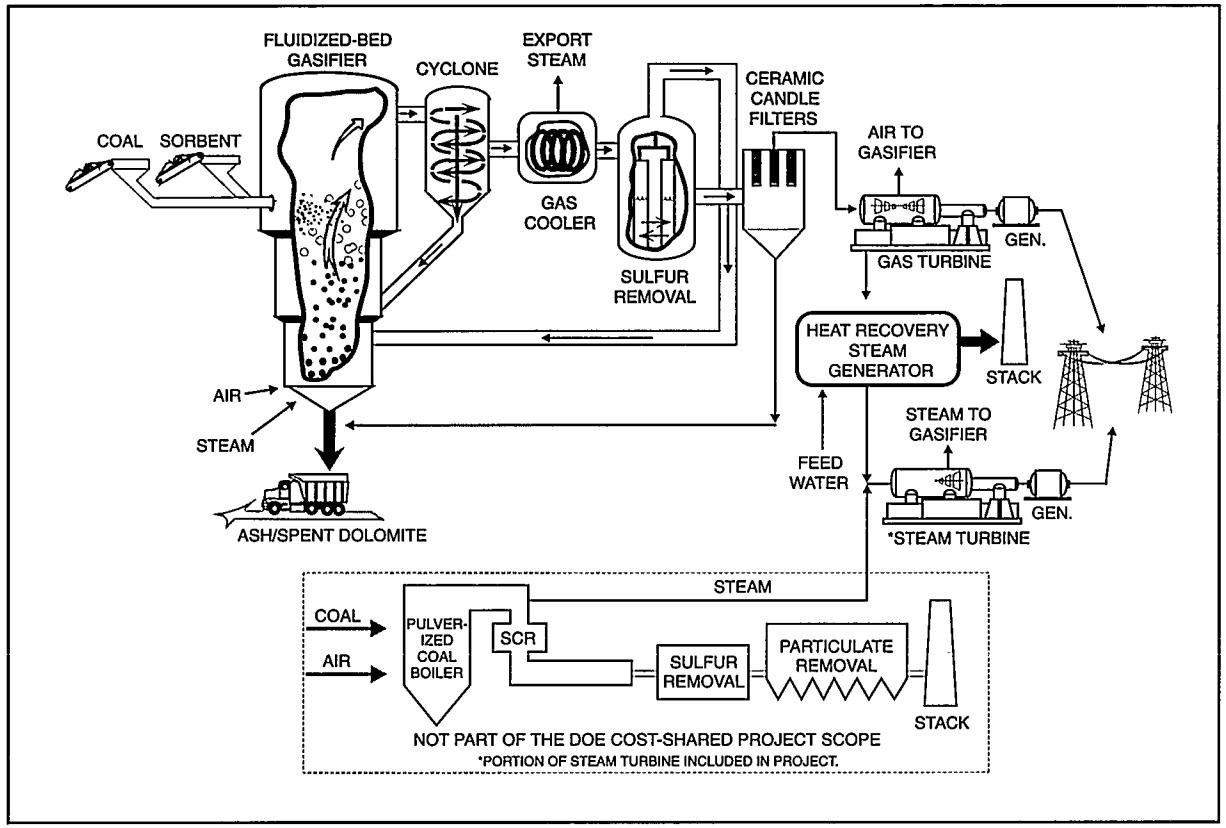
Plant Capacity/Production:
190 MWe (55 MWe IGCC and 135 MWe pulverized coal) (net)

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.

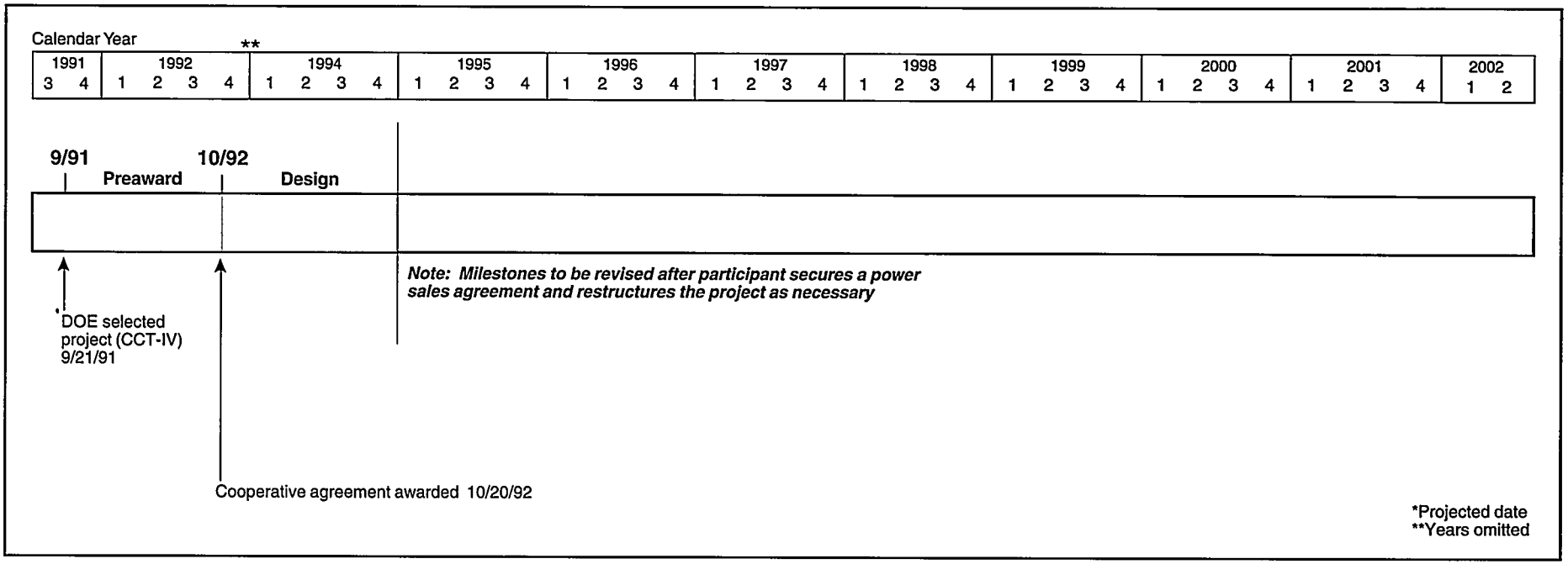


Technology/Project Description:
Coal is gasified in a pressurized, air-blown, fluidized-bed gasifier in the presence of a calcium-based sorbent. About 90% sulfur removal is accomplished in the gasifier. Solids entrained in the gas are collected by cyclones in two stages. The low-Btu gas, which leaves 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 nearly all 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 for the gasification reaction.

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 is 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 1994, efforts continued to be geared toward obtaining a power sales agreement with a third party purchaser of power. Preliminary design and project definition studies are under way.

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 SO_2 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 CO_2 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

Participant:
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, Unit 1)

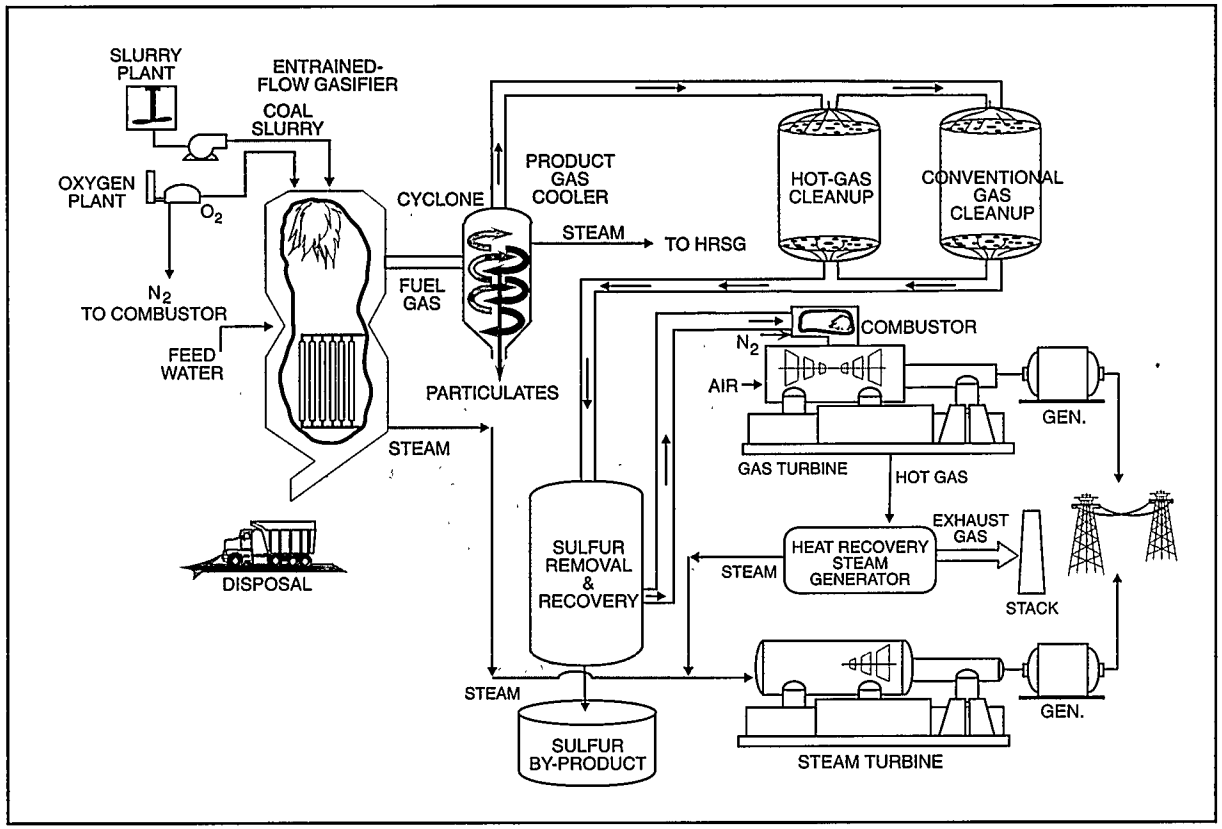
Technology:
Integrated gasification combined-cycle (IGCC) system using Texaco's pressurized, oxygen-blown, entrained-flow gasifier technology and incorporating both conventional, low-temperature acid-gas removal and hot-gas moving-bed desulfurization (advanced electric power generation/integrated gasification combined cycle)

Plant Capacity/Production:
250 MWe (net)

Project Funding:

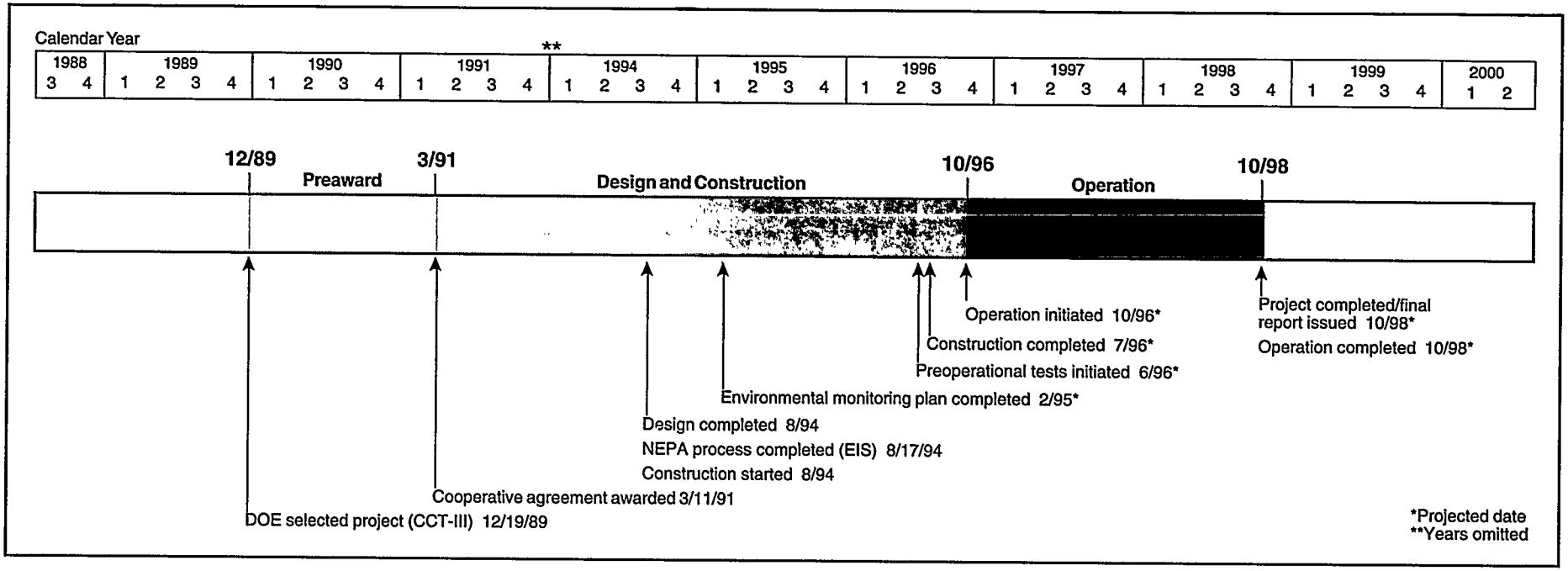
Total project cost	$260,706,446	100%
DOE	130,353,223	50
Participant	130,353,223	50

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 metal oxide 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. A portion of the syngas is passed through a moving bed of metal oxide 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 dilutent 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 120 MWe (gross). The IGCC heat rate for this demonstration is expected to be approximately 8,600 Btu/kWh (40% efficient).

The demonstration project involves only the first 250-MWe (net) portion of the planned 1,150-MWe Polk Power Station. 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 is in detailed design and early construction. In January 1994, all state permits for the plant were approved by the governor.

EPA (the lead agency) released the final EIS for public comment on June 10, 1994. Favorable records of decision were issued by EPA and the U.S. Army Corps of Engineers in July 1994. DOE issued a record of decision on the demonstration portion on August 17, 1994. Tampa Electric held a formal groundbreaking ceremony at the Polk County site on November 2, 1994. Engineering was approximately 75% complete by the year's end. Construction is expected to be completed by mid-1996 and will be followed by a 2-year demonstration period.

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% SO_2 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

Participant:
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, Unit 1)

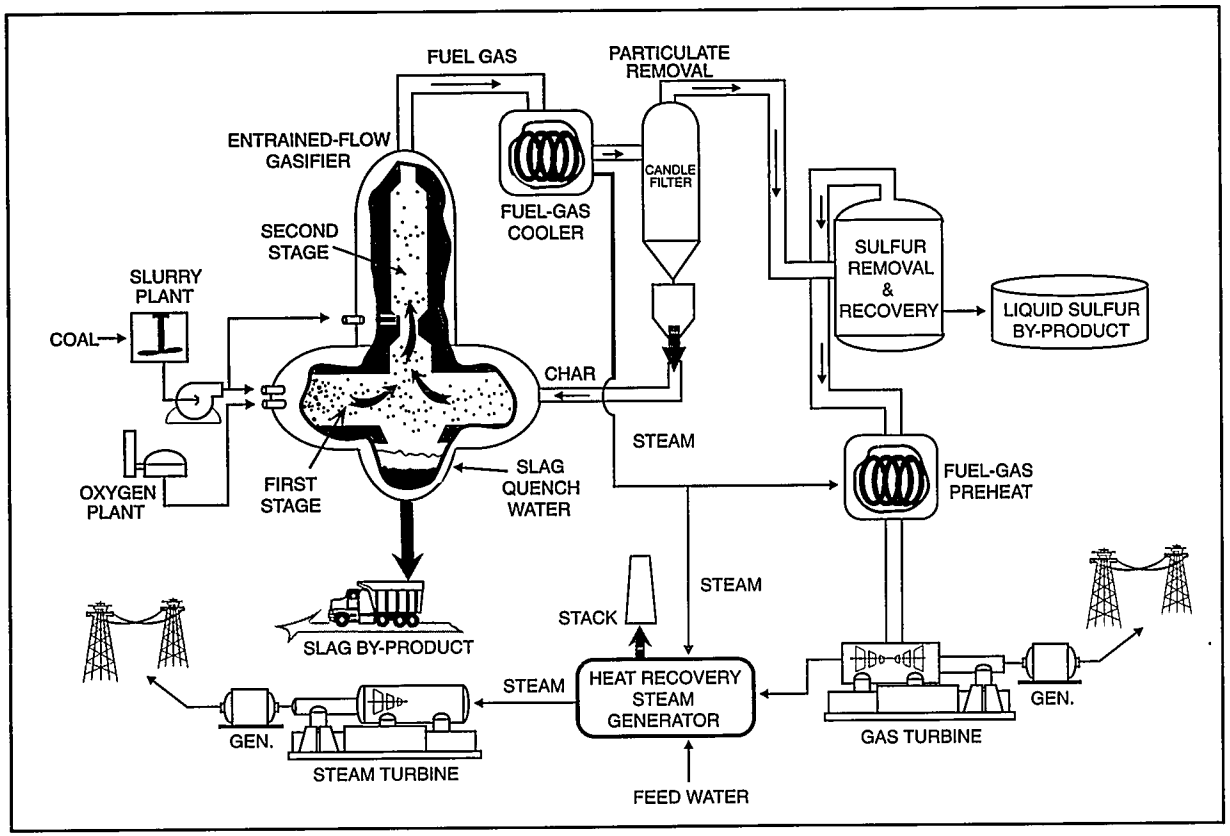
Technology:
Integrated gasification combined-cycle (IGCC) using Destec's two-stage, entrained-flow gasification system (advanced electric power generation/integrated gasification combined cycle)

Plant Capacity/Production:
262 MWe (net)

Project Funding:

Total Project cost	$438,200,000	100%
DOE	219,100,000	50
Participant	219,100,000	50

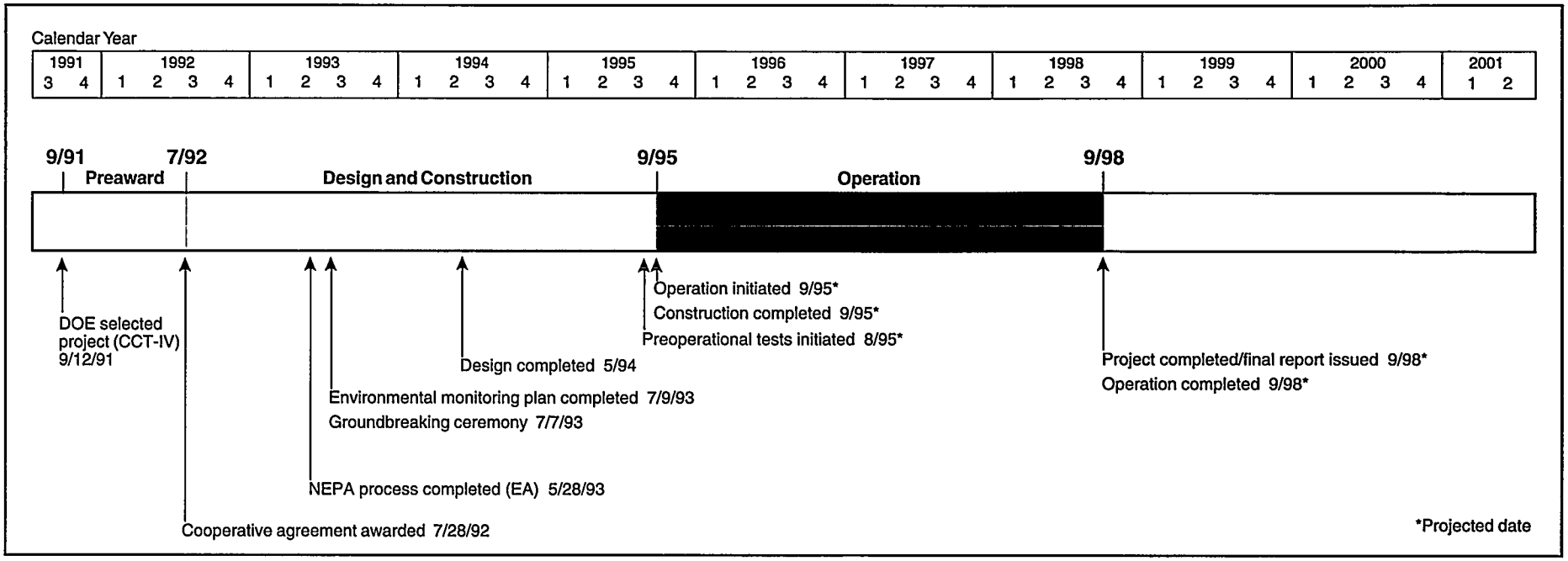
Project Objective:
To demonstrate utility repowering with a two-stage, oxygen-blown IGCC system, including advancements in the technology relevant to the use of high-sulfur bituminous coal, and to assess long-term reliability, availability, and maintainability of the system at a fully commercial scale.



Technology/Project Description:
Coal is ground, slurried with water, and gasified in a pressurized, two-stage (slagging first stage and non-slagging entrained flow second stage), oxygen-blown, 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 syngas heat recovery system, 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, SO_2 emissions are expected to be less than 0.1 lb/million Btu (98% reduc-



tion). 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:

Construction is in progress and is 70% complete. All major equipment has been installed, including the gasifiers, air separation unit, and gas turbine. At year-end 1994, activities were focused on completion of mechanical piping and electrical wiring. Upgrading of the switchyard and transmission system has been completed. The tube bundle has been installed in the heat recovery steam generator. Design specifications for several vessels have been modified to incorporate recent experience from Destec Energy's operating unit at the Louisiana Gasification Technology, Inc., facility in Plaquemine, LA.

An environmental assessment was completed, and DOE issued a finding of no significant impact on May 28, 1993. All required environmental permits have been granted.

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 that will be over 30years 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 SO_2, NO_x, and CO_2 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 CO_2.

Healy Clean Coal Project

Participant:
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)

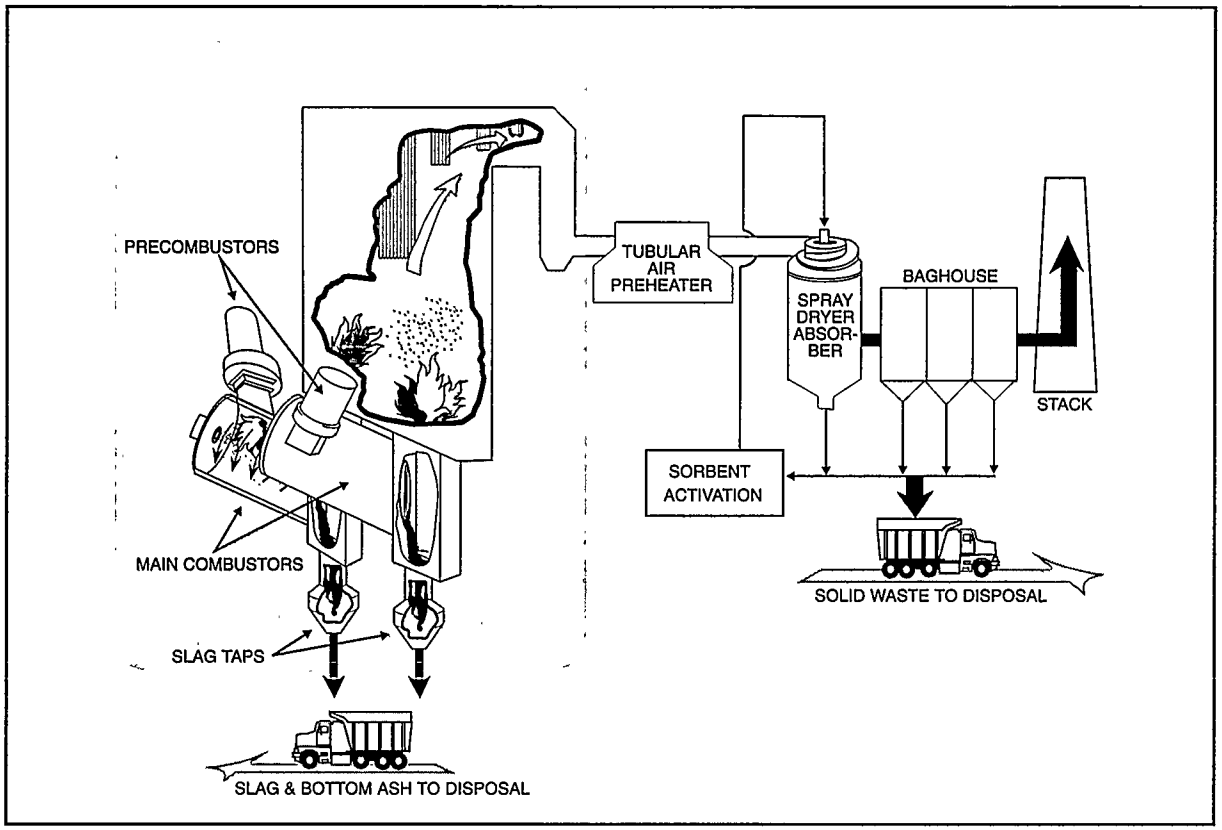
Technology:
TRW's advanced entrained (slagging) combustor
Joy Technologies' spray dryer absorber with sorbent recycle
(advanced electric power generation/advanced combustion/heat engines)

Plant Capacity/Production:
50 MWe (nominal electric output)

Project Funding:

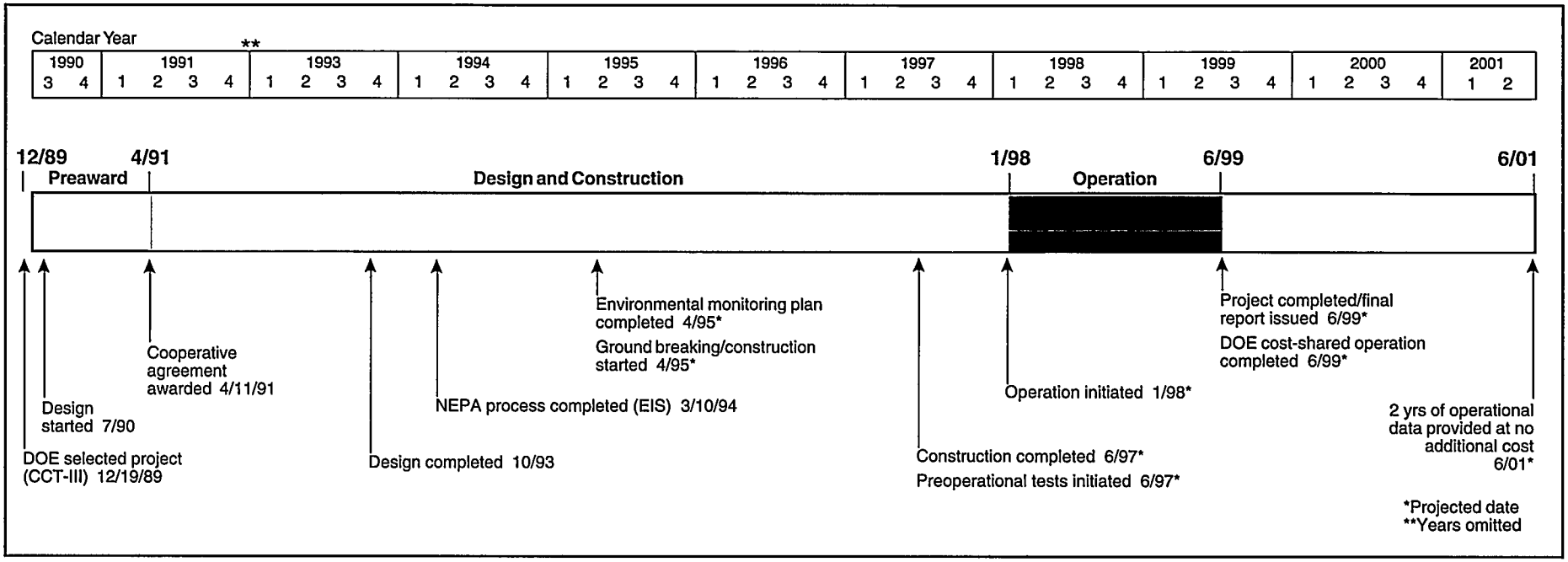
Total project cost	$242,058,000	100%
DOE	117,327,000	48
Participant	124,731,000	52

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.



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 (GVEA). The plant will use a nominal 900 tons/day of subbituminous coal containing a nominal 0.2% sulfur and waste coal and 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.

To address concerns about potential impact to the nearby Denali National Park and Preserve, DOE, the National Park Service, GVEA, and the project participant entered into an agreement to reduce the emissions from Unit #1 reducing the combined emissions from the two units to only slightly greater than those currently emitted from Unit #1 alone. Total site emissons will be further reduced to current levels if necessary 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 scale-up designs. The design and engineering is complete; bids for the general construction contract were opened in November 1994; construction is scheduled to start in April 1995.

A final EIS was issued on December 15, 1993, and a record of decision was issued on March 10, 1994. A final visibility monitoring plan has been submitted to the Alaska Department of Environmental Conservation.

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

Participant:
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
PSI—cleanup system designer
AMBAC International—coal-water fuel injection system components supplier

Location:
Easton, Talbot County, MD (The Easton Utilities Commission's Plant #2)

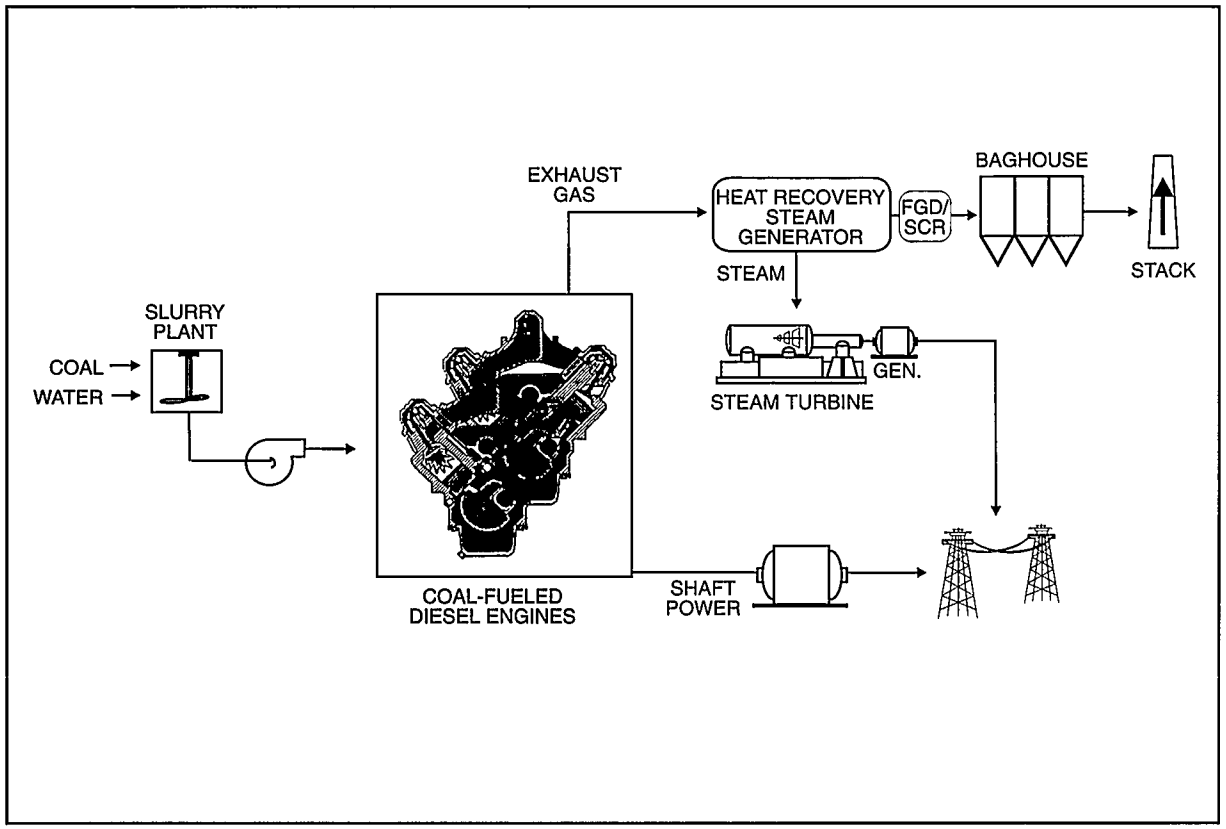
Technology:
Cooper-Bessemer's coal-fueled diesel engine combined-cycle (CDCC) system (advanced electric power generation/advanced combustion/heat engines)

Plant Capacity/Production:
14 MWe (net)

Project Funding:

Total project cost	$38,309,516	100%
DOE	19,154,758	50
Participant	19,154,758	50

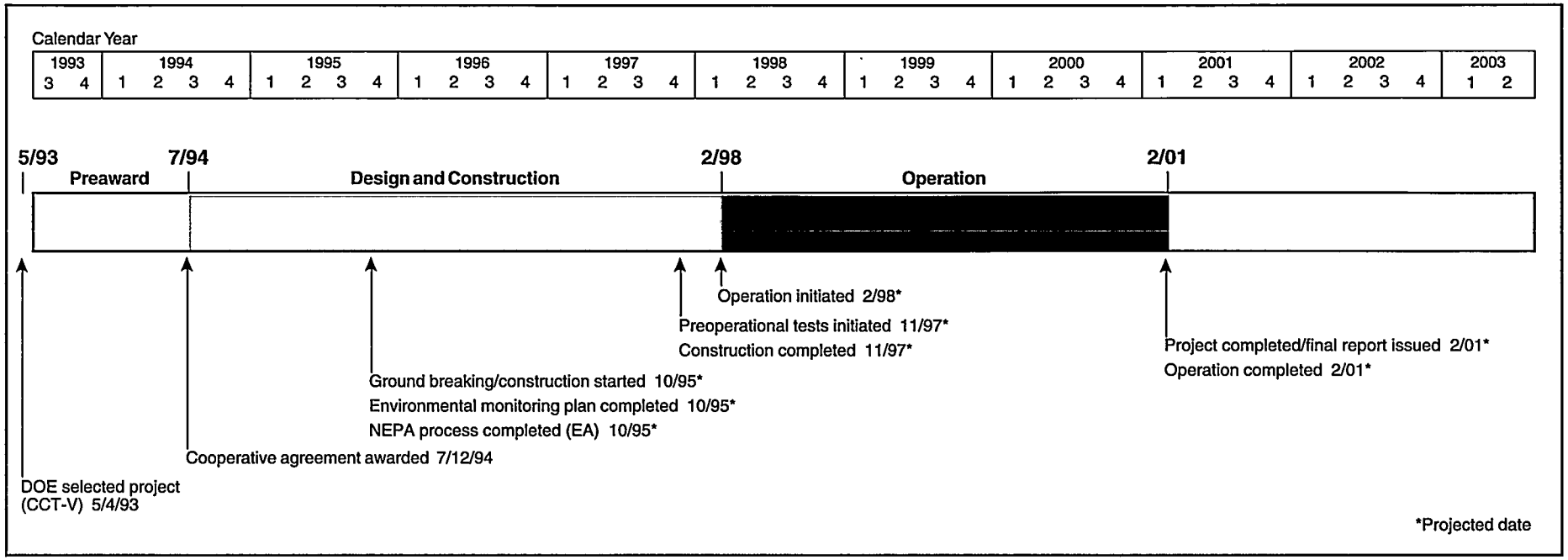
Project Objective:
To demonstrate an advanced, coal-fueled diesel engine combined-cycle system based on Cooper-Bessemer's LSB/LSVB diesel engine series. To provide critical data on the performance, reliability, and wear information of all major subsystems.



Technology/Project Description:
The project involves modifying two Cooper-Bessemer medium-speed (400 rpm) diesel engines (6.3 MWe each) 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 SO_2 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 in making the coal-water fuel is an Ohio bituminous coal



with characteristics suitable for cleaning to an ash level of less than 2% and a sulfur content of less than 2%.

Project Status/Accomplishments:

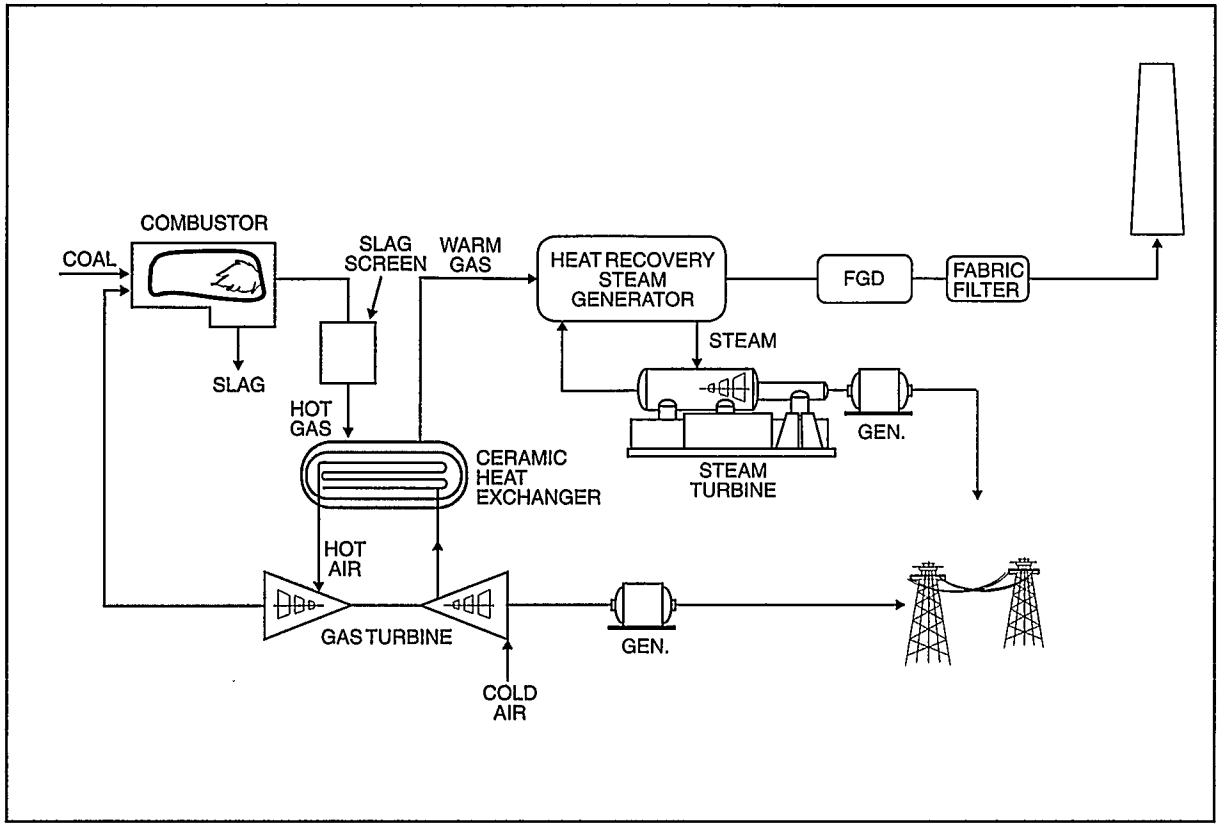
The cooperative agreement was awarded July 12, 1994. Design efforts are in progress. Environmental information is being prepared for use in the NEPA process. The participant has finalized its subcontract arrangements with Cooper-Bessemer and CQ, Inc., as well as its funding agreement with the Ohio Coal Development Office.

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 medium-speed 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



Participant:
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	$146,832,000	100%
DOE	73,416,000	50
Participant	73,416,000	50

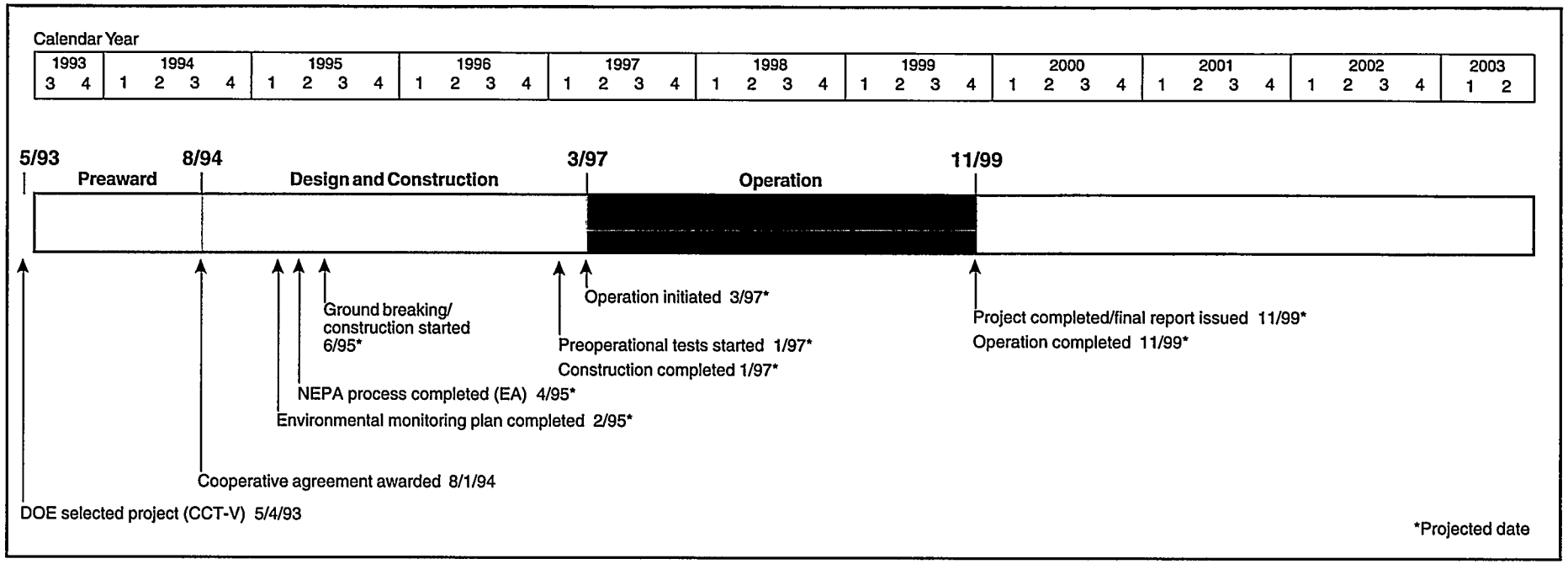
Project Objective:
To demonstrate an externally fired combined-cycle system through the use of a novel ceramic heat exchanger and to assess the system's environmental and economic performance for meeting future energy needs. Along with the heat exchanger, the system will demonstrate a ceramic slag screen for removal of combustion by-products from the product gas prior to entering the heat exchanger; 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 is a registered trademark of Hague International.



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 cooperative agreement was awarded on August 1, 1994. Design efforts are in progress. Environmental information was prepared for use in the NEPA process. An environmental assessment was drafted and was undergoing review at year's end.

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.

SO_2 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.

Participant:
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, Wisconsin Power and Light Company's (Nelson Dewey Station, Unit No. 2)

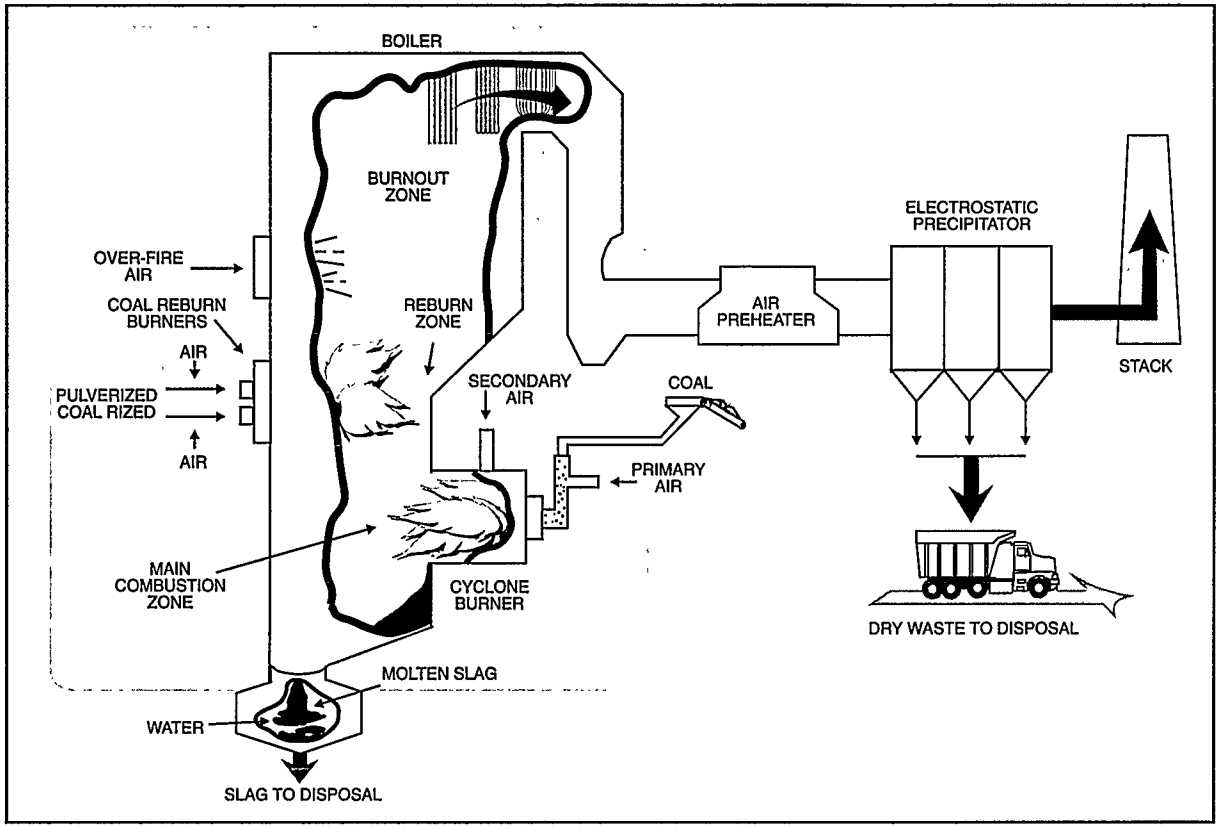
Technology:
The Babcock & Wilcox Company's coal-reburning system (environmental control devices/NO_x control technologies)

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	3/94
Economic Evaluation Report	early 1995
Public Design Report	8/91

Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit

Project completed.

Participant:
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

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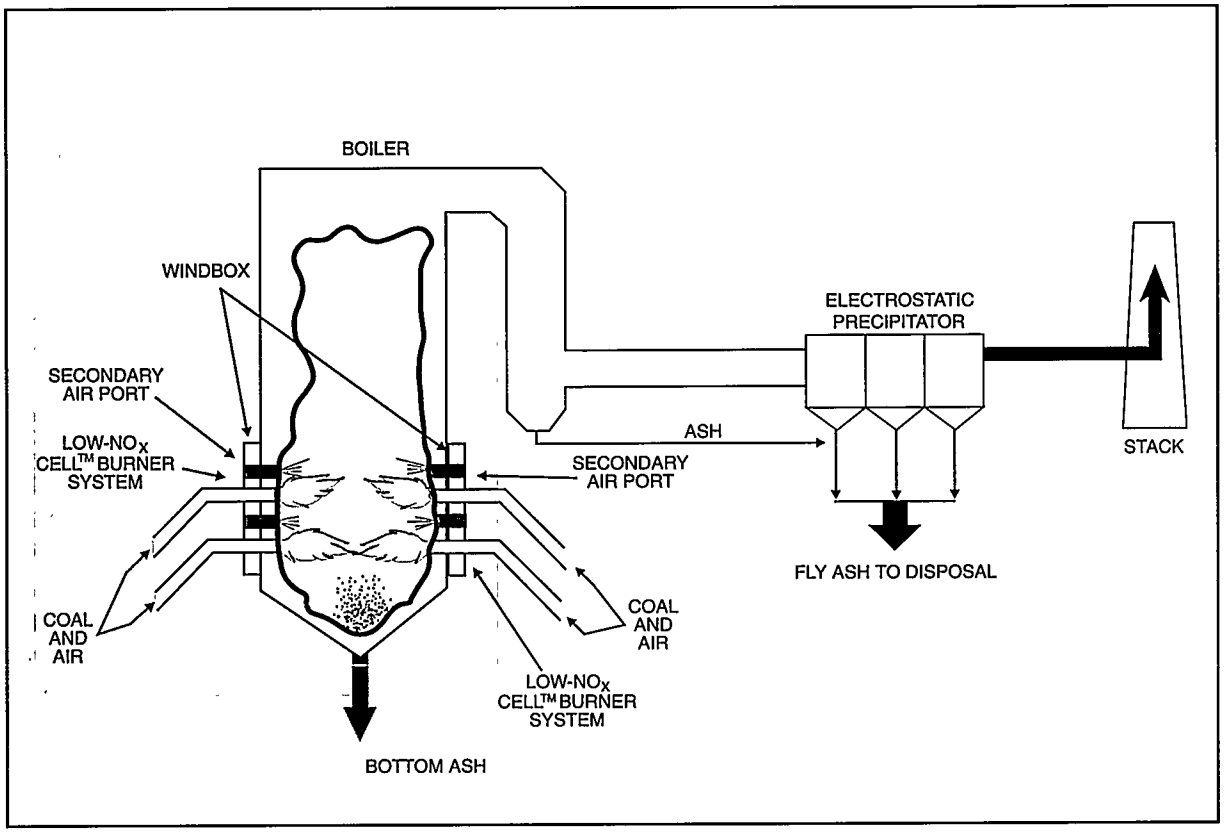


Project Objective:
To demonstrate through the first commercial-scale full burner retrofit the cost-effective reduction of NO_x from a large base-load coal-fired utility boiler with LNCB® technology; and to achieve at least a 50% NO_x reduction without degradation of boiler performance at less cost than conventional low-NO_x burners.

Technology/Project Description:
The LNCB® 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 LNCB® 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 SO_2 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 LNCB® were installed. Alternate LNCB® 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 LNCB® 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 LNCB® 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 H_2S concentrations in the furnace, ultrasonic testing of lower furnace tube walls, and destructive examination of a corrosion test panel. Environmentally, NO_x, CO, CO_2, 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 LNCB® 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 LNCB® 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 LNCB® burner were installed. The panel consisted of SA-213T2 bare tube material with some of this material aluminized, some stainless weld overlaid, and some chromized. The level of corrosion is roughly equivalent to the boiler's corrosion prior to the retrofit. The coated materials had no loss.

Commercial Applications:

The Babcock & Wilcox Company installed the LNCB® technology on more than 2,500 MWe of capacity in the United States—each installation achieving more than 50% NO_x reduction. In addition, LNCB® retrofits (introduced in early 1993) have been ordered for an additional 3,250 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.

The LNCB® project received the 1994 R&D 100 award for technical excellence in a commercial product.

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*	3/95

Final Reports:

Final Technical Report	3/95
Economic Evaluation Report	5/95
Public Design Report	8/91
Corrosion Test Results Report	5/95

* Project was extended to complete the boiler water-wall corrosion examination during the fall boiler outage.

Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler

Participant:
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)

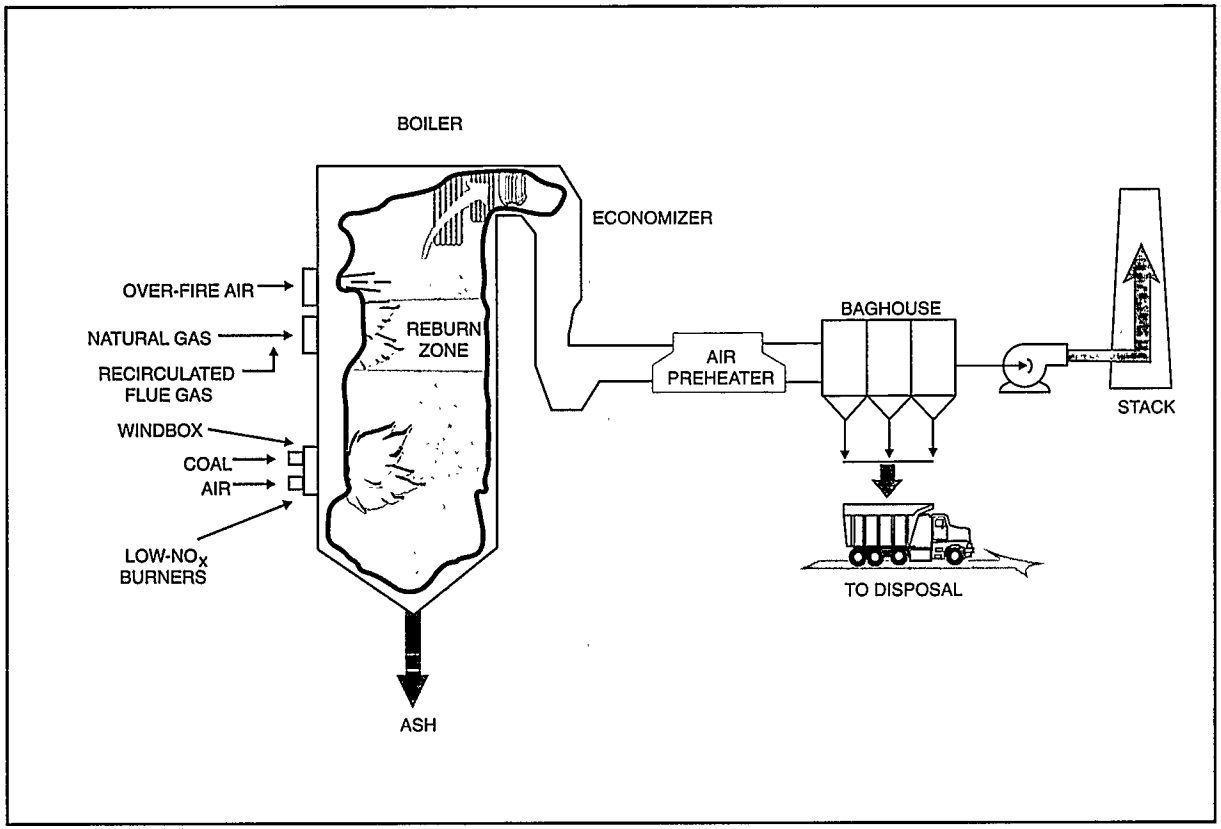
Technology:
Energy and Environmental Research Corporation's gas reburning and low-NO_x burner (GR–LNB) system (environmental control devices/NO_x control technologies)

Plant Capacity/Production:
172 MWe

Project Funding:

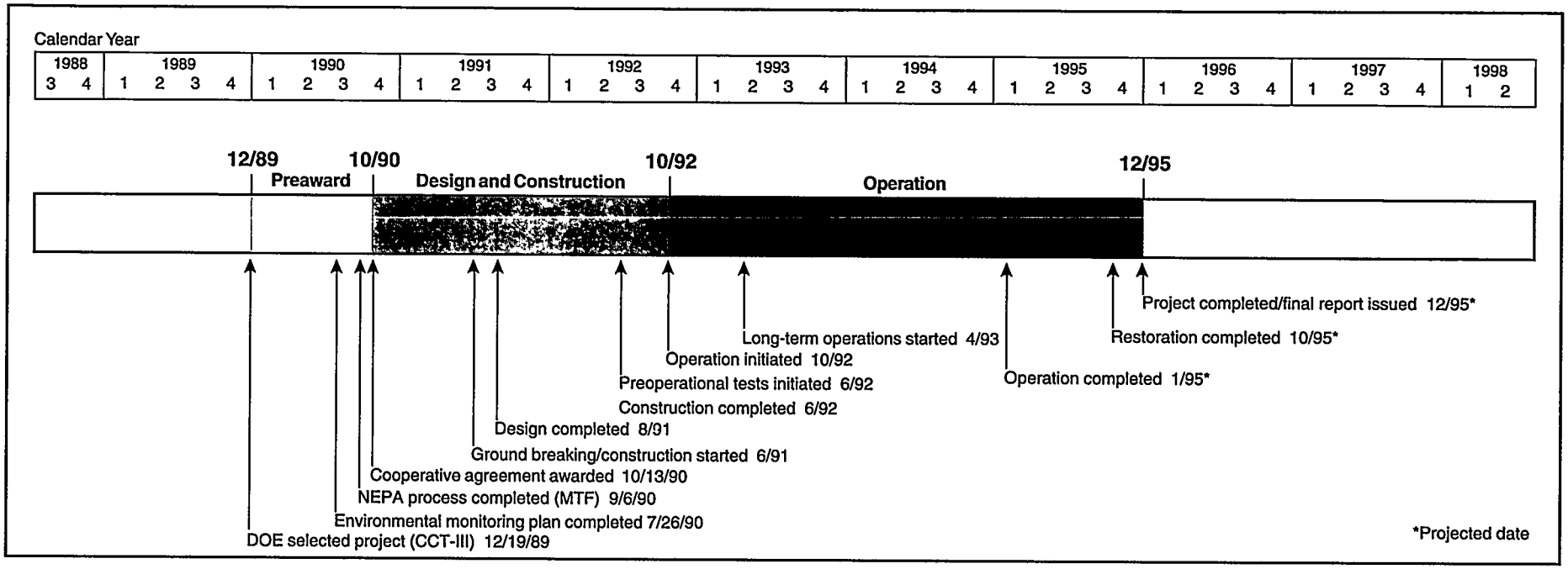
Total project cost	$17,811,172	100%
DOE	8,905,585	50
Participants	8,905,587	50

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 lowers NO_x emissions by up to 70%. Gas reburning was demonstrated with and without the use of recirculated flue gas, on a gas/gas firing mode and with optimized over-fire air.

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 were used in this demonstration.



Project Status/Accomplishments:

During construction, new boiler penetrations, new burners, refractory, and insulation were installed. In February 1994, new over-fire air nozzles and new gas injectors were installed. Also, the flue gas recirculating system was isolated so that operation on only natural gas could be demonstrated. Parametric/optimization tests began in October 1992 and continued into April 1993.

Long-term testing was initiated in April 1993 and will be completed in January 1995. Testing is yielding operating data over an extended period while the unit is under routine commercial service, determining the effect of GR–LNB operation on the unit, and obtaining incremental maintenance and operating costs with GR. The long-term test results confirmed the parametric test results. The combined GR–LNB achieved NO_x reductions of 60–73%. NO_x reductions of 60–65% were achieved with gas heat input of 5–10%. NO_x reductions by low-NO_x burners alone were typically 30–40%. NO_x emissions were insensitive to a change in recirculated flue gas flow employed to inject the natural gas.

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 that it can be retrofitted to existing units, reduces NO_x emissions by 70% or more, is suitable for use with a wide range of coals, has the potential to improve boiler operability and reduce the cost of electricity, consists of commercially available components, and 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

Participant:
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)

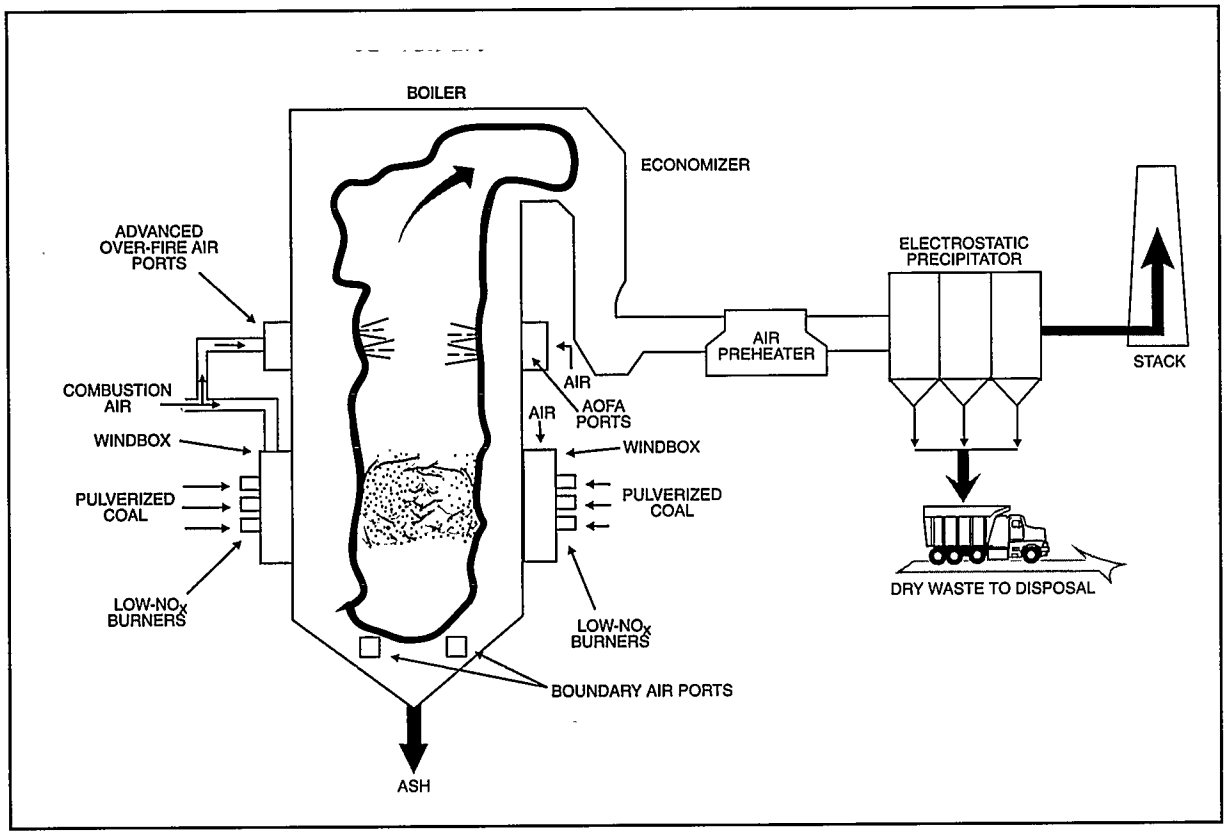
Plant Capacity/Production:
500 MWe

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.

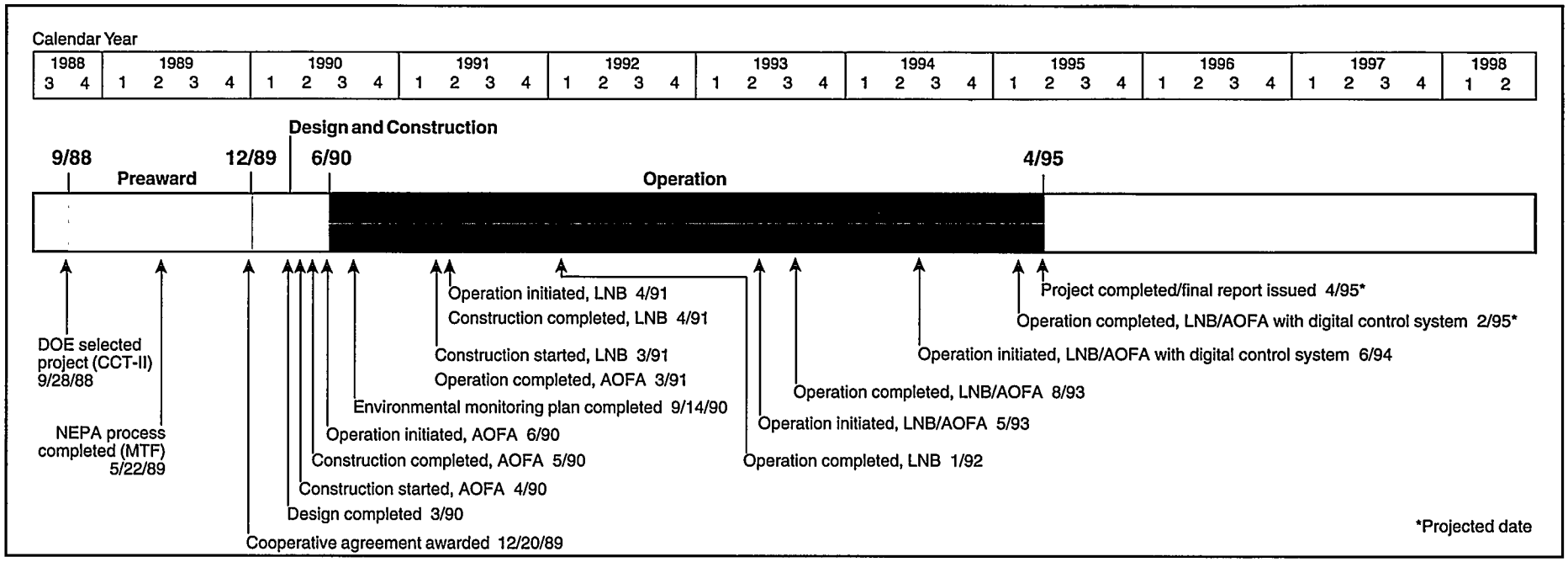


Technology/Project Description:
AOFA involves (1) improving the mixing of over-fire air with the furnace gases to achieve complete combustion, (2) depleting the air from the burner zone to minimize NO_x formation, and (3) supplying air over furnace wall tube surfaces to prevent slagging and furnace corrosion. 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. The project is using bituminous coal containing 3% sulfur.



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 about 69%. 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% with additional reductions resulting from other operational changes. On June 4, 1994, Plant Hammond Unit 4 resumed operation following a 9-month outage. The major activities during this outage included (1) installation of the digital control system, (2) replacement of the two remaining Foster Wheeler mills with Babcock & Wilcox MPS-75 mills, (3) replacement of the precipitator, (4) upgrade of the low-pressure turbine, and (5) burner repairs and modifications. The digital control system is operational and design of the artificial intelligence software package for optimizing NO_x reduction and boiler efficiency nears completion.

Completion of the final analysis of project data and issuance of the final report are scheduled for April 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.

Participant:
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

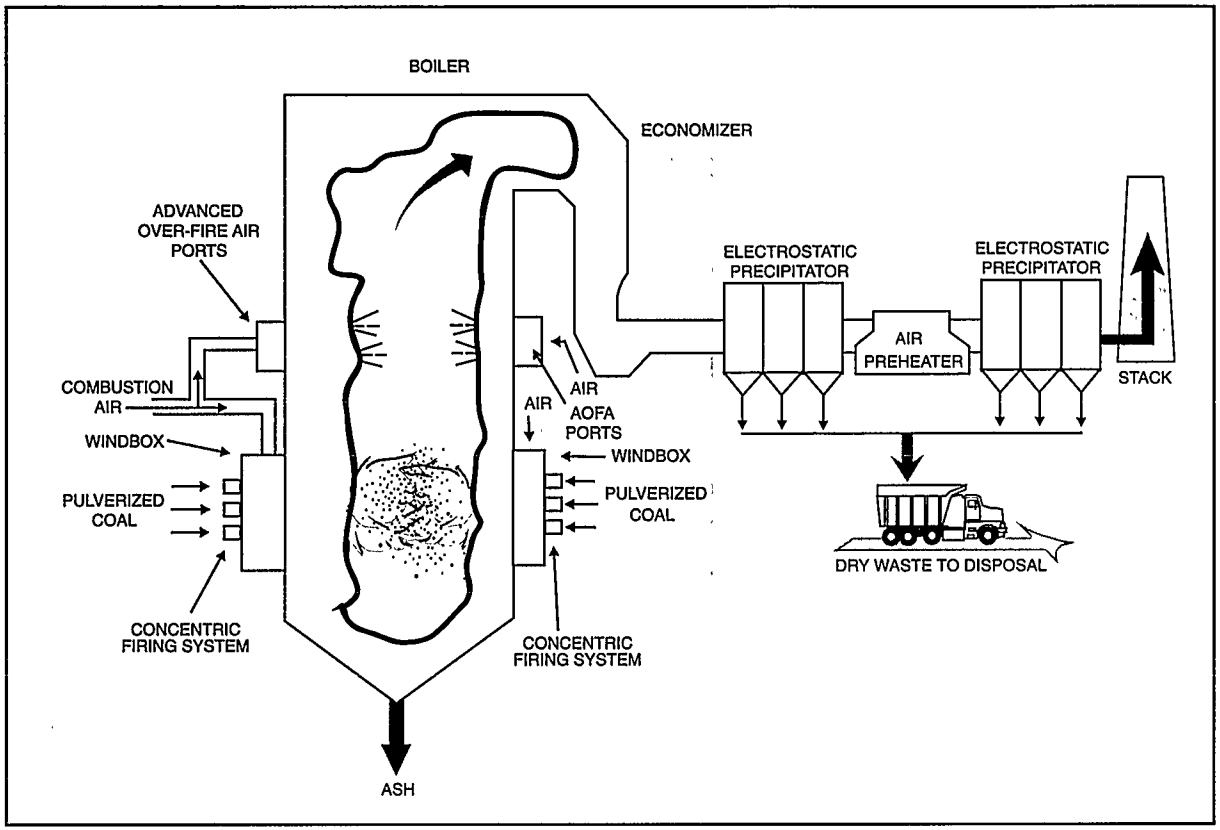
Location:
Lynn Haven, Bay County, FL (Gulf Power Company's Plant Lansing Smith, Unit No. 2)

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 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 LevelIII utilizes both CCOF A 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 CCOFA 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 SOFA 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:

Gulf Power has retained the LNCFS at its Plant Lansing Smith Unit No. 2.

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.

The estimated capital cost for LNCFS I ranges between $8–10/kW and for LNCFS II/III between $15–20/kW.

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	6/94

Final Reports:

Final Report and Key Project Findings	2/94
Chemical Emissions Report	10/93
Economic Evaluation Report	2/94
Final Design Report	9/93

Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers

Participant:
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, Unit 4)

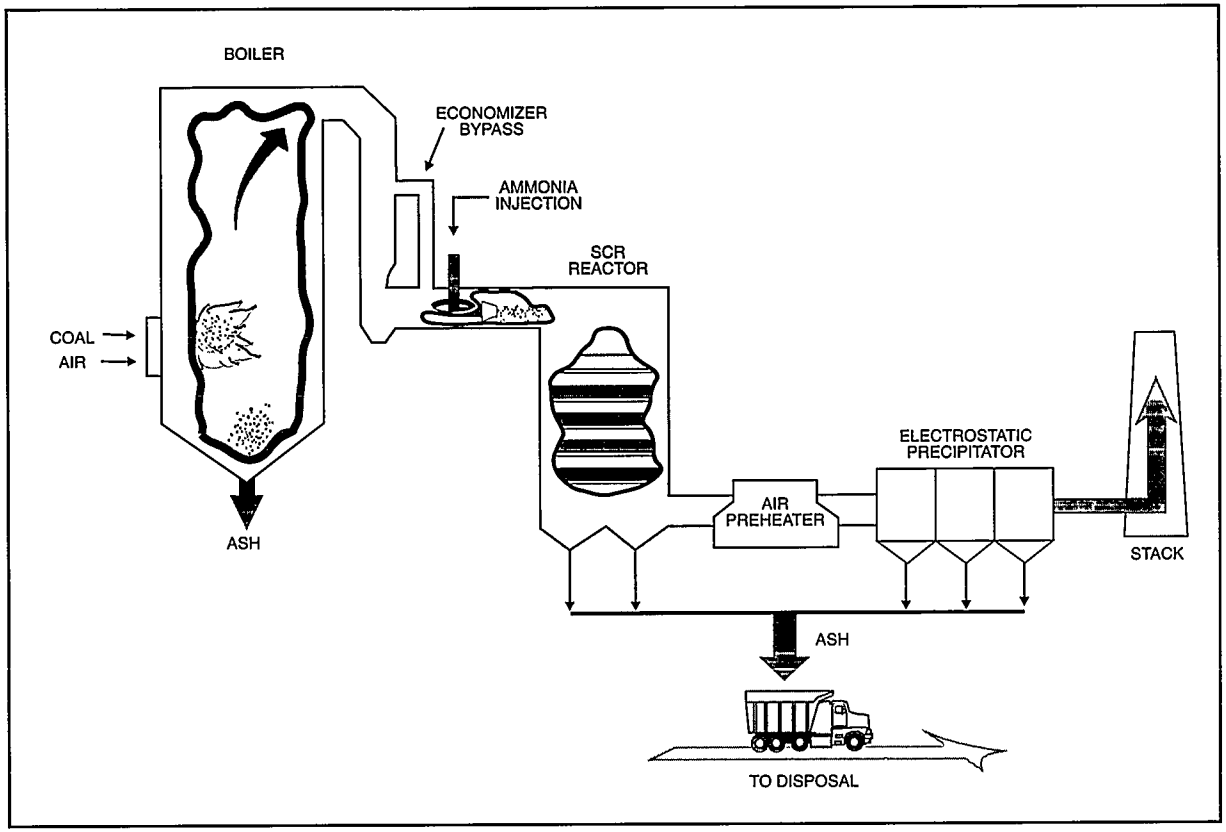
Technology:
Selective catalytic reduction (SCR) (environmental control devices/NO_x control technologies)

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.

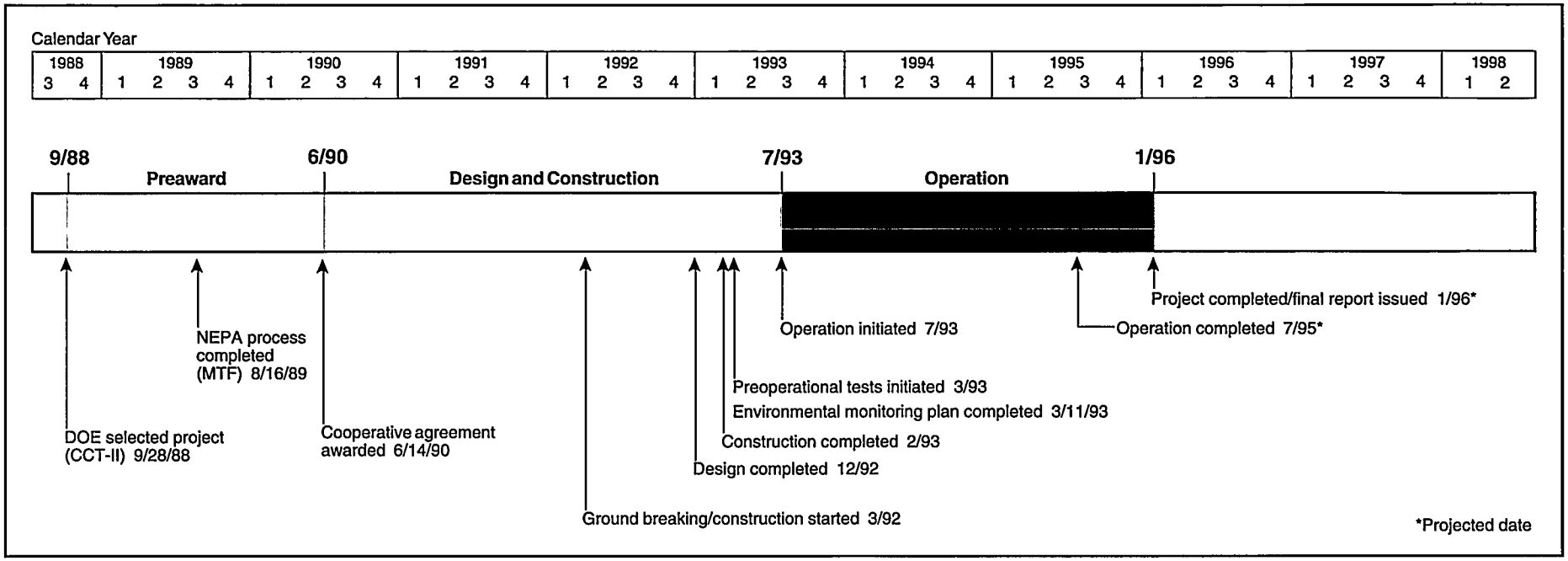


Technology/Project Description:
The SCR technology consists of injecting ammonia into boiler flue gas and passing it through a catalyst bed where the NO_x and ammonia react to form nitrogen and water vapor.

In this demonstration project, the SCR facility consists of three 2.5-MWe-equivalent SCR reactors, supplied by separate 5,000 std ft^3/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 (two U.S., two European, and two Japanese) provided eight 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 1993 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.

Results of parametric tests through December 1994 indicate that the eight different catalysts (seven high dust and one low dust), supplied by six different companies, are performing within or exceeding designed specifications, both with respect to activity and life. However, differences have been noted in NO_x reduction activity, SO_2 oxidation, physical fouling, and pressure drop.

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 1,041coal-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 termsof service date or under construction) and 144,500MW e (290boilers) 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

Participant:
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
Energy and Environmental Research Corporation—testing/environmental/technical consultant

Location:
Negotiations for a new site are under way.

Technology:
Advanced NO_x control using Fuller's micronized-coal-reburning combustion technology (environmental control devices/NO_x control technologies)

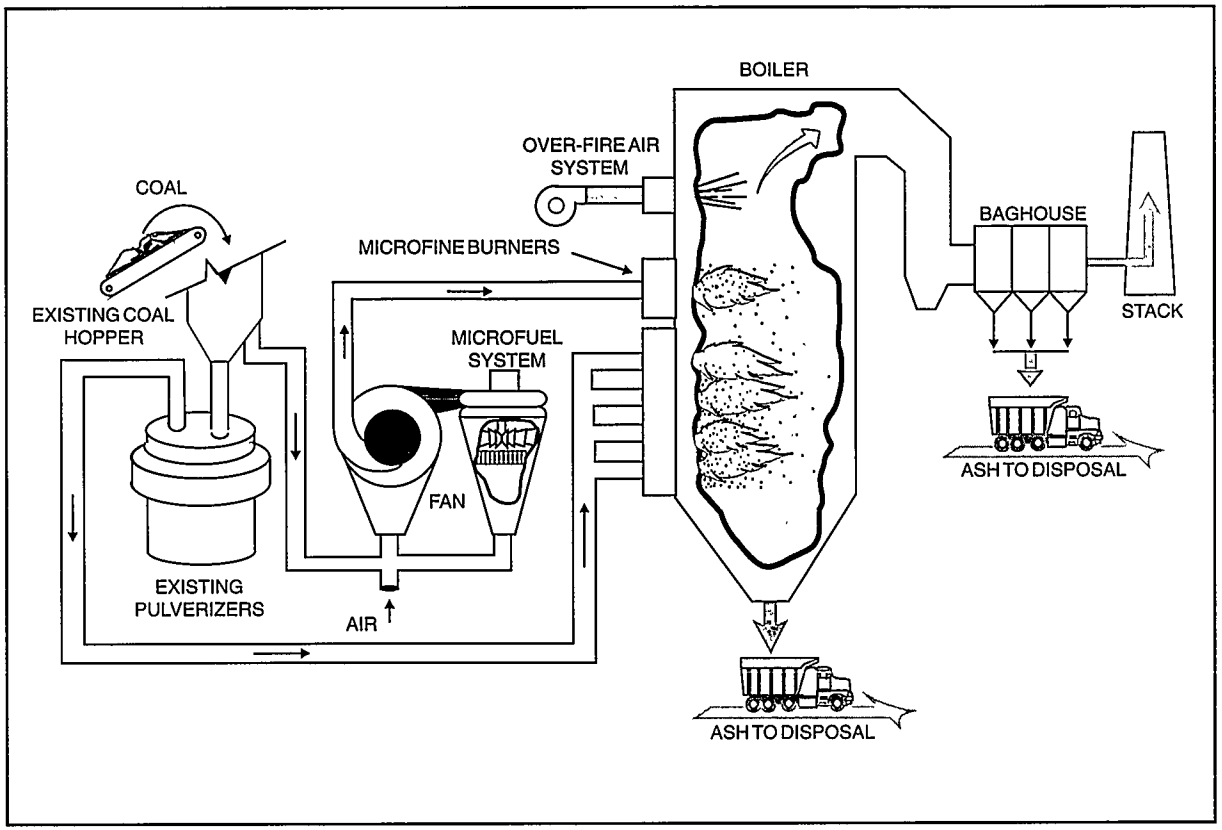
Plant Capacity/Production:
175 MWe

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.

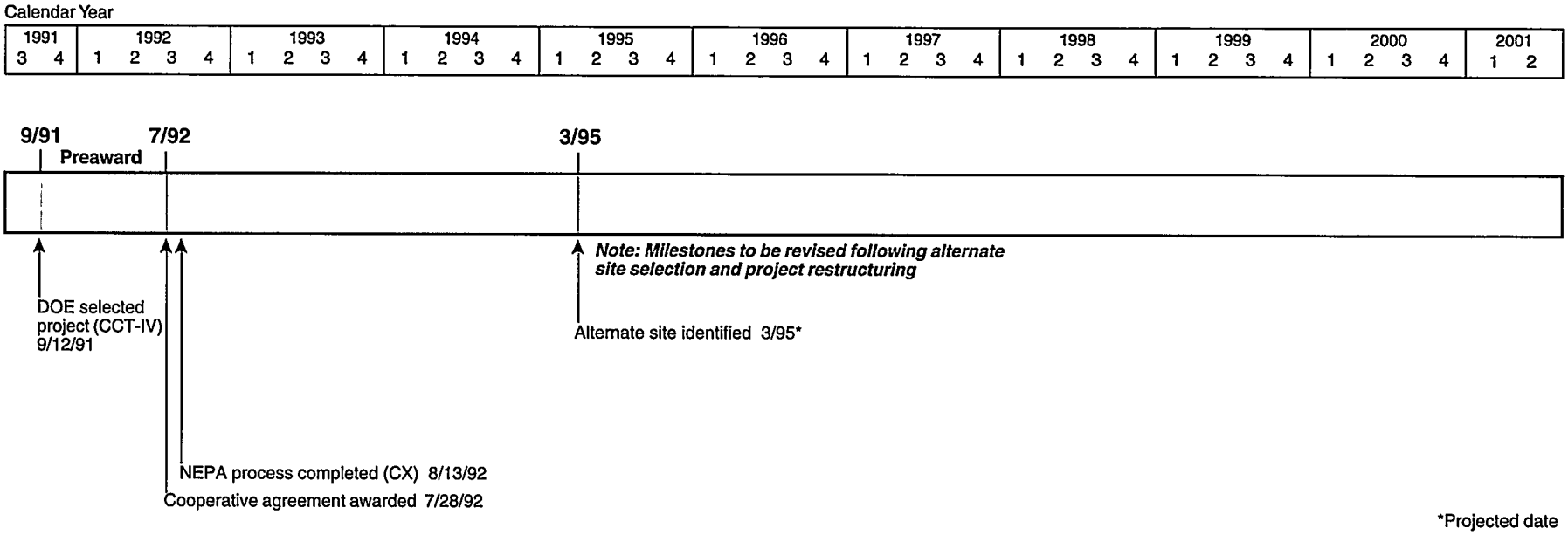


Technology/Project Description:
The technology will be applied to a pulverized coal furnace. The coal to be used to fire the furnace will be a low-sulfur bituminous coal. This same coal will be used as the reburning fuel. The reburning coal, which can comprise up to 30% of the total fuel, is micronized (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. These options can prevent higher operating costs or furnace performance derating often associated with conventional environmental controls.



Project Status/Accomplishments:

Due to plant problems and operational and environmental strategy changes, the original host site, the Tennessee Valley Authority's Shawnee Fossil Plant, was no longer suitable to demonstrate the technology. The project participant is investigating other possible host sites, including sites both inside and outside the Tennessee Valley Authority system.

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-MWe Demonstration of Gas Suspension Absorption

Project completed.

Participant:
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 Center for Emissions Research)

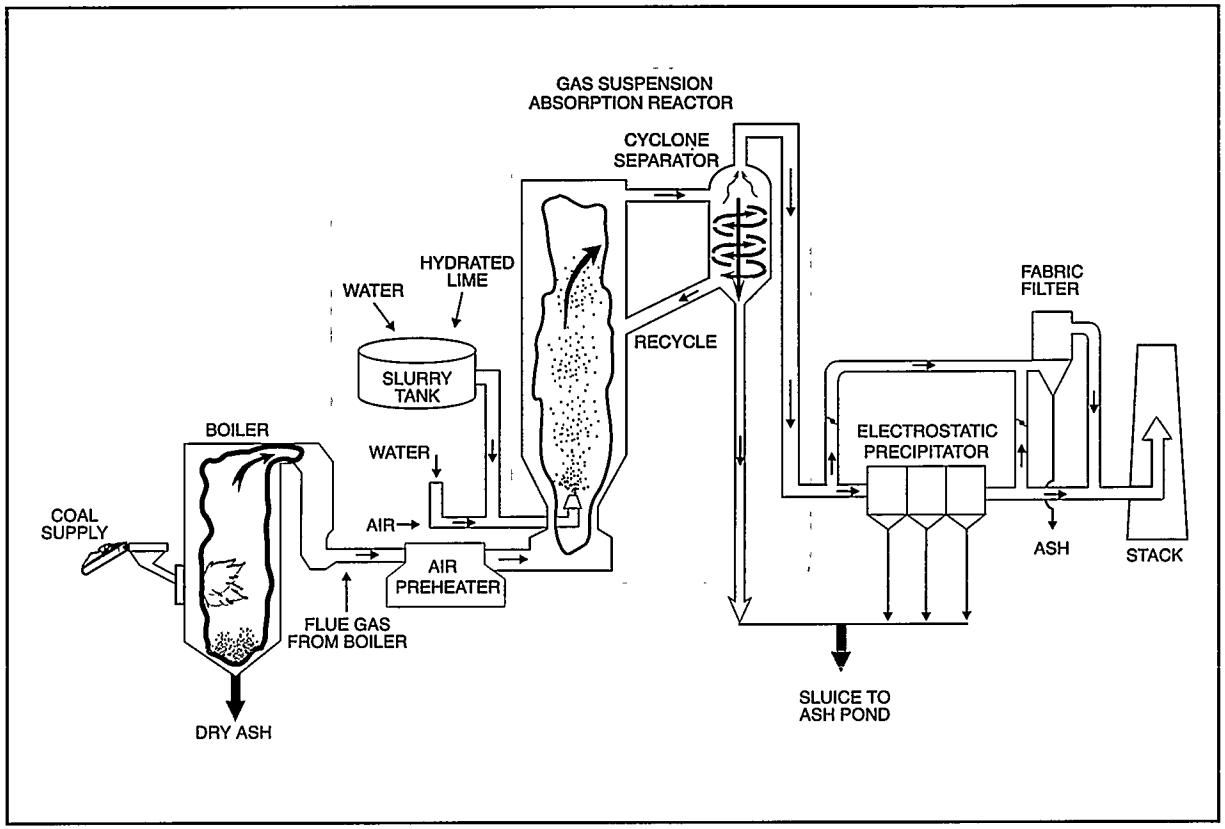
Technology:
FLS miljo a/s' Gas Suspension Absorption (GSA) system for flue gas desulfurization (FGD) (environmental control devices/SO_2 control technologies)

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 (ESP) 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 can remove in excess of 90% of the SO_2 as well as increase lime utilization efficiency with solids recycle.

This project is located at the Center for Emissions Research, 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 containing about 3% sulfur was used.

Project Results/Accomplishments:
Optimization testing was conducted to determine the effect of the process design variables on the SO_2 removal efficiency in the reactor/cyclone and the ESP. The testing

indicated that the order of importance of the key variables is (1) Ca/S, (2) approach-to-adiabatic-saturation temperature, and (3) coal chloride content.

The SO_2 removal efficiency for the overall system ranged from slightly more than 60% to nearly 95%, depending on the specific test conditions. The lower SO_2 removal efficiency levels were achieved at the higher approach-to-saturation temperature (28 °F), the lower lime stoichiometry level (Ca/S of 1.00), and lower coal chloride level (0.02–0.04%). The higher SO_2 removal efficiency levels were achieved at the closer approach-to-saturation temperatures (8 and 18 °F), the higher lime stoichiometry level (Ca/S of 1.30), and higher coal chloride level (0.12%). Most of the SO_2 removal in the GSA system occurred in the reactor/cyclone, with only about 2–5% of the overall removal occurring in the ESP.

Results of a 4-week around-the-clock demonstration run of the GSA system with the ESP indicated that the GSA/ESP is capable of consistently maintaining 90% or better SO_2 removal at a moderate lime requirement. A 14-day pulse jet baghouse (PJBH) run was successfully completed in March 1994. SO_2 removal efficiency in the GSA/PJBH system averaged more than 95% during the demonstration; this was typically about 3–5 percentage points higher than that achieved in the GSA/ESP system at the same test conditions.

The project demonstrated a number of key technical attributes, including a simple and direct method of lime/solid recirculation, high acid gas adsorption, low lime consumption with minimal waste by-product residue, low maintenance operation, no internal buildup, and reduced space requirement. In addition, the project demonstrated that a pulse jet baghouse system improved SO_2 removal efficiency by about 3–5 percentage points. Also, air toxics testing showed that a removal rate of over 95% could be achieved by the GSA.

The relative process economics for the GSA system were evaluated for a moderately difficult retrofit to a 300-MWe boiler burning a coal containing 2.6% sulfur. The design SO_2 removal efficiency was 90%. The resulting capital cost estimate (in 1990 $) is $149/kW for GSA as compared to $216/kW for a wet limestone, forced-oxidation (WLFO) scrubbing system. The levelized annual revenue requirement for the GSA process is lower than that for the WLFO system, but the difference is only about 20% (which is not considered to be significant given the limitations on the accuracy of estimates used in the analysis). The principal annual operating cost for the GSA process is the cost of the pebble lime. The 15-year levelized costs in mills/kWh for the two systems are listed below:

	GSA	WLFO
Fixed costs	2.3	2.81
Variable costs	3.1	2.93
Capital costs	5.0	7.30
Total	10.4	13.04

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 SO_2 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.

Successful testing of the AirPol demonstration project has resulted in a commercial application in Ohio. The city of Hamilton, OH, received a $5-million grant from the Ohio Coal Development Office to install the GSA technology to control emissions from a 50-MWe coal-fired boiler at the city's municipal power plant. The new system is scheduled to be operational in August 1996 and will be the first full-scale commercial GSA unit in the United States as well as the world's first GSA unit for a coal-fired boiler. The GSA technology was identified as the least-cost alternative for the city to meet CAAA compliance requirements for 1997.

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's stringent standards require an SO_2 removal efficiency of 90–95%.

The GSA should fulfill the need of the utility industry to meet the new SO_2 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.

Project Schedule:

DOE selected project (CCT-III)	12/19/89
NEPA process completed (MTF)	9/21/90
Cooperative agreement awarded	10/11/90
Construction	5/92–9/92
Environmental monitoring plan completed	10/2/92
Operational testing	10/92–3/94
Project completed	3/95

Final Reports:

Final Technical Report	3/95
Economic Evaluation Report	1/95
Public Design Report	2/95

Confined Zone Dispersion Flue Gas Desulfurization Demonstration

Project completed.

Participant:
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)

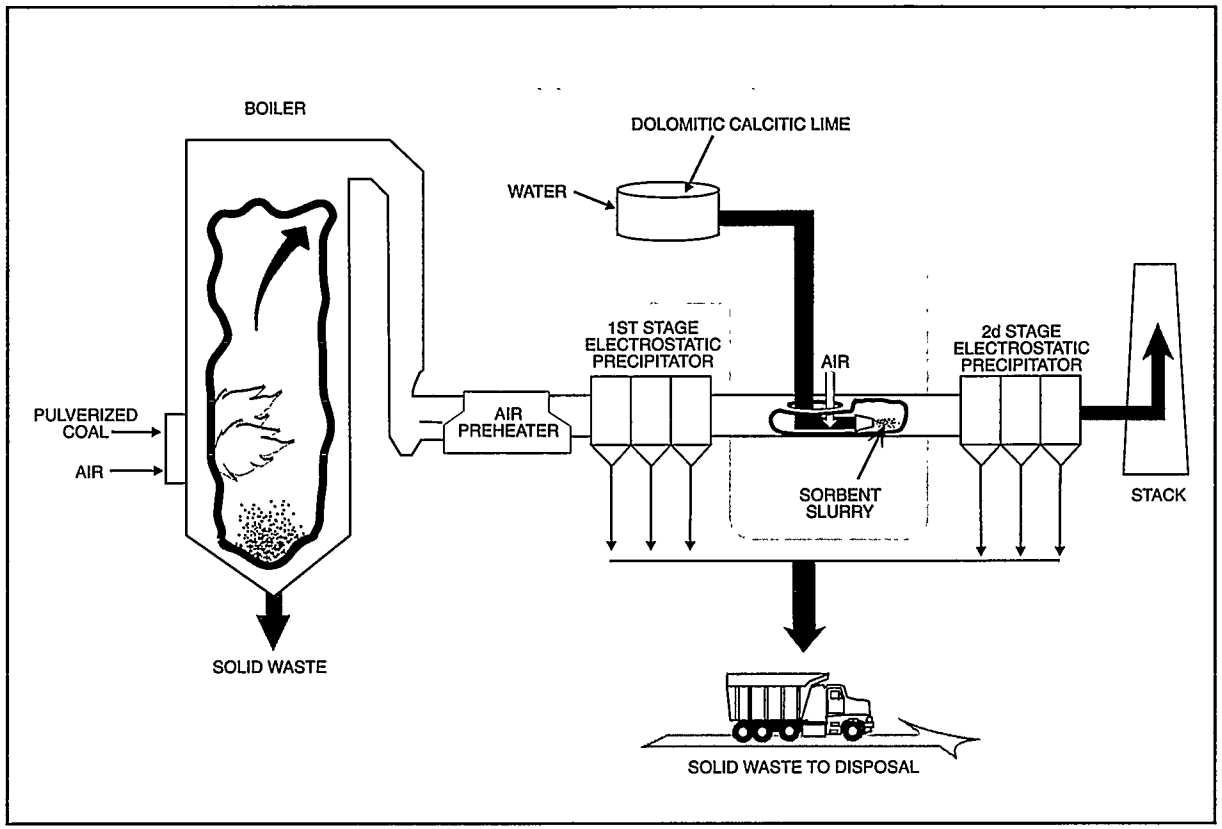
Technology:
Bechtel Corporation's in-duct, confined zone dispersion flue gas desulfurization (CZD/FGD) process (environmental control devices/SO_2 control technologies)

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 SO_2 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 SO_2 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 SO_2 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 SO_2 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% SO_2 removal efficiency.
- The process requires that drying and SO_2 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 SO_2 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 SO_2 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 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 SO_2 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	6/95

Final Reports:

Final Technical Report	6/95
Public Design Report	4/93
Economic Evaluation Report	6/96

LIFAC Sorbent Injection Desulfurization Demonstration Project

Project completed.

Participant:

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 of 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/SO_2 control technologies)

Plant Capacity/Production:

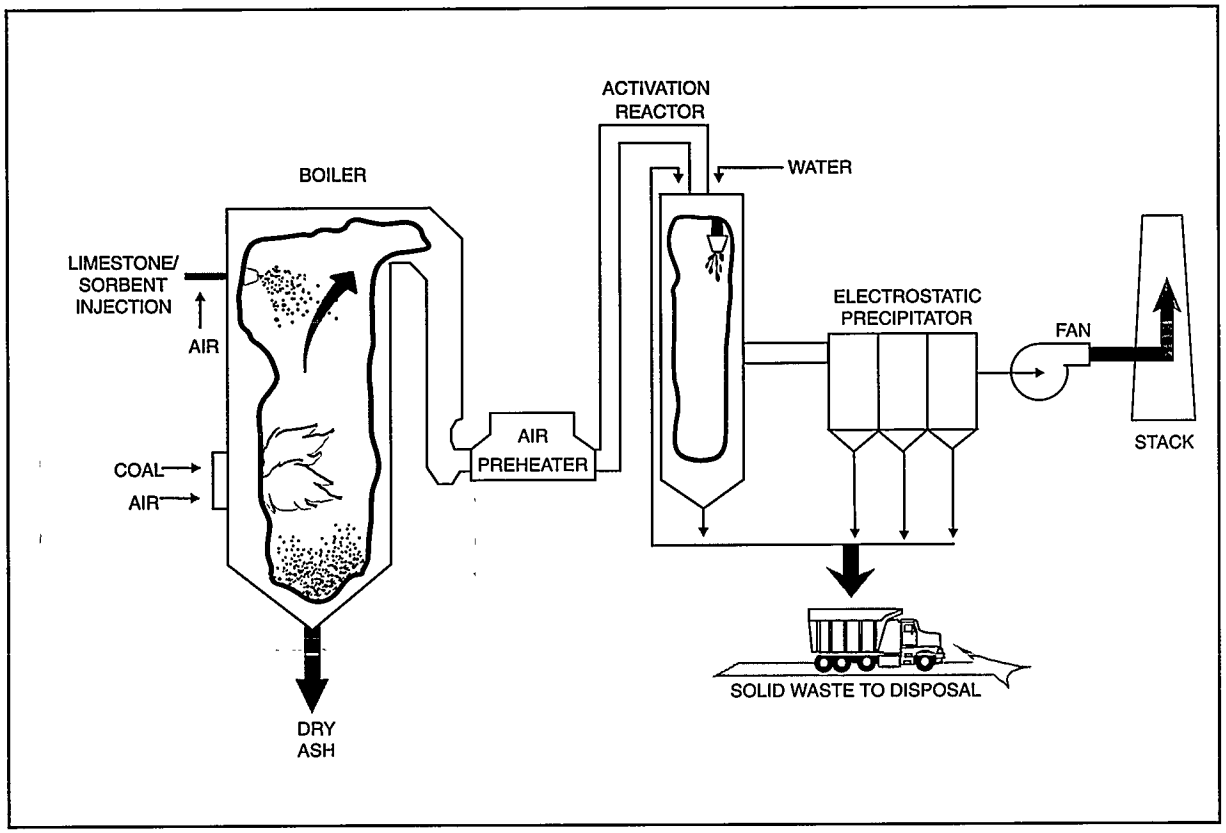
60 MWe

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 SO_2 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 SO_2 in the boiler flue gas. The limestone is calcined into calcium oxide and is available for capture of additional SO_2 downstream in the activation, or humidification, reactor. In the vertical chamber, water sprays initiate a series of chemical reactions leading to SO_2 capture. After leaving the chamber, the sorbent is easily separated from the flue gas along with the fly ash in the electrostatic precipitator (ESP). The sorbent material from the reactor and electrostatic precipitator is 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 SO_2 from flue gas and produces a dry solid waste product suitable for disposal in a landfill.

The process was demonstrated at the Whitewater Valley Station, 60-MWe Unit No. 2. This coal-fired unit is owned and operated by Richmond Power & Light and is located in Richmond, IN. Bituminous coal containing 2.0–2.9% sulfur was used.

Project Results/Accomplishments:

The total duration of the project was 2,800 hours of operation over a 2-year period.

LIFAC process values and their effects on sulfur removal efficiency were evaluated during parametric testing. The four major parameters having the greatest influence on sulfur removal efficiency were limestone quality, Ca/S, reactor bottom temperature (approach-to-saturation), and ESP ash recycling rate. Total SO_2 capture was about 15 percentage points better when injecting fine limestone (80% minus 325 mesh) than it was with coarse limestone (80% minus 200 mesh).

Parametric tests indicated that a 70% SO_2 reduction was achievable with a Ca/S of 2.0. ESP ash containing unspent sorbent and fly ash was recycled from the ESP hoppers back into the reactor inlet duct work. Ash recycling is essential for efficient SO_2 capture. The large quantity of ash removed from the LIFAC reactor bottom, and the small size of the ESP hoppers limited the ESP ash recycling rate. As a result, the amount of material recycled from the ESP was approximately 70% less than had been anticipated. However, this low recycling rate contributed an additional 15 percentage points to total SO_2 capture. During a brief test, it was found that increasing the recycle rate by 50% resulted in a 5 percentage point increase in SO_2 removal efficiency. It is anticipated that if the reactor bottom ash is recycled along with ESP ash, while sustaining a reactor temperature of 5 °F above saturation temperature, an SO_2 reduction of 85% could be maintained.

Optimization testing began in March 1994 and was followed by long-term testing in June 1994. The boiler was operated at an average load of 60 MWe during long-term testing, although it fluctuated according to power demand. The LIFAC process automatically adjusted to boiler load changes. A Ca/S of 2.0 was selected to attain SO_2 reductions above 70%. Reactor bottom temperature was about 5 °F higher than optimum to avoid ash buildup on the steam reheaters. Atomized water droplet size was smaller than optimum for the same reason. Other key process parameters held constant during the long-term tests included the degree of humidification, the grind size of the high-calcium-content limestone, and recycle of spent sorbent from the ESP.

Long-term testing showed that SO_2 reductions of 70% or more can be maintained under normal boiler operating ranges. Stack opacity was low (about 10%) and ESP efficiency was high (99.2%). The quantity of solid waste, which is a mixture of fly ash and calcium compounds, equals the amount of limestone injected. ESP and LIFAC fly ash were readily disposed of at the same local landfill

The LIFAC system proved to be highly operable because it has few moving parts and is simple to operate. The process can be easily shutdown and restarted. The process is automated by a programmable logic system, which regulates process control loops, interlocking, start-up, shut downs, and data collection. The entire LIFAC process was easily managed via two personal computers located in the host utility's control room.

The economic evaluation indicated that the capital cost of a LIFAC installation is lower than both spray dryers and wet scrubbers. Capital costs for LIFAC technology vary depending on unit size and the quantity of reactors needed:

- $99/kW for one LIFAC reactor at Whitewater Valley Station (65 MWe)
- $76/kW for one LIFAC reactor at Shand Station (150 MWe)
- $66/kW for two LIFAC reactors at Shand Station (300 MWe)

Crushed limestone accounts for about one-half of LIFAC's operating costs. LIFAC requires 4.3 tons of limestone to remove 1 ton of SO_2, assuming 75% SO_2 capture, a Ca/S of 2.0, and limestone containing 95% $CaCO_3$. If limestone costs $15/ton, then the operating cost is $65/ton of SO_2 removed.

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 is less expensive to install than conventional wet flue gas desulfurization processes, uses dry limestone instead of more costly lime, is relatively simple to operate, produces a dry, readily disposable waste, and can handle all types of coal.

The benign waste material can be disposed of in a landfill along with the fly ash. Commercial use of the LIFAC by-product in the manufacture of construction materials is currently being investigated in Finland.

Project Schedule:

DOE selected project (CCT-III)	12/19/89
Cooperative agreement awarded	11/20/90
NEPA process completed (MTF)	10/2/90
Environmental monitoring plan completed	6/12/92
Construction	5/91–6/92
Operational testing	9/92–6/94
Project completed	3/95

Final Reports:

Final Technical Report	3/95
Economic Evaluation Report	3/95
Public Design Report	3/95

Advanced Flue Gas Desulfurization Demonstration Project

Participant:

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.)

Additonal 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, Units 7 and 8)

Technology:

Pure Air's advanced flue gas desulfurization (AFGD) process (environmental control devices/SO_2 control technologies)

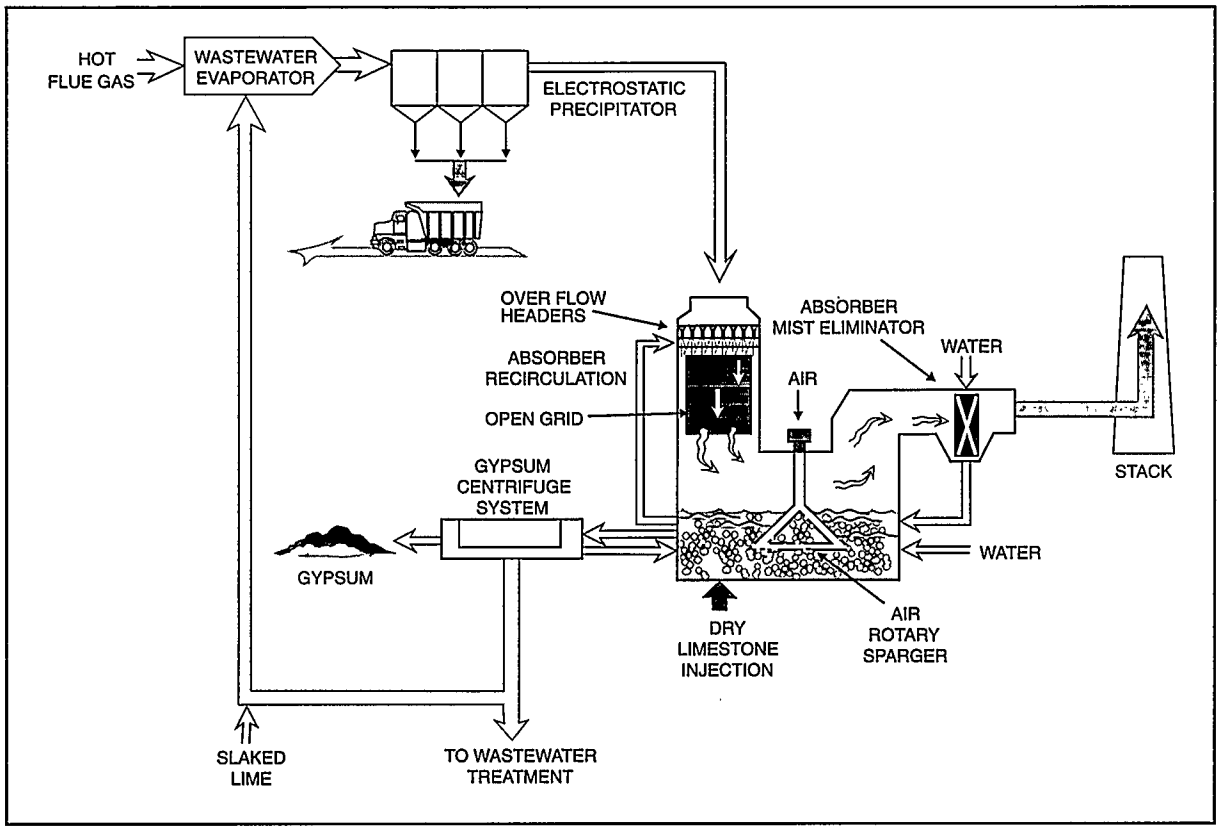
Plant Capacity/Production:

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:

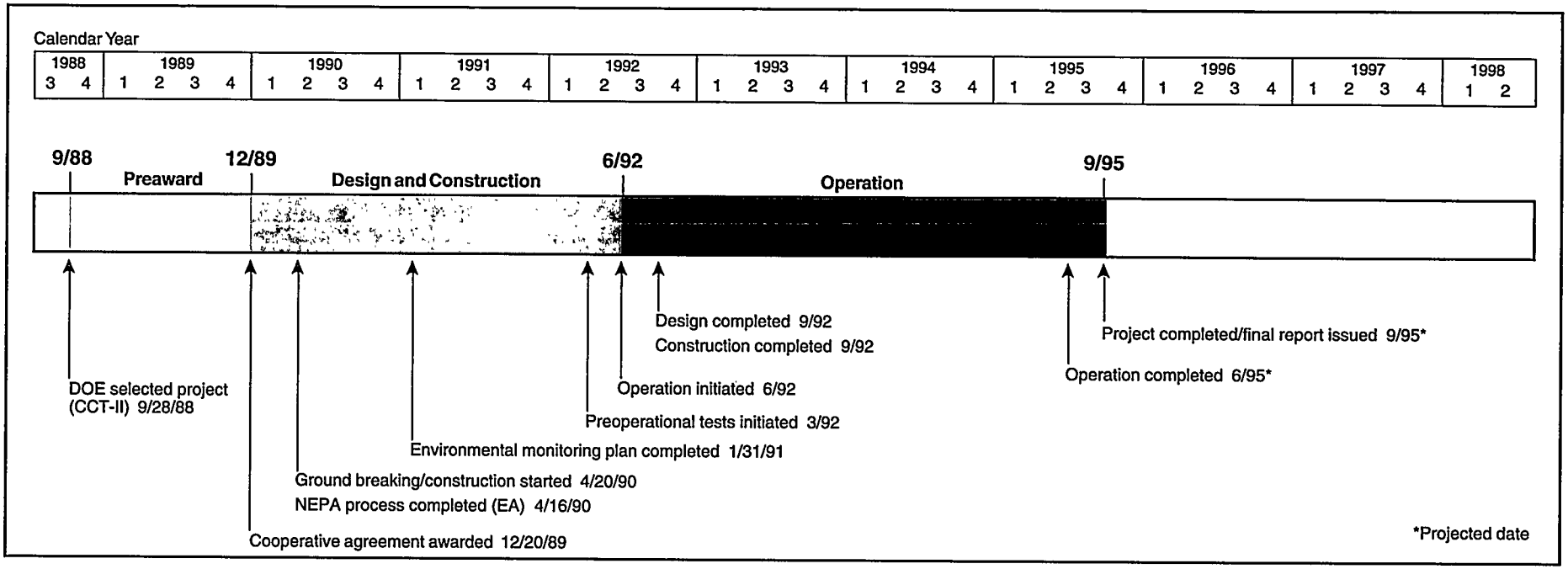
To demonstrate removal of 90–95% or more of the SO_2 at approximately one-half the cost of conventional scrubbing technology; and to demonstrate significant reduction of space requirements.

Technology/Project Description:

In this project, Pure Air has built a single SO_2 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 SO_2 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 SO_2 while providing a commercial gypsum by-product in lieu of solid waste. Some of the by-product gypsum is being agglomerated and flaked into PowerChip™ gypsum to enhance its



transportation and marketability to gypsum end-users. Additionally, wastewater treatment is being 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. After the 3-year demonstration period, 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, and testing bituminous coals containing 2–4.5% sulfur.

Project Status/Accomplishments:

Operational testing continued through 1994. 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. In 1994, tests were completed on coals with 4–4.5% sulfur and 2-2.5% sulfur. The scrubber is achieving SO_2 removals in excess of 95% while producing a commercial gypsum by-product with an average purity level of 97%. Smooth operation continues, and performance continues to be very good.

As of the end of November 1994, the AFGD facility had accumulated almost 22,000 hours of operation with an availability of 98-99% and 100% reliability. Approximately 181,500 tons of SO_2 have been removed and over 501,000 tons of gypsum produced.

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 SO_2 emissions at the Bailly Station by approximately 75,000 tons/yr. Further, the gypsum by-product and wastewater evaporation will demonstrate that SO_2 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.

In April 1994, Pure Air of Manatee, L.P., entered into a contract to provide 1,600 MWe of SO_2 scrubbing capability at Florida Power & Light Company's Manatee power plant, on an own-and-operate basis. The Manatee scrubber will feature two 800 MWe absorber vessels, PowerChip™ gypsum recycling, and wastewater evaporation.

Demonstration of Innovative Applications of Technology for the CT-121 FGD Process

Participant:
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)

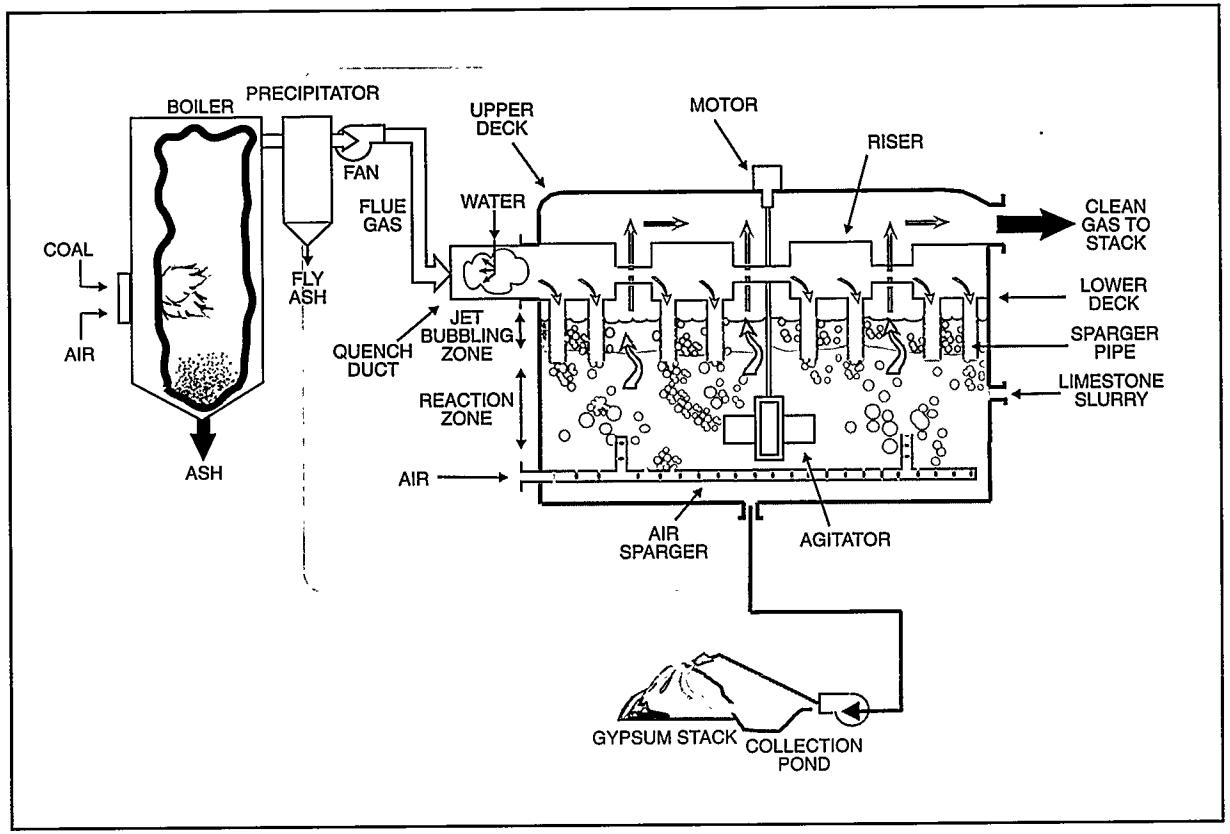
Technology:
Chiyoda Corporation's Chiyoda Thoroughbred-121 (CT-121) advanced flue gas desulfurization (FGD) process (environmental control devices/SO_2 control technologies)

Plant Capacity/Production:
100 MWe

Project Funding:

Total project cost	$43,074,996	100%
DOE	21,085,211	49
Participants	21,989,785	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% SO_2 control at high reliability with and without simultaneous particulate control with possible additional reductions in operating costs.



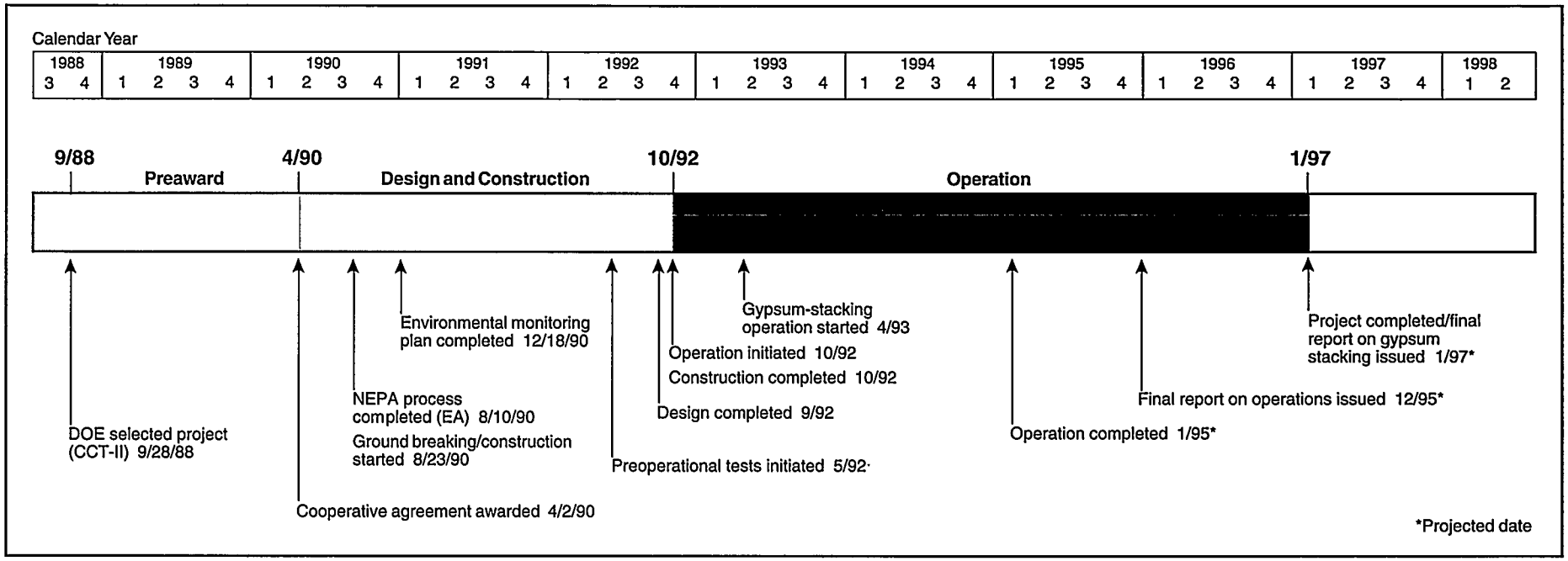
Technology/Project Description:
The project is demonstrating the CT-121 FGD process, which uses a unique absorber design known as the jet-bubbling reactor (JBR). The process combines limestone FGD reaction, forced oxidation, and gypsum crystallization in one process vessel. The process is mechanically 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 SO_2 in the flue gas is absorbed and forms calcium sulfite ($CaSO_3$). 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 SO_2 and particulates simultaneously is also being evaluated.

A nominal 2.5% sulfur bituminous coal is being used to demonstrate 90% SO_2 control with high reliability, with and without simultaneous particulate control.

Project Status/Accomplishments:
Parametric testing was completed in March 1993, and long-term testing began in May 1993. DOE-sponsored



air-toxics testing was done in June 1993. Alternate limestones were tested in December 1993.

In 1994, tests were conducted on high-sulfur coal (2.5%), compliance coal (1.5%) and low-sulfur coal (1.35%). The CT-121 process successfully removed the SO_2 from the higher sulfur test coal. The ESP was deenergized in stages in 1994 for the last year of operation to evaluate the particulate removal capability of the scrubber. The scrubber effectively removed the particulate, indicating that an ESP probably would not be needed when the process is used for SO_2 control.

Ash/gypsum product is being diverted to the northern-most disposal cell for segregation from pure gypsum. Growth studies on pure gypsum continue on the now inactive, clean gypsum stack.

The demonstration has exceeded all of its performance goals. By the end of 1994, over 12,000 hours of successful operations had been logged. Availability has been 98% and reliability has exceeded 99%, confirming the acceptability of the use of fiberglass as a reactor vessel material. At inlet SO_2 levels of about 2,000 ppm, the CT-121 system's SO_2 removal ranges between 93% and 98% at all loads and conditions at expected pH and pressure drop with 100% limestone utilization. Particulate removal has exceeded 99%.

The project received two awards in 1994: *Power Magazine's* 1994 Powerplant Award and an Outstanding Achievement Award from the Georgia chapter of the Air and Waste Management Association for the use of an innovative technology for air quality control. In 1993, Plant Yates received an environmental award from the Georgia Chamber of Commerce, based on the success of the CT-121 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 SO_2 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 SO_2 emissions from only the retrofit portion of this capacity represents over 10,500,000 tons/yr of potential SO_2 control.

In 1994 a tar sands oil extraction facility in Murray, Canada, purchased the CT-121 scrubber.

SNOX™ Flue Gas Cleaning Demonstration Project

Project completed.

Participant:
ABB Environmental Systems

Additional Team Members:
Ohio Coal Development Office—cofunder
Ohio Edison Company—cofunder and host utility
Haldor Topsoe a/s—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)

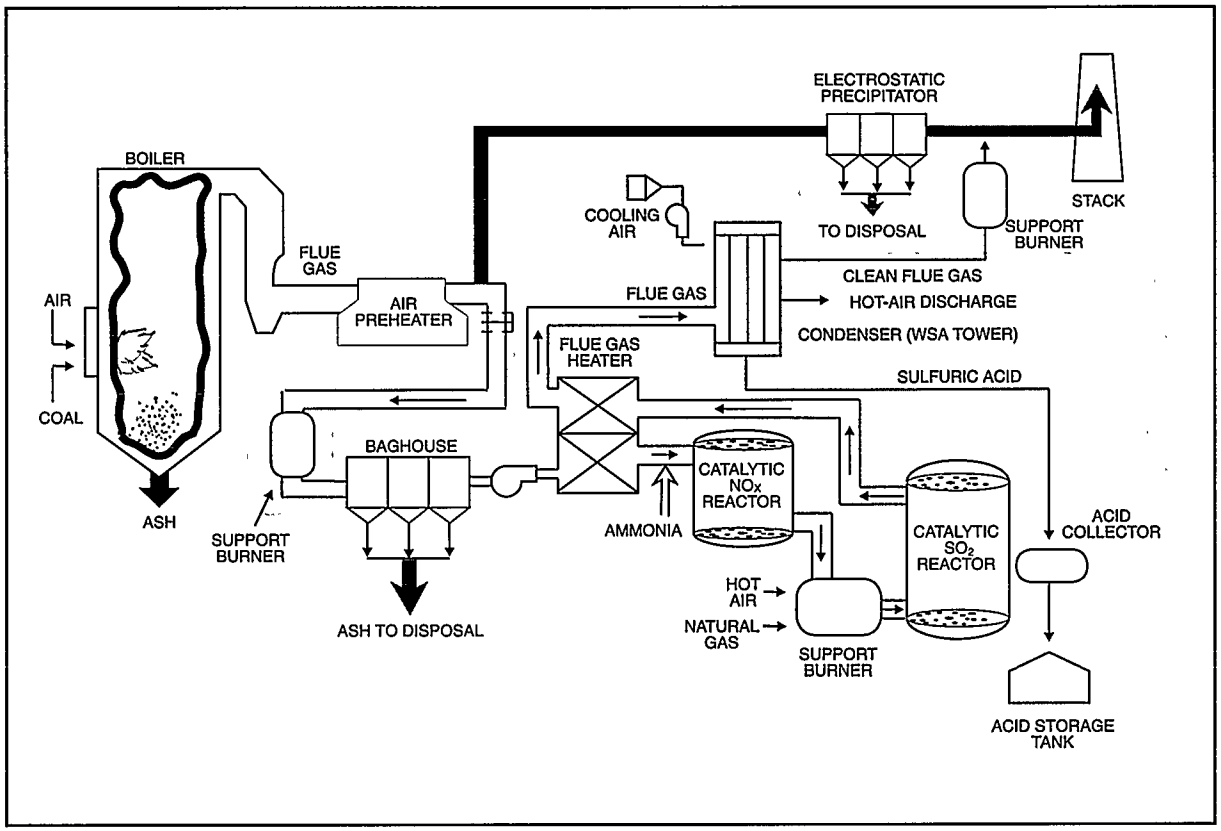
Technology:
Haldor Topsoe's SNOX™ catalytic advanced flue gas cleanup system (environmental control devices/combined SO_2/NO_x control technologies)

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 SO_2 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 SO_2 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 SO_2 is oxidized to SO_3 in a second catalytic converter. The gas then passes through a novel glass-tube condenser which allows SO_3 to hydrolyze to concentrated sulfuric acid.

The technology, while using U.S. coals, is designed to remove 95% of the SO_2 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 was conducted at Ohio Edison's Niles Station in Niles, OH. The demonstration unit treated a 35-MWe equivalent slipstream of flue gas from the 108-MWe Unit No. 2 boiler which burned a 3.4%sulfur Ohio coal. The process steps were virtually the same as for a commercial full-scale plant, and commercial-scale components were installed and operated.

Project Results/Accomplishments:

Operational testing was initiated in March 1992 and completed in December 1994. The system has operated for over 7,800 hours and produced more than 5,400 tons of commercial-grade sulfuric acid. 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.

Many tests for the SNOX™ system were designed to be conducted at 75%, 100%, and 110% of design capacity. During the test program, SO_2 removal efficiencies were normally in excess of 95% for inlet concentrations which averaged about 2,000 ppm. System NO_x reduction efficiencies averaged 94% with inlet NO_x levels of approximately 500–700 ppm.

Sulfuric acid concentrations and composition have met or exceeded federal specifications for class I acid. The acid from the plant has been sold to the agriculture industry for the production of diammonium phosphate fertilizer and to the steel industry for pickling. Ohio Edison has used a significant amount in its boiler water demineralizer system throughout its plants.

Air toxics testing at the plant indicated that, for the majority of the species examined, especially those that exit primarily as particulates at the SNOX™ fabric filter or SNOX™ outlet, removal is very high. Because of the mechanism of sulfuric acid condensation in the WSA condenser, any particulates remaining at this point act as nuclei for H_2SO_4 and are captured in the acid. For volatile species, the WSA condenser outlet temperature is lower than conventional boiler outlet temperatures and should condense and capture more of the volatile species than a plant with only an ESP or fabric filter.

The economic evaluation of the SNOX™ process showed a capital cost of approximatley $250/kW and a total operating cost of approximatley 1.3 mills/kWh.

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 SO_2 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.

The host utility, Ohio Edison, is retaining the SNOX™ technology as a permanent part of the pollution control system at Niles Station and to help Ohio Edison meet its overall SO_2/NO_x reduction goals.

Commercial SNOX™ plants also have been started up in Denmark and Sicily. In Denmark, a 305-MWe plant has been designed and constructed; it has operated since August 1991. The boiler at this plant burns coals from Vanbus suppliers around the world, including the United States; the coals contain 0.5–3.0% sulfur. The plant in Sicily, operating since March 1991, has a capacity of about 30-MWe and fires petroleum coke.

Project Schedule:

DOE selected project (CCT-II)	9/28/88
Cooperative agreement awarded	12/20/89
NEPA process completed (MTF)	1/31/90
Environmental monitoring plan completed	10/31/91
Construction	1/91–12/91
Operational testing	3/92–12/94
Project completed	3/95

Final Reports:

Final Technical Report	3/95
Economic Evaluation Report	3/95
Public Design Report	3/95

LIMB Demonstration Project Extension and Coolside Demonstration

Project completed.

Participant:
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, Unit 4)

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 SO_2/NO_x control technologies)

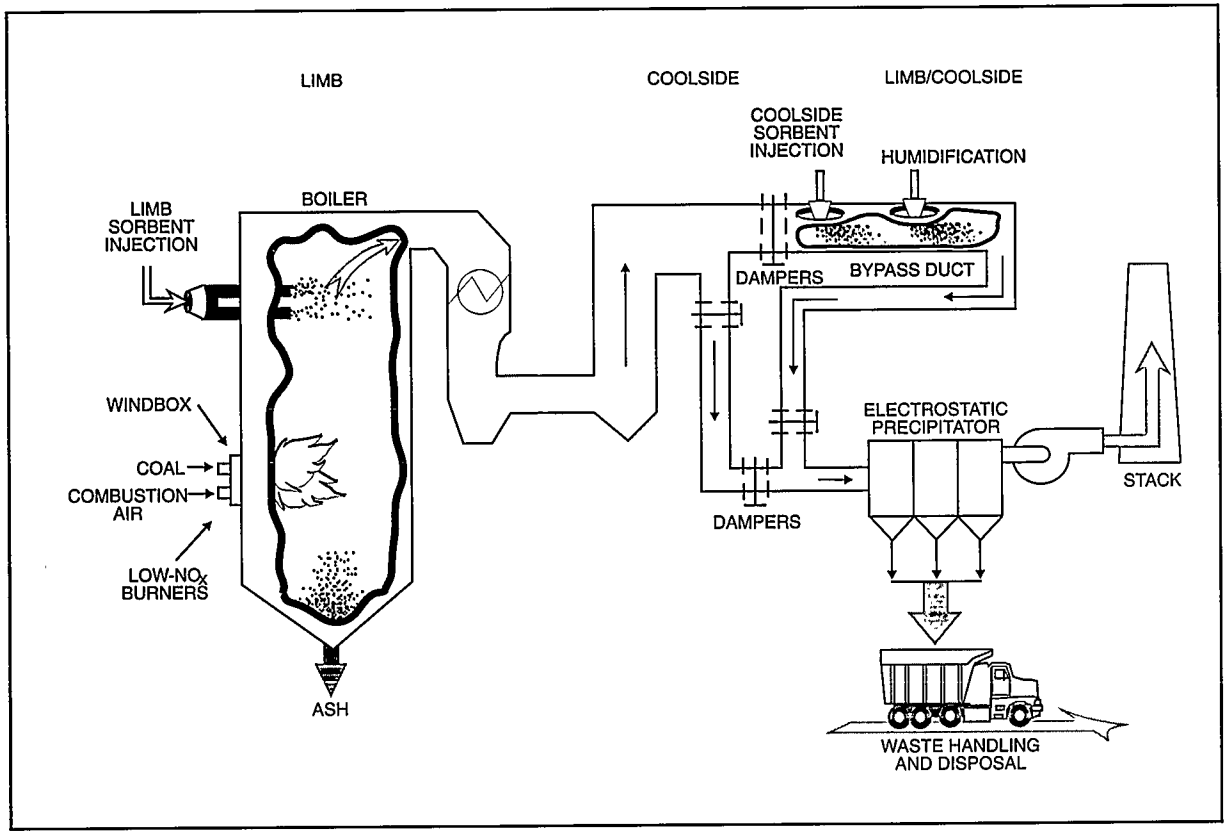
Plant Capacity/Production:
105 MWe

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 SO_2 in the combustion process, and that LIMB can achieve up to 70% NO_x and SO_2 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 SO_2 removal of up to 70%.

DRB-XCL is a registered trademark of The Babcock & Wilcox Company.



Technology/Project Description:
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 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 SO_2 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 SO_2 absorption. SO_2 absorption is improved by dissolving NaOH or Na_2CO_3 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 Ca/S ratios 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 SO_2 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 SO_2 concentration in the flue gas, affected 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% 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% SO_2 removal was achieved while burning 3.8% sulfur coal. All sorbents tested were capable of removing SO_2 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 SO_2 removal rates. Here, the sorbent was injected at close to the optimum furnace temperature of 2,300 °F.
- SO_2 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% SO_2 removal at design conditions (2.0 Ca/S, 0.2 Na/Ca, and 20 °F approach to adiabatic saturation temperature) using commercial hydrated lime. 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. Observed SO_2 removal with recycle sorbent alone was 22% at 0.5 available Ca/S and 18 °F approach to adiabatic saturation. Observed SO_2 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 competititive 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 SO_2 emissions, and for Coolside up to 70% lower SO_2 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.

Participant:
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)

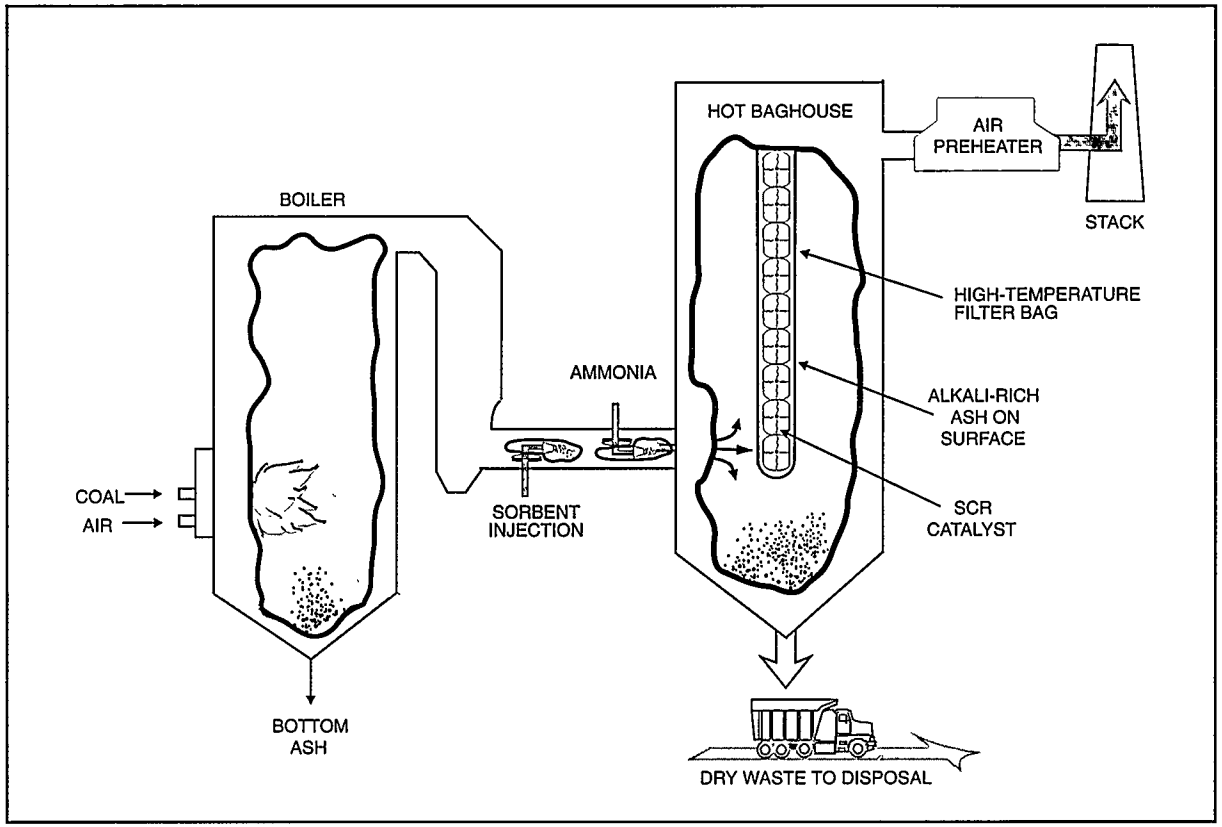
Technology:
The Babcock & Wilcox Company's SOx-NOx-Rox-Box™ (SNRB™) process (environmental control devices/combined SO_2/NO_x control technologies)

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 processing unit for treating flue gas, thereby lessening on-site space requirements and capital costs.



Technology/Project Description:
The SNRB™ process combines the removal of SO_2, NO_x, and particulates in one unit—a high-temperature baghouse. SO_2 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% SO_2 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.Bur ger 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.

SOx-NOx-Rox-Box and SNRB are trademarks of The Babcock & Wilcox Company.

Project Results/Accomplishments:

SNRB™ demonstration tests were conducted for emissions control of SO_2, NO_x, and particulates. Four different sorbents were tested for SO_2 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 SO_2 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, sulfur capture approached 90%. With an NH_3/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 ft^3), corresponding to a collection efficiency of 99.89%.

High SO_2 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 to 2.

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 SO_2 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 SO_2, 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	5/95

Final Reports:

Final Technical Report	5/95
Economic Evaluation Report	early 1995
Detailed Design Report	11/92

Enhancing the Use of Coals by Gas Reburning and Sorbent Injection

Project completed.

Participant:

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, Unit 1)
Springfield, Sangamon County, IL (City Water, Light and Power's Lakeside Station, Unit 7)

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:

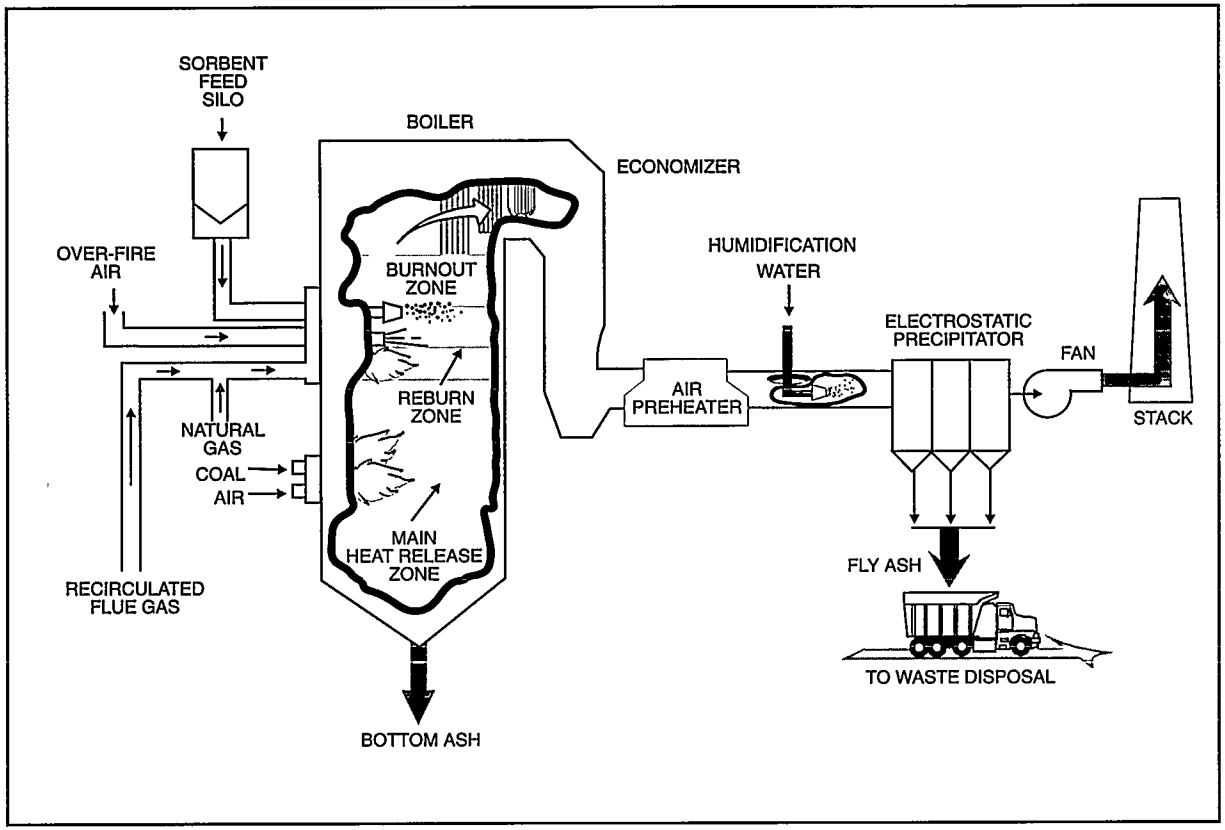
Hennepin: tangential-fired 80 MWe (gross), 71 MWe (net)
Lakeside: cyclone-fired 40 MWe (gross), 33 MWe (net)

Project Funding:

Total project cost	$37,588,955	100%
DOE	18,747,816	50
Participants	18,841,139	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:

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 tested is $Ca(OH)_2$ (lime). The goal was to achieve at least 60% NO_x reduction and at least 50% SO_2 reduction on different boiler configurations at power plants burning high-sulfur midwestern coal. This project demonstrated the gas reburning and sorbent injection GR–SI process on two separate boilers representing two different firing configurations—a tangentially fired, 80-MWe (gross) boiler at Illinois Power Company's Hennepin Plant in Hennepin, IL, and a cyclone-fired, 40-MWe (gross) boiler at City Water, Light and Power's Lakeside Station in Springfield, IL. Illinois bituminous coal containing 3% sulfur was the test coal for both Hennepin and Lakeside.

Project Results/Accomplishments:

A matrix of 32 gas reburn tests were completed on the tangentially fired boiler at the Hennepin Plant. NO_x reductions of up to 77% were achieved, with 65% being routine—exceeding the project objective of 60%. 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. Sorbent injection reduced SO_2 emissions as much as 62%, with 52%

reduction being routine—also exceeding the project objective of 50%. The Ca/S was about 1.75.

Three proprietary sorbents (including PromiSorb A, PromiSorb B, and high surface area hydrated lime) were also tested at Hennepin. The sorbents showed higher SO_2 capture and higher calcium utilization than the regular hydrated lime.

The GR–SI process reduced CO_2, HCl, and HF emissions as well as NO_x and SO_2. During sorbent injection, particulate emissions were reduced by flue gas humidification upstream of the ESP.

The system installed at Hennepin 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).

After reviewing the operational performance, boiler impact, and economics, Illinois Power, the host utility, has chosen to retain the gas-reburning portion of the gas-reburning and sorbent injection system for possible use in 1995 for NO_x control.

Parametric testing on the cyclone boiler at the Lakeside Station was conducted in three series: gas reburning parametric testing, sorbent injection parametric testing, and GR–SI optimization tests. The goal of the parametric test series was to define the optimum GR–SI operating conditions with minimal degradation of the thermal performance of the boiler and to evaluate the GR–SI process over a wide range of representative operating conditions.

A total of 100 gas reburning parametric tests were conducted at boiler loads of 33 MWe, 25 MWe, and 20 MWe. The reburn parametric tests achieved NO_x reduction levels either at or just marginally above the 60% reduction goal. Additional flow modeling and computer modeling studies indicated that smaller reburning fuel jet nozzles could increase reburning fuel mixing and improve NO_x reduction performance.

A total of 25 sorbent injection parametric tests to isolate the effects of the sorbent on boiler performance and operability were completed. Tests indicated that SO_2 reduction level varied with load because of the effect of temperature on the sulfurization reaction. At a Ca/S of 2.0, full load (33 MWe) achieved a 44% SO_2 reduction; mid-load (25 MWe), 38% reduction; and low load (20 MWe), 32% reduction at Lakeside.

In the GR–SI optimization tests, the two technologies were integrated. Modifications were made to the reburning fuel injection nozzles based on the results of the initial gas reburning parametric tests. Tests did not indicate any adverse effect of the change in the thermal profile. SO_2 reductions of over 50% could be achieved with Ca/S greater than 1.25 along with gas heat inputs of 22–25%. The total SO_2 reduction from the combined effect of fuel replacement and sorbent injection exceeded the project goal of 50% reduction.

The primary goal of the long-term testing was to operate GR–SI during the normal operating cycle of the Lakeside unit. The unit typically operated in cycling service with a very low capacity factor, so testing was conducted whenever the unit was operated. The average NO_x reduction was 67% after a total of 249 hours of gas reburning operation. The average SO_2 reduction after 221 hours of GR–SI operation was 58%. During GR–SI operation there was a 0.8% drop in thermal efficiency due to the fuel switch and a small increase in the exit flue gas temperature.

During extended tests that included a 38-hr GR–SI continuous run, a 115-hr GR-only continuous run, and a 66-hr continuous GR–SI run, process operation with variable load met the project goals of 60% NO_x reduction and 50% SO_2 reduction. No significant boiler or ESP impacts were observed. Compliance test results for particulate emissions averaged 0.016 lb/million Btu, well below the limit of 0.1 lb/million Btu.

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 SO_2 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.

Project Schedule:

DOE selected project (CCT-I)	7/24/86
Cooperative agreement awarded	7/14/87
NEPA process completed, Hennepin (MTF)	5/9/88
Environmental monitoring plan completed,	
Hennepin	10/15/89
Lakeside	11/15/89
Construction, Hennepin	5/89–8/91
Operational testing, Hennepin	1/91–1/93
NEPA process completed, Lakeside (EA)	6/25/89
Construction, Lakeside	6/90–5/92
Operational testing, Lakeside	5/93–10/94
Restoration completed	10/95
Project completed	12/95

Final Reports:

Final Technical Report, Hennepin	10/94
Final Technical Report, Edwards	10/94
Final Technical Report, Lakeside	5/95
Economic Evaluation Report	7/95
Public Design Report	7/95

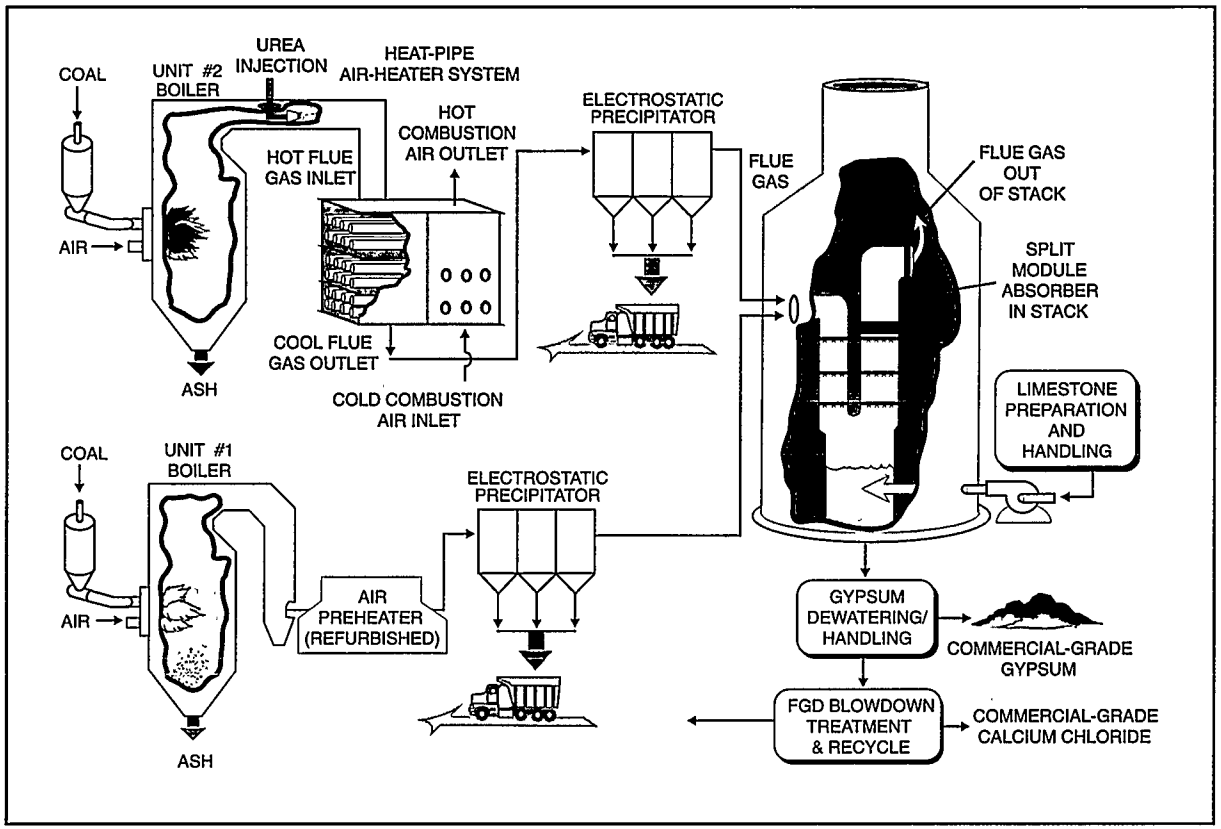
Milliken Clean Coal Technology Demonstration Project

Participant:
New York State Electric & Gas Corporation

Additional Team Members:
New York State Energy Research and Development Administration—cofunder
Empire State Electric Energy Research Corporation—cofunder
Consolidation Coal Company—technical consultant
Saarberg-Hölter-Umwelttechnik, GmbH—technology supplier
The Stebbins Engineering and Manufacturing Company—technology supplier
NALCO Fuel Tech—technology supplier
ABB Air Preheater, Inc.—technology supplier
DHR Technologies, Inc.—operator advisor system

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; ABB Combustion Engineering's Low-NO_x Concentric Firing System (LNCFS) Level III; NALCO Fuel Tech's NO_xOUT urea injection system; Stebbins' tile-lined split-module absorber; and ABB Air Preheater's heat-pipe air-heater system (environmental control devices/combined SO_2/NO_x control technologies)



Plant Capacity/Production:
300 MWe

Project Funding:

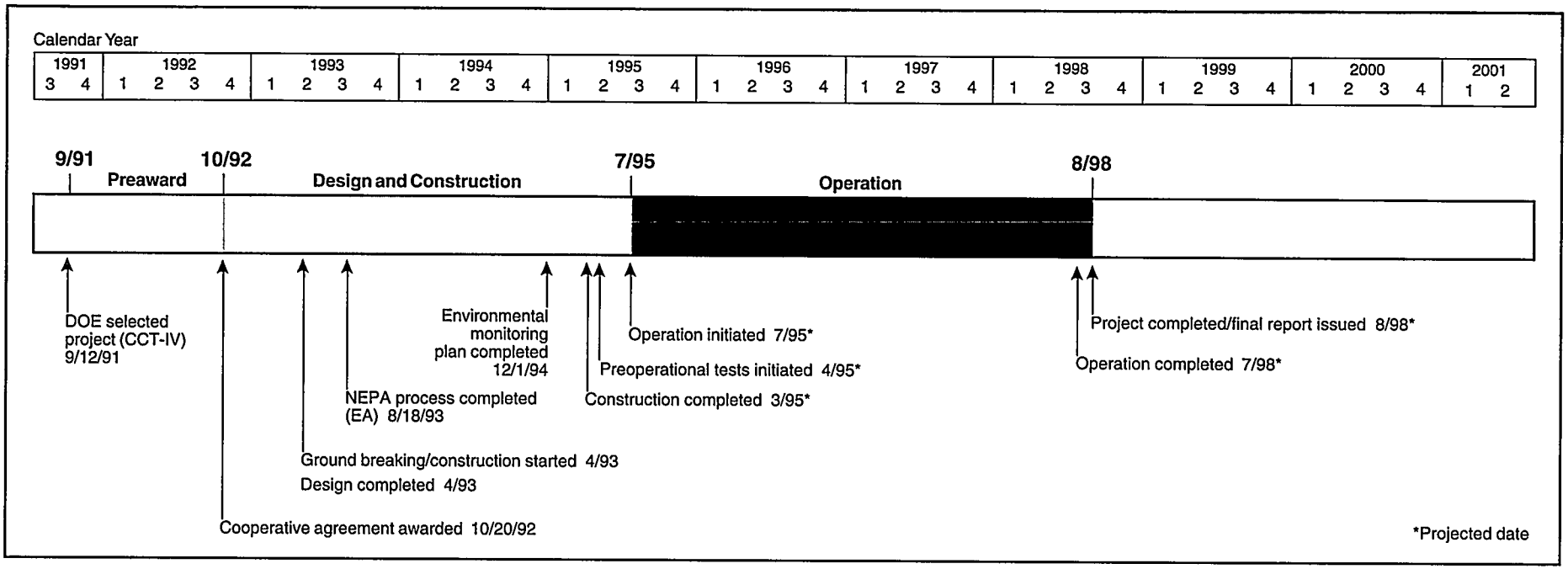
Total Project Cost	$158,607,807	100%
DOE	45,000,000	28
Participant	113,607,807	72

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 SO_2 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 SO_2 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 is being used to remove NO_x by the injection of urea into the boiler gas. This facet of the project, in conjunction with other combustion modifications, including LNCFS Level



III (low-NO_x burner system), 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. DHR Technologies, Inc., will provide a state-of-the-art boiler and plant artificial-intelligence-based control system. 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% SO_2 removal efficiency (or up to 98%) using limestone while burning high-sulfur coal. NO_x reductions will be achieved using selective non-catalytic reduction technology and separate combustion modifications. NO_x emissions have been reduced from 0.65 to 0.40 lb/million Btu (23%) by retrofitting the two boilers with low-NO_x burners. NO_xOUT is expected to reduce NO_x emissions from Unit 2 by an additional 15–20%. 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 is demonstrating these technologies at Units 1 and 2 of its Milliken Station located in Lansing, NY. Pittsburgh, Freeport, and Kittaning coals, with sulfur contents of 1.5%, 2.9%, and 4.0%, will be used.

Project Status/Accomplishments:

Construction has stayed 2–3 months ahead of schedule. Hydro testing of the scrubber began in November 1994, with passage of flue gas in December 1994. Equipment shakedown and start-up will begin in January/February 1995. Baseline and preoperational testing is expected to commence in April 1995, with full-scale operation beginning in July and running for the next 3 years.

Commercial Applications:

The S-H-U SO_2 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 SO_2 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 SO_2/NO_x Removal Flue Gas Cleanup System

Participant:
NOXSO Corporation

Additional Team Members:
ALCOA—cofunder
W.R. Grace and Company—cofunder
Gas Research Institute—cofunder
Electric Power Research Institute—cofunder

Location:
Newburgh, Warwick County, IN (Alcoa Generating Company's Warrick Power Plant, Unit 2)

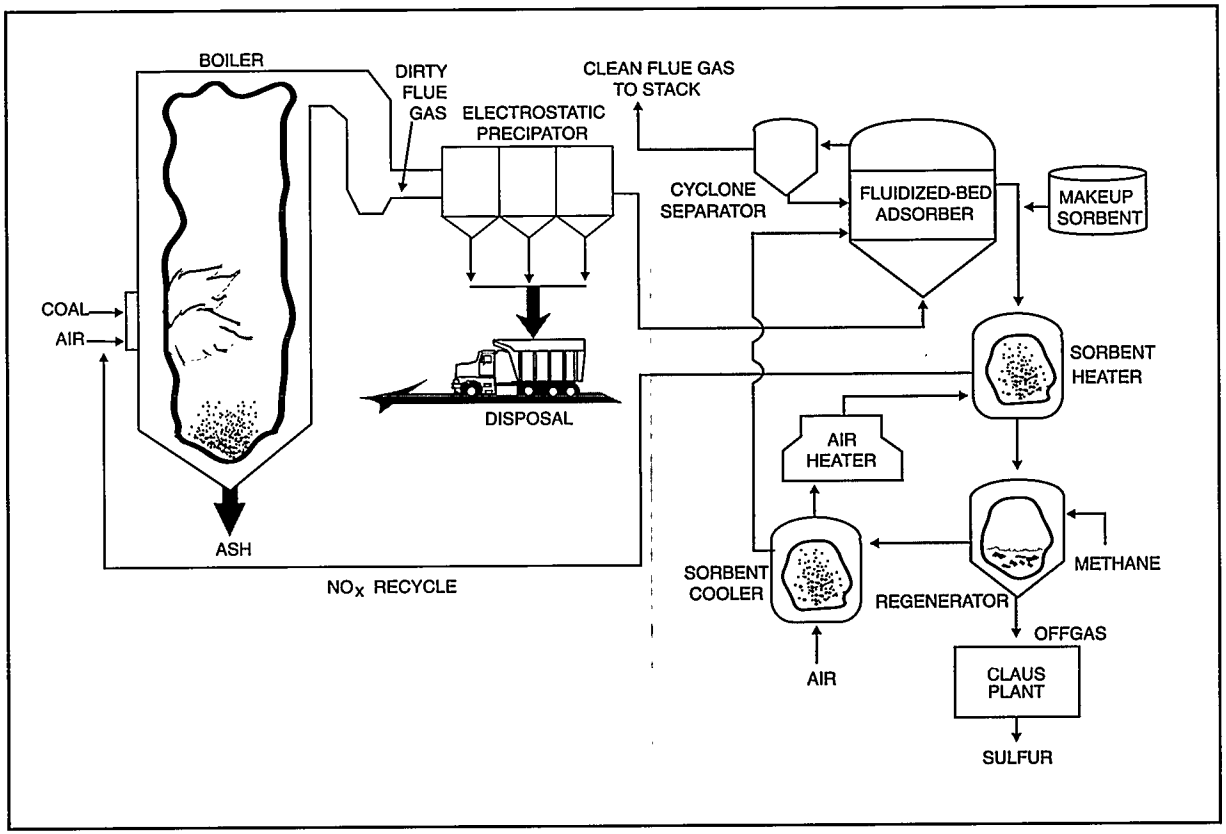
Technology:
NOXSO Corporation's dry, regenerable flue gas cleanup process (environmental control devices/combined SO_2/NO_x control technologies)

Plant Capacity/Production:
144 MWe (net)

Project Funding:

Total project cost	$67,181,325	100%
DOE	33,506,012	50
Participants	33,675,313	50

Project Objective:
To demonstrate removal of 98% of the SO_2 and 70% of the NO_x from a coal-fired boiler's flue gas using the NOXSO process.

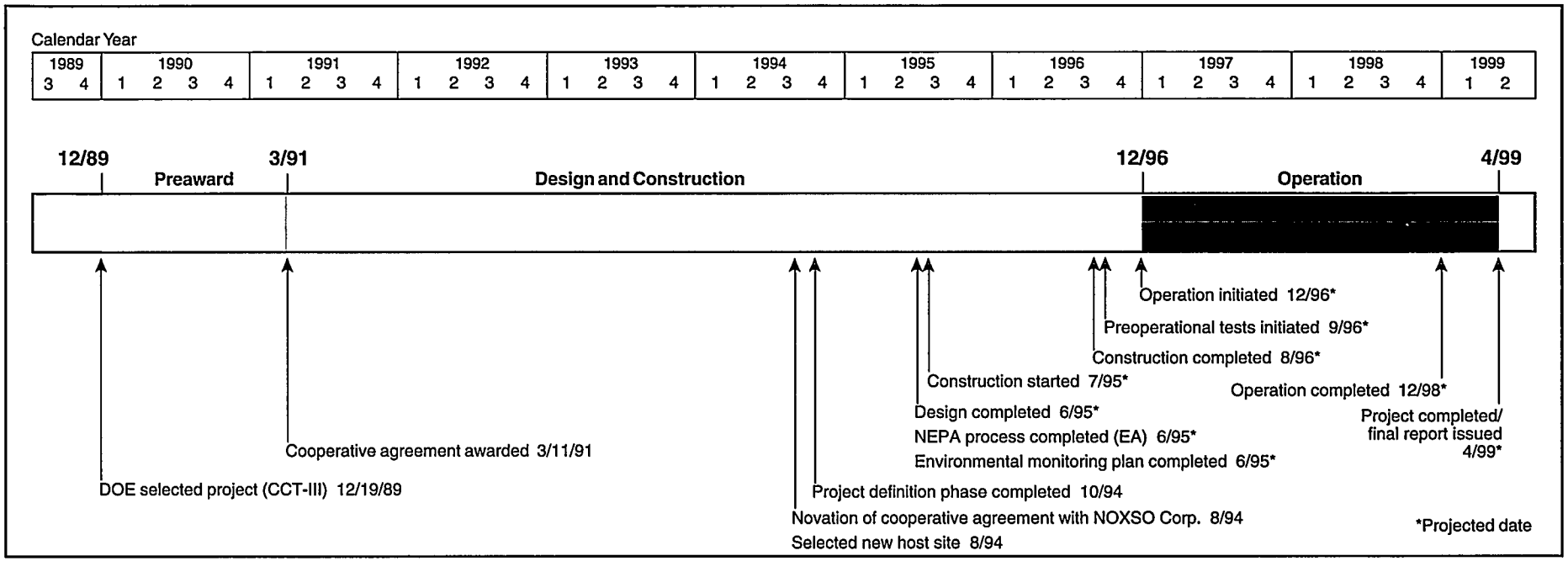


Technology/Project Description:
The NOXSO process is a dry, regenerable system capable of removing both SO_2 and NO_x in flue gas from coal-fired utility boilers burning medium- to high-sulfur coals. In the basic process, the flue gas passes through a fluidized-bed adsorber located downstream of the precipitator; the SO_2 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 through a baghouse 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 SO_2 and hydrogen sulfide (H_2S). This offgas is processed to produce elemental sulfur. The elemental sulfur will be processed further to produce liquid SO_2, a higher valued by-product.

The process is expected to achieve SO_2 reductions of 98% and NO_x reductions of 70%.

The NOXSO Corporation is demonstrating a full-scale commercial NOXSO unit on a 144-MWe (net) cyclone boiler at Alcoa Generating Company's Warrick Power Plant, Unit 2, in Newburgh, IN. The fuel coal is Indiana bituminous coal containing an average of 3.3% sulfur. Data from the proof-of-concept facility at Ohio Edison Company's Toronto Station is being incorporated into the plant design.



Project Status/Accomplishments:

A new project site was identified in 1994—Alcoa Generating Company's Warrick Power Plant Unit 2. The proof-of-concept, pilot-plant testing, which proceeded in parallel with the project definition phase of the demonstration project, is complete. The test results from the proof-of-concept and pilot plant exceed the expected goals. These results will be used for the scale-up design for the full-size commercial unit.

The NEPA process is well under way. Preliminary process flow diagrams, piping and instrumentation diagrams, equipment specifications, and plant arrangement drawings have been prepared.

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. A high-sulfur coal is being used in the demonstration; however, the process is adaptable to coals with any sulfur content.

The process produces one of the following as a salable by-product: elemental sulfur, sulfuric acid, or liquid sulfur dioxide. A readily available market exists for these products.

The technology is expected to be especially attractive to utilities that require high removal efficiencies for both SO_2 and NO_x and/or need to eliminate solid wastes.

Integrated Dry NO_x/SO_2 Emissions Control System

Participant:
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)

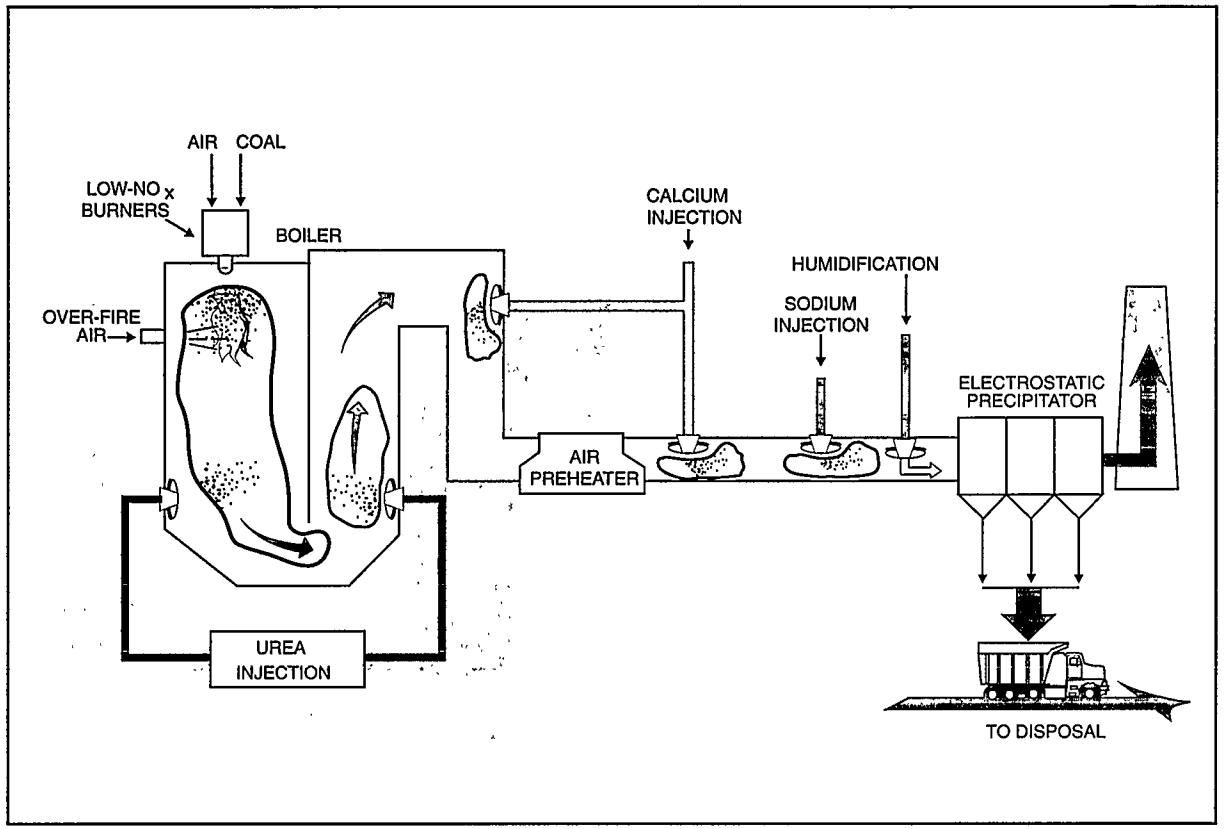
Technology:
The Babcock & Wilcox Company's DRB-XCL® low-NO_x burners, in-duct sorbent injection, and furnace (urea) injection (environmental control devices/combined SO_2/NO_x control technologies)

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 SO_2 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 SO_2 removal.

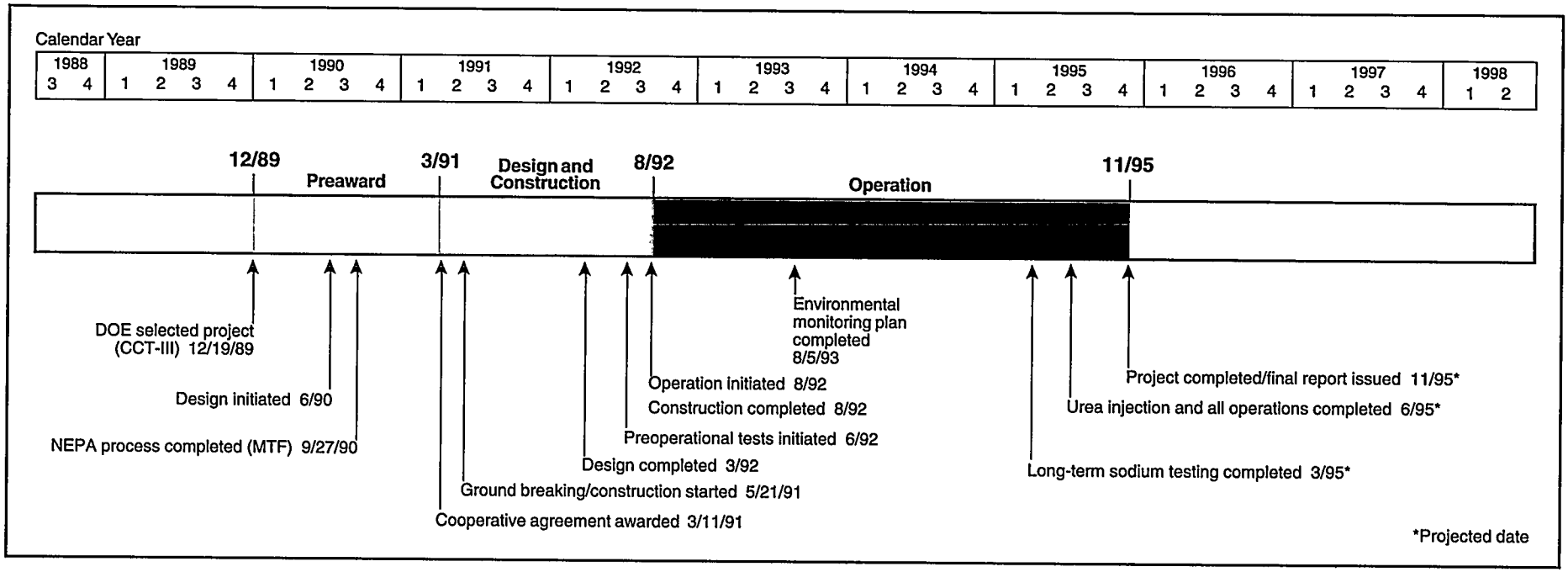


Technology/Project Description:
All of the testing is using Babcock & Wilcox's low-NO_x DRB-XCL® down-fired burners with over-fire air. These burners control NO_x by injecting the coal and the combustion air in an oxygen-deficient environment. Additional air is introduced via over-fire air ports to complete 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 SO_2 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 SO_2 capture and lowers flue gas temperature and gas flow, which can decrease pressure drop at the fabric filter dust collector.

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. All testing

DRB-XCL is a registered trademark of The Babcock & Wilcox Company.



is being conducted using a low-sulfur (0.4%) bituminous Colorado coal.

Project Status/Accomplishments:

Operational testing of the boiler with low-NO_x burners and over-fire air 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. 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 and was completed in May 1994. Sodium-bicarbonate injection achieved over 70% SO_2 removal at a stoichiometric ratio of approximately 1.0. Sodium sesquicarbonate injection after the air heater also obtained a 70% SO_2 removal but at a stoichiometric ratio of approximately 1.8. Calcium-based dry reagent injection achieved a maximum of 40% SO_2 removal and caused some operational concerns. Pre-economizer calcium-based injection achieved only 10% SO_2 removal, significantly less than expected. Testing of the integration of sodium and urea injection began in June 1994 and will be completed in mid-1995. Overall NO_x reduction of 80% has been demonstrated at full load.

The project schedule has been extended 1 year, to November 1995, to allow for additional long-term sodium injection testing. The urea injection system also will be modified to improve low-load NO_x removal.

Four series of air toxics testing have been completed. Results indicate that the baghouse successfully removes nearly all trace metal emissions and nearly 80% of the mercury emissions. Radionuclides, semi-volatile organic compounds, and dioxins/furans were below or very near their detection limit.

Arapahoe 4 has operated over 20,000 hours since combustion modifications were completed in May 1992. The availability factor during this period was over 96%.

Due to the successful application of the system, the Public Service Company of Colorado plans to continue operation of the combustion modifications and the sodium-based DSI system. A final decision on the selective noncatalytic reduction system will be made after the test program is completed. All testing will be completed in mid-1995, with project completion scheduled for November.

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.

Coal Processing for Clean Fuels Fact Sheets

Development of the Coal Quality Expert

Participants:

ABB Combustion Engineering, Inc.
CQ, Inc.

Additional Team Members:

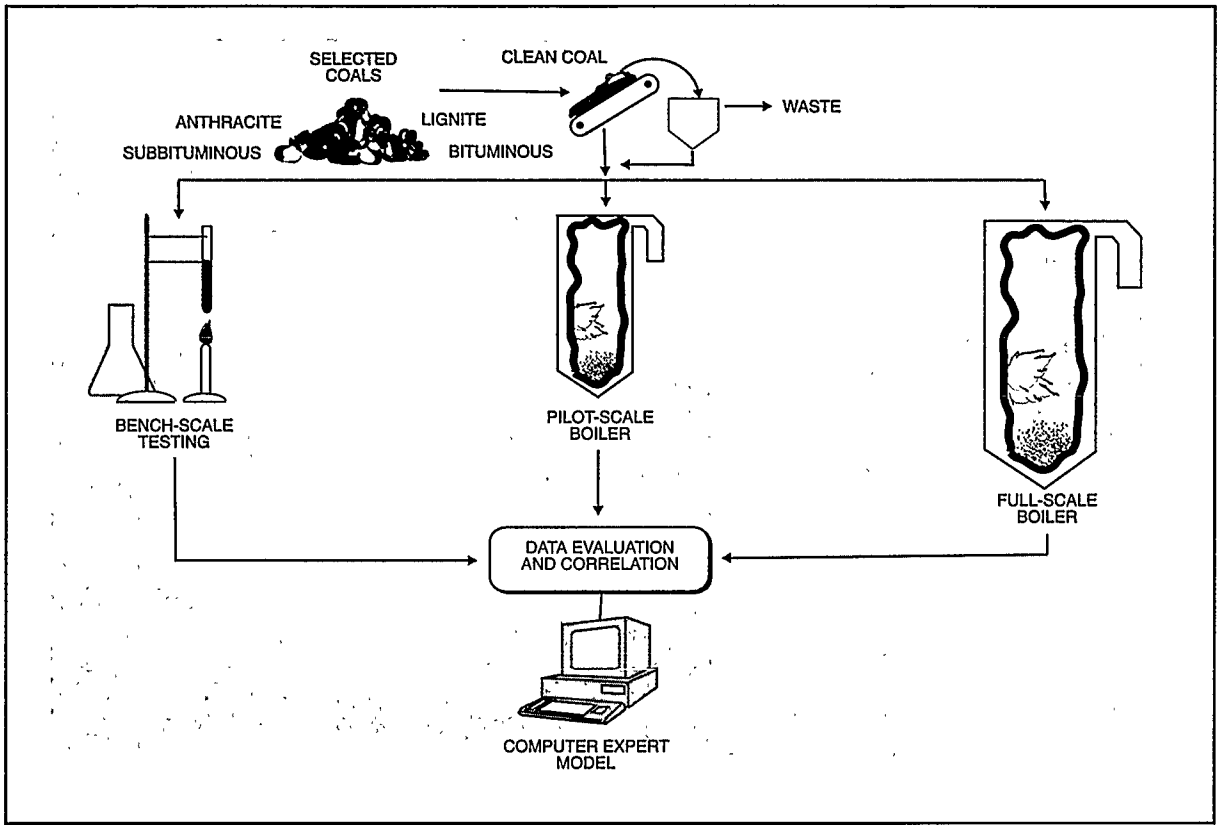
Black and Veatch—cofunder and expert system developer
Electric Power Research Institute—cofunder
The Babcock & Wilcox Company—cofunder and pilot-scale testing
Guild Products, Inc.—expert system architecture developer
Electric Power Technologies, Inc.—field testing
University of North Dakota, Energy and Environmental 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 took 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

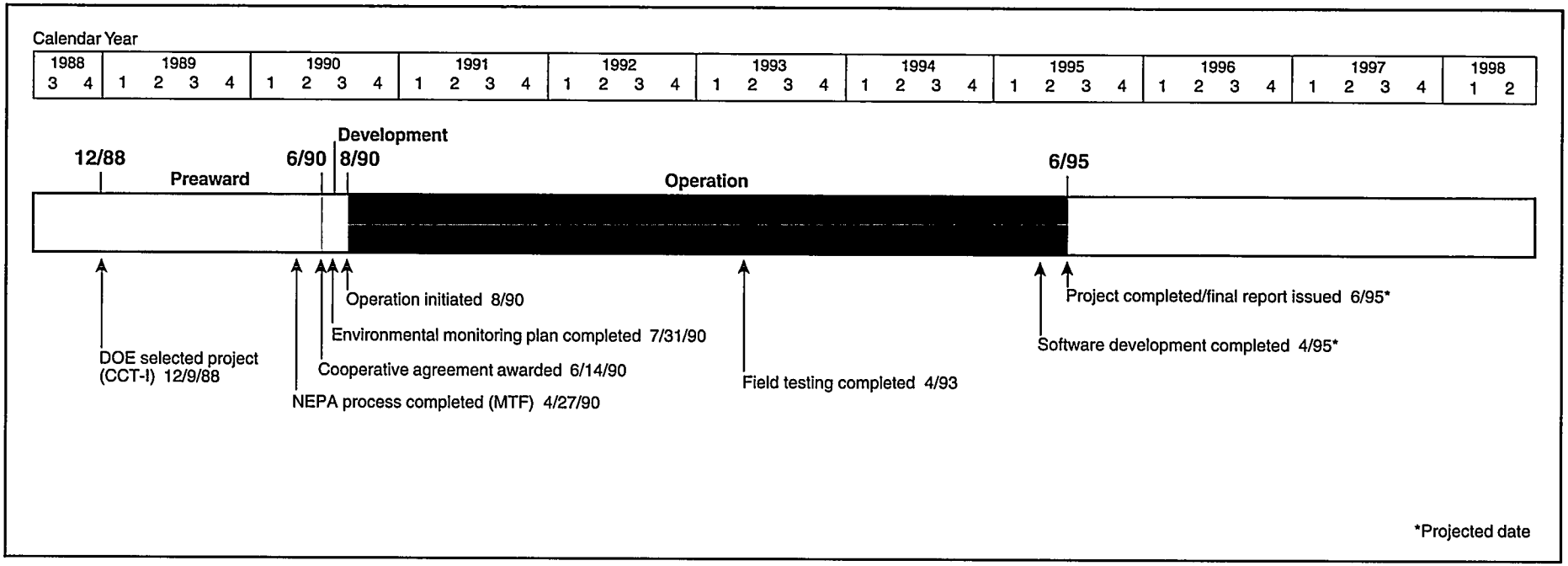
Project Objective:

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 were 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 consisted of burning a baseline coal and an alternate coal over a 2-month period. The baseline coal, the one currently used as fuel, was used to characterize the operating performance of the boiler. The alternate coal, a blended or cleaned coal of improved quality, was burned in the boiler for the remaining test period.



The baseline and alternate coals for each test site also were burned in bench- and pilot-scale facilities under similar conditions. The alternate coal was 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 were evaluated and correlated to formulate algorithms being used to develop the model.

Bench-scale testing was performed at ABB Combustion Engineering's facilities in Windsor, CT, and the University of North Dakota's Energy and Environmental Research Center in Grand Forks, ND; pilot-scale testing was performed at ABB Combustion Engineering's facilities in Windsor, CT, and Alliance, OH. The six field test sites were Gatson, Unit 5 (880MW e), Wilsonville, AL; Watson, Unit 4 (250MW e), Gulfport, MS; Brayton Point, Unit 2 (285 MWe) and Unit 3 (615 MWe), Somerset, MA; King Station (560MW e), Bayport, MN; and Northeastern, Unit4 (445 MW e), Oologah, OK.

Project Status/Accomplishments:

All six field tests have been completed. A CQE prototype was showcased in September 1993. Emphasis during 1994 was on final model development, prototyping, and validation. A CQE beta version will be released in early 1995, and the final version is expected in June 1995.

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 SO_2 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. A commercial sale of the CQE Acid Rain Advisor software package was made in March 1993.

CQ, Inc., and Black and Veatch have signed a commercialization agreement which gives Black and Veatch nonexclusive worldwide rights to sell users' licenses and to offer consulting services that include the use of CQE software.

Self-Scrubbing Coal™: An Integrated Approach to Clean Air

Participant:

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
CQ, Inc.—operator

Locations:

Central City, Somerset County, PA (advanced coal-cleaning plant)
Springdale, Allegheny County, PA (combustion tests at Duquesne Light's Cheswick Power Station, Unit 1)
Richmond, Wayne County, IN (combustion tests at Richmond Power & Light's Whitewater Valley Generating Station, Unit No. 2)
Ashtabula, Trumbull County, OH (combustion tests at Centerior Energy's Ashtabula C)

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)

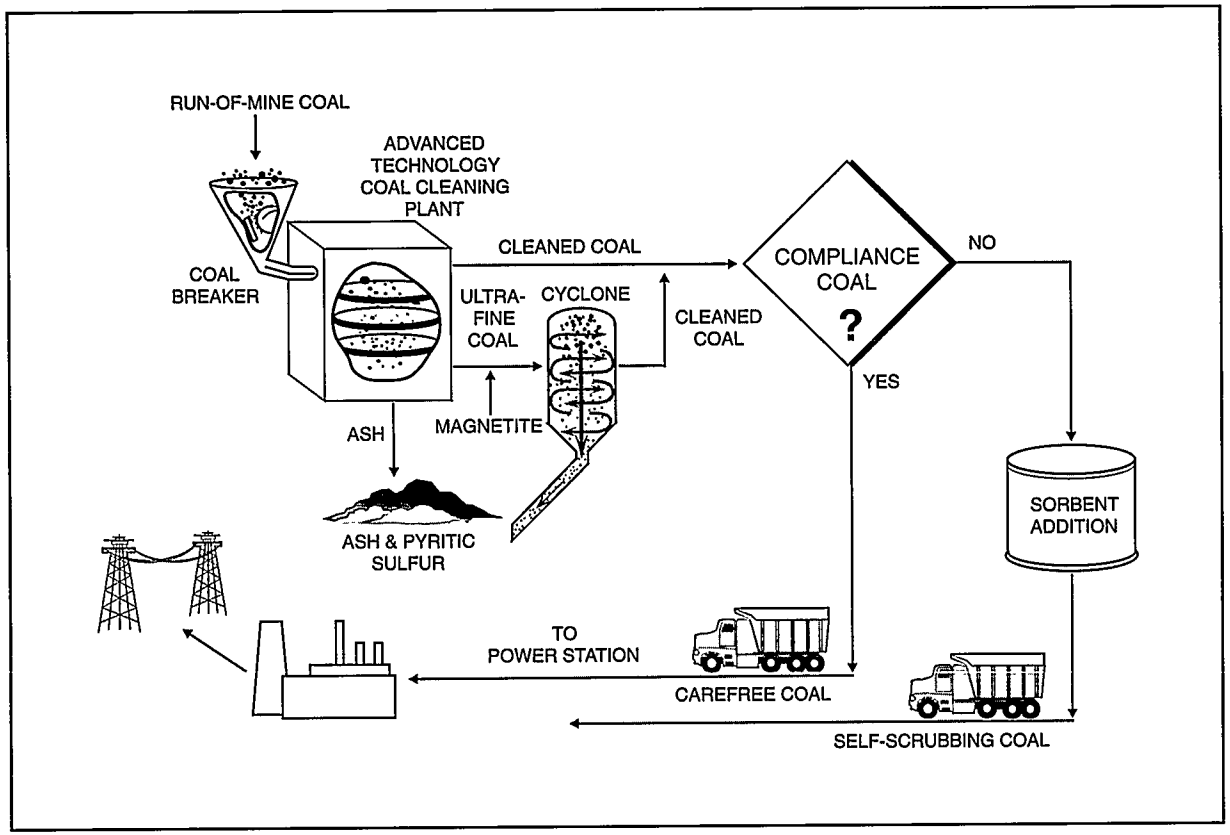
Plant Capacity/Production:

500 tons/hr

Project Funding:

Total project cost	$89,715,781	100%
DOE	38,038,656	42
Participant	51,677,125	58

Self-Scrubbing Coal and Carefree Coal are trademarks of Custom Coals International.



Project Objective:

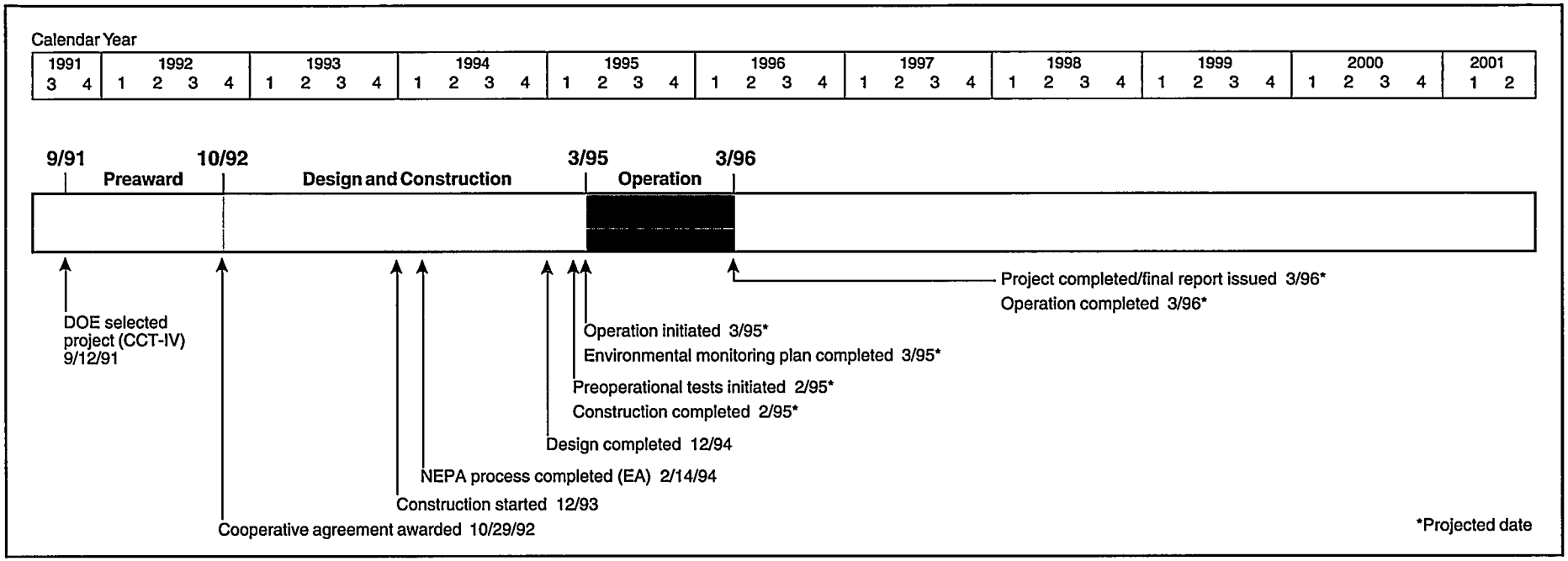
To demonstrate advanced coal-cleaning unit processes to produce low-cost compliance coals that can meet full requirements for commercial-scale utility power plants to satisfy CAAA of 1990 provisions.

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 SO_2 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 SO_2 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 (2.7% sulfur) from Wabash County, IL, and Lower Freeport seam coal (3.9% sulfur) from Belmont County, OH—will be used to produce Self-Scrubbing Coal™. Carefree Coal™ will be made using Sewickley coal (4.8% sulfur) from Greene County, PA. The Sewickley coal will be combustion tested at Duquesne Light Company's Cheswick Power Station located in Springdale, PA; the Illinois No. 5 coal will be tested at Richmond Power & Light's Whitewater Valley Generating Station Unit No. 2 located in Richmond, IN; and the Lower Freeport seam coal will be tested at Centerior Energy's Ashtabula C Power Plant near Ashtabula, OH.

Project Status/Accomplishments:

Construction has moved at a rapid pace since beginning in December 1993. Structural steel erection is complete. Over 99% of the equipment has been installed. Raw coal burn testing to provide baseline data to determine the cleaning effect is scheduled to begin in early 1995.

DOE approved a finding of no significant impact for an environmental assessment on February 14, 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%.

In August 1994, a U.S.-led consortium with Custom Coals Corporation as the principal partner signed a cooperative agreement with the People's Republic of China to build a coal-cleaning plant, a 500-mile underground slurry pipeline, and port facility. The pipeline will bring coal from the Shanxi province in northwest China to the coastal province of Shandong. The work included under the agreement is valued at $888.6 million.

Advanced Coal Conversion Process Demonstration

Participant:
Rosebud SynCoal Partnership (a partnership between Western Energy Company and the NRG Group, a nonregulated subsidiary of Northern States Power Company)

Additional Team Member:
None

Location:
Colstrip, Rosebud County, MT (adjacent to Western Energy Company's Rosebud Mine)

Technology:
Rosebud SynCoal Partnership's advanced coal conversion process for upgrading low-rank subbituminous and lignite coals (clean processing for clean fuels/coal preparation technologies)

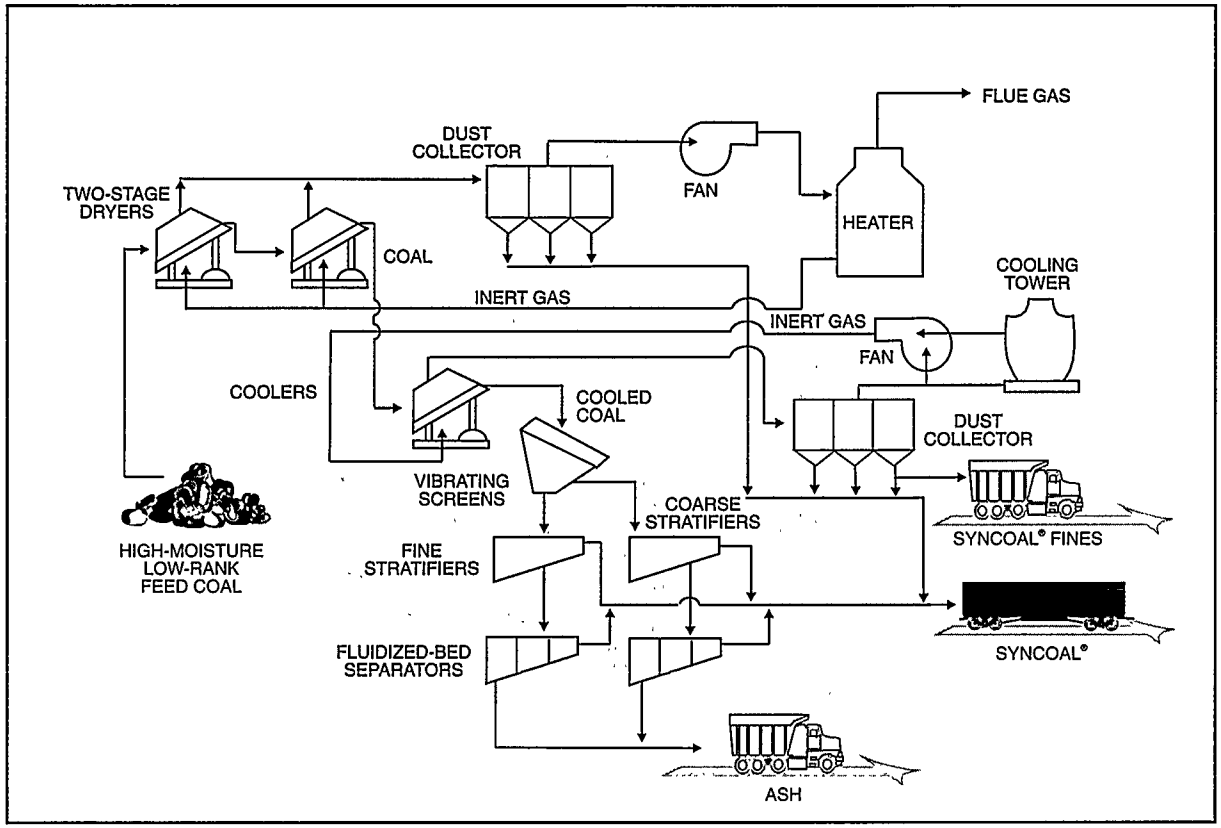
Plant Capacity/Production:
45 tons/hr of SynCoal® product (300,000 tons/yr)

Project Funding:

Total project cost	$105,700,000	100%
DOE	43,125,000	41
Participant	62,575,000	59

Project Objective:
To demonstrate Rosebud SynCoal'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.

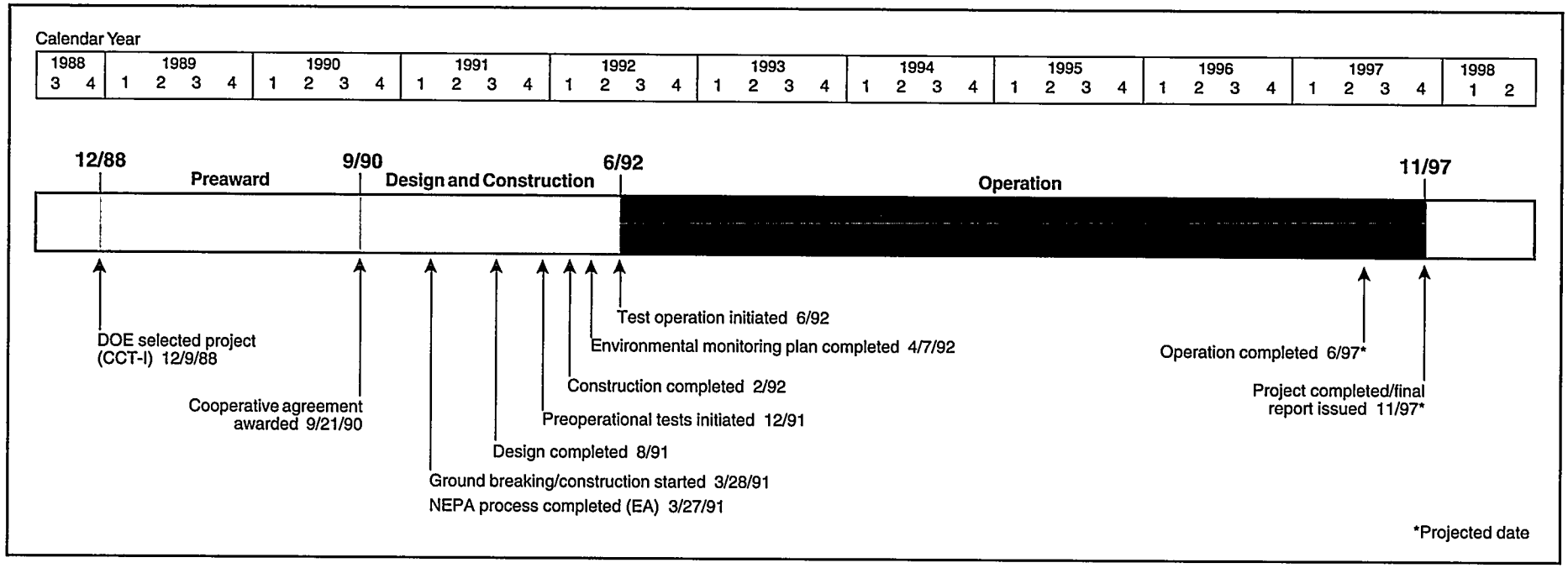
SynCoal is a registered trademark of the Rosebud SynCoal Partnership.



Technology/Project Description:
Being demonstrated is an advanced thermal coal conversion 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 conversion, the coal is put through a deep-bed stratifier cleaning process to effect separation of the ash.

The technology enhances low-rank western coals, usually with a moisture content of 25–40%, sulfur content of 0.5–1.5%, and heating value of 5,500–9,000 Btu/lb, by producing an 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. The demonstration plant is one-tenth the size of a commercial facility. However, the process equipment is at 1/3–1/2 commercial scale because a full-sized commercial plant will have multiple process trains.



Project Status/Accomplishments:

Ground was broken on March 28, 1991. Initial "turnover" of equipment started in December 1991, and final construction was completed in February 1992. Initial "hot" operations began in March 1992. On December 6, 1993, the plant exceeded its 68-ton/hr design capacity by processing 70 tons/hr.

In March 1994 a 50/50 SynCoal® blend test was completed at Montana Power Company's J.E. Corette Plant. Wyoming subbituminous feedstock was tested at the SynCoal® demonstration plant in May 1994. This plant demonstrated a 75% availability factor and 98% capacity factor for the first 6 months of 1994.

A scheduled maintenance and plant improvement outage was completed in September 1994. A follow-up test burn using a 50/50 SynCoal® blend was conducted at the J.E. Corette Plant following chemical cleaning of the boiler. Testing at the power plant continues at the main utility test burn site. A total of 5,412 tons have been delivered to the utility. In addition, 5,757 tons have been delivered to Ash Grove Cement, Bentonite Corporation, and Empire Sand and Gravel.

Commercial Applications:

Rosebud SynCoal'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® is an ideal low-sulfur coal substitute for these and other plants because it allows 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 produces SynCoal® which has a consistently low moisture content, a low sulfur content, a high heating value, and a high volatile content. Because of these characteristics, SynCoal® could have significant impact on SO_2 reduction and provide an economical clean alternative fuel to many regional industrial facilities and small utilities being forced to use fuel oil and natural gas. Rosebud Syncoal's process, therefore, will be attractive to industry and 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 applying the coal processing technology to a commercial plant integrated into an existing power plant site. The study's results have been positive, but market commitments are still necessary.

ENCOAL Mild Coal Gasification Project

Participant:
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 licenser
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)

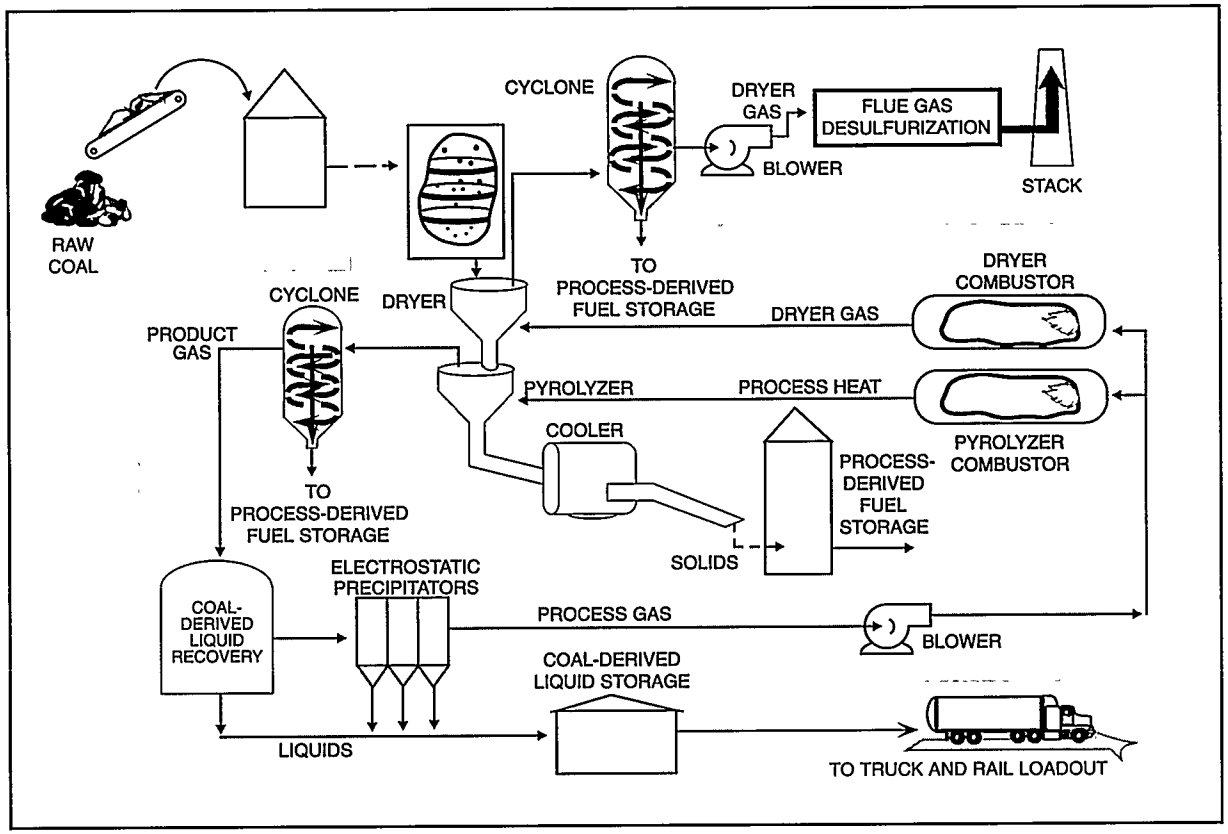
Technology:
SGI International's liquids from coal process (coal preparation for clean fuels/mild gasification)

Plant Capacity/Production:
1,000 tons/day of subbituminous coal feed

Project Funding:

Total project cost	$90,664,000	100%
DOE	45,332,000	50
Participants	45,332,000	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.

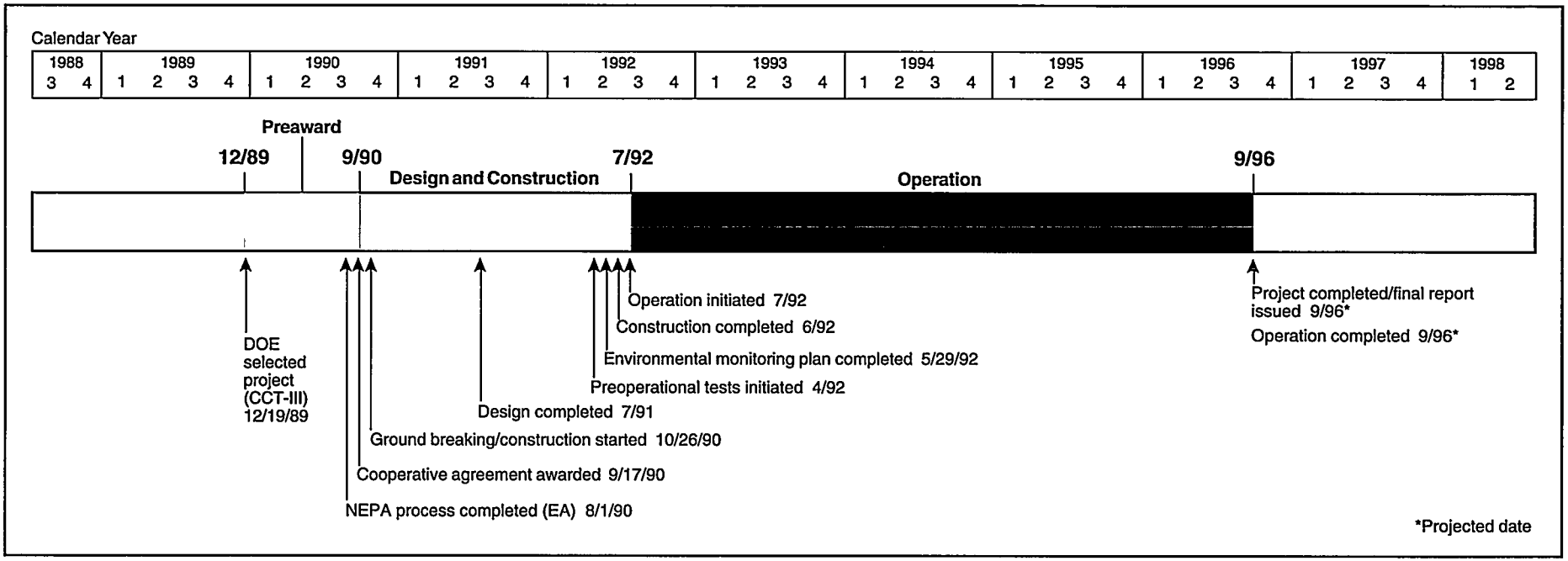


Technology/Project Description:
The ENCOAL mild coal gasification process involves heating coal under carefully controlled conditions. Coal is fed into a rotary grate dryer where it is heated by a hot gas stream to reduce the coal's moisture content. The solid bulk temperature is controlled so that no significant amounts of methane, CO, or CO_2 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 SO_2, 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:

The plant officially entered the production mode in June 1994; operation has been at a coal feed rate of 500 tons/day. By year-end 1994, 22 test runs were completed, representing more than 5,000 hours of operation on coal. Solid and liquid products being produced by the plant are being shipped to industrial and utility customers. In September 1994, approximately 8,000 tons of solid product were shipped as 15–35% blends with Powder River Basin coal for use in electricity generation at the Western Farmers Cooperative's Hugo plant in Oklahoma. This rural electric cooperative used the product successfully in its boilers. ENCOAL also has contracted with Wisconsin Power & Light for the sale of 30,000 tons of solid product. A contract to sell blends of up to 92% solid product was signed with Muscatine Power and Water of Muscatine, IA. Other major utility companies have expressed interest in purchasing solid product. Tank cars of liquid product are being shipped on a regular basis to several customers in the Midwest for use in industrial boilers. The Dakota Gasification Company tested the liquid product in 1992 and in 1994 purchased an additional 800,000 gallons for use in its synfuel plant in Beulah, ND.

The project has been extended for 2 years in order to resolve problems with the in-process stabilization of the solid product and to conduct and analyze utility test burns of solid product.

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 and also shows promise for iron ore reduction applications. 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 12,000Btu/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 SO_2 emissions at industrial and utility facilities currently burning high-sulfur bituminous coals or fuel oils.

SGI International and Mitsubishi Heavy Industries are studying the economic and engineering feasibility of developing a 6,000-metric-ton/day liquids-from-coal plant in the Shandong province of the People's Republic of China. Feasibility studies have also been proposed for projects in Indonesia and Poland.

Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process

Participant:

Air Products Liquid Phase Conversion Company, L.P. (a limited partnership between Air Products and Chemicals, Inc., the general partner, and Eastman Chemical Company)

Additional Team Members:

Air Products and Chemicals, Inc.—technology supplier and cofunder

Eastman Chemical Company—host; synthesis gas and services provider

Acurex Environmental Corporation—fuel methanol testing and cofunder

Electric Power Research Institute—fuel methanol testing 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)

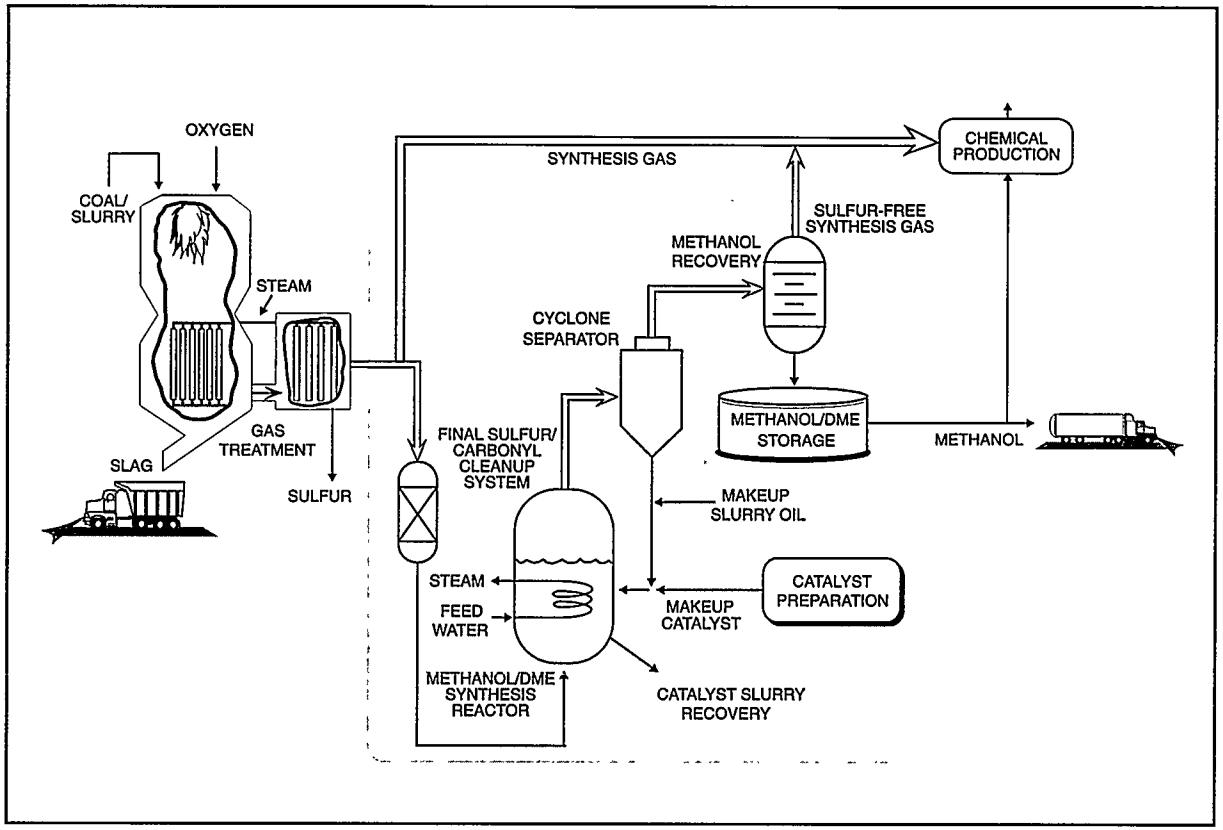
Plant Capacity/Production:

260 tons/day of methanol (nominal)

Project Funding:

Total project cost:	$213,700,000	100%
DOE	92,708,370	43
Participants	120,991,630	57

LPMEOH is a trademark of Air Products and Chemicals, Inc.



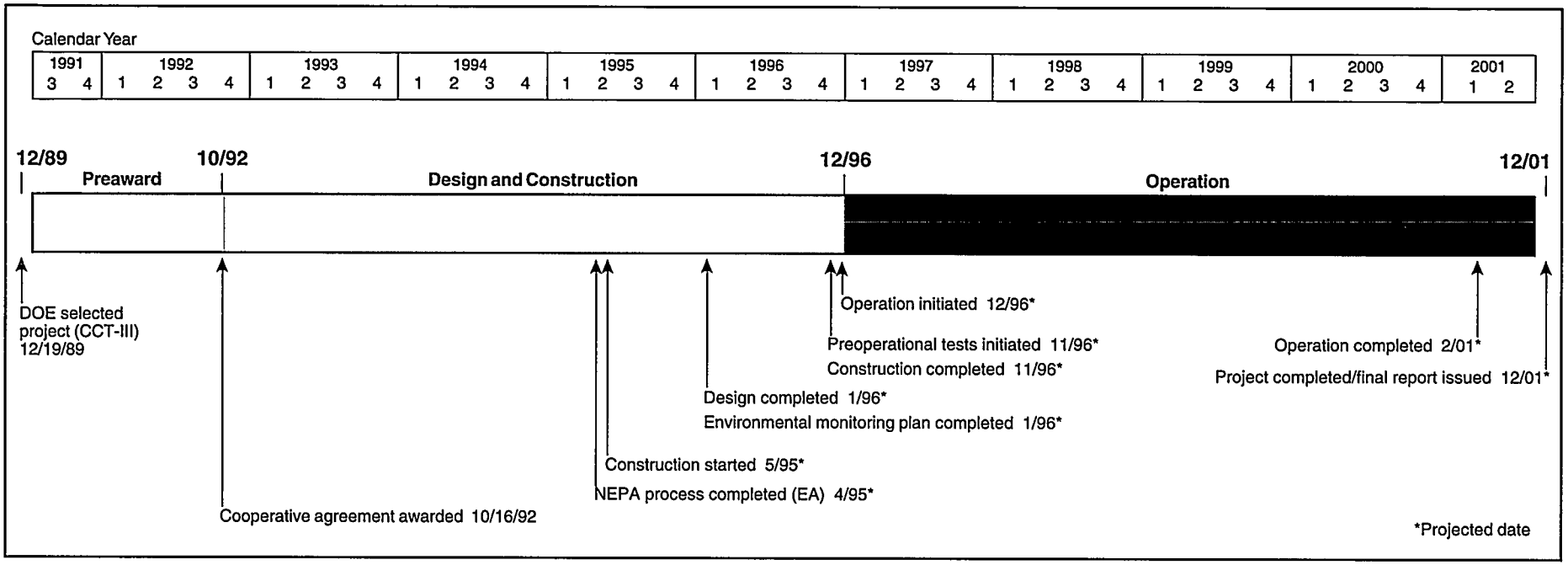
Project Objective:

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. If practical, the production of dimethyl ether (DME) as a mixed coproduct with methanol also will be demonstrated.

Technology/Project Description:

This project is demonstrating, at commercial scale, the LPMEOH™ process to produce methanol from coal-derived synthesis gas. The combined reactor and heat removal system is different from other commercial methanol processes. The liquid phase not only suspends 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 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 off-site stationary and mobile applications, such as boilers, fuel cells, buses, and van pools. Design verification testing for the production of DME as a mixed coproduct with methanol for use as a storable fuel is planned, and a decision to



demonstrate will be made. Eastern high-sulfur bituminous coal (Mason seam) containing 3% sulfur (5% maximum) and 10% ash will be used.

Project Status/Accomplishments:

To provide a contractual basis to manage and execute the LPMEOH™ demonstration project, Air Products and Chemicals and the Eastman Chemicals Company have formed the limited partnership, Air Products Liquid Phase Conversion Company. Project definition activities were completed in September 1994 and design was initiated. Relevant environmental information for the NEPA process is being updated; an environmental assessment is in progress. Construction is expected to start in May 1995.

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, can be substituted for conventional fuels in stationary and mobile combustion applications, is an excellent fuel for peak power production, contains no sulfur, and has exceptionally low-NO_x characteristics when burned. Methanol can be produced from coal as a coproduct in an IGCC facility.

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

Participant:
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)

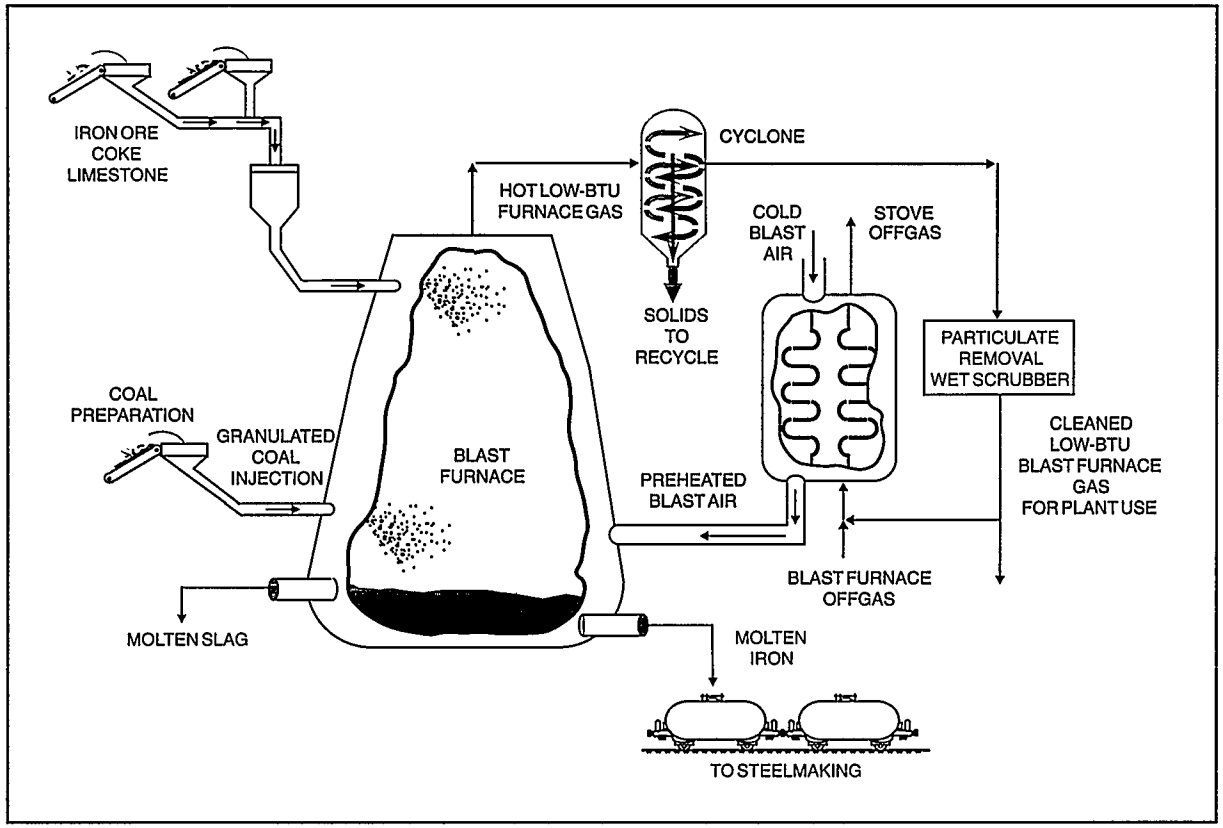
Technology:
British Steel's blast furnace granulated-coal injection (BFGCI) process (industrial applications)

Plant Capacity/Production:
7,000 net tons/day of hot metal (each blast furnace)

Project Funding:

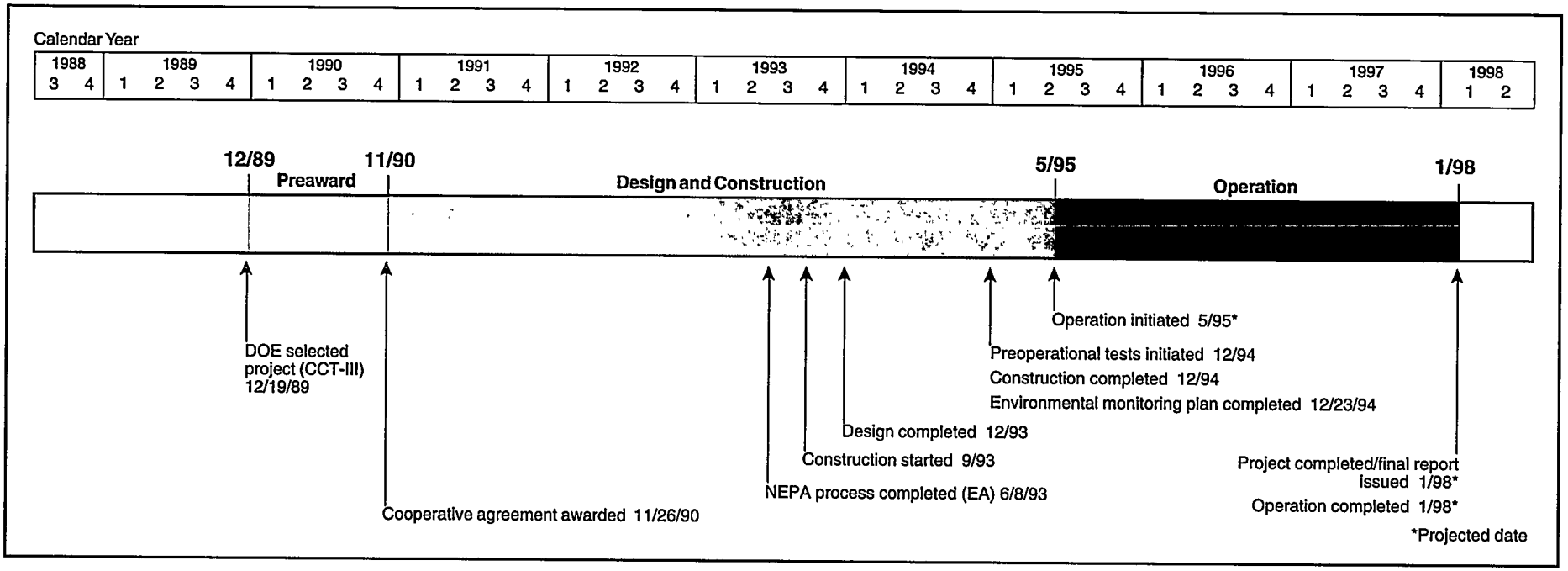
Total project cost	$191,700,000	100%
DOE	31,259,530	16
Participant	160,440,470	84

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:

Construction has been completed, and preoperational tests have been initiated. Facilities 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 were modified to accept the prepared coal. The necessary modifications to furnace D were made on-the-fly through a series of short outages on the operating furnace. Furnace C was modified during a reline in late 1994.

Bethlehem Steel expects to submit a public design report in January 1995.

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 that has a moisture content no higher than 12%. 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

Participant:
Bethlehem Steel Corporation

Additional Team Member:
Thyssen Still/Otto Technical Services—technology developer

Location:
Sparrows Point, Baltimore County, MD (Bethlehem Steel Corporation's Sparrows Point Plant, Coke Oven Batteries A, 11, and 12)

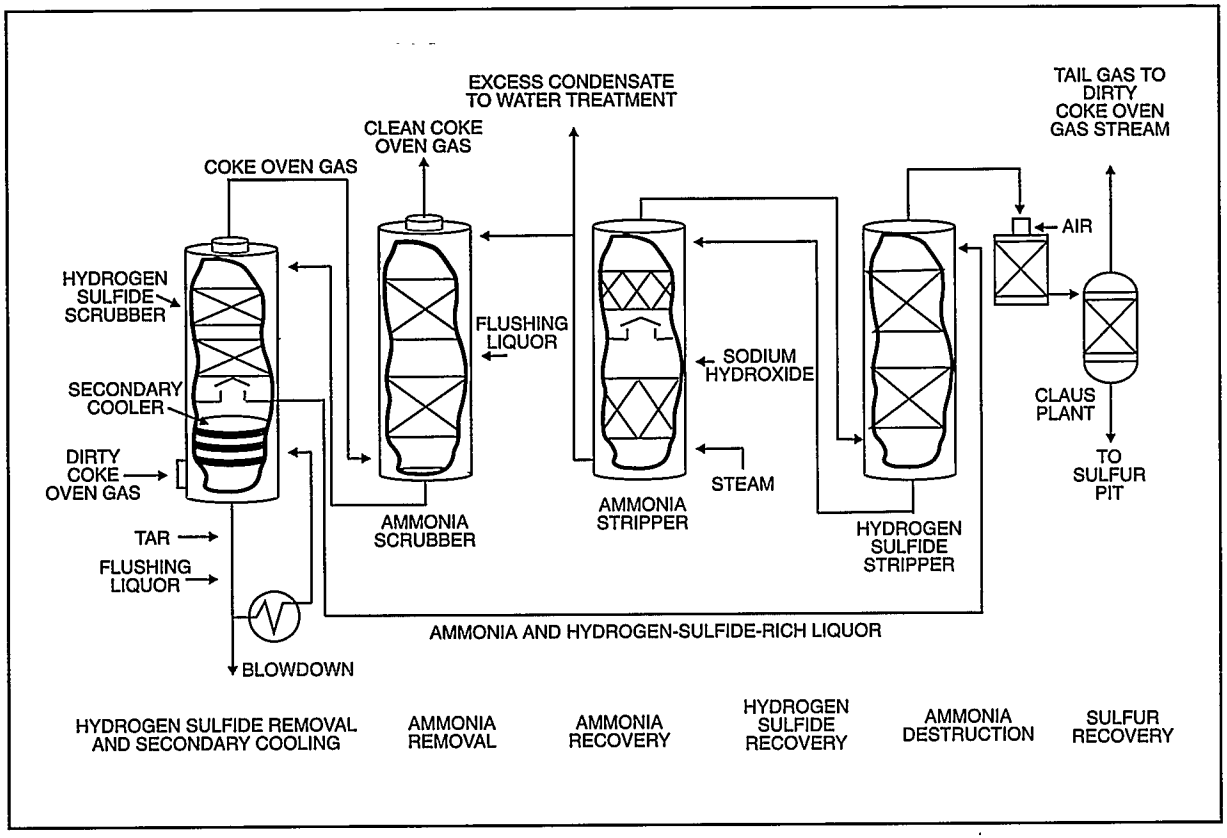
Technology:
Thyssen Still/Otto's process for precombustion cleaning of coke oven gas (COG) (industrial applications)

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

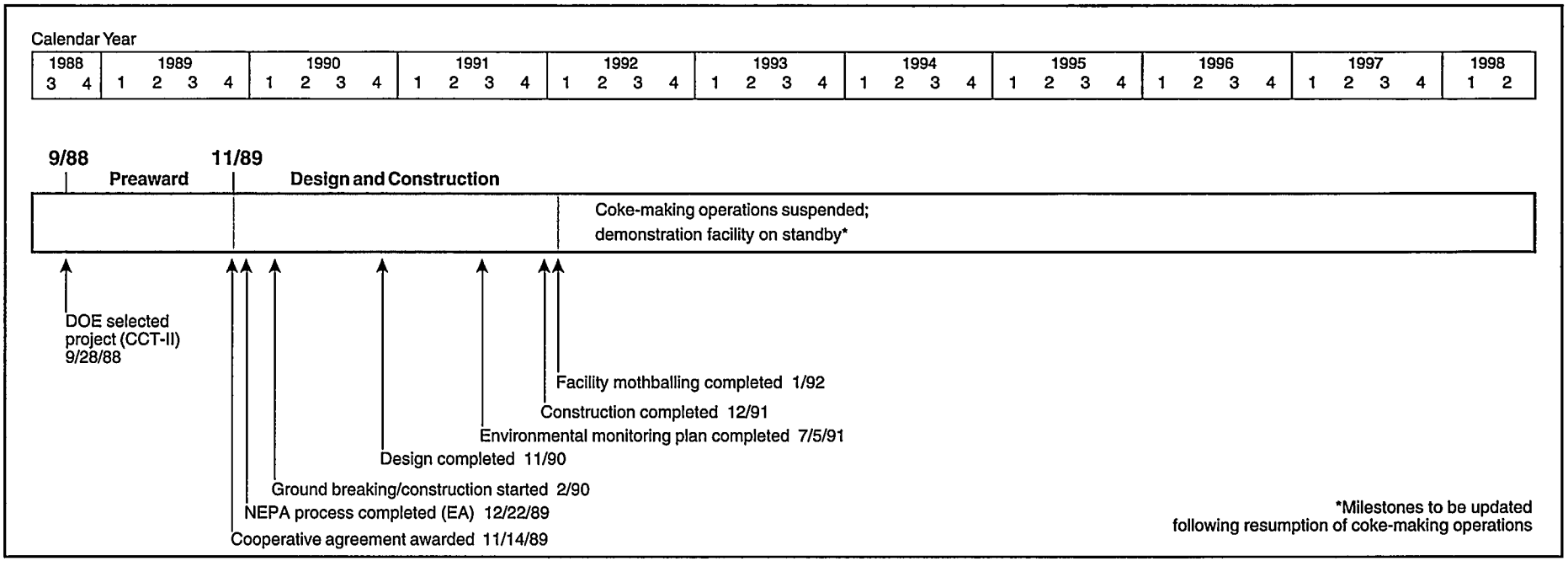
Project Objective:
To demonstrate a first-of-a-kind novel integration of commercially available process steps for simultaneous removal of hydrogen sulfide and ammonia from COG, recovery of hydrogen sulfide and ammonia, destruction of ammonia, and recovery of sulfur in a commercial-sized application; and to reduce SO_2 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 Thyssen 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 74millionstdft ³/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 December 5, 1991, Bethlehem Steel Corporation suspended all coke production at its Sparrows Point facility for a period of 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 interest is for long-term coke independence at this 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.

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 ft^3/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 Thyssen Still/Otto to the existing 30 coke oven plants in the United States which emit about 300,000 tons/yr of SO_2. This COG-cleaning process could be applicable to 24 plants with corresponding SO_2 emission levels of 200,000 tons/yr. If the technology were installed in all 24 plants, the SO_2 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®)

Participant:
Centerior Energy Corporation

Additional Team Members:
Geneva 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

Location:
Vineyard, Utah County, UT (Geneva Steel Company's mill)

Technology:
Integration of Deutsche Voest-Alpine Industrieanlagenbau's COREX® iron-making process with a combined-cycle power generation system (industrial applications)

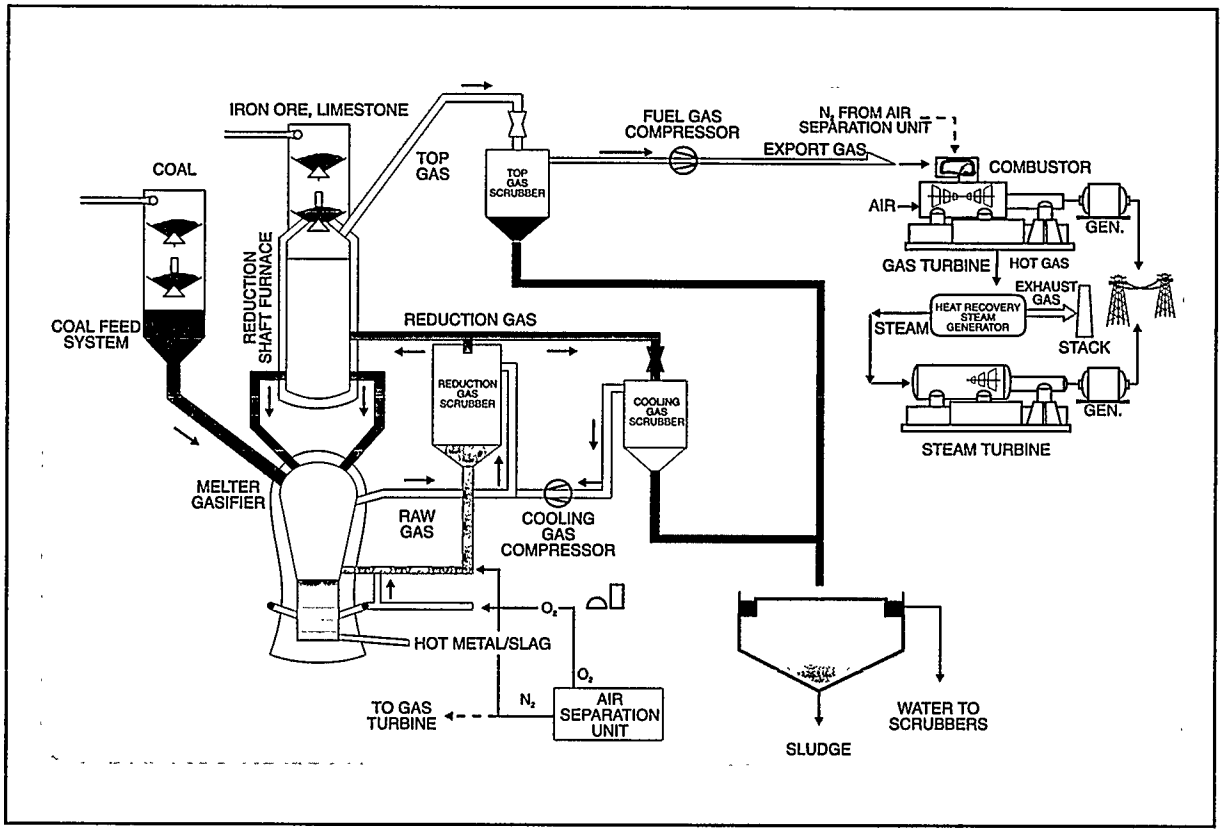
Plant Capacity/Production:
195 MWe (net) and 3,300 tons/day of hot metal (liquid iron)

Project Funding:

Total project cost	$825,092,000	100%
DOE	150,002,000	18
Participants	675,090,000	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.

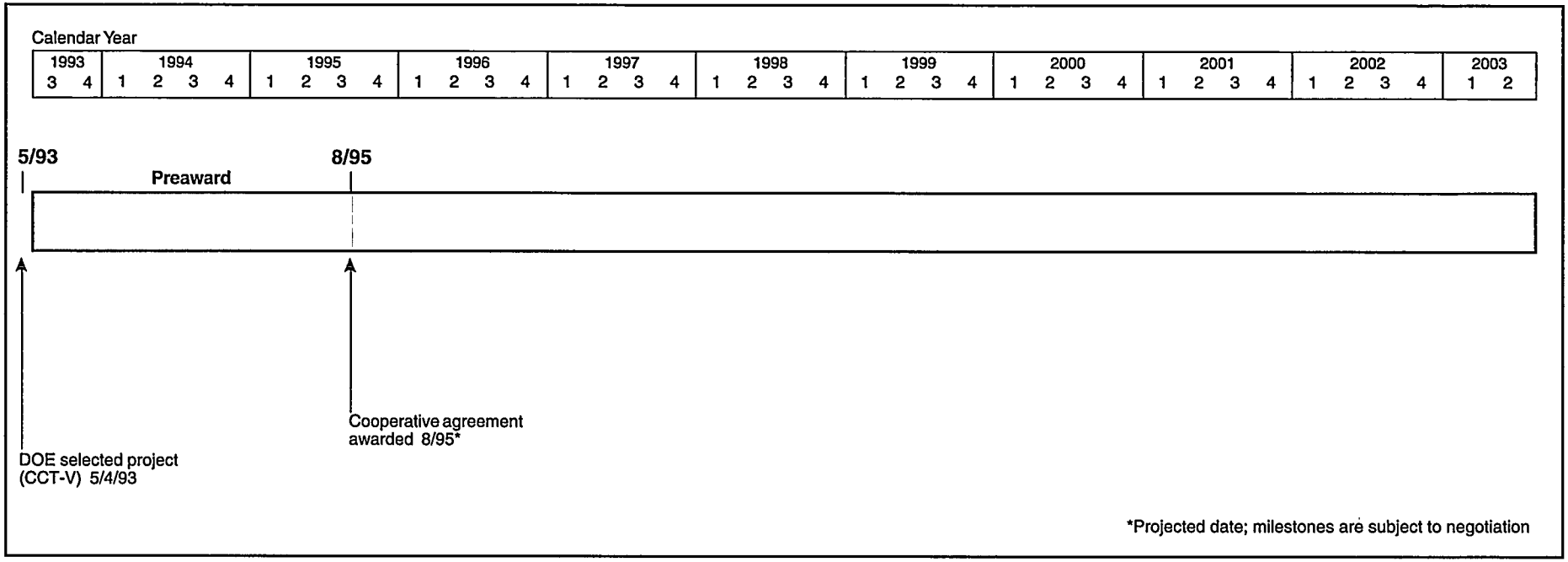


Project Objective:
To demonstrate the integration of a direct iron-making process (COREX®) with the production of electricity using various U.S. coals in an efficient and environmentally responsible manner.

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 burned in a gas turbine generator system capable of combusting low-Btu gas to make electric power. 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 3,400 tons/day of a bituminous coal blend containing about 0.5% sulfur will be utilized. The project will produce 3,300 tons/day of hot metal and 195 MWe for sale.



CPICOR™ technology is less complex and environmentally superior than competing iron-making and power-generating technologies. Criteria air pollutants are reduced substantially largely due 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™ technology is much 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.

Project Status/Accomplishments:

The project is in negotiation. In April 1994, LTV Steel elected to withdraw from the proposed project. In July 1994, Air Products and Chemicals, Centerior Energy, and Geneva Steel Company signed an agreement to develop and site the project at Geneva Steel's mill in Vineyard, UT (near Orem).

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 noncoking range.

The total emissions of NO_x from a future commercial plant are expected to be 0.012 lb/million Btu of coal, 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 SO_2 from the commercial facility are expected to be 0.024 lb/million Btu, a reduction of more than 90%. The net electrical generating efficiency of the commercial facility is estimated to be 47% (a net effective heat rate of 7,262 Btu/kWh on an LHV basis). This compares to a net efficiency of 32% 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 usable in applications such as ballast for road construction and foundations.

Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control

Project completed.

Participant:
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)

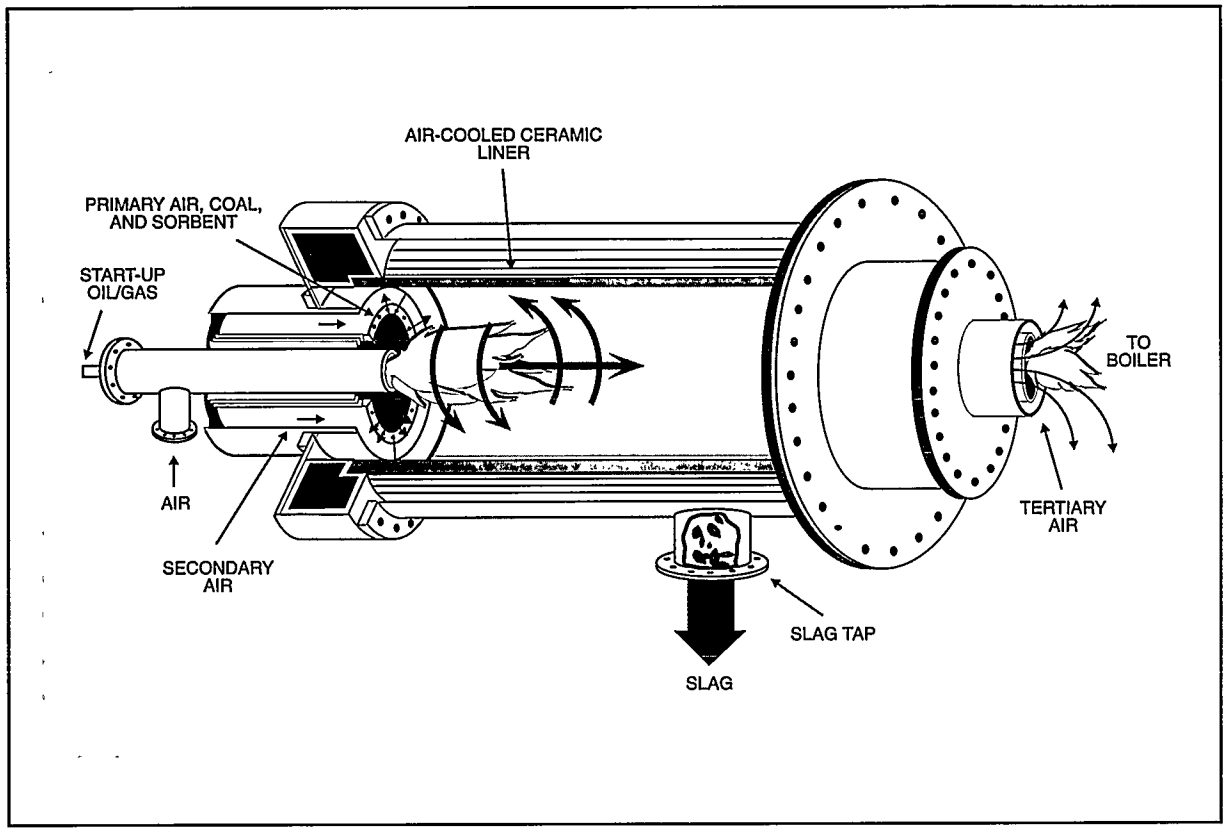
Technology:
Coal Tech's advanced, air-cooled, slagging combustor (industrial applications)

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 cumbustor. 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 utlity 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.

Participant:
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)

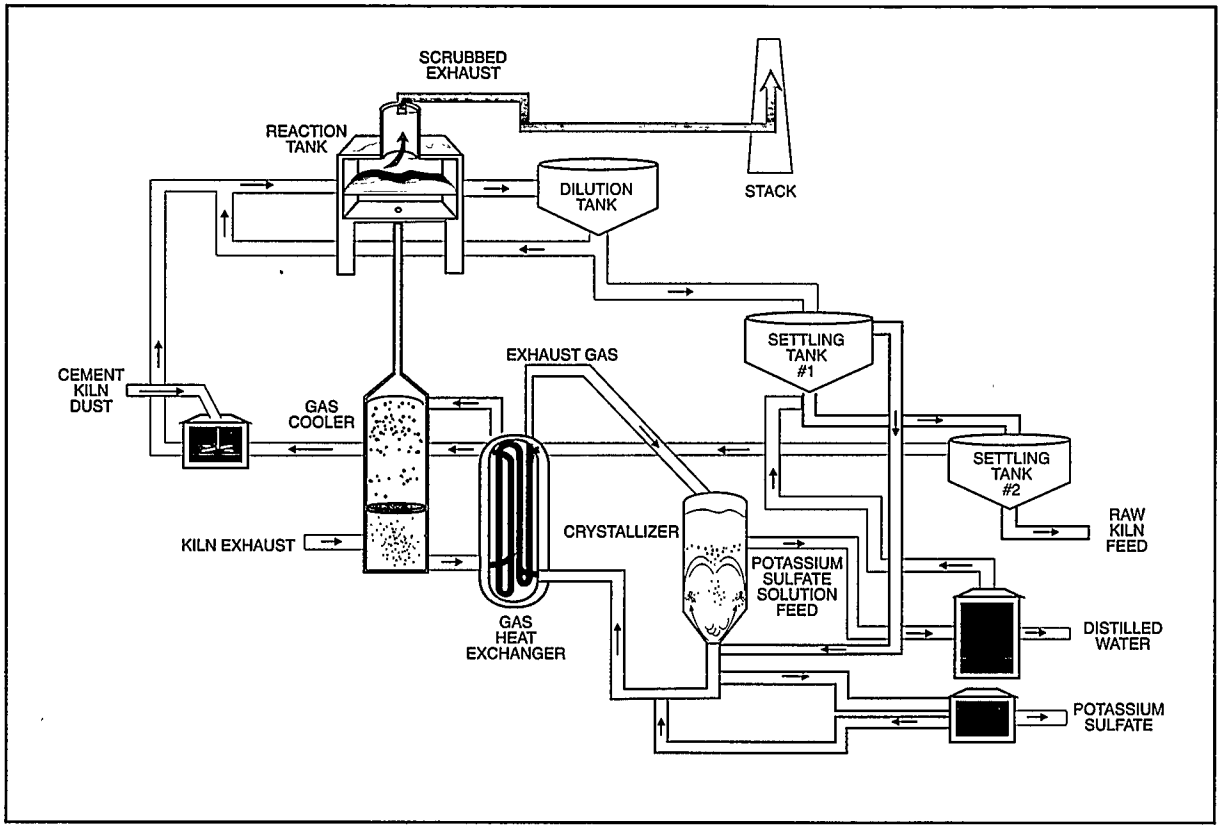
Technology:
Passamaquoddy Technology Recovery Scrubber™ (industrial applications)

Plant Capacity/Production:
1,450 tons/day of cement; 250,000 std ft^3/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
Participant	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% SO_2 reduction using high-sulfur 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.

Passamaquoddy Technology Recovery Scrubber is a trademark of the Passamaquoddy Tribe.

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 SO_2 and treated 6,000tons of kiln dust for return to the kiln as raw feed. Initial testing of the scrubbing system achieved the project objective of 90–95% SO_2 emission reduction, with a maximum reduction of 98%. The effect on NO_x emissions also was determined during the demonstration. NO_x emissions were reduced 5–15%. Operations have totaled 5,316 hours. Capital costs are approximately $10 million for a 450,000-ton/yr plant, with a simple payback in about 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 SO_2. 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, SO_2 emissions could be reduced by approximately 150,000 tons/yr. Commercialization of the technology may be spurred on when EPA issues emissions limits on cement kilns under the CAAA of 1990. The technology may also have broader applications in paper production and municipal waste incineration in the United States and abroad.

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.

In 1994 a Taiwanese cement company engaged Passamaquoddy Technologies, L.P., to do a preliminary study for the installation of the Passamaquoddy Technology Recovery Scrubber™ on a new cement plant in Taiwan.

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 (including economic assessment)	2/94
Topical Report	3/92
Public Design Report	10/93

Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal

Participant:
ThermoChem, Inc.

Additional Team Member:
Manufacturing and Technology Conversion International, Inc.—technology supplier

Location:
Near Gillette, Campbell County, WY (Caballo Rojo Mine)

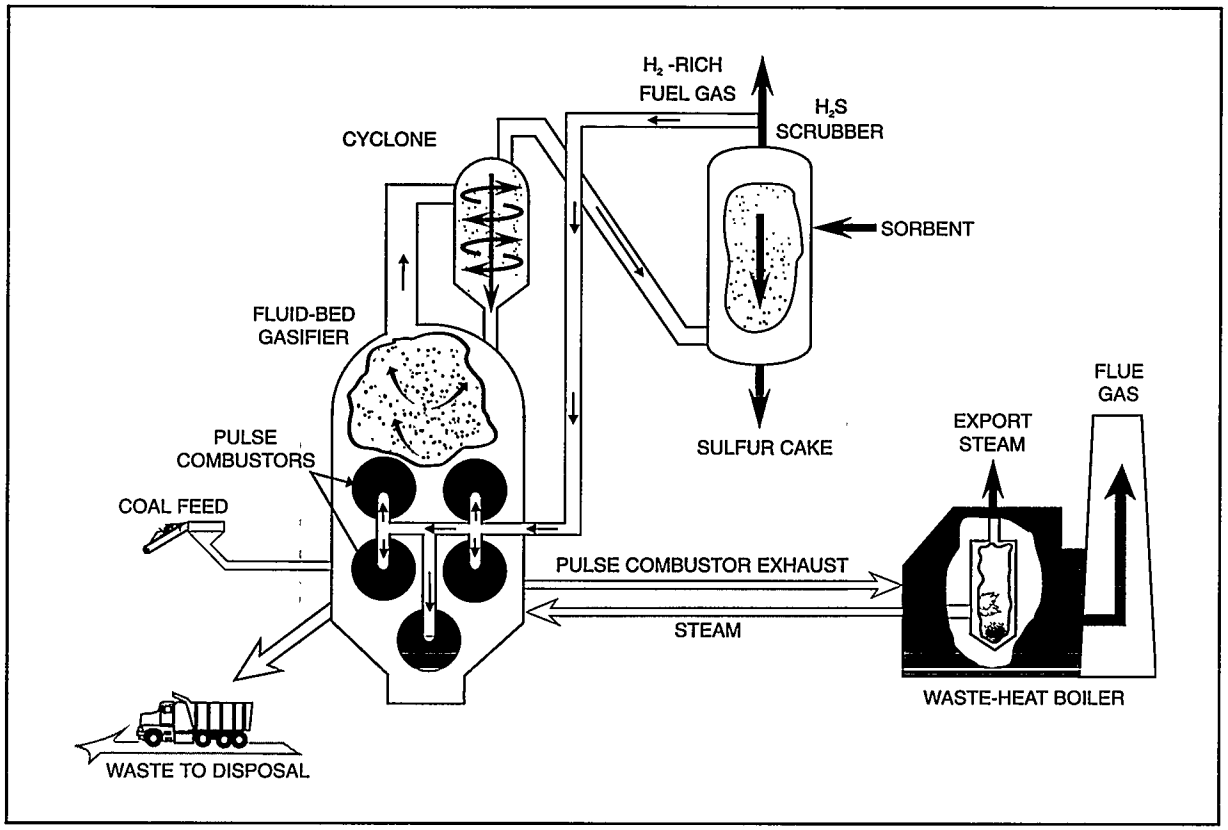
Technology:
Advanced combustion using Manufacturing and Technology Conversion International's (MTCI) pulse combustor/gasifier (industrial applications)

Plant Capacity/Production:
161 million Btu/hr of 325 Btu/std ft^3 medium-Btu fuel gas plus 40,0001b/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.

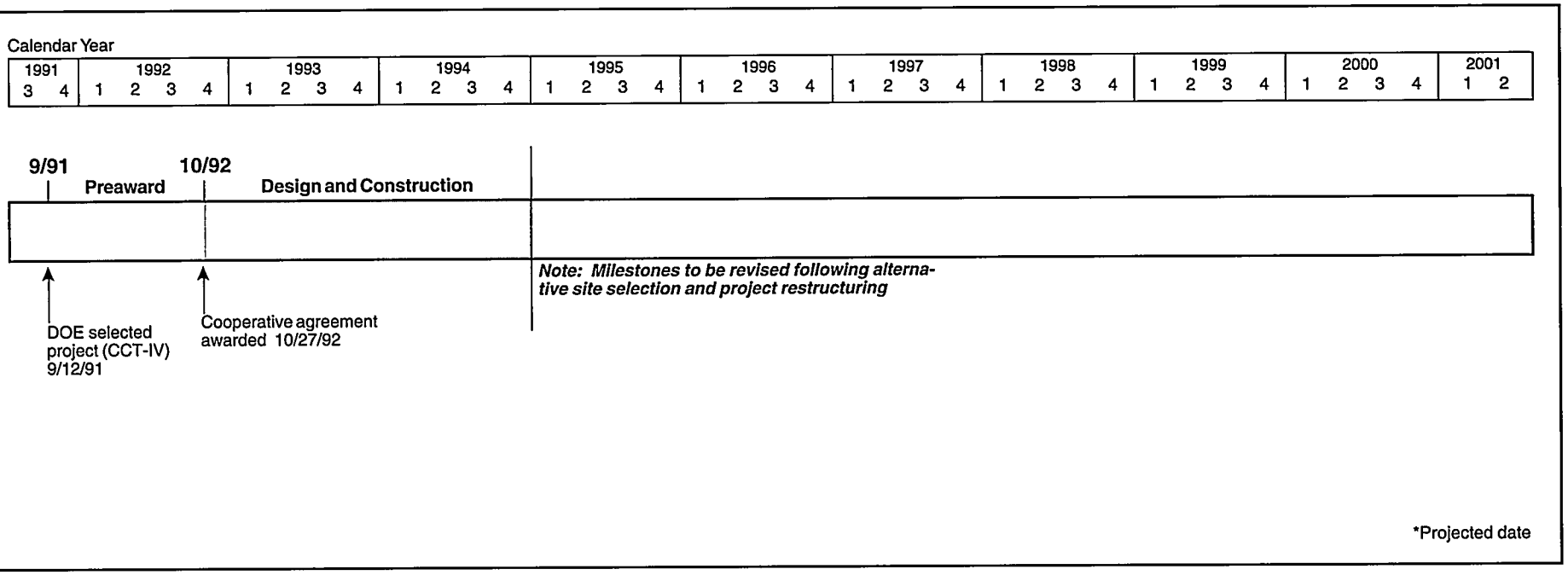


Technology/Project Description:
The MTCI fluidized-bed gasifier incorporates an innovative indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean, medium-Btu fuel gas without the need for an oxygen plant. The indirect heat transfer is provided by MTCI's 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.

SO_2 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. Subbituminous coal (0.3% sulfur) will be used.



Project Status/Accomplishments:

The cooperative agreement was awarded on October 27, 1992. Design verification tests at MTCI's Baltimore facility are continuing. The design tests include the construction and test firing of one full-size pulse combustor tube bundle. Fabrication of the design-verification–scale 252-tube pulse combustor has been completed. On October 26, 1994, ThermoChem, Inc., requested that DOE consider relocating the project to an alternative host site. A detailed planning conference on changing sites was held in December 1994.

Commercial Applications:

The MTCI fluidized-bed gasifier is expected to provide the exceptional environmental performance exhibited by coal gasification in general. SO_2 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 28units 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 porposals 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 Lau 100-202 ius 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 thrid 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-PSO1-89 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".

Public Law 103-332

CLEAN COAL TECHNOLOGY

The first paragraph under this head in Public Law 101–512, as amended, is further amended by striking the phrase "$100,000,000 on October 1, 1994, and $50,000,000 on October 1, 1995" and inserting "$18,000,000 on October 1, 1994, $100,000,000 on October 1, 1995, and $32,000,000 on October 1, 1996"; and by striking the phrase "$275,000,000 on October 1, 1994, and $100,000,000 on October 1, 1995" and inserting "$19,121,000 on October 1, 1994, $100,000,000 on October 1, 1995, and $255,879,000 on October 1, 1996": *Provided,* That not to exceed $18,000,000 available in fiscal year 1995 may be used for administrative oversight of the Clean Coal Technology program.

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 participants, 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 participant, The Babcock & Wilcox Company (LIMB Demonstration Project Extension and Coolside Demonstration).

July 1987
DOE signed a cooperative agreement with CCT-I participant, 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 participants, 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 participant, Colorado-Ute Electric Association, Inc. (Nucla CFB Demonstration Project).

November 1988
DOE signed a cooperative agreement with CCT-I participant, TRW, Inc. (Direct Iron Ore Reduction to Replace Coke Oven/Blast Furnace for Steelmaking).

December 1988
Negotiations were 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 participant, 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 participants: 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 participants: 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-participants of one CCT-I project, ABB Combustion Engineering, Inc., and CQ, Inc., (Development of the Coal Quality Expert) and with two CCT-II participants: 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 participant, Rosebud SynCoal Partnership (formerly Western Energy Company; Advanced Coal Conversion Process Demonstration); one CCT-II participant, 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 participant, ENCOAL Corporation (ENCOAL Mild Coal Gasification Project).

Negotiations terminated with CCT-II participant, Southwestern Public Service Company (Nichols CFB Repowering Project).

October 1990

DOE signed cooperative agreements with four CCT-III participants: AirPol, Inc. (10-MWe 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 Environmental 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 participant, The City of Tallahassee (Arvah B. Hopkins Circulating Fluidized-Bed Repowering Project); one CCT-II participant, ABB Combustion Engineering, Inc. (Combustion Engineering IGCC Repowering Project); and two CCT-III participants, 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 participant, Otisca Industries, Ltd. (Otisca Fuel Demonstration Project).

March 1991
DOE signed cooperative agreements with three CCT-III participants: MK-Ferguson Company (Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System); Public Service Company of Colorado (Integrated Dry NO_x/SO_2 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 participant, 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 participant, DMEC-1 Limited Partnership (formerly Dairyland Power Cooperative; PCFB Demonstration 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; final reports have been issued.

April 1992
Tri-State Generation and Transmission Association, Inc., (formerly Colorado-Ute Electric Association, Inc.) completed its CCT-I project, Nucla CFB Demonstration Project; final reports have been issued.

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 participants: 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 participant, 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 participant'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 participant, Air Products and Chemicals, Inc. (Commercial-Scale Demonstration of the Liquid-Phase Methanol [LPMEOH™] Process) and with four CCT-IV participants: 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; final reports have been issued.

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, SOx-NOx-Rox-Box™ Flue Gas Cleanup Demonstration Project, was completed; final reports are in preparation.

The Babcock & Wilcox Company's CCT-II project, Demonstration of Coal Reburning for Cyclone Boiler NO_x Control, was completed; the final technical report has been issued.

Bechtel Corporation's CCT-III project, Confined Zone Dispersion Flue Gas Desulfurization Demonstration, was completed; final reports are in preparation.

February 1994
The Passamaquoddy Tribe's CCT-III project, Cement Kiln Flue Gas Recovery Scrubber, was completed; final reports have been issued.

June 1994
DOE signed a cooperative agreement with CCT-V participant, Arthur D. Little, Inc. (Coal Diesel Combined-Cycle Project).

Southern Company Services' CCT-III project, 180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers, was completed; final reports have been issued.

August 1994
DOE signed cooperative agreements with two CCT-V participants, Four Rivers Energy Partners, L.P. (Four Rivers Energy Modernization Project); and Pennsylvania Electric Company (Warren Station Externally Fired Combined-Cycle Demonstration Project).

The CCT-III project, Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System, was relocated and transferred to NOXSO Corporation.

September 1994
The Air Products and Chemicals CCT-III project, Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process, was transferred to Air Products Liquid Phase Conversion Company, L.P.

December 1994
DOE signed a cooperative agreement with CCT-V participant, Clean Energy Partners Limited Partnership (formerly Duke Energy Corp.; Clean Energy Demonstration Project).

The Babcock & Wilcox Company's CCT-II project, Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit, was completed (operational testing was completed April 1993; project was extended to complete the boiler water-wall corrosion examination during the fall 1994 boiler outage); final reports are in preparation.

AirPol's CCT-III project, 10-MWe Demonstration of Gas Suspension Absorption, was completed; final reports are in preparation.

LIFAC–North America's CCT-III project, LIFAC Sorbent Injection Desulfurization Project, was completed; final reports are in preparation.

ABB Environmental Systems' CCT-II project, SNOX™ Flue Gas Cleaning Demonstration Project, was completed; final reports are in preparation.

Energy and Environmental Research Corporation's CCT-I project, Enhancing the Use of Coal by Gas Reburning and Sorbent Injection, was completed; final reports for Hennepin and Edwards have been issued and the final report for Lakeside is in preparation.

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 participant and the CCT Program. Key CCT Program publications available at year-end 1994 are listed in this appendix. Project-specific reports and newsletter articles are listed by application category and, within each category, by project.

The CCT Program reports are available through the National Technical Information Service (NTIS), U.S. Department of Commerce, 5285 Port Royal Road, Springfield, VA 22161.

To receive issues of the newsletter, *Clean Coal Today,* send name and address to U.S. Department of Energy, FE-22, Washington, DC 20858.

To receive program-related information via the Fossil Energy TechLine, a fax-on-demand system, call (202) 586-4300 from a tone phone and follow the voice instructions. For additional TechLine information, call (202) 586-6503.

A computer bulletin board also provides updates; call (202) 586-6495 via modem (300, 1200, or 2400 bps).

Program Updates

Clean Coal Technology Demonstration Program: Program Update 1993 (As of December 31, 1993). Report No. DOE/FE-0299P. U.S. Department of Energy. March 1994.

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.

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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.)

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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

Comprehensive Report to Congress on the Clean Coal Technology Program: Four Rivers Energy Modernization Project. (Air Products and Chemicals, Inc.) Report No. DOE/FE-0295P. U.S. Department of Energy. June 1994.

The Ohio Power Company—Tidd PFBC Demonstration Project

Tidd PFBC Demonstration Project Topical Report—First Eighteen Months of Operation. Report No. DOE/MC/24132-3746. The Ohio Power Company. March 1994. (Available from NTIS as DE 9400-4120.)

"Tidd Sets Mark, with Continuous 45-Day Run." *Clean Coal Today.* Report No. DOE/FE-0215P-14. Summer 1994.

"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. (Available from NTIS as 9300-0233.)

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"Tidd Plant Resumes Operation." *Clean Coal Today.* Report No. DOE/FE-0215P-4. Winter 1991.

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"TIDD Plant Produces Power: Operations Planned Early 1991." *Clean Coal Today.* Report No. DOE/FE-0215P. Winter 1990.

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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: Topical Report. Report No. DOE/MC/25137-3127. Colorado-Ute Electric Association, Inc. March 1992. (Available from NTIS as DE 9300-0212.)

Nucla Circulating Atmospheric Fluidized Bed Demonstration Project: 1990 Annual Report. Report No. DOE/MC/25137-3089. Colorado-Ute Electric Association, Inc. February 1992. (Available from NTIS as DE 9200-1275.)

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York County Energy Partners, L.P.—York County Energy Partners Cogeneration Project

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CE IGCC Repowering Project; Topical Report: Preliminary Hazard Analysis. Report No. DOE/MC/ 26308-3637. ABB Combustion Engineering, Inc. June 1993. (Available from NTIS as DE 9400-4056.)

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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.

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Wabash River Coal Gasification Repowering Project Joint Venture—Wabash River Coal Gasification Repowering Project

"Largest U.S. Single Train IGCC Facility." *Clean Coal Today.* Report No. DOE/FE-0215P-12. Winter 1993/1994.

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

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Comprehensive Report to Congress on the Clean Coal Technology Program: ENCOAL Mild Coal Gasification Project. (ENCOAL Corporation). Report No. DOE/FE-0194P. U.S. Department of Energy. June 1990.

Coal Processing for Clean Fuels/Indirect Liquefaction

Air Products Liquid Phase Conversion Company, L.P.—Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process

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Comprehensive Report to Congress: The Appalachian Project. (M.W. Kellogg Company). Report No. DOE/FE-0095. U.S. Department of Energy. December 1987.

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CCT-III Solicitation

Comprehensive Report to Congress: Proposals Received in Response to the Clean Coal Technology III Program Opportunity Notice. Report No. DOE/FE-0163. U.S. Department of Energy. February 1990.

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Summary Proceedings: Public Meetings on Increasing Western Participation in the 1989 Clean Coal Technology Solicitation. Report No. DOE/FE-0113. U.S. Department of Energy. December 1988.

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

Comprehensive Report to Congress: Proposals Received in Response to the Clean Coal Technology V Program Opportunity Notice. Report No. DOE/FE-0277. U.S. Department of Energy. June 1993.

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"Update—Clean Coal Air Toxics Testing Programs." *Clean Coal Today.* Report No. DOE/FE-0215P-12. Winter 1993/1994.

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Region 4 Market Description Summary—South Atlantic. Report No. DOE/FE-62046 H-2. U.S. Department of Energy. September 1993.

Export of Coal and Coal Technology. The National Coal Council. 1993.

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"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.

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Clean Coal Technology. The National Coal Council. 1986.

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 ways 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 Review Meeting (Morgantown Energy Technology Center)
- International Conference on Fluidized-Bed Combustion
- International Joint Power Generation Conference
- Power-Gen: International Conference and Exhibition for the Power Generating Industries

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

L.K. Carpenter and R.J. Dellefield (DOE/METC). "The U.S. Department of Energy PFBC Perspective—1994 Update." Presented at the Electric Power Research Institute Conference: Fluidized Bed Combustion for Power Generation (Atlanta, GA). May 1994.

The Appalachian Power Company—PFBC Demonstration Utility Demonstration Project

DMEC-1 Limited Partnership—PCFB Project

G.E. Kruempel (Midwest Power) and R. Dryden (Pyropower Corporation). "DMEC-1 Pressurized Circulating Fluidized Bed Demonstration Project." *Third Annual Clean Coal Technology Conference: Technical Papers.* U.S. Department of Energy and The Center for Energy and Economic Development. September 1994.

J. Isakson (Ahlstrom) et al. "Efficiency and Emission Improvement through Ahlstrom PCFB Technology." *Proceedings of Power-Gen Europe: Where the Industry Connects (Cologne, Germany).* Book III, Volume 7. May 1994.

P. Licht (Midwest Power Company). "Midwest Power's Perspective of Circulating PFBC." Presented at the Electric Power Research Institute Conference: Fluidized Bed Combustion for Power Generation (Atlanta, GA). May 1994.

S.J. Provol (PyroPower Corporation) et al. "The Midwest Power PCFB Demonstration Project Ahlstrom PYROFLOW Pressurized Circulating Fluidized Bed Technology." *Proceedings of the America Power Conference, 56th Annual Meeting (Chicago, IL).* Volume 56-II. April 1994.

R. Dryden (Pyropower Corporation) and S.J. Ambrose (Midwest Power). "PCFB Repowering Options for Utilities." *Proceedings of the 6th International Conference and Exhibition for the Power Generating Industries (Dallas, TX).* Book IV, Volume X. November 1993.

Four Rivers Energy Partners, L.P.—Energy Modernization Project

E.P. Holley (Air Products and Chemicals, Inc.) et al. "Four Rivers Energy Modernization Project; Advanced Pressurized Circulating Fluidized Bed Combustion Process: Project Overview and Status." *Third Annual Clean Coal Technology Conference: Technical Papers.* U.S. Department of Energy and The Center for Energy and Economic Development. September 1994.

The Ohio Power Company—Tidd PFBC Demonstration Project

M. Marrocco and D.A. Bauer (American Electric Power Service Corporation). "American Electric Power Pressurized Fluidized Bed Combined Cycle Technology Status." *Third Annual Clean Coal Technology Conference: Technical Papers.* U.S. Department of Energy and The Center for Energy and Economic Development. September 1994.

D.A. Bauer (American Electric Power Service Corporation) et al. "Update on the Operation and Performance Testing of the Tidd PFBC Demonstration Plant." Presented at the Electric Power Research Institute Conference: Fluidized Bed Combustion for Power Generation (Atlanta, GA). May 1994.

M.E. Zando and D.A. Bauer (American Electric Power Service Corporation). "Baseline Performance of a 200 MWt Pressurized Fluidized Bed Combustor." *Proceedings of the American Power Conference, 56th Annual Meeting (Chicago, IL).* Volume 56-II. April 1994.

M.I. Mudd (American Electric Power Service Corporation). "The Economics of Pressurized Fluidized Bed Combustion Technology." Presented at the Conference on Comparative Economics of Emerging Clean Coal Technologies III (Washington, DC). February 1994.

S. Whitney and P. Wertzel (The Babcock & Wilcox Company). "Design Characteristics of Coal Plants for PFBC Repowering." *Proceedings of the 6th International Conference and Exhibition for the Power Generating Industries (Dallas, TX).* Book IV, Volume X. November 1993.

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

S.A. Bush (Tri-State Generation and Transmission Association, Inc.) et al. "Tri-State's Nucla Station: Demonstration to Commercialization." *Proceedings of the American Power Conference, 56th Annual Meeting (Chicago, IL).* Volume 56-II. April 1994.

York County Energy Partners, L.P.—York County Energy Partners Cogeneration Project

D.C. Wolfson and B.F. Hahn (Air Products and Chemicals, Inc.), "The Future of Atmospheric Circulating Fluidized Bed Combustion: York County Energy Partners, L.P., 250 MW Single Train CFB Cogeneration Facility." *Third Annual Clean Coal Technology Conference: Technical Papers.* U.S. Department of Energy and The Center for Energy and Economic Development. September 1994.

B.F. Hahn (York County Energy Partners). "CFB Cogeneration Project: An Economic Discussion." Presented at the Conference on Comparative Economics of Emerging Clean Coal Technologies III (Washington, DC). February 1994.

Advanced Electric Power Generation/ Integrated Gasification Combined Cycle

R.D. Brdar and G.R. Friggens (DOE/METC). "Taking Steps Forward—The IGCC Demos." Presented at the Eleventh Annual International Pittsburgh Coal Conference (Pittsburgh, PA). September 1994.

ABB Combustion Engineering, Inc.—Combustion Engineering IGCC Repowering Project

L.J. Peletz (ABB Combustion Engineering Systems). "Combustion Engineering IGCC Repowering Project." *Third Annual Clean Coal Technology Conference: Technical Papers.* U.S. Department of Energy and The Center for Energy and Economic Development. September 1994.

Clean Energy Partners Limited Partnership—Clean Energy Demonstration Project

K.S. Johnson (Duke Energy). "Application of British Gas/Lurgi Gasification Process in the U.S. DOE Clean Coal Technology Program—Round Five." *Third Annual Clean Coal Technology Conference: Technical Papers.* U.S. Department of Energy and The Center for Energy and Economic Development. September 1994.

Sierra Pacific Power Company—Piñon Pine IGCC Power Project

J.W. Motter (Sierra Pacific Power Company) et al. "Piñon Pine Power Project—An Update." *Third Annual Clean Coal Technology Conference: Technical Papers.* U.S. Department of Energy and The Center for Energy and Economic Development. September 1994.

J.W. Motter (Sierra Pacific Power Company). "The Piñon Pine IGCC Project Economic Issues." Presented at the Conference on Comparative Economies of Emerging Clean Coal Technologies III (Washington, DC). February 1994.

TAMCO Power Partners—Toms Creek IGCC Demonstration Project

M.R. Schmid (Tampella Power Corporation). "The Toms Creek Clean Coal IGCC Demonstration Project." *Third Annual Clean Coal Technology Conference: Technical Papers.* U.S. Department of Energy and The Center for Energy and Economic Development. September 1994.

M. Schmid (Tampella Power Inc.) "The Simplified IGCC Process—Clean Coal Technology for Power Generation." Presented at the Conference on Comparative Economies of Emerging Clean Coal Technologies III (Washington, DC). February 1994.

Tampa Electric Company—Tampa Electric Integrated Gasification Combined-Cycle Project

D.E. Pless (TECO Power Services). "Tampa Electric Company Integrated Gasification Combined Cycle Project: Current Status." *Third Annual Clean Coal Technology Conference: Technical Papers.* U.S. Department of Energy and The Center for Energy and Economic Development. September 1994.

S.D. Jenkins (TECO Power Services Corporation). "Tampa Electric Company, Polk Power Station IGCC Project." Presented at the Conference on Comparative Economies of Emerging Clean Coal Technologies III (Washington, DC). February 1994.

Wabash River Coal Gasification Repowering Project Joint Venture—Wabash River Coal Gasification Repowering Project

J.J. Cook (PSI Energy, Inc.) and L.A. Lednicky (Destec Energy, Inc.). "The Wabash River Coal Gasification Repowering Project; An Investment in the Future." *Third Annual Clean Coal Technology Conference: Technical Papers.* U.S. Department of Energy and The Center for Energy and Economic Development. September 1994.

M.D. Foster (PSI Energy, Inc.). "Wabash River Coal Gasification Repowering Project." *Proceedings of the American Power Conference, 56th Annual Meeting (Chicago, IL).* Volume 56-II. April 1994.

M.W. Roll (Destec Energy, Inc.). "Repowering with Coal Gasification Technology." *Proceedings of the American Power Conference, 56th Annual Meeting (Chicago, IL).* Volume 56-II. April 1994.

D.G. Sundstrom (Destec Energy, Inc.). "The Wabash River Coal Gasification Repowering Project Challenges." Presented at Alternate Energy '94 (La Quinta, CA). April 1994.

W. Lessig and J. Frederick (Destec Energy, Inc.). "Environmental Considerations of Coal Gasification Technology and the Wabash River Repowering Project." *Proceedings of the 6th International Conference and Exhibition for the Power Generating Industries (Dallas, TX).* Book IV, Volume X. November 1993.

Advanced Electric Power Generation/ Advanced Combustion/Heat Engines

Alaska Industrial Development and Export Authority—Healy Clean Coal Project

R. Gleiser (Joy Technologies). "The Healy Clean Coal Project." *Third Annual Clean Coal Technology Conference: Technical Papers.* U.S. Department of Energy and The Center for Energy and Economic Development. September 1994.

Arthur D. Little, Inc.—Coal Diesel Combined-Cycle Demonstration Project

R.P. Wilson, Jr. (Arthur D. Little, Inc.). "Coal-Fueled Diesels for Modular Power Generation." *Third Annual Clean Coal Technology Conference: Technical Papers.* U.S. Department of Energy and The Center for Energy and Economic Development. September 1994.

R.P. Wilson et al. (Arthur D. Little, Inc.). "Coal-Fueled Diesels for Modular Power Generation Performance and Emissions Characteristics Based on 1.8 MW System Test." *Proceedings of the American Power Conference, 56th Annual Meeting (Chicago, IL).* Volume 56-I. April 1994.

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Environmental Control Devices/NO_x Control Technologies

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

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The Babcock & Wilcox Company—Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit

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

D.A. Engelhardt (Energy and Environmental Research Corporation) et al. "Gas Reburning in Tangentially-, Wall-, and Cyclone-Fired Boilers—An Introduction to Second Generation Gas Reburning." *Third Annual Clean Coal Technology Conference: Technical Papers.* U.S. Department of Energy and The Center for Energy and Economic Development. September 1994.

A. Sanyal (Energy and Environmental Research Corporation). "Advanced NO_x Control Technologies." *Proceedings of the 6th International Conference and Exhibition for the Power Generating Industries (Dallas, TX).* Book II, Volume IV. November 1993.

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

J.N. Sorge and S.M. Wilson (Southern Company Services, Inc.). "500 MW Demonstration of Advanced Wall-Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers." *Third Annual Clean Coal Technology Conference: Technical Papers.* U.S. Department of Energy and The Center for Energy and Economic Development. September 1994.

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

J. Grusha (ABB C-E Services, Inc.). "Operating Results from ABB C-E Services' LNCFS Low NO_x Concentric Firing System Retrofit Installations—1993 Update." *Proceedings of the 6th International Conference and Exhibition for the Power Generating Industries (Dallas, TX).* Book V, Volume XIII. November 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 (Southern Company Services, Inc.) et al. "Demonstration of Selective Catalytic Reduction (SCR) Technology for the Control of Nitrogen Oxides (NO_x) Emissions from High Sulfur, Coal-Fired Boilers at Plant Crist SCR Test Facility." *Third Annual Clean Coal Technology Conference: Technical Papers.* U.S. Department of Energy and The Center for Energy and Economic Development. September 1994.

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Environmental Control Devices/SO_2 Control Technologies

AirPol, Inc.—10-MWe Demonstration of Gas Suspension Absorption

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J. Patel. "LIFAC Fluegas Desulfurization Process; An Alternate SO_2 Control Strategy." Presented at the Second International Conference on Energy and Environment: Transitions in East Central Europe (Prague, Czech Republic). November 1994.

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Environmental Control Devices/Combined SO_2/NO_x Control Technologies

ABB Environmental Systems—SNOX™ Flue Gas Cleaning Demonstration Project

D.C. Borio (ABB Environmental Systems) et al. "Commercialization of the SNOX Process through the Clean Coal Technology Program." *Third Annual Clean Coal Technology Conference: Technical Papers.* U.S. Department of Energy and The Center for Energy and Economic Development. September 1994.

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The Babcock & Wilcox Company—LIMB Demonstration Project Extension and Coolside Demonstration

The Babcock & Wilcox Company—SOx-NOx-Rox-Box™ Flue Gas Cleanup Demonstration Project

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T. Niquette. "SynCoal Advanced Coal Conversion Process." Presented at the Second International Conference on Energy and Environment: Transitions in East Central Europe (Prague, Czech Republic). November 1994.

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ENCOAL Corporation—ENCOAL Mild Coal Gasification Project

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C.L. Miller (DOE). "The Technology of Clean Coal." *Proceedings of the 6th International Conference and Exhibition for the Power Generating Industries (Dallas, TX)*. Book VI, Volume XVI. November 1993.

Appendix E: CCT Project Contacts

Listed in this section are 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 participant 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

Participant:
The Appalachian Power Company

Contacts:
Mario Marrocco, Manager, PFBC Programs
(614) 223-1740
(614) 223-2466 (fax)

American Electric Power Service Corporation
1 Riverside Plaza
Columbus, OH 43215

Jeffrey Summers, DOE/HQ, (301) 903-4412
Larry K. Carpenter, METC, (304) 285-4161

PCFB Demonstration Project

Participant:
DMEC-1 Limited Partnership

Contacts:
Gary E. Kruempel, Project Manager
(515) 281-2459
(515) 281-2355 (fax)

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) 285-4161

Four Rivers Energy Modernization Project

Participant:
Four Rivers Energy Partners, L.P.

Contacts:
Edward Holley, Senior Project Manager
(610) 481-8568
(610) 481-3228 (fax)

Air Products and Chemicals, Inc.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

William Fernald, DOE/HQ, (301) 903-9448
Larry K. Carpenter, METC, (304) 285-4161

Tidd PFBC Demonstration Project

Participant:
American Electric Power Service Corporation as agent for The Ohio Power Company

Contacts:
Mario Marrocco, Manager, PFBC Programs
(614) 223-1740
(614) 223-2466 (fax)

American Electric Power Service Corporation
1 Riverside Plaza
Columbus, OH 43215

Jeffrey Summers, DOE/HQ, (301) 903-4412
Larry K. Carpenter, METC, (304) 285-4161

Nucla CFB Demonstration Project

Participant:
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) 285-4066

York County Energy Partners Cogeneration Project

Participant:
York County Energy Partners, L.P.

Contacts:
Bradley F. Hahn, Project Manager
(610) 481-3955
(610) 481-2393 (fax)

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) 285-4066

Advanced Electric Power Generation/ Integrated Gasification Combined Cycle

Combustion Engineering IGCC Repowering Project

Participant:
ABB Combustion Engineering, Inc.

Contacts:
Henry H. Vroom, Project Director
(203) 285-9085
(203) 285-3861 (fax)

ABB Combustion Engineering, Inc.
P.O. Box 500
Windsor, CT 06095-0500

Lawrence Saroff, DOE/HQ, (301) 903-9483
Gary A. Nelkin, METC, (304) 285-4216

Clean Energy Demonstration Project

Participant:
Clean Energy Partners Limited Partnership

Contacts:
Victor Shellhorse, Vice President
(704) 373-2474
(704) 382-9325 (fax)

Duke Energy Corp.
400 S. Tryon Street
Charlotte, NC 28202

Stanley Roberts, DOE/HQ, (301) 903-9431
Donald W. Geiling, METC, (304) 285-4784

Piñon Pine IGCC Power Project

Participant:
Sierra Pacific Power Company

Contacts:
John W. (Jack) Motter, Project Manager
(702) 689-4013
(702) 689-3047 (fax)

Sierra Pacific Power Company
6100 Neil Road
P.O. Box 10100
Reno, NV 89520-0400

Lawrence Saroff, DOE/HQ, (301) 903-9483
Douglas M. Jewell, METC, (304) 285-4720

Toms Creek IGCC Demonstration Project

Participant:
TAMCO Power Partners

Contacts:
J.G. Patel, Project Director
(404) 859-2621
(404) 984-2441 (fax)

Tampella Power Corporation
2300 Windy Ridge Parkway
Suite 1125
Atlanta, GA 30339

John Geffken, DOE/HQ, (301) 903-9430
Gary A. Nelkin, METC, (304) 285-4216

Tampa Electric Integrated Gasification Combined-Cycle Project

Participant:
Tampa Electric Company

Contacts:
Donald E. Pless, Director, Advanced Technology
(813) 228-1332
(813) 228-1308 (fax)

TECO Power Services Corporation
P.O. Box 111
Tampa, FL 33601-0111

William Fernald, DOE/HQ, (301) 903-9448
Nelson F. Rekos, METC, (304) 285-4066

Wabash River Coal Gasification Repowering Project

Participant:
Wabash River Coal Gasification Repowering Project Joint Venture

Contacts:
Michel R. Woodruff
(713) 735-4131
(713) 735-4169 (fax)

Destec Energy, Inc.
2500 City West Boulevard, Suite 1500
Houston, TX 77042

Jeffrey Summers, DOE/HQ, (301) 903-4412
Gary A. Nelkin, METC, (304) 285-4216

Advanced Electric Power Generation/ Advanced Combustion/Heat Engines

Healy Clean Coal Project

Participant:
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

Stanley Roberts, DOE/HQ, (301) 903-9431
Robert M. Kornosky, PETC, (412) 892-4521

Coal Diesel Combined-Cycle Project

Participant:
Arthur D. Little, Inc.

Contacts:
Robert P. Wilson, Vice President
(617) 498-5806
(617) 498-7206 (fax)

Arthur D. Little, Inc.
200 Acorn Park
Cambridge, MA 02140

Jeffrey Summers, DOE/HQ, (301) 903-4412
Nelson F. Rekos, METC, (304) 285-4066

Warren Station Externally Fired Combined-Cycle Demonstration Project

Participant:
Pennsylvania Electric Company

Contacts:
Kenneth Gray, Project Manager
(814) 533-8593
(814) 533-8108 (fax)

Pennsylvania Electric Company
1001 Broad Street
Johnsontown, PA 15907

Douglas Archer, DOE/HQ, (301) 903-9443
Donald W. Geiling, METC, (304) 285-4784

Environmental Control Devices/NO_x Control Technologies

Demonstration of Coal Reburning for Cyclone Boiler NO_x Control

Participant:
The Babcock & Wilcox Company

Contacts:
Tony Yagiela
(216) 829-7403

The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601

Jeffrey Summers, DOE/HQ, (301) 903-4412
Ronald W. Corbett, PETC, (412) 892-6141

Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit

Participant:
The Babcock & Wilcox Company

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Tony Yagiela
(216) 829-7403

The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601

Jeffrey Summers, DOE/HQ, (301) 903-4412
Ronald W. Corbett, PETC, (412) 892-6141

Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler

Participant:
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

Participant:
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
Scott M. Smouse, PETC, (412) 892-5725

180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers

Participant:
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

Participant:
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

Participant:
Tennessee Valley Authority

Contacts:
Tom Butler, Mechanical Engineer
(615) 751-6120

Tennessee Valley Authority
1101 Market Street, ATTN: MR-3A
Chattanooga, TN 37402

Stanley Roberts, DOE/HQ, (301) 903-9431
James U. Watts, PETC, (412) 892-5991

Environmental Control Devices/SO_2 Control Technologies

10-MWe Demonstration of Gas Suspension Absorption

Participant:
AirPol, Inc.

Contacts:
Frank E. Hsu, Project Manager
(201) 288-7070

AirPol, Inc.
32 Henry Street
Teterboro, NJ 07608

Lawrence Saroff, DOE/HQ, (301) 903-9483
Sharon K. Marchant, PETC, (412) 892-6008

Confined Zone Dispersion Flue Gas Desulfurization Demonstration

Participant:
Bechtel Corporation

Contacts:
Joseph T. Newman, Project Manager
(415) 768-6514

Bechtel Corporation
P.O. Box 3965
San Francisco, CA 94119-3965

Stanley Roberts, DOE/HQ, (301) 903-9431
Arthur L. Baldwin, PETC, (412) 892-6011

LIFAC Sorbent Injection Desulfurization Demonstration Project

Participant:
LIFAC–North America

Contacts:
Jim Hervol, Project Manager
(412) 497-2735

ICF Kaiser Engineers, Inc.
4 Gateway Center
Pittsburgh, PA 15222-1207

John Geffken, DOE/HQ, (301) 903-9430
Joanna M. Markussen, PETC, (412) 892-5734

Advanced Flue Gas Desulfurization Demonstration Project

Participant:
Pure Air on the Lake, L.P.

Contacts:
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(215) 481-3687

Pure Air on the Lake, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

Lawrence Saroff, DOE/HQ, (301) 903-9483
Thomas A. Sarkus, PETC, (412) 892-5981

Demonstration of Innovative Applications of Technology for the CT-121 FGD Process

Participant:
Southern Company Services, Inc.

Contacts:
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(205) 870-6329

Southern Company Services, Inc.
P.O. Box 2625
Birmingham, AL 35202-2625

Lawrence Saroff, DOE/HQ, (301) 903-9483
Harry J. Ritz, PETC, (412) 892-6137

Environmental Control Devices/Combined SO_2/NO_x Control Technologies

SNOX™ Flue Gas Cleaning Demonstration Project

Participant:
ABB Environmental Systems

Contacts:
Bill Kingston, Project Manager
(205) 995-5368

ABB Environmental Systems
P.O. Box 43030
Birmingham, AL 35243

Stanley Roberts, DOE/HQ, (301) 903-9431
Gerard G. Elia, PETC, (412) 892-5862

LIMB Demonstration Project Extension and Coolside Demonstration

Participant:
The Babcock & Wilcox Company

Contacts:
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(216)860-1074
(216) 860-2045 (fax)

The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601

William Fernald, DOE/HQ, (301) 903-9448
Joanna M. Markussen, PETC, (412) 892-5734

SOx-NOx-Rox-Box™ Flue Gas Cleanup Demonstration Project

Participant:
The Babcock & Wilcox Company

Contacts:
Kevin Redinger
(216) 829-7719

The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601

John Geffken, DOE/HQ, (301) 903-9430
John C. McDowell, PETC, (412) 892-6237

Enhancing the Use of Coals by Gas Reburning and Sorbent Injection

Participant:
Energy and Environmental Research Corporation

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Milliken Clean Coal Technology Demonstration Project

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Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System

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Integrated Dry NO_x/SO_2 Emissions Control System

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Coal Processing for Clean Fuels/Coal Preparation Technologies

Development of the Coal Quality Expert

Participants:
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Self-Scrubbing Coal™: An Integrated Approach to Clean Air

Participant:
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Advanced Coal Conversion Process Demonstration

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Coal Processing for Clean Fuels/Mild Gasification

ENCOAL Mild Coal Gasification Project

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Coal Processing for Clean Fuels/Indirect Liquefaction

Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process

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Industrial Applications

Blast Furnace Granulated-Coal Injection System Demonstration Project

Participant:
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Innovative Coke Oven Gas Cleaning System for Retrofit Applications

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Clean Power from Integrated Coal/Ore Reduction (COREX®)

Participant:
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Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control

Participant:
Coal Tech Corporation

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Cement Kiln Flue Gas Recovery Scrubber

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Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal

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Appendix F: Acronyms and Abbreviations

Acronyms

ABB CE	ABB Combustion Engineering, Inc.
ABB ES	ABB Environmental Systems
ACFB	atmospheric circulating fluidized bed
AFBC	atmospheric fluidized-bed combustion
AFGD	advanced flue gas desulfurization
AIDEA	Alaska Industrial Development and Export Authority
AOFA	advanced over-fire air
BFGCI	blast furnace granulated-coal injection
BG	British Gas
BG/L	British Gas/Lurgi
B&W	The Babcock & Wilcox Company
CAAA	Clean Air Act Amendments of 1990
CCOFA	close-coupled over-fire air
CCT	clean coal technology
CCT Program	Clean Coal Technology Demonstration Program
CDCC	coal-fueled diesel engine combined cycle
CEQ	Council on Environmental Quality
CFB	circulating fluidized bed
COG	coke oven gas
CQE	Coal Quality Expert
CX	categorical exclusion
CZD	confined zone dispersion
DME	dimethyl ether
DOE	U.S. Department of Energy
DOE/HQ	U.S. Department of Energy Headquarters
EA	environmental assessment
EER	Energy and Environmental Research Corporation
EFCC	externally fired combined cycle
EIA	Energy Information Administration
EIS	environmental impact statement
EMP	environmental monitoring plan
EPA	U.S. Environmental Protection Agency
EPACT	Energy Policy Act of 1992
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
EWG	exempt wholesale generator
FBC	fluidized-bed combustion
FGD	flue gas desulfurization
FONSI	finding of no significant impact
FRP	fiberglass-reinforced plastic
FY	fiscal year
GE	General Electric
GR	gas reburning
GR–LNB	gas reburning and low-NO_x burner
GR–SI	gas reburning and sorbent injection
GSA	gas suspension absorption
HAP, HAPs	hazardous air pollutant(s)
HHV	higher heating value
HRSG	heat recovery steam generator
IGCC	integrated gasification combined cycle
JBR	jet-bubbling reactor
LHV	lower heating value
LIMB	limestone injection multistage burner
LNB	low-NO_x burner
LNCFS	low-NO_x concentric-firing system
LSFO	limestone forced oxidation
MCFC	molten carbonate fuel cell
METC	Morgantown Energy Technology Center
MTCI	Manufacturing and Technology Conversion International
MTF	memorandum(memoranda)-to-file
NEPA	National Environmental Policy Act
NSPS	New Source Performance Standards
NTIS	National Technical Information Service
NYSEG	New York State Electric & Gas Corporation
PCFB	pressurized circulating fluidized bed
PEIS	programmatic environmental impact statement
PETC	Pittsburgh Energy Technology Center
PFBC	pressurized fluidized-bed combustion
PJBH	pulse jet baghouse
PON	program opportunity notice
PSCC	Public Service Company of Colorado
PURPA	Public Utility Regulatory Policies Act of 1972

R&D	research and development
RD&D	research, development, and demonstration
SBIR	Small Business Innovative Research
SCR	selective catalytic reduction
SCS	Southern Company Services, Inc.
SI	sorbent injection
SNCR	selective noncatalytic reduction
SOFA	separated over-fire air
TVA	Tennessee Valley Authority
UBCL	unburned carbon boiler efficiency losses
WLFO	wet limestone, forced oxidation

Abbreviations

States are abbreviated using two-letter postal codes.

atm	atmosphere(s)
avg	average
Btu	British thermal unit
C/H	molar ratio of carbon to hydrogen
$CaCO_3$	calcium carbonate (calcitic limestone)
CaO	calcium oxide (lime)
$Ca(OH)_2$	calcium hydroxide (calcitic hydrated lime)
$Ca(OH)_2 \cdot MgO$	dolomitic hydrated lime
Ca/S	molar ratio of calcium to sulfur
$CaSO_3$	calcium sulfite
$CaSO_4$	calcium sulfate
CO	carbon monoxide
CO_2	carbon dioxide
^0F	degrees Fahrenheit
ft, ft^2, ft^3	foot (feet), square feet, cubic feet
GW	gigawatt(s)
GWe	gigawatt(s)-electric
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid
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
MWt	megawatt(s)-thermal
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_2CO_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
SO_3	sulfur trioxide
std ft^3	standard cubic feet
yr, yrs	year, years

Index of CCT Projects