

**CLEAN  
COAL  
TECHNOLOGY**



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

DOE/FE-0364

# Clean Coal Technology Demonstration Program

## Program Update 1996-97

**October 1997**

This report has been reproduced directly from the best available copy.

Available to DOE and DOE contractors from the Office of Scientific and Technical Information, P.O. Box 62, Oak Ridge, TN 37831; prices available from (615) 576-8401.

Available to the public from the National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Rd., Springfield, VA 22161.

**CLEAN  
COAL  
TECHNOLOGY**



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

DOE/FE-0364

# Clean Coal Technology Demonstration Program

## Program Update 1996-97

October 1997

# Contents

## **Executive Summary: The Clean Coal Technology Demonstration Program—Responding to a Need**

Introduction *ES-1*  
Evolution of the Coal Technology Portfolio *ES-2*  
Performance Results *ES-2*  
Technology Successes *ES-3*  
Model Government/Industry Partnership for Technology Advancement *ES-9*  
Continuing the Mission *ES-10*

## **Section 1: Role of the CCT Program**

Introduction *1-1*  
Coal Technologies Respond to Need *1-1*  
Coal Technologies for Environmental Performance *1-3*  
    Acid Rain Mitigation *1-3*  
    Air Toxics *1-7*  
    Global Climate Change Protection *1-8*  
    Value-Added Solid Waste *1-9*  
Coal Technologies for Competitive Performance *1-9*  
Coal Technologies to Keep America Secure *1-12*  
Coal Technology for the Future *1-13*

## **Section 2: Program Implementation**

Introduction *2-1*  
Implementation Principles *2-1*  
Implementation Process *2-2*  
Commitment to Commercial Realization *2-4*  
Solicitation Results *2-5*  
Future Implementation Direction *2-12*  
    Issue 1: Role of CCTs in the Evolving Domestic Electricity Market *2-13*  
    Issue 2: International Markets—Seizing the Opportunity *2-13*  
    Issue 3: Environmental Issues Affecting CCT Deployment *2-14*  
    Issue 4: CCT Deployment—From Today into the Next Millennium *2-14*

### **Section 3: Funding and Costs**

Summary	3-1
Program Funding	3-1
Availability of Funding	3-2
Use of Appropriated Funds	3-2
Project Funding, Costs, and Schedules	3-4
Cost-Sharing	3-4
Recovery of Government Outlays (Recoupment)	3-8

### **Section 4: CCT Program Accomplishments**

Introduction	4-1
Marketplace Commitment	4-1
Environmental Control Devices	4-2
Advanced Electric Power Generation	4-5
Coal Processing for Clean Fuels	4-6
Industrial Applications	4-7
Understanding the Domestic Market	4-9
An Emerging International Market	4-10
Market Communications	4-12

### **Section 5: CCT Projects**

Summary	5-1
Environmental Control Devices	5-8
SO <sub>2</sub> Control Technology	5-8
NO <sub>x</sub> Control Technology	5-30
Combined SO <sub>2</sub> /NO <sub>x</sub> Control Technology	5-56
Advanced Electric Power Generation Technology	5-82
Fluidized-Bed Combustion	5-82
Integrated Gasification Combined Cycle	5-83
Integrated Gasification Fuel Cell	5-83
Coal-Fired Diesel	5-83
Slagging Combustor	5-84
Status of Projects	5-84

**Section 5: CCT Projects (continued)**

Coal Processing for Clean Fuels Technology 5-114

Industrial Applications Technology 5-128

**Appendix A: Historical Perspective and Relevant Legislation**

Historical Perspective A-1

Legislative History A-2

**Appendix B: Program History**

Solicitation History B-1

Selection and Negotiation History B-1

**Appendix C: Environmental Aspects**

Introduction C-1

Role of NEPA in the CCT Program C-1

Compliance with NEPA C-1

    Categorical Exclusions C-2

    Memoranda-to-File C-2

    Environmental Assessments C-2

    Environmental Impact Statements C-5

    NEPA Actions in Progress C-5

Environmental Monitoring C-5

Air Toxics C-6

**Appendix D: CCT Project Contacts**

CCT Project Contacts D-1

**Appendix E: Acronyms and Abbreviations**

Acronyms E-1

Abbreviations E-2

**Index**

Index F-1

# Exhibits

## Executive Summary: The Clean Coal Technology Demonstration Program—Responding to a Need

### Section 1: Role of the CCT Program

### Section 2: Program Implementation

### Section 3: Funding and Costs

### Section 4: CCT Program Accomplishments

ES-1	Completed Projects by Application Category	ES-3
ES-2	Summary of Results of Completed CCT Projects	ES-4
ES-3	Award-Winning CCT Projects	ES-11
1-1	Phase I SO <sub>2</sub> Compliance Methods	1-3
1-2	CAAA NO <sub>x</sub> Emission Limits	1-5
1-3	Comparison of Energy Projections	1-11
2-1	CCT Program Selection Process Summary	2-5
2-2	Clean Coal Technology Demonstration Projects, by Solicitation	2-6
2-3	Geographic Location of CCT Projects—Environmental Control Devices	2-8
2-4	Geographic Location of CCT Projects—Advanced Electric Power Generation	2-9
2-5	Geographic Location of CCT Projects—Coal Processing for Clean Fuels	2-10
2-6	Geographic Location of CCT Projects—Industrial Processes	2-11
3-1	CCT Project Costs and Cost-Sharing	3-1
3-2	Relationship between Appropriations and Subprogram Budgets for the CCT Program	3-2
3-3	Annual CCT Program Funding, by Appropriations and Subprogram Budgets	3-3
3-4	CCT Financial Projections as of June 30, 1997	3-4
3-5	Financial Status of the CCT Program as of June 30, 1997	3-5
3-6	CCT Project Schedules and Funding, by Application Category	3-6
4-1	Commercial Successes—SO <sub>2</sub> Control Technology	4-3
4-2	Commercial Successes—NO <sub>x</sub> Control Technology	4-4
4-3	Commercial Successes—Combined SO <sub>2</sub> /NO <sub>x</sub> Control Technology	4-5
4-4	Commercial Successes—Advanced Electric Power Generation	4-7
4-5	Commercial Successes—Coal Processing for Clean Fuels	4-8
4-6	Commercial Successes—Industrial Applications	4-9
4-7	How to Obtain Updated CCT Program Information	4-14

## Section 5: CCT Projects

5-1	Project Fact Sheet, by Application Category and Participant	5-3
5-2	CCT Projects that Completed Operational Testing by June 30, 1997	5-7
5-3	CCT Program SO <sub>2</sub> Control Technology Characteristics	5-9
5-4	Variables and Levels Used in GSA Factorial Testing	5-12
5-5	GSA Factorial Testing Results	5-12
5-6	SO <sub>2</sub> Removal Performance	5-24
5-7	Estimated Costs for an AFGD System	5-25
5-8	Flue Gas Desulfurization Economics	5-25
5-9	Operation of CT-121 Scrubber	5-28
5-10	SO <sub>2</sub> Removal Efficiency	5-28
5-11	Particulate Capture Performance	5-28
5-12	CT-121 Air Toxics Removal	5-29
5-13	Group 1 and 2 Boiler Statistics and Phase II NO <sub>x</sub> Emission Limits	5-30
5-14	CCT Program NO <sub>x</sub> Control Technology Characteristics	5-31
5-15	Coal Reburn Test Results	5-34
5-16	Coal Reburn Economics	5-35
5-17	NO <sub>x</sub> Data from Cherokee Station, Unit 3	5-42
5-18	Catalysts Tested	5-50
5-19	Avg SO <sub>2</sub> Oxidation Rate	5-50
5-20	Design Criteria	5-51
5-21	LNCFS™ Configurations	5-54
5-22	Concentric Firing Concept	5-54
5-23	Unit Performance Impacts Based on Long-Term Testing	5-55
5-24	Average Annual NO <sub>x</sub> Emissions and % Reduction	5-55
5-25	CCT Program Combined SO <sub>2</sub> /NO <sub>x</sub> Control Technology Characteristics	5-57
5-26	LIMB SO <sub>2</sub> Removal Efficiencies	5-64
5-27	Capital Cost Comparison	5-65
5-28	Annual Levelized Cost Comparison	5-65
5-29	CCT Program Advanced Electric Power Generation Technology Characteristics	5-85



**Section 5: CCT Projects (continued)**

- 5-30 Effect of Bed Temperature on Ca/S Requirement 5-98
- 5-31 Calcium Requirements and Sulfur Retentions for Various Fuels 5-98
- 5-32 CCT Program Coal Processing for Clean Fuels Technology Characteristics 5-115
- 5-33 CQE™ Stand-Alone System Requirements 5-118
- 5-34 CCT Program Industrial Applications Technology Characteristics 5-129
- 5-35 Summary of Emissions and Removal Efficiencies 5-140

**Appendix A: Historical Perspective and Relevant Legislation**

- A-1 CCT Program Legislative History A-4

**Appendix C: Environmental Aspects**

- C-1 NEPA Reviews Completed through June 30, 1997 C-2
- C-2 Memoranda-to-File Completed C-3
- C-3 Environmental Assessments Completed C-4
- C-4 Environmental Impact Statements Completed C-5
- C-5 NEPA Reviews in Progress C-6
- C-6 Status of Environmental Monitoring Plans for CCT Projects C-6
- C-7 CCT Projects Monitoring Hazardous Air Pollutants C-10

# Executive Summary: The Clean Coal Technology Demonstration Program—Responding to a Need

## Introduction

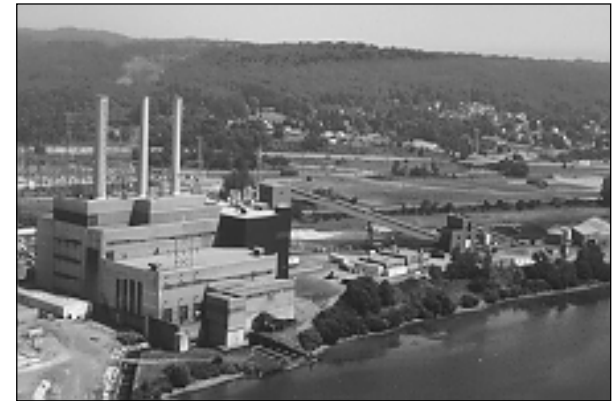
The Clean Coal Technology Demonstration Program (known as the CCT Program) reached a significant milestone in 1996 with the completion of 20 of the 39 active projects. This milestone showed that this cooperative government/industry cost-shared program has yielded technologies that (1) are capable of meeting the environmental performance requirements established in current and emerging environmental standards and (2) will be capable of meeting the operational and economic performance necessary to compete in the era of deregulation and competition.

The CCT Program is responding to a need to demonstrate and deploy a portfolio of technologies that will assure the U.S. recoverable coal reserves of 297 billion tons could continue to supply the nation's energy needs economically and in a manner that meets the nation's environmental objectives. This portfolio of technologies includes environmental control devices that contributed to meeting the accords on transboundary air pollution recommended by the Special Envoys on Acid Rain in 1986. Operational, technical, environmental, and economic performance information and data are now flowing from highly efficient, low-emission, advanced power generation technologies that will enable coal to retain its prominent role into the next millennium. Further, advanced technologies are emerg-

ing that will enhance the competitive use of coal in the industrial sector, such as in steelmaking. Coal processing technologies will enable the entire coal resource base to be used while complying with environmental requirements. These technologies are producing products used by utilities and industrial processes. The capability to coproduce products, such as liquid and solid fuels, electricity, and chemicals, is being demonstrated at a commercial scale by projects in the CCT Program. In summary, this portfolio of technologies is satisfying the national need to maintain a multifuel energy mix in which coal is a key component because of its low-cost, availability, and abundant supply within the nation's borders.

The international opportunities for coal technology exports are enormous. It is estimated that the worldwide demand for energy will reach 542 quadrillion British thermal units (Btu) annually by 2015, 1.6 times the current level. Coal is expected to account for about 25 percent of this demand. The worldwide power-generation equipment market could be as high as \$1 trillion by 2015. Capturing just 20 percent of this market would bring in revenues of \$200 billion and support more than 100,000 jobs over three decades in the domestic power equipment industry alone. There are opportunities for U.S. technology suppliers, developers, architect/engineers, and other firms to capitalize on the knowledge and experience gained through participation in the CCT Program.

▼ Tidd PFBC Demonstration Project (The Ohio Power Company)—1991 Powerplant Award presented by *Power* magazine.



▲ Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)—1997 Powerplant Award presented by *Power* magazine.

## Evolution of the Coal Technology Portfolio

The CCT Program has been implemented through a series of five nationwide competitive solicitations conducted over a 9-year period. The first solicitation was directed towards demonstrating the feasibility of future commercial application of clean coal technology, which would balance the goals of expanding coal use and minimizing environmental impact. The next two solicitations were aimed primarily at the technologies that could mitigate the potential impacts of acid rain from existing coal-fired power plants in response to the recommendations of the Special Envoys on Acid Rain. The fourth and fifth solicitations addressed the post-2000 energy supply and demand situations with sulfur dioxide (SO<sub>2</sub>) emissions capped under the Clean Air Act Amendments of 1990 (CAAA), increased need for electric power, and the need to alleviate concerns over global climate change—a situation that translates into a need for technologies with very high efficiencies and extremely low emissions.

The technologies are categorized in four market sectors:

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

Approximately 56 percent, or about \$3.2 billion, of the total CCT Program costs are directed toward enhancing efficiency, environmental performance, and reliability of electric power production by the demon-

stration of advanced electric power generation systems. Over 900 megawatts (MWe) of new capacity and over 800 MWe of repowered capacity are represented by 11 advanced electric power generation projects. Projects include 4 integrated gasification combined-cycle systems, 5 fluidized-bed combustion systems, and 2 advanced combustion/heat engine systems. These projects will provide environmentally sound, more efficient, and less costly electric power generation in the late-1990s and also will provide the demonstrated technology base necessary to meet new capacity requirements in the 21st century.

There are 19 environmental control devices projects valued at more than \$704 million. These projects include 7 nitrogen oxide (NO<sub>x</sub>) emissions control systems installed on over 1,700 MWe of utility generating capacity, 5 SO<sub>2</sub> emissions control systems installed on about 770 MWe, and 7 combined SO<sub>2</sub>/NO<sub>x</sub> emissions control systems installed on about 700 MWe of capacity. Most of these environmental

▼ Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)—1994 Powerplant Award presented by *Power* magazine.



control devices had their operating experience documented by the end of 1996.

The five projects in the coal processing for clean fuels application category, valued at more than \$519 million, represent a diversified portfolio of technologies. Three projects involve the production of high-energy-density solid compliance fuels for utility or industrial boilers; one of these projects also produces a liquid for use as a chemical feedstock. One project is demonstrating a new methanol production process. The other project developed an expert computer software system that enables a utility to predict operating performance of coals being considered but not previously burned in the utility's boiler.

The four projects in the industrial applications category have a combined value of nearly \$1.3 billion. Projects encompass the substitution of coal for 40 percent of the coke used in iron making, integration of a direct iron-making process with the production of electricity, reduction of cement kiln emissions and solid waste generation, and the demonstration of an efficient industrial-scale combustor.

## Performance Results

The CCT Program has extended the technical, economic, and environmental performance envelope of a broad portfolio of advanced coal technologies. As of June 30, 1997, 20 projects—50 percent of the total number—have completed operation, 11 are in operation, 1 project is in construction, 3 are in design, and 4 are being restructured. Exhibit ES-1 shows the number of completed projects by application category. Exhibit

ES-2 provides a summary of the key technical and environmental results from the 20 completed demonstration projects and the capital cost, where available. (See Appendix E for explanations of acronyms and abbreviations.)

## Technology Successes

The CCT Program is establishing marketplace credibility as the demonstrated technologies are entering commercial use. Today, technologies used to reduce NO<sub>x</sub> emissions are being retrofitted on a significant percentage (i.e., over 25 percent) of the nation's coal-fired capacity and provide the capability of

achieving not only existing regulated levels, but those proposed by the Environmental Protection Agency (EPA) for 2000. In fact, EPA has used the results from the NO<sub>x</sub> technology demonstrations to guide its efforts in establishing NO<sub>x</sub> control regulations. The CCT Program has also shown that several advanced technologies have led to significant improvements in the economic and environmental performance of SO<sub>2</sub> controls. Circulating fluidized-bed technology has become a commercial success in the utility sector worldwide due largely to the data generated from a CCT project that was one of the first utility-scale circulating fluidized-bed projects in the world. The electric power generation technologies for the next century are being demonstrated in the form of the pressurized fluidized-bed combustion (PFBC) systems

and integrated gasification combined-cycle (IGCC) systems. Further, technologies are being used to transform low-rank and non-compliance coals to useful, environmentally superior coal-based fuels for use by domestic utility and industrial coal users and are being considered for major projects abroad. Finally, coal-based industrial processes are benefiting environmentally and economically from the demonstration of advanced coal technologies.

Market credibility has been enhanced by the following project successes:



▲ Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)—1993 Powerplant Award presented by *Power* magazine.

- Successful testing of the AirPol technology resulted in the city of Hamilton, Ohio, receiving a \$5-million grant from the Ohio Coal Development Office to install the gas suspension absorption technology to control SO<sub>2</sub> emissions from a 50-MWe coal-fired boiler at the municipal power plant. This project has an estimated employment impact of 70 person-years. Additional sales have been made to the U.S. Army for hazardous waste disposal, to Sweden for an iron ore sinter plant, and to Taiwan and India.
- Pure Air on the Lake, L.P., will continue to operate the advanced flue gas desulfurization unit at the Northern Indiana Public Service Company's Bailly Generating Station for 17 years beyond the 3-year demonstration, which was completed in 1995. In April 1994, Pure Air of Manatee, L.P., entered into a contract to provide 1,600 MWe of SO<sub>2</sub>

<b>Exhibit ES-1 Completed Projects by Application Category</b>	
<b>Application Category</b>	<b>Number of Projects Completed</b>
<b>Environmental Control Devices</b>	
NO <sub>x</sub> control technology	5
SO <sub>2</sub> control technology	5
Combined SO <sub>2</sub> /NO <sub>x</sub> control technology	5
<b>Advanced Electric Power Generation</b>	
Atmospheric fluidized-bed combustion	1
Pressurized fluidized-bed combustion	1
<b>Coal Processing for Clean Fuels</b>	
	1
<b>Industrial Applications</b>	
Industrial cyclone combustor	1
Cement kiln flue gas recovery scrubber	1

## Exhibit ES-2 Summary of Results of Completed CCT Projects

Project and Participant	Key Results	Capital Cost
<b>Environmental Control Devices</b>		
<b>SO<sub>2</sub> Control Technology</b>		
10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.)	Gas suspension absorption (GSA)/electrostatic precipitator (ESP)—SO <sub>2</sub> removal efficiency of 90% at Ca/S of 1.4, 18 °F approach to saturation, and 0.12% chloride  GSA/pulse jet baghouse—SO <sub>2</sub> removal efficiency 3–5% greater than GSA/ESP (3.0% sulfur bituminous coal)	\$149/kW for GSA (\$216/kW for conventional wet limestone forced oxidation) (1990\$)
Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)	SO <sub>2</sub> reduction of 50% (1.2–2.5% sulfur bituminous coal)	Less than \$30/kW at 500 MWe
LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC–North America)	SO <sub>2</sub> removal efficiency of 70% at 2.0 Ca/S ratio (2.0–2.8% sulfur bituminous coal)	\$66/kW for two reactors (300 MWe); \$76/kW for one reactor (150 MWe); \$99/kW for one reactor (65 MWe)
Advanced Flue Gas Desulfurization Project (Pure Air on the Lake, L.P.)	SO <sub>2</sub> removal efficiency of 95% or more at availabilities of 99.5% when operating on 2.0–4.5% sulfur bituminous coal  Maximum SO <sub>2</sub> removal efficiency of 98%  Over 3-year demonstration, 237,000 tons of SO <sub>2</sub> removed while producing 210,000 tons of gypsum  Gypsum purity—97.2%  Power consumption—5,275 kW (61% of expected)  Water consumption—1,560 gal/min (52% of expected)	\$210/kW at 100 MWe; \$121/kW at 300 MWe; \$94/kW at 500 MWe (3.0% sulfur coal)
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	SO <sub>2</sub> removal efficiency of over 90% at SO <sub>2</sub> inlet concentrations of 1,000–3,500 ppm  Particulate removal efficiency of 97.7–99.3% at inlet mass loadings of 0.303–1.392 lb/10 <sup>6</sup> Btu  Produced wallboard-grade gypsum as a by-product  Fiberglass-reinforced-plastic equipment—chemically and structurally durable	Not yet available

**Exhibit ES-2 (continued)**  
**Summary of Results of Completed CCT Projects**

Project and Participant	Key Results	Capital Cost
<b>NO<sub>x</sub> Control Technology</b>		
Demonstration of Coal Reburning for Cyclone Boiler NO <sub>x</sub> Control (The Babcock & Wilcox Company)	NO <sub>x</sub> reductions of 52% using bituminous coal and 55% using subbituminous coal at full load (110 MWe); 36% and 53%, respectively, at 60 MWe	\$66/kW at 110 MWe; \$43/kW at 605 MWe
Full-Scale Demonstration of Low-NO <sub>x</sub> Cell Burner Retrofit (The Babcock & Wilcox Company)	NO <sub>x</sub> reductions of 54–58% using bituminous coal at full load (605 MWe); 48% at 350 MWe	\$9/kW at 600 MWe
Evaluation of Gas Reburning and Low-NO <sub>x</sub> Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)	LNB alone (second generation)—37% NO <sub>x</sub> reduction; GR-LNB (second generation)—64% NO <sub>x</sub> reduction (13% gas heat input)	Approximately \$15/kW for gas reburning, plus gas pipeline cost
Demonstration of Selective Catalytic Reduction Technology for Control of NO <sub>x</sub> Emissions from High-Sulfur-Coal-Fired Boilers (Southern Company Services, Inc.)	NO <sub>x</sub> reductions of over 80% at ammonia slip well under 5 ppm	Levelized cost at 80% NO <sub>x</sub> reduction—2.79 mills/kWh or \$2,036/ton of NO <sub>x</sub> removed
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for Reduction of NO <sub>x</sub> Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	NO <sub>x</sub> reductions of 37% for LNCFS™ I and II, and 45% for LNCFS™ III, which includes both separated overfire air and close-coupled overfire air	LNCFS I—\$5–15/kW LNCFS II/III—\$15–25/kW
<b>Combined SO<sub>2</sub>/NO<sub>x</sub> Control Technology</b>		
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	NO <sub>x</sub> reduction with SCR over 94% at inlet concentrations of 500–700 ppm SO <sub>2</sub> removal efficiency over 95% at inlet concentrations of 2,000 ppm	\$305/kW at 500 MWe (3.2% sulfur coal)
LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)	Produced salable sulfuric acid by-product SO <sub>2</sub> removal efficiency (3.8% sulfur coal, Ca/S of 2.0): LIMB—53–61% for ligno lime, 51–58% for calcitic lime Coolside—70% for hydrated lime	LIMB—\$31–102/kW (100–500 MWe) Coolside—\$69–160/kW (100–500 MWe)
SO <sub>x</sub> -NO <sub>x</sub> -Rox Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)	NO <sub>x</sub> reduction of 40–50% SO <sub>2</sub> reductions of 80–90% using 3–4% sulfur bituminous coal, depending on sorbent and conditions NO <sub>x</sub> reduction of 90% with 0.9 NH <sub>3</sub> /NO <sub>x</sub> ratio	\$233/kW at 250 MWe (3.5% sulfur coal and inlet NO <sub>x</sub> level of 1.2 lb/10 <sup>6</sup> Btu)

**Exhibit ES-2 (continued)**  
**Summary of Results of Completed CCT Projects**

Project and Participant	Key Results	Capital Cost
<p>Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)</p> <p>Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> Emissions Control System (Public Service Company of Colorado)</p>	<p>Hennepin—NO<sub>x</sub> reduction of 67% avg with 18% gas input; SO<sub>2</sub> removal efficiency of 53% at 1.75 Ca/S ratio</p> <p>Lakeside—NO<sub>x</sub> reduction of 66% avg and SO<sub>2</sub> reductions of 58% during extended continuous combined (GR-SI) runs at 29 MWe, about 22% gas input, and 1.8 Ca/S ratio</p> <p>NO<sub>x</sub> reduction of 67% avg during long-term testing of gas reburning only</p> <p>NO<sub>x</sub> reduction of 62–69% with low-NO<sub>x</sub> burners and maximum overfire air (50–110 MWe)</p> <p>NO<sub>x</sub> reduction of 63% with low-NO<sub>x</sub> burners and minimum overfire air; steady state conditions</p> <p>NO<sub>x</sub> reduction decreased by 10–25% under load following</p> <p>SNCR obtained NO<sub>x</sub> reduction of 30–50%, thereby increasing total NO<sub>x</sub> control system reduction to more than 80%</p> <p>SO<sub>2</sub> removal efficiency of 70% with sodium bicarbonate at normalized stoichiometric ratio of 1.0</p> <p>Sorbent injection reduced ammonia slip</p>	<p>\$15/kW for gas reburning, plus gas pipeline cost</p> <p>\$50/kW for sorbent injection</p> <p>Not yet available</p>
<p><b>Advanced Electric Power Generation</b></p> <p>Tidd PFBC Demonstration Project (The Ohio Power Company)</p>	<p>SO<sub>2</sub> reduction of 90–95% (Ohio bituminous coal, 2–4% sulfur) at 1.1–1.5 Ca/S ratio</p> <p>NO<sub>x</sub> emissions of 0.15–0.33 lb/10<sup>6</sup> Btu</p> <p>Particulate emissions of 0.02 lb/10<sup>6</sup> Btu</p> <p>Heat rate—10,280 Btu/kWh</p> <p>Combustion efficiency—99.6%</p> <p>Commercially viable design</p> <p>Gas turbine operable in PFBC environment</p>	<p>Not yet available</p>

**Exhibit ES-2 (continued)**  
**Summary of Results of Completed CCT Projects**

Project and Participant	Key Results	Capital Cost
Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.)	<p>SO<sub>2</sub> reduction of 70–95% (up to 1.8% sulfur coal), depending on Ca/S ratio</p> <p>NO<sub>x</sub> emissions of 0.18 lb/10<sup>6</sup> Btu avg</p> <p>Particulate emissions of 0.0072–0.0125 lb/10<sup>6</sup> Btu avg</p> <p>Heat rate—11,600 Btu/kWh</p> <p>Combustion efficiency—96.9–98.9%</p> <p>Commercial viability established</p>	Approximately \$1,123/net kW (repower cost)
<p><b>Coal Processing for Clean Fuels</b></p> <p>Development of the Coal Quality Expert™ (ABB Combustion Engineering, Inc., and CQ Inc.)</p>	<p>CQE™ features:</p> <p>Fuel evaluator—performs system-, plant-, and/or unit-level fuel quality, economic, and technical assessments</p> <p>Plant engineer—provides in-depth performance evaluations with a more focused scope than provided in the fuel evaluator</p> <p>Environmental planner—provides access to evaluation and presentation capabilities of the Acid Rain Advisor</p> <p>Coal cleaning expert—establishes the feasibility of cleaning a coal, determines cleaning processes, and predicts associated costs</p>	CQE™ package sells for between \$75,000 and \$100,000
<p><b>Industrial Applications</b></p> <p>Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)</p> <p>Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)</p>	<p>SO<sub>2</sub> reduction of over 80% with sorbent injection; 58% maximum with limestone injection at 2.0 Ca/S ratio</p> <p>NO<sub>x</sub> emissions of 160–184 ppm (75% reduction)</p> <p>Slag/sorbent retention of 55–90% in combustor; inert slag</p> <p>SO<sub>2</sub> reduction of 90–95% (2.5–3% sulfur bituminous coal); 98% maximum reduction</p> <p>NO<sub>x</sub> reduction of 18.8% avg</p> <p>Particulate emissions of 0.005–0.007 gr/std ft<sup>3</sup> with loading of 0.04 gr/std ft<sup>3</sup></p>	<p>Not available</p> <p>\$10 million for 450,000 ton/yr wet-process plant</p>



scrubbing capacity at Florida Power & Light's Manatee power plant. The estimated value of the sale is \$200 million with an estimated employment benefit of 1,400 person-years.

- Georgia Power is retaining the CT-121 flue gas desulfurization system at its Plant Yates, Unit No. 1, for use in commercial operation. In 1994, a tar sands oil extraction facility in Murray, Canada, purchased a CT-121 scrubber. Sales of 1,200 MWe of flue gas desulfurization capacity were made to the Czech Republic and Korea.
- Richland Power & Light is retaining the LIFAC technology for commercial use at Whitewater Valley Station, Unit No. 2. Ten commercial units are in operation or under construction in Canada, China, Finland, Russia, and the United States.
- NO<sub>x</sub> control testing was conducted on the four major boiler types (wall-, tangential-, cyclone-



▲ Full-Scale Demonstration of Low-NO<sub>x</sub> Cell Burner Retrofit (The Babcock & Wilcox Company)—1994 R&D 100 Award presented by *R&D* magazine.

fired, and cell-burner boilers) representing over 90 percent of the pre-New Source Performance Standards boilers.

- The demonstration of low-NO<sub>x</sub> burners on a 500-MWe wall-fired boiler was supplemented with the demonstration of the Generic NO<sub>x</sub> Control Intelligence System (GNOCIS), a neural-network design to aid digital boiler controls, enhance NO<sub>x</sub> reduction, and improve boiler efficiency. Six systems have been sold, with 11 more sales projected.
- The Low-NO<sub>x</sub> Concentric Firing System (LNCFS™) supplied by ABB Combustion Engineering, Inc., is being retained by Gulf Power at its Plant Lansing Smith. The technology also is being used at a number of other utilities, including Tennessee Valley Authority, Illinois Power, Public Service Company of Colorado, Indianapolis Power and Light, Cincinnati Gas and Electric, Virginia Power, Union Electric, and New York State Electric & Gas Corporation.
- The Babcock & Wilcox DRB-XCL® low-NO<sub>x</sub> burner demonstrated in Public Service Company of Colorado's Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> Emissions Control System has been a commercial success. Sales have involved 1,829 burners, or approximately 23,664 MWe of capacity, at an estimated value of over \$240 million, and an employment benefit of over 1,670 person-years. A derivative of the selective nongatalytic reduction (SNCR) system has been sold to Pennsylvania Electric Company and Mitsubishi Heavy Industries of America.



▲ Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)—1996 Powerplant Award presented by *Power* magazine.

- Ohio Edison is retaining the SNOX™ technology as a permanent part of the emissions control system at Niles Station to help the utility meet its overall SO<sub>2</sub> and NO<sub>x</sub> reduction goals. Commercial SNOX™ plants are operational in Denmark and Sicily, Italy.
- A software package developed as part of the Milliken project to assist the utility in optimizing project operation has become a commercial product. The Plant Emission Optimization Advisor (PEOA™) has been sold to City Public Service in San Antonio, Texas; three bids are outstanding in Korea and one in Israel.
- The Tidd demonstration was the first utility-scale PFBC system in the United States and confirmed that the system could be applied to electric power generation. The plant represented a 13:1 scale-up from the pilot facility

and led to significant refinements and understanding of the technology. The unit accumulated over 11,400 hours of operation and established the commercial viability of the design.

- As a result of the Tri-State Generation and Transmission Association's Nucla CFB Demonstration Project, Pyropower Corporation was able to save almost 3 years in establishing a commercial line of atmospheric circulating fluidized-bed units.
- Three IGCC units are in various stages of operation at three separate utilities. PSI Energy's 262-MWe Wabash River Generating Station Unit 1 has produced over 360,000 MWh of electricity using coal-derived syngas. Tampa Electric Company's 250-MWe Polk Power Station Unit 1 began operation in July 1996 and was placed into commercial service in September. Sierra Pacific Power Company's 99-MWe Tracy Station System initiated startup activities during 1996 and will begin commercial service in mid-1997.
- The first commercial sale of the Coal Quality Expert™ (CQE™) Acid Rain Advisor software package, developed as part of CQE™ to assist utilities in making CAAA compliance decisions, was made in 1993. The final CQE™ software was released in December 1995 and is being offered commercially. Over 40 U.S. and 1 U.K. utilities have access to CQE™ through their membership in the Electric Power Research Institute.

- The Self-Scrubbing Coal™ demonstration has resulted in (1) a proposed agreement with domestic coal-marketing companies to purchase 1 million tons of compliance coal annually, (2) a proposed agreement with China to build a coal-cleaning plant, together with a 500-mile underground slurry pipeline and port facility, at an estimated value of \$450 million, (3) signed letters of intent from two Polish power plants that wish to produce 5.0 million tons per year of cleaned coal, with an estimated value of \$50 million, and (4) a letter of intent for three additional pipelines in China, with an estimated value of \$3 billion.
- Rosebud SynCoal Partnership is working on a potential semi-commercial stand-alone minemouth project located in Wyoming.

- The ENCOAL® Mild Coal Gasification project has operated successfully for 5 years. Fifteen unit trains of process-derived fuel has been shipped to five utilities. Additionally, 3 million gallons of coal-derived liquids has been shipped to industrial clients. ENCOAL® Corporation's newly formed company, NuCoal, L.L.C., signed a contract with Mitsubishi International Corporation to construct a \$460-million, 15,000-metric-ton-per-day commercial plant in Wyoming. Feasibility studies were completed for two Indonesian projects and a Russian project.
- Granular-coal injection technology developer, British Steel, has granted exclusive worldwide marketing rights to codeveloper CPC-Macawber. A commercial sale was made to United States Steel Corporation.



▲ Development of the Coal Quality Expert™ (ABB Combustion Engineering, Inc., and CQ Inc.)—1996 recognized by Secretary of Energy and EPRI as one of best cost-shared utility projects.

## Model Government/Industry Partnership for Technology Advancement

The successful implementation of the CCT Program over the past 10 years is based on a number of principles that evolved as a result of the dedicated effort of industry and DOE to cement a partnership to advance clean coal technologies. Highlights of some of these principles follow:

- Strong and stable financial commitments for the life of the project were put into place by Congress.

- Multiple solicitations spread over a number of years enabled the program to address a broad range of national needs with a portfolio of evolving technologies.
- The technology agenda was determined by industry, not government.
- Demonstrations were conducted at commercial scale in actual user environments.
- The respective roles of government and industry were clearly defined.
- At least 50 percent cost sharing was required through all project phases.
- Allowance for cost growth, but with a statutory limit, provided an important check-and-balance feature of the program.
- Repayment of funds to the government was required of successful industrial participants.
- Real and intellectual property rights were retained by industry.
- Technology developed is made available on a nondiscriminatory basis to all U.S. companies that seek, under reasonable terms and conditions, to use the technology.

These principles, in large measure, led to wide private industry and non-federal government participation in the program. Non-DOE funds of nearly \$3.8 billion have come from a wide variety of sources. Approximately 55 investor-owned utilities, nonutility power generators, municipalities, and cooperatives have invested over \$2.3 billion into projects. These electric power generators represent approximately 50 percent

of the coal-fired capacity in the United States and almost 70 percent of the units affected by Phase I under Title IV of the CAAA of 1990. Further, over 50 industry participants, including technology owners and equipment vendors, have committed over \$1.3 billion of cost sharing to the projects. Finally, seven state agencies and eight industry and academic research and development organizations have provided over \$200 million as their portion of cost sharing.

This broad-based cost-shared participation in the program has translated into jobs in many trades and professions. For example, each emissions control project provides 100–200 jobs and each advanced power generating project provides over 1,000 construction jobs.

In addition, the excellent quality and importance of the CCT projects are well recognized by the business, environmental, and technical communities. Numerous industry and environmental awards for excellence and outstanding achievement have been presented to CCT projects since 1991. These award-winning projects and honors received are highlighted in Exhibit ES-3.

In summary, the joint effort between industry and the government in the CCT Program is a success. The number of complex, capital-intensive projects put into place by the CCT Program partnership is unprecedented, as is the degree of cost sharing. The partnership is important not only for the end objectives it is achieving, but for the benefits, tangible and intangible, created by continuing association of the partners. The CCT Program has shown that, with the government serving as a risk-sharing partner, industry funding can be leveraged to improve the environment, reduce the cost of electricity, create jobs, and assure technology is available to enable coal to continue as the major

contributor to the nation's and the world's energy future.

## Continuing the Mission

DOE has structured an integrated Coal and Power Systems Research, Development, and Demonstration (RD&D) Program with the mission to foster the development and deployment of advanced clean, affordable fossil-based power systems and alternate fuels through the clean utilization of coal. The CCT Program is an integral part of the Coal and Power Systems RD&D Program and is being implemented in three primary product lines:

- Advanced power generation systems
- Environmental systems
- Coal fuels and industrial systems

During 1997, the following three projects, currently in the operational phase, should be completed:

- Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler
- Self-Scrubbing Coal™: An Integrated Approach to Clean Air
- ENCOAL® Mild Coal Gasification Project

Further, the following four projects should begin their operational phase:

- Micronized Coal Reburning Demonstration for NO<sub>x</sub> Control
- Piñon Pine IGCC Power Project

## Exhibit ES-3 Award-Winning CCT Projects

Project and Participant	Award
Full-Scale Demonstration of Low-NO <sub>x</sub> Cell Burner Retrofit (The Babcock & Wilcox Company)	1994 R&D 100 Award presented by <i>R&amp;D</i> magazine to the U.S. Department of Energy for development of the low-NO <sub>x</sub> cell burner.
Evaluation of Gas Reburning and Low-NO <sub>x</sub> Burners on a Wall-Fired Boiler; Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)	1997 J. Deanne Sensenbaugh Award presented by the Air and Waste Management Association to the U.S. Department of Energy, Gas Research Institute, and U.S. Environmental Protection Agency for the development and commercialization of gas-reburning technology.
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	1993 Powerplant Award presented by <i>Power</i> magazine to Northern Indiana Public Service Company's Bailly Generating Station. 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.)	1995 Design Award presented by the Society of Plastics Industries in recognition of the mist eliminator. 1994 Powerplant Award presented by <i>Power</i> magazine to Georgia Power's Plant Yates. 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. 1993 Environmental Award presented by the Georgia Chamber of Commerce. 1992 National Energy Resource Organization award for demonstration of energy-efficient technology.
Tidd PFBC Demonstration Project (The Ohio Power Company)	1991 Powerplant Award presented by <i>Power</i> magazine to American Electric Power Company's Tidd project. Co-recipient was The Babcock & Wilcox Company. 1997 Powerplant Award presented by <i>Power</i> magazine to Tampa Electric's Polk Power Station.
Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	1996 Association of Builders and Contractors Award presented to Tampa Electric for quality of construction. 1993 Ecological Society of America Corporate Award presented to Tampa Electric for its innovative siting process. 1993 Timer Powers Conflict Resolution Award presented to Tampa Electric by the state of Florida for the innovative siting process. 1991 Florida Audubon Society Corporate Award presented to Tampa Electric for the innovative siting process. 1996 Powerplant Award presented by <i>Power</i> magazine to CINergy Corp./PSI Energy, Inc.
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	1996 Engineering Excellence Award presented to Sargent & Lundy upon winning the 1996 American Consulting Engineers Council competition.
Development of the Coal Quality Expert™ (ABB Combustion Engineering, Inc., and CQ Inc.)	In 1996 recognized by then Secretary of Energy Hazel O'Leary and EPRI President Richard Balzhiser as the best of nine DOE/EPRI cost-shared utility R&D projects under the Sustainable Electric Partnership Program.

- Healy Clean Coal Project
- Commercial-Scale Demonstration of Liquid-Phase Methanol (LPMEOH™) Project

Assessments will be made of the impacts that evolving and anticipated domestic and international environmental rulings will have on the commercial deployment of the technologies demonstrated under the CCT Program. The environmental performance data from completed projects will be analyzed, documented, and distributed to potential users of the technology as well as environmental and regulatory stakeholders. This information and data would be available and can be considered during the deliberations on new standards for the reduction of acid rain precursors, hazardous air pollutants, and greenhouse gas emissions, with the purpose of assuring that new standards will be reasonable and achievable in a cost-effective manner.

Technical and economic performance data from the completed projects will be reviewed and analyzed to identify opportunities to improve the competitiveness of the clean coal technologies. Opportunities could lead to benefits such as reduced capital costs, increased efficiencies, increased fuel flexibility, or reduced cost of electricity to the customer by offsetting production costs through coproduct profits. Timely identification of opportunities to improve the competitive position of clean coal technologies is essential to achieving these objectives as the utility sector moves into the era of deregulation and competition. These opportunities could be acted on by program stakeholders, such as technology suppliers and federal, state, and industry RD&D organizations.

The CCT Program will continue to refine the effectiveness of the outreach program in reaching and

informing all customers and stakeholders about the program and its projects and improving the perception of coal as a low-cost, environmentally acceptable fuel. In order to accomplish this objective, participation of the CCT Program stakeholders/customers will be pursued vigorously with a view toward establishing cooperative activities to advance compatible agendas. These activities could involve CCT project site visits by interested stakeholders/customers, expansion of the audience in attendance at the Annual Clean Coal Technology Conference, expanded support for international technology conferences, and increased level of support for state-level education programs.

# 1. Role of the CCT Program

## Introduction

Over the past quarter century, the nation's energy picture has been one of dynamic change. The oil embargoes of the 1970s, the environmental debates of the 1980s, the implementation of controls for acid rain precursors, the beginning of electric utility deregulation, and the concerns about global warming in the 1990s have been forces that shaped the nation's energy policy, the private sector's response in the domestic and international marketplace, and the capability of technology. Since 1985, a joint effort between government and industry, known as the Clean Coal Technology Demonstration Program (CCT Program), has responded to the challenges represented by these dynamic changes. The number of complex, capital-intensive projects put into place by the CCT Program is unprecedented, as is the magnitude of participation by the industrial participants as represented by the level of cost and risk sharing. More than \$5.7 billion is being expended, with industry investing two dollars for every government dollar applied to the program. With half of the projects completed, the technological successes have become evident. New technologies to reduce the emissions of acid rain processors, namely sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>), are now in the marketplace and are being used by electric power producers and in industrial applications. Advanced electric power generation systems that can generate electricity with greater efficiency and less environmental intrusion are

now operating, utilizing the nation's most plentiful fossil energy resource, coal. Coal, which accounts for nearly 94 percent of the proven fossil energy reserves in the United States, supplies the bulk of the low-cost, reliable electricity vital to the nation's economy and global competitiveness. According to the Energy Information Administration (EIA), coal was used by electric utilities and nonutility generators to produce over 1,670 billion kilowatt-hours or 54 percent of the nation's electricity in 1995. EIA projects that coal will continue to dominate electric power production at least through 2015 (the end of the forecast period) when coal will be used to generate over 2,050 billion kilowatt-hours or nearly 50 percent of all electricity generated.

The ability of coal and coal technologies to respond to the nation's need for low-cost, reliable electricity hinges on the ability to meet two central requirements: (1) the capability to meet the environmental performance requirements established in current and emerging environmental regulations and (2) the ability of the technologies to achieve the operational and economic performance required to compete in the era of utility deregulation and competition. The CCT Program is responding to these needs and will produce a portfolio of advanced coal-based technologies that will enable coal to retain its prominent role in the nation's power generation future. Further, advanced technologies emerging from the CCT Program will also enhance coal's competitive position in the industrial sector. Technology advances in steelmaking will reduce the cost of production

while greatly improving environmental performance. The technologies for the coproduction of products, such as liquid and solid fuels, electricity and chemicals, and industrial cogeneration, could enable coal to increase market share in the industrial sector.

While the technologies emerging from the CCT Program are vital to the nation's ability to use coal competitively and with environmental acceptability in the next millennium, these technologies also establish the basis for an export industry needed to meet the global demand for energy. With coal as the fuel of necessity for many economies, these technologies, known as clean coal technologies worldwide, allow U.S. industry to capitalize on the advances and knowledge base established through the CCT Program's government/industry partnership.

## Coal Technologies Respond to Need

The environmental and competitive performance of coal technologies has evolved over 25 years of industry and government research, development, and demonstration programs. The programs were pursued to assure that the U.S. recoverable coal reserves of 297 billion tons could securely supply the nation's energy needs economically and in an environmentally acceptable manner.

During the 1970s and early 1980s, many of the government-sponsored technology demonstrations focused on the synthetic fuels production technology. In 1980, the Synthetic Fuels Corporation (SFC) was established under the Energy Security Act to reduce the U.S. vulnerability to disruptions of crude oil imports. It was to be accomplished by encouraging the private sector to build and operate synthetic fuels production facilities that would use abundant domestic energy resources, primarily coal and oil shale. The strategy was for the SFC to be primarily a financier of pioneer commercial- and near-commercial-scale facilities.

The goal of the SFC was to achieve production capacities of 500,000 barrels per day by 1987 and 2 million barrels per day by 1992, at an estimated cost of \$8.8 billion. By 1985, it became apparent that the need for synthetic fuels had changed, as oil prices declined, world oil supplies stabilized, and a short-term supply buffer was provided by the Strategic Petroleum Reserve.

Congress observed the decline of private-sector interest in the production of synthetic fuels in light of unfavorable market conditions. Public Law 99-190, Department of the Interior and Related Agencies Appropriations Act for Fiscal Year 1986, abolished the SFC and transferred project management to the Treasury Department. Public Law 98-473, Joint Resolution Making Continuing Appropriation for Fiscal Year 1985 and Other Purposes, provided \$750 million from the Energy Security Reserve to be deposited in a separate account in the U.S. Treasury entitled The Clean Coal Technology Reserve. The nation moved from an energy policy based on synthetic fuels production to a more balanced policy, which

established that the nation should have an adequate supply of energy, maintained at a reasonable cost and consistent with environmental, health, and safety objectives. Energy stability, security, and strength were the foundations for this policy. It was recognized that coal would be a major contribution to meeting this goal for the foreseeable future because of the following factors:

1. The location, magnitude, and characteristics of the coal resource base were well understood.
2. The technology and skilled labor base of nearly 1.1 million workers were available to safely and economically extract, transport, and use coal.
3. A multi-billion dollar infrastructure was in place to gather, transport, and deliver this valuable energy commodity to serve the domestic and international marketplace.
4. Coal was used to produce over 54 percent of the nation's electric power in 1995 and was vital to industrial processes, such as steel and cement production as well as industrial power.
5. The most abundant fossil energy resource was secure within the nation's borders and relatively invulnerable to disruptions because of the coal industry's production responsiveness and stockpiling capability.
6. Coal was the fuel of necessity in many lesser developed economies.

It was recognized that the continued viability of coal as a source of energy was dependent on the demonstration and commercial application of a new

generation of advanced coal-based technologies characterized by enhanced technical, economic, and environmental performance.

With these factors very evident, the CCT Program was established to demonstrate the commercial feasibility of clean coal technology application. In 1986, the first solicitation (CCT-I) for clean coal technology projects was issued to be responsive to this need, and the solicitation resulted in a broad range of projects being selected in four major product markets—environmental control devices, advanced electric power generation, coal processing for clean fuels, and industrial applications.

In 1987, the CCT Program became the centerpiece for satisfying the recommendations contained in the 1986 *Joint Report of the Special Envoys on Acid Rain*, which included a 5-year, \$5-billion U.S. effort to curb precursors of acid rain formation—SO<sub>2</sub> and NO<sub>x</sub>. Thus the second solicitation (CCT-II), issued in February 1988, provided for the demonstration of technologies that were capable of achieving significant reductions in SO<sub>2</sub> and/or NO<sub>x</sub> emissions from existing power plants. These technologies were to be more cost-effective than current technologies and capable of commercial deployment in the 1990s when the Clean Air Act Amendments were to become effective. In May 1989 a third solicitation (CCT-III) was issued with essentially the same objective as the second, but encouraging technologies that would produce clean fuels from run-of-mine coal.

The next two solicitations recognized evolving energy and environmental issues and were thus focused on seeking highly efficient, economically competitive, low-emission technologies. Specifically, the fourth solicitation (CCT-IV), released in January

1991, had as its objective the demonstration of energy efficient, economically competitive technologies capable of retrofitting, repowering, or replacing existing facilities while achieving significant reductions in SO<sub>2</sub> and NO<sub>x</sub> emissions. In July 1992, the fifth and final solicitation (CCT-V) was issued to provide for demonstration projects that significantly advanced the efficiency and environmental performance of technologies applicable to new or existing facilities.

As a result of these five solicitations, a total of 50 government/industry cost-shared projects were negotiated, of which 39 valued at more than \$5.7 billion have been completed or remain active in the CCT Program.

The success of the government/industry CCT Program is directly attributable to its responsiveness to public and private sector needs to reduce environmental emissions and maximize economic and efficient energy production. This will strengthen the economy, enhance energy security, and reduce the vulnerability of the economy to global energy market shocks.

## Coal Technologies for Environmental Performance

### *Acid Rain Mitigation*

During the late 1980s, work began on drafting what was to become the Clean Air Act Amendments of 1990 (CAAA) and on November 15, 1990, Congress enacted the CAAA. Title IV, Acid Deposition

Control, established emissions reduction targets for SO<sub>2</sub>, capped SO<sub>2</sub> emissions in the post-2000 time-frame, and directed the establishment of allowable emission limitations for NO<sub>x</sub>. Title IV represented the first large-scale approach to regulating overall emissions levels by using marketable allowances. The utilities could adopt a control strategy that was most cost-effective for their given systems and plants rather than having to apply a “command-and-control” approach wherein the emission-reduction technique is specified.

The emission reduction requirements for SO<sub>2</sub> were to be met in two phases. Phase I, which provided for the initial increment of SO<sub>2</sub> reduction, began on January 1, 1995, and the second increment implemented through Phase II will begin on January 1, 2000. Title IV identified 261 generating units (designated affected units) that were required to comply with Phase I. Most of these units are coal-fired with fairly high emissions. An additional 174 units are participating in Phase I based on Environmental Protection Agency (EPA) rules, which allow a utility to designate substitution or compensating units as part of Phase I compliance strategies. There-

fore, 435 units are considered Phase I units. Under Phase II, more than 2,000 units will be affected. Exhibit 1-1 summarizes the compliance methods used by the 261 affected units listed in Title IV to satisfy Phase I requirements.

By the end of 1995, the Phase I units had significantly reduced SO<sub>2</sub> emissions compared to previous years. In 1990 the Phase I units emitted 9.7 million tons of SO<sub>2</sub>; in 1995 emissions were down to 5.3 million tons, a 45 percent reduction. This is contrasted to non-Phase-I units whose emissions were 12 percent higher (6.6 million tons) than their 1990 emissions of 5.9 million tons.

The following projects within the CCT Program were designated affected units and were required to achieve compliance with Phase I requirements:

**Exhibit 1-1  
Phase I SO<sub>2</sub> Compliance Methods**

Method	No. of Units	% of Units	% SO <sub>2</sub> Reduction from 1985 Baseline	% of Total SO <sub>2</sub> Reduction
Fuel switching/blending	136	52	60	59
Additional SO <sub>2</sub> allowances	83	32	16	9 <sup>a</sup>
Scrubbers	27	10	83	28
Retirements	7	3	100	2
Other <sup>b</sup>	8	3	86	2
<b>Total</b>	<b>261</b>	<b>100</b>		<b>100</b>

<sup>a</sup> Includes reduced coal consumption of 2.5 million tons and 16% reduction in sulfur content.

<sup>b</sup> Includes 1 repowered unit, 2 switched to natural gas, and 5 switched to No. 6 fuel oil.

Source: *The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update*, Energy Information Administration, March 1997.



- Northern Indiana Public Services' Bailly Generating Station, 528-MWe Units 7 and 8; advanced flue gas desulfurization unit
- Georgia Power Company's Plant Yates, 100-MWe Unit 1; Chiyoda Thoroughbred-121 advanced flue gas desulfurization
- New York State Gas & Electric's Milliken Station, 300-MWe Units 1 and 2; S-H-U formic-acid-enhanced, wet limestone scrubber
- PSI Energy's Wabash River Station, 262-MWe repowered integrated gasification combined-cycle unit

EIA estimates the annualized Phase I compliance cost to be \$836 million (1995 dollars). The cost ranged from \$113 per ton of SO<sub>2</sub> removed for fuel switching to \$322 per ton of SO<sub>2</sub> removed for flue gas desulfurization.

One of the more significant effects of compliance with Phase I requirements was the change in coal use. As shown in Exhibit 1-1, the fuel switching and/or blending compliance strategy was selected by 52 percent of the affected units. This switch to lower sulfur coal affected regional coal distribution. Between 1990 and 1995, the following changes in coal sales resulted:

- Powder River Basin coal—increased 78 million tons
- Central Appalachian coal—increased 15 million tons
- Rocky Mountain coal—increased 10 million tons

- Northern Appalachian coal—decreased 29 million tons
- Illinois Basin coal—decreased 40 million tons

In Phase II, beginning in 2000, emissions are limited to 1.2 pounds of SO<sub>2</sub> per million Btu at the consumption rate established in the 1985–1987 timeframe. Most utilities have not finalized their compliance strategies because the industry is faced with major changes in the way it is structured and does business under the requirements of the Energy Policy Act (EPA) of 1992, the Federal Energy Regulatory Commission (FERC)

Orders No. 888 and 889, and state-level utility restructuring legislation. Under the previous regulatory environments, state regulators would allow the utilities to pass on pollution control costs to consumers. However, in a restructured, competitive environment, the added cost of capital-intensive environmental controls could put a utility at a disadvantage to those utilities that can achieve compliance with lower cost alternatives, such as fuel switching and/or blending. EIA projects that fuel switching and/or blending will be the predominant strategy used, with allowance acquisition being the second choice. However, it is expected that allowance prices will increase after 2000, and thus the scrubbing option will become more cost competitive so that by 2010 about 23 gigawatts of coal-fired capacity will be retrofitted. This could provide an opportunity to deploy SO<sub>2</sub> or combined SO<sub>2</sub>/NO<sub>x</sub> environmental control device technologies



▲ New York State Electric & Gas Corporation's Milliken Station used the S-H-U scrubber to achieve Phase I SO<sub>2</sub> compliance.

demonstrated under the CCT Program. Another option available to utilities is to repower with a clean coal technology. Under this option a 4-year extension (to December 31, 2003) is available to comply with the Phase II requirements.

Title IV of the CAAA required EPA to establish annual allowable emissions limitations for NO<sub>x</sub> in two phases. Phase I required NO<sub>x</sub> reductions from tangentially fired and dry-bottom wall-fired boilers. These are referred to as Group 1 boilers. In March 1994, EPA promulgated a rule establishing emission limitations of 0.45 pound per million Btu for tangentially fired units and 0.50 pound per million Btu for wall-fired units. However, in November 1994 after a challenge from utility groups, the U.S. Court of Appeals found that the definition of low-NO<sub>x</sub> burner technology contained in the March rule exceeded EPA's statutory authority and vacated the rule. In April 1995, after agreement with environmental and

utility organizations, EPA issued a final rule revising the definition of low-NO<sub>x</sub> burner technology. Further, the rule extended the compliance date to January 1, 1996.

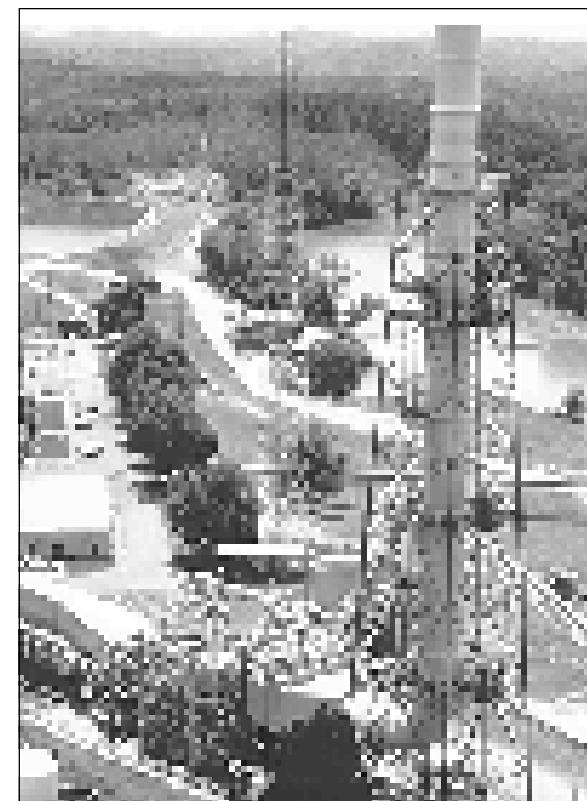
On August 3, 1995, EPA issued a proposed regulation that included a provision for “open market” trading, somewhat similar to SO<sub>2</sub> allowance trading. Under this rule, utilities would not need state and federal approval for transactions of NO<sub>x</sub> and volatile organic carbon (VOCs) credit trading. Instead, utilities would be able to comply with various air pollution mandates by buying and using an appropriate number of tons of “discrete emissions reductions,”

or DERs. Utilities would be able to generate emission reduction credits for smog precursors by voluntarily reducing NO<sub>x</sub> and VOCs and bank, use, or sell the credits under the open market emissions trading proposal. (In addition to trading VOCs and NO<sub>x</sub> under the program, the utilities also would be able to trade water pollution credits.) The DERs will not require certification by regulators until they are used, either by the utility that generates them for later use or by a second utility that purchases the DERs from the first utility.

On December 19, 1996, EPA issued a rule to implement Phase II by establishing NO<sub>x</sub> emissions

limitations for additional coal-fired boilers (Group 2) and reducing the NO<sub>x</sub> emissions limitations on Group 1 units. The types of Group 1 and 2 units and the Phase I and II NO<sub>x</sub> emission limits are shown in Exhibit 1-2.

In response to the need to formulate NO<sub>x</sub> emission reductions that were realistic and achievable, EPA was able to use the database developed during the Southern Company Services evaluation of NO<sub>x</sub> control on wall-fired and tangentially



▲ Chiyoda’s CT-121 system allowed Georgia Power’s Plant Yates to meet Phase I SO<sub>2</sub> requirements.

fired boilers. Further, the technical, environmental, and economic data on NO<sub>x</sub> controls were developed under the CCT Program for the four major boiler types (wall-fired, tangentially-fired, cyclone-fired, and cell-burner), which constitute over 90 percent of the pre-New Source Performance Standard boiler types. In addition, low-NO<sub>x</sub> burners were installed on a vertically fired boiler and tested. Other alternative NO<sub>x</sub>-control technologies were demonstrated, including coal and gas reburning, selective noncatalytic reduction (SNCR), and selective catalytic reduction (SCR). This portfolio of NO<sub>x</sub> controls will not only

### Exhibit 1-2 CAAA NO<sub>x</sub> Emission Limits

Group 1 Unit Type	Group 2 Unit Type	Phase I NO <sub>x</sub> Emission Limits <sup>a</sup> (lb/10 <sup>6</sup> Btu)	Phase II NO <sub>x</sub> Emission Limits <sup>a</sup> (lb/10 <sup>6</sup> Btu)
Tangentially fired boilers		0.45	0.40
Dry-bottom wall-fired boilers <sup>b</sup>		0.50	0.46
	Cell-burner boilers		0.68
	Cyclone boilers >155 MWe		0.86
	Wet-bottom wall-fired boilers >65 MWe		0.84
	Vertically fired boilers		0.80

<sup>a</sup> Emission limits are lb/10<sup>6</sup> Btu of heat input on an annual average basis.  
<sup>b</sup> Other than units applying cell-burner technology

assure Phase I and II emission reductions are achievable, but will provide the technology base necessary to achieve even deeper NO<sub>x</sub> reductions that may be necessary to meet CAAA Title I requirements for ozone in nonattainment areas.

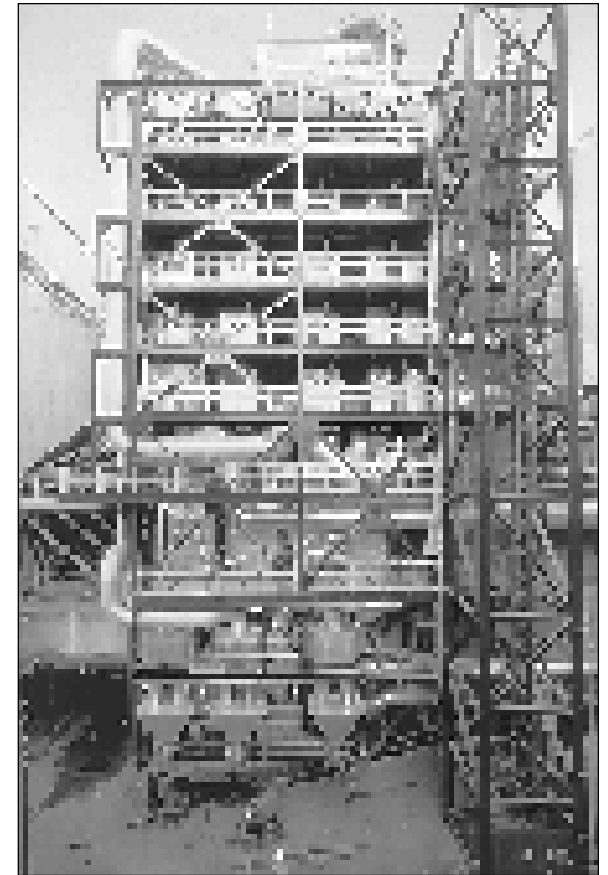
The EPA is in the process of considering and issuing new rules that go beyond the acid rain provisions contained in the CAAA. Some of these rules are



▲ Scaffolding and cell-burner penetration into the boiler wall are viewed from inside of a boiler.

in the discussion phase; other rules have been proposed or finalized and will need to be considered in the research, development, and deployment of clean coal technologies. The following initiatives are included:

- **Clean Air Power Initiative (CAPI).** CAPI was established by EPA to combine the rule making for SO<sub>2</sub>, NO<sub>x</sub>, and fine particulates into one rulemaking effort. CAPI would consider the cap-and-trade approach to pollutant reductions rather than the traditional command-and-control approach. The proposed emission rates for NO<sub>x</sub> would be 0.15–0.25 pound per million Btu for utility sources and a 50–60 percent reduction in SO<sub>2</sub> beyond the Title IV CAAA requirements. These would take place in 2005 or 2010. EPA would provide long-term relief from additional regulations.
- **Attainment of Ozone Standards (Title I).** CAAA Title I established the Ozone Transport Commission (OTC) to address regional transport of pollutants that contributes to ozone nonattainment in the Northeast. The Northeast Ozone Transport Commission approved a Memorandum of Understanding in September 1994 to reduce power plant emissions of NO<sub>x</sub> by as much as 70 percent. Reductions are to be accomplished in 1999 and 2003. The Ozone Transport Assessment Group (OTAG) was a voluntary collaborative effort by 37 states, begun in June 1995, to address the issue of ozone transportation. On June 19, 1997, the OTAG Policy Group issued its recommendations, which called for utilities



▲ Selective catalytic reduction technology achieves deep NO<sub>x</sub> reductions.

in a number of affected states to control NO<sub>x</sub> at a level between the CAAA level and the less stringent 85% reduction from the 1990 rate or 0.15 pound per million Btu. Control levels are to be determined and implemented through statewide tonnage budgets established by EPA with control measures determined and implemented by the states. Through State Implementation Plans (SIPs), the SIP process is scheduled to be implemented on September 1,

1997, with EPA establishing the emissions budgets. Final approval of the SIPs is scheduled for March 2001. Further, OTAG approved a recommendation that would allow states to sell or trade credits to exceed the budget.

- **Soot and Smog.** On June 25, 1997, EPA recommended new National Ambient Air Quality Standards (NAAQS) for particulate matter and ozone (commonly referred to as soot and smog), with standards becoming final in July 1997. The standard for coarse particles remains essentially unchanged, while a new standard for fine particles—those measuring 2.5 micrometers in diameter and smaller (instead of the previous 10 microns)—was set at an annual limit of 15 micrograms per cubic meter, with a 24-hour limit of 65 micrograms per cubic meter. For ozone, the recommended final standard was tightened from 0.12 parts per million (or 120 parts per billion) of ozone measured over 1 hour to a new standard of 0.08 parts per million (or 80 parts per billion) measured over 8 hours, with the average fourth highest concentration over a 3-year period determining whether an area is out of compliance. EPA also will issue an implementation package and work from the regional plan developed by OTAG to address long-distance transport of ozone.
- **NO<sub>x</sub> Emissions Standards (Title IV).** EPA proposed revised New Source Performance Standards (NSPS) for NO<sub>x</sub> on July 9, 1997. The proposed changes reduce limits of NO<sub>x</sub>

emissions from utilities to 1.35 pound per megawatt-hour (net energy output) regardless of fuel type. Compliance is determined on a 30-day rolling average basis. An alternate standard of 0.15 pound per million Btu (heat input) has also been proposed.

### *Air Toxics*

Under Title III of the CAAA, EPA is responsible for determining the hazards to public health posed by 189 hazardous air pollutants (HAPs) and is required to perform a study of HAPs to determine the public health roles that are likely to occur as a result of power plant emissions. DOE recognized the importance of detecting and measuring HAPs in stack gases. A program was implemented with industry to monitor HAPs emissions at CCT projects sites, under both baseline and demonstration operating conditions. Two objectives of the 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. As a result, 24 CCT projects are monitoring HAPs, with 10 having been completed by the end of 1996 (see Appendix C, Exhibit C-7).

In another effort begun in January 1993, EPA, with the participation of the U.S. Department of Energy (DOE) under the Coal R&D Program, the Electric Power Research Institute (EPRI),

and the Utility Air Regulatory Group (UARG), began an emissions data collection program using state-of-the-art sampling and analysis techniques. Emissions data were collected from eight utilities representing nine process configurations, several of which were sites for CCT projects. These utilities represented different coal types, process configurations, furnace types, and pollution control methods. The report, *A Comprehensive Assessment of Toxic Emissions from Coal-Fired Power Plants: Phase I Results from the U.S. Department of Energy Study*, was released in September 1996 and provided the raw data from the emissions testing. In another effort, HAPs data were collected from 16 power plants. A report released in July 1996, *Summary of Air Toxics Emissions Testing at Sixteen Utility Plants*, provides an assessment of HAPs measured in the coal, across the major pollution control devices, and the HAPs emitted from the stack.



▲ Hazardous air pollutants will be measured at the Wabash River IGCC unit.

The second phase of the DOE/EPRI effort currently in progress will conduct sampling at other sites, including the CCT Program's Wabash River integrated gasification combined-cycle (IGCC) project. Further, the results from the first phase will be used to determine what configuration and coal types require further assessment.

In October 1996, EPA submitted to Congress an interim version of its technical assessment of toxic air pollutant emissions from power plants, *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units, Interim Final Report*. EPA plans to continue evaluating the potential exposures and potential public health concerns from mercury emissions from utilities. In addition, the agency will evaluate information on various potential control technologies for mercury. If EPA decides that HAPs pose a risk, then it must propose air toxic emissions controls by November 15, 1998, and make them final 2 years later.

However, the results of the HAPs program have significantly mitigated concerns about HAPs emission from coal-fired power generation and focused attention on but a few flue gas constituents. The results have the potential to make the forthcoming EPA regulations less strict, which could avoid unnecessary control costs and thus save consumers money on electricity bills.

### ***Global Climate Change Protection***

The CCT Program had its roots in the reduction of acid rain precursors and was responsive to the U.S. and Canadian Special Envoys' recommendations. Ten years later, the future of coal and clean coal technology may rest on the outcome of international concerns

and negotiations on emissions of greenhouse gases (GHG), particularly carbon dioxide (CO<sub>2</sub>).

In 1992, the United States became a signatory to the Framework Convention on Climate Change (FCCC). The FCCC directed Annex I parties (developed countries) to implement programs and actions aimed at returning GHG emissions to 1990 levels by 2000. As a result, the *Climate Change Action Plan*, published in October 1993, initiates a number of voluntary mitigation actions. In 1995, the first meeting of the Conference of Parties (COP-I) to the FCCC was held in Berlin. The purpose of this conference was to determine whether the non-binding FCCC was adequate. It was determined that most parties at COP-I were not meeting the previously agreed to goals. As a result, the Berlin Mandate was adopted. The Berlin Mandate calls for negotiation of a protocol to enhance the commitments of Annex I parties for the period beyond 2000. An Ad Hoc Group on the Berlin Mandate is charged with (1) setting quantified emissions limitations and reduction objectives within specified time frames; (2) establishing a joint implementation pilot program that would reduce, avoid, or sequester greenhouse gases; and (3) not introducing any new commitments from non-Annex-I parties. A draft negotiating text of the protocol has been circulated for comment. The Ad Hoc Group is scheduled to meet during July-August 1997 and in October 1997 to continue efforts to build consensus and finalize the protocol document.

COP-II, held in Geneva, Switzerland, in July 1996, resulted in the Geneva Declaration calling for Annex I parties to adopt legally binding commitments by COP-III scheduled for Kyoto, Japan, in December 1997. The U.S. position supported verifiable medium-

term targets that are realistic and achievable, with maximum flexibility (including joint implementation and emissions trading among nations).

The responsiveness and role of clean coal technologies in meeting GHG reduction goals of U.S. utilities is found in the *Climate Change Action Plan's* Climate Challenge Program. The basis of the program is described in the April 20, 1994, Memorandum of Understanding between DOE and representatives of the nation's electric utility industry:

- Edison Electric Institute
- American Public Power Association
- National Rural Electric Cooperative Association
- Large Public Power Council
- Tennessee Valley Authority

The program consists of voluntary commitments by electric utilities to undertake actions to reduce, avoid, offset, or sequester GHG emissions. These commitments are formalized in individual utility Participation Accords for large utilities and in Letters of Participation for small utilities. DOE provides technical information and support, reports on the progress of the program, and provides public recognition to utility participants. The types of commitments are broad enough so that any utility can participate, regardless of size, type, or amount of generation, resource mix, or load growth.

Clean coal technologies can play an important role in implementation of these Participation Accords. Improvements in generation technology, how generation is operated and maintained, and where on the grid it is located can have measurable beneficial effects on

both GHG emissions and operating costs. Utilities are pursuing three broad strategies for reducing GHG emissions through more efficient power generation: (1) improving the efficiency of existing capacity, (2) repowering or replacing generation with more efficient generation, and (3) repowering or replacing generation with generation that uses lower-carbon fuels.

More than half of the Participation Accords include fossil-related activities; many of the remaining accords are from utilities not having fossil-fired generating capacity. Fossil-related GHG reduction commitments total about 7.4 million metric tons of carbon equivalent in the year 2000, approximately one-sixth of all Climate Challenge Program tonnage commitments.

As part of its accord, CINEnergy has installed clean coal technology at the Wabash River Generating Station, which is owned by its subsidiary, PSI Energy. In a fully commercial setting, PSI Energy and its partner, Destec Energy, are demonstrating coal gasification repowering of an existing unit. Where there was an aging, inefficient, little-utilized unit, there is now a very clean and highly efficient unit that will generate power at high load well into the next century. The original plant capacity was 100 MWe, but is now 262 MWe (net); and the original heat rate of 11,000 Btu per kilowatt-hour is now under 9,000, one of the lowest for commercial coal plants in the United States. Because the heat rate is so much lower, the rate of CO<sub>2</sub> emissions is decreased by about 20 percent. Additionally, emissions of SO<sub>2</sub>, NO<sub>x</sub>, and particulate matter (PM) are reduced by at least 90 percent.

The 250-MWe Tampa Electric compound integrated gasification combined-cycle project began

operations in 1996. With a heat rate of 8,600 Btu per kilowatt-hour (40 percent efficiency), it will result in a GHG emission reduction of over 20 percent, compared to conventional technology. Sierra Pacific Power Company's Piñon Pine integrated gasification combined-cycle project (99 MWe) scheduled to begin operation in mid-1997 will result in similar reductions. Other technologies, such as the pressurized fluidized-bed combustion and integrated gasification fuel cell, being demonstrated under the CCT Program offer a major opportunity to contribute to this international environmental issue.

Finally, in an effort to increase the awareness of the role that clean coal technologies can have in meeting global climate concerns, the United States is participating in the International Energy Agency Greenhouse Gas R&D Program (IEA/GHG). The work conducted by the program focuses on technical and economic assessments and collaborative research on technology to address global concerns due to possible climate change resulting from atmospheric buildup of greenhouse gases. The IEA/GHG investigates and evaluates technical ways of reducing greenhouse gas emissions through improved fossil fuel technologies and by capture and sequestration of greenhouse gases. Participation in the IEA/GHG collaboration leverages the funding by the United States. This program also serves as a source of independent expert data on coal technologies to address global climate concerns for policy makers, industry, and the public.

The IEA/GHG is conducting studies of a number of technologies, including many clean coal technologies. For example, completed studies include integrated coal gasification combined cycles, advanced

pulverized coal cycles, ocean sequestration of CO<sub>2</sub>, and chemical utilization of CO<sub>2</sub>. Examples of ongoing studies include integrated gasification fuel cells and IGCC using Orimulsion.

### ***Value-Added Solid Waste***

The CCT Program addressed the issue of trading off air emissions at the expense of solid waste. For example, conventional SO<sub>2</sub> emissions control technologies generate a scrubber sludge that must be carefully handled and disposed of in sludge ponds. Estimates are that by 2015 over 4,500 acres per year would be required to dispose of FGD sludge if wet FGD systems were used. Most of technologies being demonstrated under the CCT Program produce dry solid wastes that significantly reduce the disposal problem. Nine projects produce dry, solid compounds or composites that can be used as building materials, agriculture supplements, neutralizing agents for use with acid mine drainage, and for other purposes; five CCT projects produce commercial-grade gypsum; and eight projects produce a salable by-product in the form of commercial-grade sulfur or sulfuric acid. One project, the Passamaquoddy Technology Recovery Scrubber™ produced fertilizer and distilled water.

## **Coal Technologies for Competitive Performance**

In 1986 when the CCT Program was begun, the electric utility industry was highly regulated. The major uncertainty was the breadth and depth of environmental regulatory requirements that would be

imposed on the industry. Even this uncertainty was mitigated by the fact that most of the environmental control costs could be passed through to the consumer if approved by the state regulatory commission. As long as the utility made prudent investments in plant and equipment, their economic future was fairly stable and predictable. It was assumed that coal and nuclear energy would carry the burden of baseload generation, oil would be phased out, and natural gas would be used for meeting peak load requirements.

By mid-1997, the picture was entirely different: the utility industry is in the midst of a major restructuring to accommodate a competitive marketplace. This restructuring was driven by legislative, consumer, and technology factors as follows:

- Consumers became a major factor in pushing for competition and regulatory reform even though regulators provide the oversight necessary to assure consumers were paying a fair price. However, the price differential among the states and regions of the country meant that large industrial users of electricity in some areas were burdened with high electricity prices, while their competitors in other areas had access to much lower cost electricity costs and thus a competitive production cost edge.
- The Public Utility Regulatory Policies Act of 1978 (PURPA) and the Energy Policy Act of 1992 (EPAcT) were two major legislative drivers. Under PURPA, utilities were required to purchase electricity from certain “qualified facilities” (QFs) at a price equal to the utility’s estimated avoided cost. As a result, the amount of electricity generated by these

nonutility power producers increased dramatically to over 280 billion kilowatt-hours or about 10 percent of the utility generation in 1995. EPAcT, in amending the Public Utility Holding Company Act of 1935 (PUHCA), lifted more of the constraints on the development of nonutility generation as well as some of the restrictions on competition in wholesale electricity markets.

- EPAcT created a new class of producer called the exempt wholesale generator (EWG), which was defined as “any person determined by the Federal Energy Regulatory Commission to be engaged directly through one or more affiliates—and exclusively in the business of owning or operating—all or part of one or more eligible facilities and selling electric energy at wholesale.” This amendment to PUHCA provided that nonutility companies could develop EWGs without coming under the provisions of PUHCA and exempt holding companies could also develop EWGs without losing their exemption from PUHCA. Any EWG also in the retail utility’s rate base had to receive state regulatory approval before it could be exempted from PUHCA. EPAcT (Section 711) specifically allowed both registered and exempt holding companies to own, acquire, and operate EWGs. The law also allowed for so-called “hybrid plants,” which have ownership divided between utility companies, whose portion is included in the rate base, and EWGs, whose portion is exempt. The act sought to limit the abuse of affiliate transactions by prohibiting an electric

utility company from purchasing wholesale energy from an EWG that was one of its affiliates. Unlike PURPA, PUHCA reforms did not guarantee EWGs a market for their power, thereby requiring that it compete with power from other sources in the wholesale power market.

- EPAcT further promoted wholesale competition by mandating that transmission facility owners must provide open access to the grid by wheeling power to wholesale customers at cost-based rates (Subtitle B of the Electricity Title VII). Further, anyone may petition FERC for access to the transmission grid. On April 14, 1996, FERC issued two closely related orders, Orders No. 888 and 889, detailing rules to assure nondiscriminatory open access to interstate electricity transmission and recovery of the utilities’ prudently incurred costs.
- Consumer pressures for access to lower priced power have been successful in bringing about competition in retail as well as wholesale power markets. Deregulation of retail markets is occurring at the state level. (FERC is prohibited from ordering retail wheeling.) Under EPAcT, states continue to have responsibility for regulating (1) any electric company operating within its jurisdiction, (2) any EWG selling electricity wholesale to such a utility, and (3) any holding company that was an associate or affiliate of an EWG selling power to a regulated utility. By early 1997, three states—California, Pennsylvania, and Rhode Island—had enacted legislation to allow

competition in the retail electricity market. In 38 other states, retail deregulation is either planned or under discussion, with 10 of these states having a proposed time schedule for deregulation. Pilot projects are ongoing in Massachusetts, New Hampshire, New York, Illinois, Idaho, and Washington and have been proposed in five other states. Under retail deregulation, end users are not required to purchase power from their local utility company, but instead may purchase power from generators or marketers located in other states and regions of the country. In this competitive market environment, power is priced according to market conditions, not necessarily according to generation costs.

- Advances in the technology of electricity production are another factor that has had an impact on restructuring. Nonutility generators have taken advantage of these advances, such as aero-derived gas turbines, to generate cheaper electricity than can be achieved using conventional fossil steam and/or nuclear generators. The new technologies are often more efficient and less environmentally obtrusive and can be installed in a very short period of time in capacity modules closely matching the load growth curves.

These factors have had a pronounced effect on the utility market for coal and clean coal technology. A comparison of 1985 and 1996 energy projections for coal, natural gas, and oil shown in Exhibit 1-3 illustrates the magnitude of the change that restructuring is playing, as well as environmental regulation discussed previously. Coal is projected to maintain its lead in the production of electricity in 2010 at 50 percent; however, that is down from 60 percent when the CCT Program started. The differential has been, for the most part, made up by the growth in natural-gas-fueled power generation. Nuclear power's contribution to the nation's electric power generation in 2010 is about the same in both projections.

Industry restructuring and competition will impact coal and coal technologies for the foreseeable future. Utilities are expected to improve their operating efficiencies by using existing plants at higher capacity factors. EIA has projected that the capacity

factor for coal-fired power plants will increase from 63 percent in 1995 to 74 percent in 2015. Between 1995 and 2010, the most economical choice for new power generation is natural-gas-fired capacity. EIA projects gas-fired generation to grow from over 330 billion kilowatt-hours in 1995 to 1,184 billion in 2015, most of that using combined-cycle technology. EIA further predicts that no net coal-fired capacity additions will be made until after 2010, when rising natural gas costs and nuclear retirements are projected to cause increasing demand for coal-fired baseload capacity. At that time, new, highly efficient, low-emissions power systems will enter the power production markets. New concepts to reduce delivered electricity prices will likely be employed. Examples include minemouth plants that reduce or eliminate the coal transportation cost component in power production and electric power and coproduct production systems, which allow the consumer's cost of electrici-

**Exhibit 1-3  
Comparison of Energy Projections**

	<b>Electricity Sales (10<sup>9</sup> kWh)</b>			<b>Coal (10<sup>6</sup> tons)</b>			<b>Gas (10<sup>12</sup> ft<sup>3</sup>)</b>			<b>Oil (10<sup>6</sup> barrels)</b>		
	<b>A</b>	<b>B</b>	<b>% dif</b>	<b>A</b>	<b>B</b>	<b>% dif</b>	<b>A</b>	<b>B</b>	<b>% dif</b>	<b>A</b>	<b>B</b>	<b>% dif</b>
1995	3,018	3,008	0	924	959	4	3.0	3.5	17	0.2	0.3	50
2000	3,384	3,290	-3	1,059	1,017	-4	2.7	4.3	60	0.6	0.2	-66
2010	4,176	3,784	-9	1,355	1,099	-19	1.7	6.9	305	0.4	0.3	-25

% dif = % difference between the two projections.

A *National Energy Policy Plan Projections to 2010*, U.S. Department of Energy, December 1985.  
 B *Annual Energy Outlook 1997 with Projections to 2015*, Energy Information Agency, December 1996.



ty to be offset by the profitability of coproducts. The CCT Program is demonstrating the first commercial versions of the advanced high-efficiency coal systems that will be needed when older plants are retired and new capacity additions are needed to assure continued low-cost, reliable electric power service.

## Coal Technologies to Keep America Secure

It is in the national interest to maintain a multi-fuel energy mix to sustain national economic growth. Coal is a key component of national energy security because of its low cost, availability, and abundant supplies within the nation's borders. The CCT Program pursues a strategy that leads to the development and deployment of a technology portfolio that enhances the efficient use of this coal resource base while assuring national and global environmental goals are achieved. The domestic coal resources are large enough to meet demand for almost 270 years at current rates of consumption.

The United States is increasingly dependent on imported oil as low prices have resulted in decreased domestic oil production for 13 years. That trend was broken in 1995 by an oil production capacity increase of 0.4 million barrels per day. However in 1995, net petroleum imports were 7.9 million barrels per day, or 45 percent of domestic consumption. In its latest projections for 2015, EIA expects imports to range from 10.8 to 15.9 million barrels per day depending on oil price. The EIA reference case for 2015 calls for net imports of 13.5 million barrels per day, which is

equivalent to over 60 percent of consumption. Also, natural gas imports are expected to grow from 12.4 percent of total gas consumption in 1995 to 14.0 percent in 2015. These imports are primarily from Canada, which does not represent a supply stability problem but does represent a drain on balance of payments.

U.S. coal consumption is equivalent to approximately 10 million barrels of oil per day and represents a reduction in balance of payments of over \$50 billion per year. Clean coal technologies will provide the utilization and conversion technologies that will enable the coal fuel cycle to continue as a major component in the nation's economy while achieving the environmental quality that society demands. The domestic and export value of 1995 coal production approaches \$25 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.

A U.S. coal conversion industry could also directly reduce the nation's dependency on imported oil. The economic impact of adding to domestic oil production or reducing the cost of imported oil is very significant. For example, in 2015, if the cost per barrel of oil is reduced by one dollar, the overall savings to the economy would be over \$8 billion. If domestic production of liquid fuels could be increased



▲ National energy security is enhanced by coal cleaning technology being demonstrated at this Custom Coals facility.

by one million barrels per day, the U.S. balance of payments could be reduced by nearly \$150 billion over the period 2015–2030. The CCT Program is responding to this opportunity through development and demonstration of mild gasification and liquid-phase methanol production technology.

U.S. coal is exported to more than 40 nations and amounted to 89 million tons in 1995. Coal exports to foreign destinations contributed \$3.5 billion to the U.S. balance of payments in 1995. Worldwide demand for energy is expected to reach 542 quadrillion Btu by 2015, 1.6 times the current level. According to EIA, worldwide coal use is expected to account for about 25 percent of total energy consumption. Exports of U.S. coal are projected to increase during this period to over 120 million tons.

The worldwide market for power generation technologies could be as high as \$1 trillion by 2015.

Capturing just 20 percent of this market would bring in revenues of \$200 billion and support more than 100,000 jobs over three decades in the U.S. power equipment industry alone. 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. However, other governments are recognizing the enormous economic benefits that their economies can enjoy if their manufacturers capture a greater share of this market.

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 for the Future

DOE has structured an integrated Coal and Power Systems Research, Development, and Demonstration (RD&D) Program with the mission to foster the development and deployment of advanced, clean, affordable power systems and technologies for the clean utilization of coal. Pursuit of this mission is to assure an ample, secure, clean, low-cost domestic electricity and domestic fuel supply through viable technical options. This mission has a key role in achieving

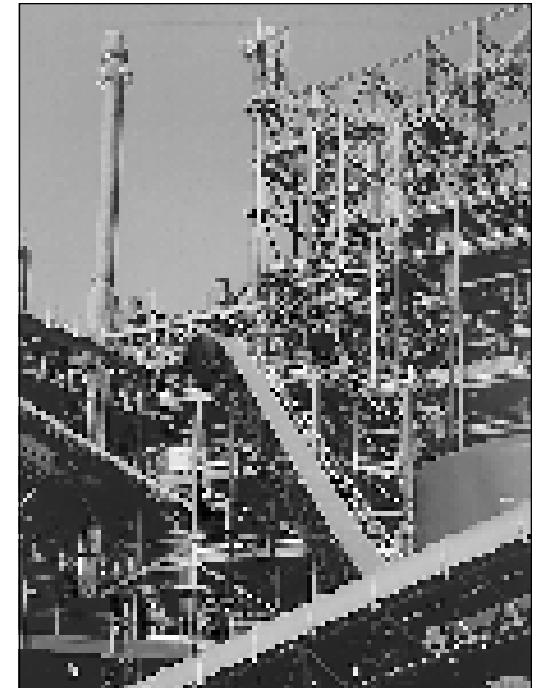
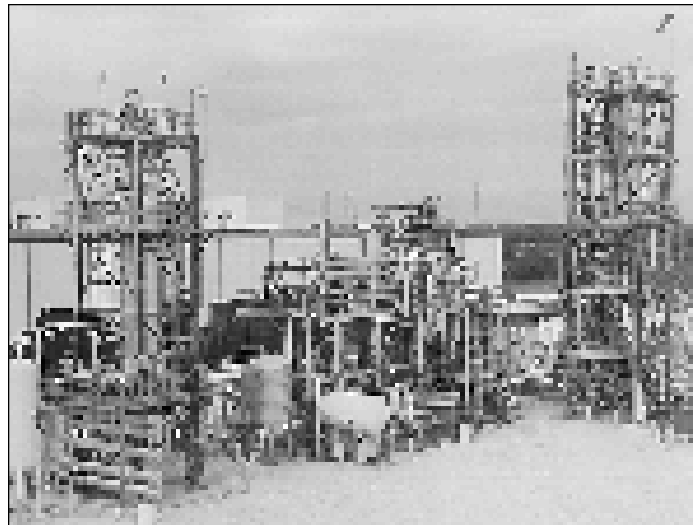
the national energy policy goals of sustainable development. Sustainable development involves a simultaneous commitment to economic prosperity, social equity, and ecological integrity.

The technology strategy followed in the integrated coal and power systems program is to (1) build on past R&D successes and experience, (2) build a portfolio of technologies including advanced, revolutionary and "leap frog" technologies, (3) provide timely and effective dissemination of technology results, and (4) use analyses as a guiding tool in RD&D direction.

The role of the Coal and Power Systems RD&D Program in advancing clean coal technology's future is shaped by a number of realities:

- Utility deregulation and the promotion of competition is having a profound effect on the utility sector's approach to R&D, resulting in sharply reduced private R&D funding and shifting the emphasis to projects with immediate or near-term payoffs.
- The era of flat or slowly rising oil prices has resulted in nearly total abandonment of liquefaction technologies RD&D funding by the private sector, as the time horizon is too long to achieve the required near-term payback.
- Increased pressure on Coal and Power Systems RD&D budgets for deficit reduction will likely continue for the foreseeable future, thus

▼ RD&D assures that clean, affordable coal technologies will be available in the future. Air Product's LaPorte coal liquefaction test facility (left) and Southern Company Services' Wilsonville power system development facility (right) contribute to RD&D efforts.



requiring innovative approaches for leveraging public-sector funds with private-sector resources in order to achieve the mission objectives.

- Industry and government support for RD&D of a broad portfolio of technologies is necessary if the domestic and global environmental challenges are to be met efficiently and economically and if U.S. industry is to maintain its position of leadership in world trade of coal and power systems technologies.

Under the Coal and Power Systems Program, RD&D are pursued in three primary product lines:

- Advanced power generation systems
- Environmental systems
- Coal fuels and industrial systems

The advanced power systems program will pursue the completion of the 10 remaining CCT Program advanced power systems projects and the dissemination of the technical, economic, and environmental results into the domestic and international marketplace. Further, advances will be pursued in the product line portfolio, including low-emission boiler systems, pressurized fluidized bed combustion, integrated gasification combined-cycle systems, indirect-fired cycles, gasification-fuel cell combinations, advanced gas turbines, fuel cells, and hybrid fuel-cell-turbine cycles. The potential performance efficiencies of these systems range from mid-40 percent up to 70 percent. The goal is to achieve these performance levels while reducing cost of electricity by 10–20 percent and emissions by 70–90 percent over current standards.

The environmental control technology portfolio includes super-clean emission control devices for the removal of SO<sub>2</sub> and NO<sub>x</sub> from power plant flue gases, hazardous air pollutant controls, innovative technologies for CO<sub>2</sub> management leading to near-zero emissions, and solid waste reduction, disposal, and use approaches. Specific goals are to develop new, advanced environmental control technologies by 2015, primarily to meet existing and pending regulations on gas-phase HAPs and NO<sub>x</sub>. The target is to attain 70–90 percent reduction in NO<sub>x</sub> at 25–50 percent of current costs and to achieve 90 percent reduction in HAPs at one-half the cost of current alternative technologies. Further, the remaining four CCT Program environmental control device projects will be completed and the technical, environmental, and economic results disseminated. The results from the 24 CCT Program HAPs monitoring projects will be analyzed and disseminated.

The coal fuels and industrial systems product line program is to develop an RD&D portfolio in liquid fuels technology that could be used for the conversion of coal, natural gas, oil shale, biomass, and other carbonaceous resources on a cost-competitive basis. Further, the coproduction of liquids and power is being pursued. Coal preparation technologies will emphasize advanced methods for removing inorganic matter that causes air toxics and other air pollutants. Industrial systems technologies will assure that industrial steam coal users and other users, such as the steel industry, will have advanced, high-efficiency and low-emission technologies available that will keep the energy contribution to the final product cost low and the product cost-competitive in the global marketplace. Further the program includes the completion of

the CCT Program's two industrial applications projects and the four coal processing for clean fuels projects. Once completed the technical, economic, and environmental results will be disseminated to the domestic and international marketplace.

The above product line programs are undergirded by advanced research that provides the fundamental science and engineering basis for future fossil energy concepts. The specific strategy is to (1) develop by 2005 key and critical evolutionary technologies that will improve performance and reduce costs of advanced power, environmental control, and fuels production systems while creating derivatives that will have immediate high-value applications; (2) develop by 2010 revolutionary technologies and processes with the potential for substantial improvements and advances in product line systems; and (3) develop by 2015 a series of "leap frog" technologies, such as advanced CO<sub>2</sub> management schemes, advanced hybrid process and cycles, smart systems, and others to address the significant issues of the early 21st century. These issues relate to achieving net-zero emissions and closing the fossil-fuel cycle to use fossil energy resources more effectively as part of sustainable development.

# 2. Program Implementation

## Introduction

The CCT Program founding principles and implementing process resulted in one of the most successful cost-shared government/industry partnerships forged to date to respond to critical national needs. Through five nationwide competitions, a total of 39 projects, valued at nearly \$6 billion, were implemented. Of this total, the industry cost-share is an unprecedented 66 percent. Half the projects have reached successful completion. The balance are moving forward, with operational testing under way for 10 projects

Over the 9-year period of soliciting and awarding projects, the thrust of the environmental concerns relative to coal use changed. But the adopted implementing process allowed the program to remain responsive to the changing needs. The result is a portfolio of technologies and a data base that will enable coal to remain a major contributor to the U.S. energy mix without being a threat to the environment. This will ensure secure, low-cost energy requisite to a healthy economy well into the 21st century.

Success of the CCT Program is measured by the degree to which demonstrated technologies are placed into commercial service. This was a driving force in establishing the principles that created the foundation for the implementation process. The government role is non-traditional, moving away from a command-and-control approach to a performance-based approach,

where the government sets performance objectives and industry responds with its ideas and is allowed broad latitude in technical management of the projects. This encourages technology innovation and cost-sharing. The implementing process also provides for public participation. Industry and the public play major roles in this process, reflecting their respective roles in moving technologies into the marketplace.

## Implementation Principles

The principles underlying the CCT Program were developed after much study of previous government demonstration programs, those meeting with both positive and negative results. Together, the principles represent a composite of incentives and checks and balances that allows all participants to best apply their expertise and resources. These guiding principles are outlined below.

- **A strong and stable financial commitment exists for the life of the projects.** Full funding for the government's share of selected projects was appropriated by Congress at the outset of the program. This up-front commitment has been vital to getting industry's response in terms of quantity and quality of proposals received and the achievement of 65 percent cost-sharing.
- **Multiple solicitations spread over a number of years enabled the program to address a broad range of national needs with a portfolio of evolving technologies.** Allowing time between solicitations enabled Congress to adjust the goals of the program to meet changing national needs, provided DOE time to revise the implementation process based on lessons learned in prior solicitations, and provided industry the opportunity to develop better projects and more confidently propose evolving technologies.
- **Demonstrations are conducted at commercial scale in actual user environments.** Typically a technology is constructed at commercial scale with full system integration, reflective of its intended commercial configuration, and operated as a commercial facility or installed on an existing commercial facility. This enables the technology's performance potential to be judged in the intended commercial environment.
- **The technical agenda is determined by industry, not the government.** Based on goals established by Congress and policy guidance received, DOE set definitive performance objectives and performance-based evaluation criteria against which proposals would be judged. Industry was given the flexibility to use their expertise and innovation to define the technology and proposed project

in response to the objectives and criteria. DOE selected the projects based on those that best met the evaluation criteria.

- **Roles of the government and industry are clearly defined and reflect the degree of cost-sharing required.** The government plays a significant role up front in structuring the cooperative agreements to protect public interests. This includes negotiating definitive performance milestones and decision points throughout the project. Once the project begins, the industrial participant is responsible for technical management, while the government oversees the project through aggressive monitoring and engages in implementation only at decision points. Continued government support is assured as long as project milestones and terms and conditions of the original cooperative agreement continue to be met.
- **At least 50 percent cost-sharing is required throughout all project phases.** Industry's cost-share was required to be tangible and directly related to the project, with no credit for previous work. By sharing essentially in each dollar expended along the way, on at least an equal basis, industry's commitment to fulfilling project objectives was ensured.
- **Allowance for cost growth provides an important check-and-balance feature to the program.** Statutory provisions allow for additional financial assistance beyond the original agreement in an amount up to 25 percent of DOE's original contribution. Such financial assistance, if provided, must be cost-

shared by the industrial participant at no less than the cost-share ratio of the original cooperative agreement. This statutory provision recognizes the risk involved in first-of-a-kind demonstrations by allowing for cost growth. At the same time, it recognizes the need for the industrial participant's commitment to share cost growth and limits the government's exposure.

- **Industry retains real and intellectual property rights.** The level of cost-sharing warrants the industrial participant retaining intellectual and real property rights and removes potential constraints to commercialization. Industry would otherwise be reluctant to come forward with technologies they have developed to the point of demonstration, relinquishing their competitive position.
- **Industry must make a commitment to commercialize the technology.** Consistent with program goals, the industrial participant is required to make the technology available on a nondiscriminatory basis to all U.S. companies that seek, under reasonable terms and conditions, to use the technology. While the technology owner is not forced to divulge know-how to a competitor, the technology must be made available to potential domestic users on reasonable commercial terms.
- **Upon successful commercialization of the technology, repayment up to the government's cost-share is required.** The repayment obligation occurs only upon successful commercialization of the technology. It is

limited to the government's level of cost-sharing and the 20-year period following demonstration.

In summary, there are built-in checks and balances to ensure that the industry and government roles are appropriate and that the government serves as a risk-sharing partner without impeding industry from utilizing its expertise and getting the technology into the marketplace.

## Implementation Process

Significant public and private sector involvement was integral to the process leading to technology demonstration and critical to program success. Even before engaging in a solicitation, a public process was instituted under the National Environmental Policy Act (NEPA) to review whether the planned course of action was prudent. A programmatic environmental impact assessment (PEIA), followed by a programmatic environmental impact statement (PEIS), was prepared prior to initiating solicitations. Public comment and resolution of comments were required prior to proceeding with the program.

As to the solicitation process, Congress set the goals for each solicitation in the enabling legislation and report language (see Appendix A for legislative history and Appendix B for program implementation history). DOE translated the congressional guidance and direction into performance-based criteria and developed approaches to address lessons learned from previous rounds. Before proceeding with a solicitation, however, an outline of the impending solicitation

and attendant issues and options was presented in a series of regional public meetings to obtain input. The public meetings were structured along the lines of workshops to facilitate discussion and obtain comments from the broadest range of interests. Comments from the public meetings were then used in preparing a draft solicitation, which in turn was issued for public comment. Comments received were formally resolved prior to solicitation issuance.

To aid proposers, preproposal conferences were held for the purpose of clarifying any aspects of the solicitation. Further, every attempt was made in the solicitation to impart a clear understanding of what was being sought, how it would be evaluated, and what contractual terms and conditions would apply. A section was devoted to helping potential proposers determine technology eligibility, and numerical quantification of the evaluation criteria was provided. The solicitation also contained a model cooperative agreement with the key relevant contractual terms and conditions.

Project selection and negotiation leading to award were conducted under stringent rules carrying criminal penalties for non-compliance. Proposals were evaluated and projects negotiated strictly against and within the criteria and terms and conditions established in the solicitation. In the spirit of NEPA, information required and evaluated included project-specific environmental, health, safety, and socioeconomic aspects of project implementation.

Upon project award, another public process was engaged to ensure that all site-specific environmental concerns were addressed. NEPA requires that a rigorous environmental assessment be conducted to address all potential

environmental, health, safety, and socioeconomic impacts associated with the project. The findings can precipitate a more formal environmental impact statement (EIS) process, or the findings can remain as an environmental assessment (EA) along with a finding of no significant impact. Under an EIS, public meetings are held for the purpose of disclosing the intended project activities, with emphasis on potential environmental, health, safety, and socioeconomic impacts and planned mitigating measures. Comments are sought and must be resolved before the project can proceed. This has led to additional actions taken by the industrial participant beyond the original project scope. To facilitate the NEPA process, DOE encouraged environmental data collection through cost-sharing during the negotiation period contingent upon project award.

Because of the environmental nature of the CCT Program, DOE took a proactive posture in carrying out the principles of NEPA. Environmental concerns were aggressively addressed and the public engaged

▼ The NEPA process assured environmental acceptability of the Healy Clean Coal Project on the border of Denali National Park in Alaska.



prior to major expenditure of public funds. Furthermore, DOE required that an in-depth environmental monitoring plan (EMP) be prepared, fully assessing potential pollutant emissions, both regulated and unregulated, and defining the data to be collected and the methodology for collection. All cooperative agreements required preparation of environmental monitoring reports that provide results of the monitoring activities. As discussed previously, as environmental issues emerged, every effort was made to address them directly with the understanding that commercial technology acceptance hinged on satisfying users and the public as to acceptable environmental performance. Appendix C reviews the proactive environmental stance taken by the program, further delineates the NEPA process, and provides the status of key actions.

Projects are managed by the participant, not the government. However, public interests are protected by requiring defined periods of performance referred to as budget periods, throughout the project. Budget periods are keyed to major decision points. A set amount of funds are allotted to each budget period, along with performance criteria to be met before receiving funds for the next budget period. These criteria are contained in project evaluation plans (PEPs). Progress reports and meetings during budget periods serve to keep the government informed. At the decision points, progress against PEPs is formally evaluated, as is the PEP for the next budget period. Financial data is also examined to ensure the participant's capability to continue required cost-sharing. Failure to perform as expected results in greater government involvement in the decision-making process. Proposal of major project changes precipitates

not only in-depth programmatic assessment, but legal and procurement review as well. Decisions regarding continuance into succeeding budget periods, any increase in funding, or major project changes require the approval of the Assistant Secretary with program responsibility.

Beyond the formal process associated with the solicitations, parallel efforts were conducted to inform stakeholders of ongoing events, results, and issues, and to engage them in discussion on matters pertinent to ensuring that the program remained responsive to needs. A continuing dialog was facilitated by direct involvement in the projects of a large number of utilities, technology suppliers, and states as well as key industry-based research organizations (e.g., EPRI and GRI). This was accompanied by executive seminars designed to fill communications gaps in the utility, independent power production, regulatory, and financial sectors. The approach was to identify those sectors where inputs were missing and then structure seminars to provide information on the program and obtain the executives' perspectives and suggestions for enhancing program performance. An annual CCT conference was instituted to serve as a forum for updating progress and results and discussing issues. A CCT outreach program (discussed in Section 4) was put in place to ensure that needed information was prepared and disseminated in the most efficient manner, leveraging a variety of domestic and international conferences, symposia, and workshops.

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 accom-

plishment of shared objectives. The experience developed in dealing with complex business arrangements of multi-million-dollar CCT projects is a significant asset that has contributed greatly to the CCT Program's success—an asset of value to other programs seeking to forge government/industry partnerships. Because of this, *The Clean Coal Technology Program Lessons Learned* was published in July 1994. This report documents the knowledge acquired over the course of the CCT Program through the completion of five solicitations. The report was based on the belief that it is of mutual advantage to the private and public sectors to identify those factors thought to contribute to the program's success and to point out pitfalls encountered and corrective actions taken.

## 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 the technologies achieve widespread commercial success. The importance attached to commercial realization of clean coal technologies is highlighted in Senate Report 99-82, which contains the following recommendation 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 cooperative agreements that the project participant must pursue commercialization of the technology after successful demonstration.

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

- 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 that 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's business, marketing, or energy utilization strategies

The cooperative agreement contains three mechanisms to ensure that 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 nondiscriminatory 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 implementation of the above project-specific mechanisms, the government role also includes the following functions:

- 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 CCT deployment
- 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 CCTs

## Solicitation Results

Each solicitation was issued as a Program Opportunity Notice (PON)—a solicitation mechanism for cooperative agreements where the program goals and objectives are defined but the technology is not. Proposals for demonstration projects consistent with the objectives of the PON were submitted to DOE by specific deadlines. DOE evaluated, selected, and negotiated projects strictly within the bounds of the PON provisions. Award was made only after Congress was allowed 30 in-session days to consider the projects as outlined in *Comprehensive Reports to Congress*. Exhibit 2-1 summarizes the results of solicitations. Exhibit 2-2 identifies the projects currently in the CCT Program (including two projects that were concluded in 1997) and the solicitation under which the projects were selected. Appendix B provides a

summary of the procurement history and a chronology of project selection, negotiation, restructuring, and completion or termination. Project sites are mapped in Exhibits 2-3 through 2-6, which indicate the geographic locations of projects by application category.

The resultant projects have achieved broad-based industry involvement. Some 55 individual electric generators serving 33 states have participated in the program. These utilities generate more than 178,000 MWe, approximately 25 percent of U.S. capacity, and consume about 36 percent of the coal produced domestically. Also participating were over 50 companies supplying technology and 30 providing engineering, construction, and consulting services.

The contributions of the selected projects to domestic and international energy and environmental needs are significant:

- Completed demonstration and proved commercial viability of a suite of cost-effective SO<sub>2</sub> and NO<sub>x</sub> control options to achieve moderate (50 percent) to deep emission reduction

### Exhibit 2-1 CCT Program Selection Process Summary

Solicitation	PON Issued	Proposals Submitted	Projects Selected	Projects in CCT Program as of June 30, 1997
CCT-I	February 17, 1986	51	17	8
CCT-II	February 22, 1988	55	16	9
CCT-III	May 1, 1989	48	13	13
CCT-IV	January 17, 1991	33	9	5
CCT-V	July 6, 1992	24	5	4
		211	60	39



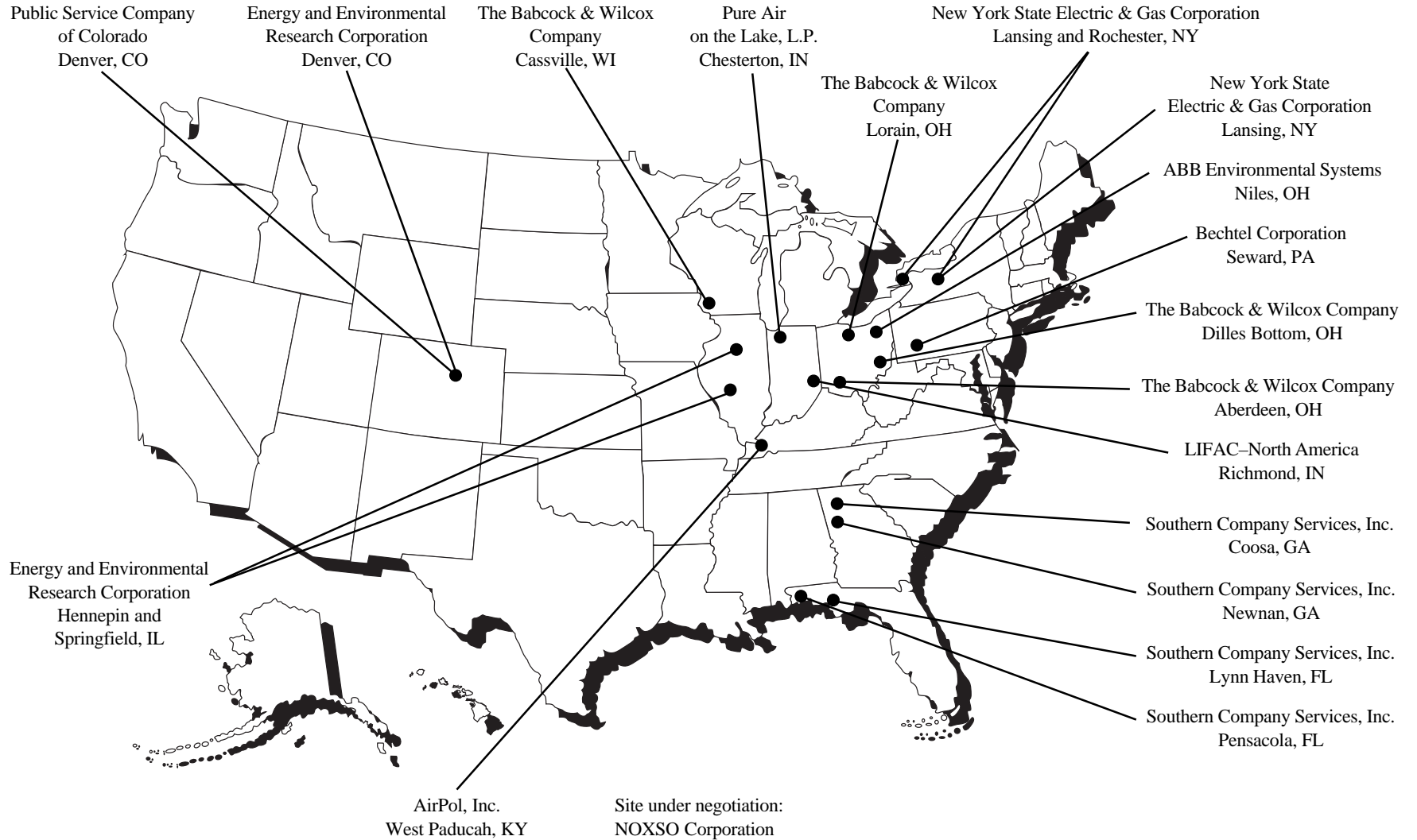
**Exhibit 2-2**  
**Clean Coal Technology Demonstration Projects, by Solicitation**

<b>Project and Participant</b>	<b>Location</b>
<b>CCT-I</b>	
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
ACFB Demonstration Project (York County Energy Partners, L.P.)	To be determined
<b>CCT-II</b>	
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	Niles, OH
Demonstration of Coal Reburning for Cyclone Boiler NO <sub>x</sub> Control (The Babcock & Wilcox Company)	Cassville, WI
SO <sub>x</sub> -NO <sub>x</sub> -Rox Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)	Dilles Bottom, OH
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 <sub>x</sub> 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 <sub>x</sub> Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	Lynn Haven, FL
<b>CCT-III</b>	
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
Healy Clean Coal Project (Alaska Industrial Development and Export Authority)	Healy, AK
Full-Scale Demonstration of Low-NO <sub>x</sub> Cell Burner Retrofit (The Babcock & Wilcox Company)	Aberdeen, OH

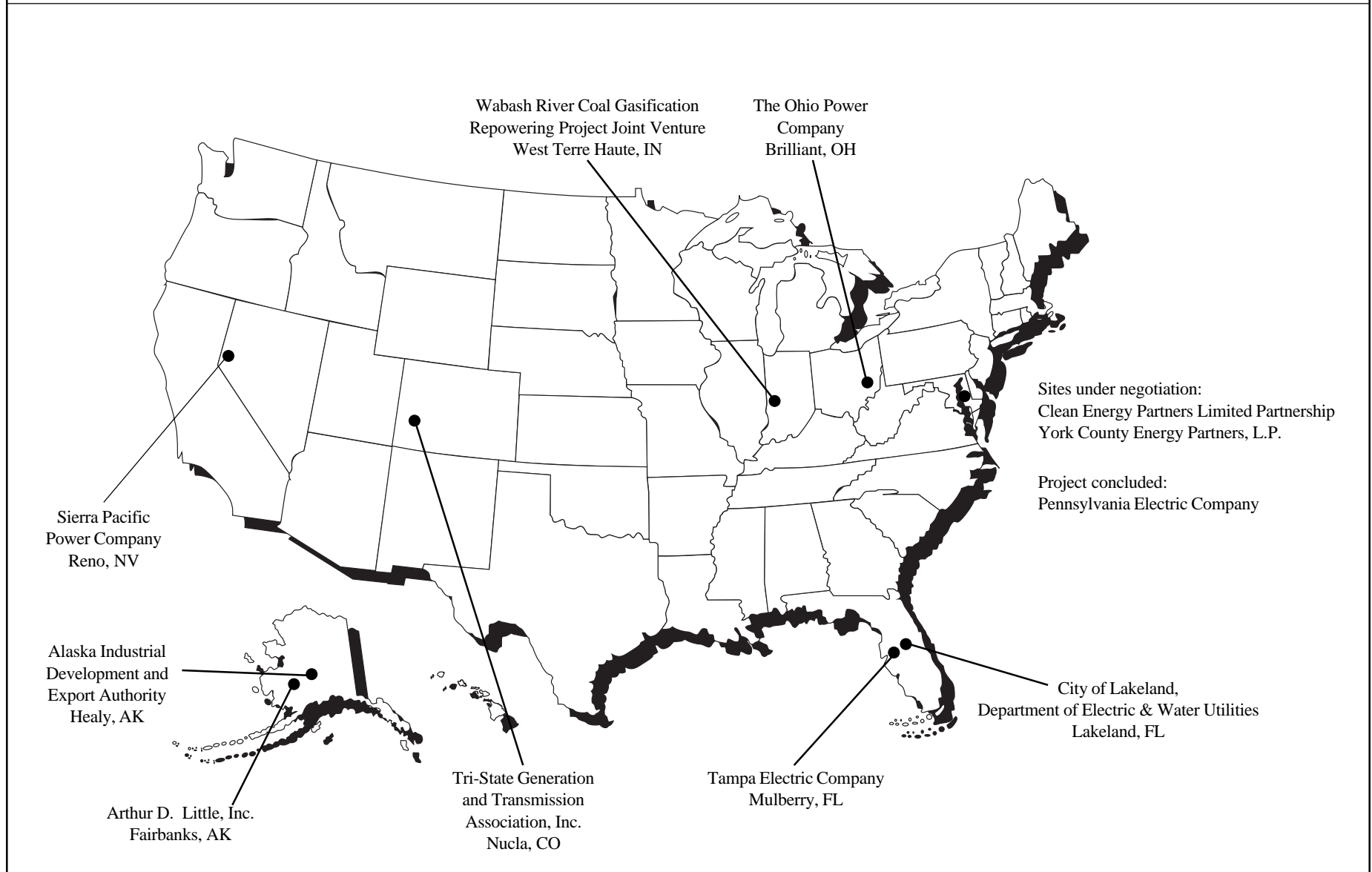
**Exhibit 2-2 (continued)**  
**Clean Coal Technology Demonstration Projects, by Solicitation**

<b>Project and Participant</b>	<b>Location</b>
<b>CCT-III (continued)</b>	
Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)	Seward, PA
Blast Furnace Granular-Coal Injection System Demonstration Project (Bethlehem Steel Corporation)	Burns Harbor, IN
McIntosh Unit 4A PCFB Demonstration Project (City of Lakeland, Department of Electric & Water Utilities)	Lakeland, FL
ENCOAL® Mild Coal Gasification Project (ENCOAL® Corporation)	Gillette, WY
Evaluation of Gas Reburning and Low-NO <sub>x</sub> 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 <sub>2</sub> /NO <sub>x</sub> Removal Flue Gas Cleanup System (NOXSO Corporation)	NOXSO site under negotiation Charleston, TN
Integrated Dry NO <sub>x</sub> /SO <sub>2</sub> Emissions Control System (Public Service Company of Colorado)	Denver, CO
Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	Mulberry, FL
<b>CCT-IV</b>	
Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International)	Central City and Lower Mt. Bethel, PA Richmond, IN Ashtabula, OH
Micronized Coal Reburning Demonstration for NO <sub>x</sub> Control (New York State Electric & Gas Corporation)	Lansing and Rochester, NY
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
Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal (ThermoChem, Inc.) (project concluded)	Not applicable
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	West Terre Haute, IN
<b>CCT-V</b>	
Clean Coal Diesel Demonstration Project (Arthur D. Little, Inc.)	Fairbanks, AK
Clean Power from Integrated Coal/Ore Reduction (CPICOR™) (CPICOR™ Management Company, L.L.C.)	Vineyard, UT
Clean Energy Demonstration Project (Clean Energy Partners Limited Partnership)	East coast site
McIntosh Unit 4B Topped PCFB Demonstration Project (City of Lakeland, Department of Electric & Water Utilities)	Lakeland, FL
Externally Fired Combined-Cycle Demonstration Project (Pennsylvania Electric Company) (project concluded)	Not applicable

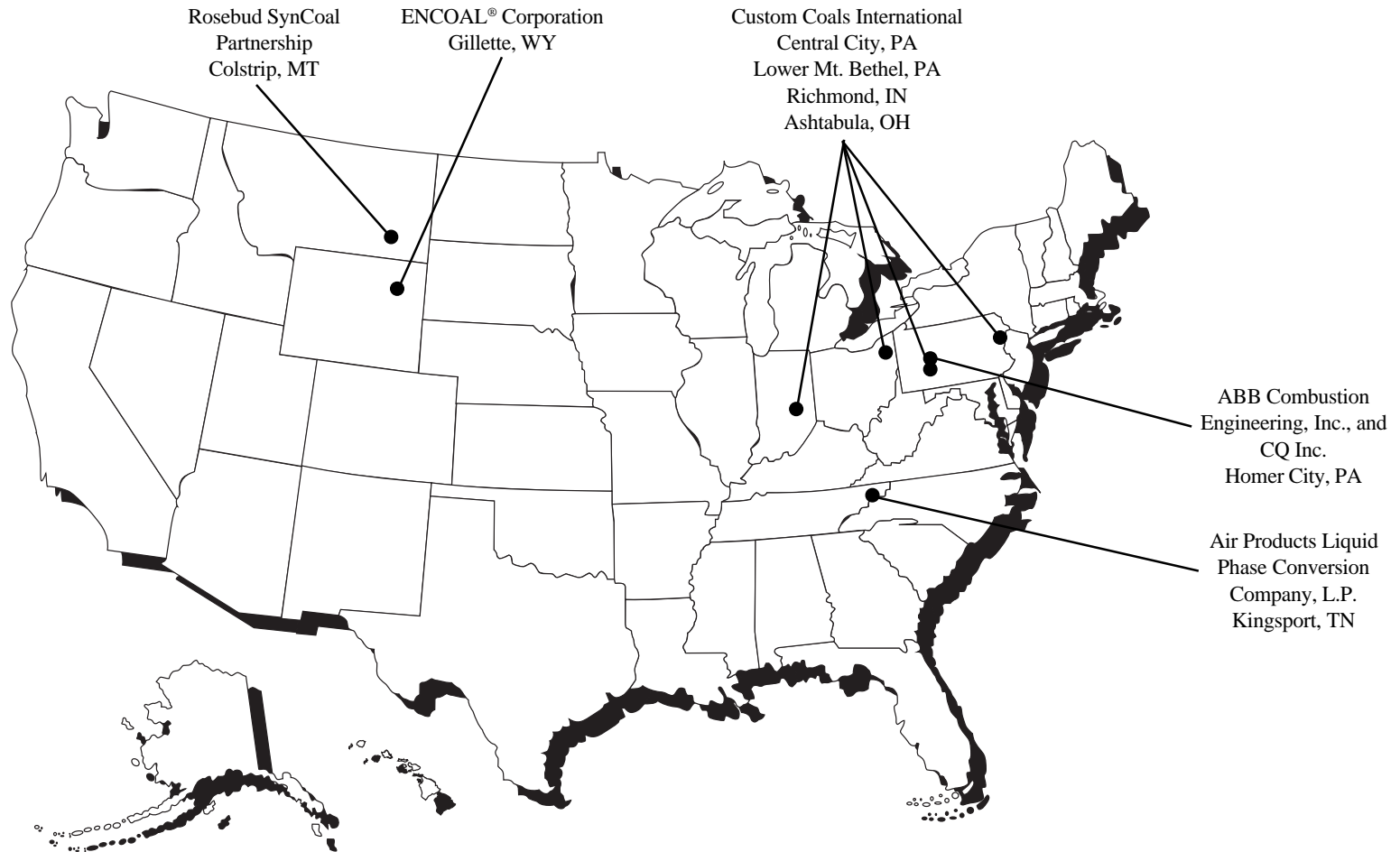
## Exhibit 2-3 Geographic Locations of CCT Projects—Environmental Control Devices



## Exhibit 2-4 Geographic Locations of CCT Projects—Advanced Electric Power Generation

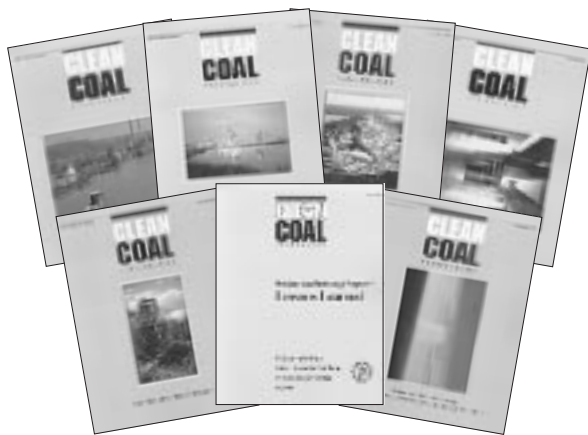


**Exhibit 2-5**  
**Geographic Locations of CCT Projects—Coal Processing for Clean Fuels**



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





▲ Publications keep stakeholders informed of CCT Program contributions.

(70–95 percent) for the full range of coal-fired boiler types

- Provided the data base and operating experience requisite to making AFBC a commercial technology at utility scale
- Completing demonstration of a number of coal processes to produce high-energy-density, low-sulfur solid fuels and clean liquids from a range of coal types
- Currently laying the foundation for the next generation of technologies to meet the energy and environmental demands of the 21st century:
  - Three IGCC plants in operation at three separate utilities
  - Demonstration of PFBC at 70 MWe successfully completed and two larger scale demonstrations in progress
- Demonstrating significant efficiency and pollutant emission reduction enhancements in

steelmaking; advanced combustion for combined SO<sub>2</sub>, NO<sub>x</sub>, and particulate control for industrial/small utility boilers; and innovative SO<sub>2</sub> control for waste elimination in cement production

## Future Implementation Direction

The future implementation direction of the CCT Program focuses on completing the existing projects as promptly as possible and assuring the collection, analyses, and reporting of the technical, economic, and environmental performance data necessary to support subsequent commercialization activity. During 1997, the following projects are expected to complete operational testing:

- Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler
- Self-Scrubbing Coal™: An Integrated Approach to Clean Air
- ENCOAL® Mild Coal Gasification Project

Further, the following projects are scheduled to begin their operational phase:

- Micronized Coal Reburning Demonstration for NO<sub>x</sub> Control
- Piñon Pine IGCC Power Project
- Commercial-Scale Demonstration of Liquid Phase Methanol (LPMEOH™) Project

Assessments will be made of the impacts that evolving and anticipated domestic and international

environmental rulings will have on the commercial deployment of technologies demonstrated under the CCT Program. The environmental performance data from completed projects will be analyzed, documented, and distributed to potential users of the technology as well as to environmental and regulatory stakeholders. This information and data can be considered during the deliberations on new standards for the reduction of acid rain precursors, hazardous air pollutants, and greenhouse gas emissions with the purpose of assuring that new standards will be reasonable and achievable in a cost-effective manner.

Technical and economic performance data from the completed projects will be reviewed and analyzed to identify opportunities to improve the competitiveness of the clean coal technologies. Opportunities could lead to such benefits as reduced capital costs, increased efficiencies, increased fuel flexibility, or reduced cost of electricity to the customer by offsetting production costs through co-product profits. Timely identification of opportunities to improve the competitive position of clean coal technologies is essential to achieving these objectives as the utility sector moves into the era of deregulation and competition. These opportunities could be acted on by program stakeholders such as technology suppliers, and federal, state, and industry RD&D organizations.

The CCT Program will continue to refine the effectiveness of the outreach program in reaching and informing all customers and stakeholders about the program and its projects and improving the perception of coal as a low-cost, environmentally acceptable fuel. In order to accomplish this objective, participation of the CCT Program stakeholders/customers will be pursued vigorously with a view toward establishing

cooperative activities to advance compatible agendas. These activities could involve CCT project site visits by interested stakeholders/customers, expansion of the audience in attendance at the Annual Clean Coal Technology Conference, expanded support for international technology conferences, and increased support for state-level education programs.

The Fifth Annual Clean Coal Technology Conference provided an opportunity to elicit recommendations for the future direction of the CCT Program from nearly 300 stakeholders by addressing four key issues facing the program as it moves into the next millennium.

### ***Issue 1: Role of CCTs in the Evolving Domestic Electricity Market***

A number of initiatives were suggested to enhance the entry of CCTs into the marketplace.

- Private sector initiatives could focus on (1) coproduction (including tri-generation of electricity, heat, and chemicals) in order to bring the price of electricity down; (2) cofiring with lower grade fuels; (3) development of standardized plants and modular production to lower capital costs; and (4) development of integrated projects (e.g., minemouth plants) within the coal sector to improve the competitive position of coal with respect to natural gas.



▲ Clean coal technology conferences provide a forum for public input for future program direction.

- Public sector (including federal and state) initiatives conceived were (1) identification of new approaches to support “favored technologies” while transitioning to deregulation, such as a nonbypassable “wire” charge to collect funds to support favored technology RD&D; (2) the implementation of a portfolio standard that requires sellers to obtain a certain percentage of their power from favored technologies, and the introduction of regulatory requirements favorable to certain technologies; (3) incentives for overseas deployment of CCTs in order to demonstrate the technologies adequately by the time they are needed domestically; and (4) recognition of the benefits of fuel diversity represented by the continued use of coal.

### ***Issue 2: International Markets—Seizing the Opportunity***

The following initiatives were identified to address international market opportunities for CCTs:

- In view of the growing evidence that a number of countries have been confused by the conflicting information and advice received about CCTs and with evidence that a number of U.S. senior energy company executives are unaware of the breadth of the CCT Program, increased efforts in education should be undertaken.
- Efforts should be focused and concentrated on a few key growth areas, such as China and India.
- A consensus needs to be developed as to what are the main barriers to technology deployment within individual countries. Further, a strategy should be developed to collectively overcome these barriers.
- Private sector/government cooperation on efforts to disseminate technical and economic information about CCTs is important. Further, a recommendation was made that the distribution of this data be accomplished under the auspices of the International Energy Agency as part of the World Bank’s clean coal initiative.
- The next Annual Clean Coal Technology Conference should contain a session during which progress on overseas demonstration projects would be reported, and increased efforts should be made to invite representatives—decision makers as well as technical and financial advisors—from key market areas to



identify what information they require to enhance the “market pull” of CCTs.

### ***Issue 3: Environmental Issues Affecting CCT Deployment***

The environmental issues that affect clean coal technology deployment and power development were found to be both international and domestic in nature.

- Environmental guidelines and requirements facing developers of international projects are promulgated by various entities, including multi-national, regional, or national development banks, private banks, finance companies, the host country, or other organizations. These guidelines may be procedural or operational in nature, and they constitute a confusing matrix for the developer. It was recommended that the World Bank expedite the finalization of its guidelines. Further, it was noted that developers should work with all entities that might affect the project. Giving attention during early project definition to the environmental aspects of site selection, baseline data and monitoring requirements, and public perception could reduce environmental compliance uncertainties.
- Domestically, it was believed that the cap-and-trade approach outlined in CAPI would result in cost savings over the command-and-control approach and should be encouraged. Further, EPA was encouraged to explore peak-shaving approaches to some problems, such as ozone attainment, as cost-effective measures. With respect to CO<sub>2</sub>, it was recommended that any agreements on emission targets should be multi-

year, involve a time horizon that is long enough to allow normal rather than premature turnover of capital stock, and allow for emissions trading and joint implementation. It also was recognized that electro-technologies could lead to total emissions reductions when electricity is substituted for direct fossil-fuel combustion. Finally, the importance of educating congressional members as well as the public on CCTs was recognized.

### ***Issue 4: CCT Deployment—From Today into the Next Millennium***

A number of uncertainties that are creating barriers and hurdles for the deployment of CCTs were identified. These barriers included the restructuring of the electric utility industry and the subsequent associated postponement of the installation of coal-fired capacity; increased competition from cheap natural gas and maturing advanced natural gas power generation technologies; CCTs being perceived as high-cost, unproven technologies; and uncertainty of environmental regulations with the potential that plant upgrading and retrofits will trigger revised NSPS.

The following initiatives were suggested to overcome some of these barriers:

- Utility restructuring legislation should emphasize use of domestic resources and contain environmental and reliability provisions to encourage the use of retrofit technologies.
- Technical initiatives should include standardization of facilities, recognition that some technologies are commercial and no longer in the demonstration phase, reduction of operating

expenses through the use of smart systems, encouragement of dual-fuel generating capacity, the use of technologies capable of multi-product production, and/or the use of multiple feedstocks.

- Government incentives should include expedited permitting, local tax incentives, targeted export assistance, and expanded state/federal coordination.
- Other near-term actions might include developing a comprehensive document listing state and local incentives (i.e., update ICTAP’s 1989 *Report to the Secretary of Energy Concerning Commercialization Incentives*); conducting an international conference on IGCC that would explore integration with other processes, products, and feedstocks; initiating a program to offer federal and state regulators tours of CCT project sites; and making Congress aware of the need to increase the use of domestic resources and to encourage dual-fuel standards to assure electric system reliability. Finally, the need was recognized for a vigorous outreach and education program that would promote awareness of the CCT Program and its projects and erase the perceived stigma of coal in general.

# 3. Funding and Costs

## Summary

Congress has appropriated a federal budget of nearly \$2.41 billion for the CCT Program. These funds have been committed to demonstration projects selected through five competitive solicitations. As of June 30, 1997, the program consisted of 39 active or completed projects.

These 39 projects have resulted in a combined commitment by the federal government and the private sector of more than \$5.7 billion. DOE's cost-share for these projects exceeds \$1.9 billion, or approximately 34 percent of the total. The project participants (i.e., the non-federal-government participants) are providing the remaining \$3.8 billion, or 66 percent of the total. Exhibit 3-1 summarizes the total costs of CCT projects as well as cost-sharing by DOE and project participants.

## 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 governments 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

**Exhibit 3-1**  
**CCT Project Costs and Cost-Sharing**  
(Dollars in Thousands)

	Total Project Costs	%	Cost-Share		Percent	
			DOE <sup>b</sup>	Participants	DOE	Participants
<b>Subprogram</b>						
CCT-I	801,469	14	239,645	561,824	30	70
CCT-II	319,177	6	139,520	179,657	44	56
CCT-III	1,409,387	25	618,947	790,440	44	56
CCT-IV	1,029,203	18	472,752	556,451	46	54
CCT-V	2,163,952	37	461,128	1,702,824	21	79
Total <sup>a</sup>	5,723,188	100	1,931,992	3,791,196	34	66
<b>Application Category</b>						
Advanced Electric Power Generation	3,220,239	56	1,219,011	2,001,228	38	62
Environmental Control Devices	704,862	12	295,191	409,671	42	58
Coal Processing for Clean Fuels	519,196	9	230,024	289,172	44	56
Industrial Applications	1,278,891	23	187,766	1,091,125	15	85
Total <sup>a</sup>	5,723,188	100	1,931,992	3,791,196	34	66
<sup>a</sup> Totals may not appear to add due to rounding.						
<sup>b</sup> DOE share does not include \$53,712,000 obligated for withdrawn and terminated projects.						

**Exhibit 3-2**  
**Relationship between Appropriations and Subprogram Budgets**  
**for the CCT Program**  
(Dollars in Thousands)

Appropriation Enacted	Subprogram	Adjusted Appropriations	SBIR & STTR Budgets <sup>a</sup>	Program Direction Budget	Projects Budget
P.L. 99-190	CCT-I	380,600	4,902	318,231	318,231
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 <sup>b</sup>	CCT-IV	427,000	7,065	25,000	394,935
P.L. 101-121 <sup>b</sup>	CCT-V	450,000	5,427	25,000	419,573
Total		2,407,595	31,081	162,527	2,213,987

<sup>a</sup> Small Business Innovation Research (SBIR) and Small Business Technology Transfer (STTR) Programs.  
<sup>b</sup> P.L. 101-121 was revised by P.L. 101-512, 102-154, 102-381, 103-138, 103-332, 104-6, 104-208, and 105-18.

by periodically reviewing project performance with the participant, and participates in decision making at major project junctures negotiated into the cooperative agreement. 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 appropriation acts and adjustments. (See Appendix A for legislative history and excerpts from the relevant funding legislation.)

Exhibit 3-2 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 Innovation Research (SBIR) Program, the Small Business Technology Transfer (STTR) Program, and CCT program direction.

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

The STTR Program implements the Small Business Technology Transfer Act of 1992 that establishes a pilot program and funding for small business concerns performing cooperative R&D efforts.

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

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

**Availability of Funding**

Although all funds necessary to implement the entire CCT Program were appropriated by Congress prior to FY 1990, the legislation also directed that these funds be made available (i.e., apportioned) to DOE on a time-phased basis. Exhibit 3-3 depicts this apportionment of funding to DOE from FY 1986, when the program was initiated, through FY 1997, when the final increment of funding became available to DOE. Exhibit 3-3 also shows the program's yearly funding profile by appropriations act and by subprogram. Funds can be transferred among 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 cooperative agreement.

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

<b>Fiscal Year</b>	<b>1986-87</b>	<b>1988</b>	<b>1989</b>	<b>1990</b>	<b>1991</b>	<b>1992</b>	<b>1993</b>	<b>1994</b>	<b>1995</b>	<b>1996</b>	<b>1997</b>	<b>Total<sup>d</sup></b>
<b>Adjusted Appropriations<sup>a</sup></b>												
P.L. 99-190	248,500	149,100									(17,000)	380,600
P.L. 100-202		50,000	190,000	135,000	199,997							574,997
P.L. 100-446				419,000	155,998							574,998
P.L. 101-121 <sup>b</sup>					35,000	315,000	0	100,000	18,000	50,000	(91,000)	427,000
P.L. 101-121 <sup>b</sup>						100,000	0	125,000	19,121	100,000	105,879	450,000
<b>Total</b>	<b>248,500</b>	<b>199,100</b>	<b>190,000</b>	<b>554,000</b>	<b>390,995</b>	<b>415,000</b>	<b>0</b>	<b>225,000</b>	<b>37,121</b>	<b>150,000</b>	<b>(2,121)</b>	<b>2,407,595</b>
<b>Subprogram Budgets</b>												
CCT-I Projects	241,958	145,273							(18,000)	(18,000)	(33,000)	318,231
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	48,925	(91,000)	394,935
CCT-V Projects						74,062	0	123,063	18,719	97,850	105,879	419,573
<b>Projects Subtotal</b>	<b>241,958</b>	<b>176,367</b>	<b>173,800</b>	<b>524,809</b>	<b>361,420</b>	<b>385,125</b>	<b>0</b>	<b>221,513</b>	<b>18,341</b>	<b>128,775</b>	<b>(18,121)</b>	<b>2,213,987</b>
Program Direction	3,479	20,500	14,000	22,548	25,000	25,000			18,000	18,000	16,000	162,527
<b>Fossil Energy Subtotal</b>	<b>245,437</b>	<b>196,867</b>	<b>187,800</b>	<b>547,357</b>	<b>386,420</b>	<b>410,125</b>	<b>0</b>	<b>221,513</b>	<b>36,341</b>	<b>146,775</b>	<b>(2,121)</b>	<b>2,376,514</b>
SBIR & STTR <sup>c</sup>	3,063	2,233	2,200	6,643	4,575	4,875	0	3,487	779	3,225	0	31,081
<b>DOE Total<sup>d</sup></b>	<b>248,500</b>	<b>199,100</b>	<b>190,000</b>	<b>554,000</b>	<b>390,995</b>	<b>415,000</b>	<b>0</b>	<b>225,000</b>	<b>37,121</b>	<b>150,000</b>	<b>(2,121)</b>	<b>2,407,595</b>

<sup>a</sup> Shown are appropriations less amounts sequestered under the Gramm-Rudman-Hollings Deficit Reduction Act.

<sup>b</sup> 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, 103-332, 104-6, 104-208, and 105-18.

<sup>c</sup> Small Business Innovation Research (SBIR) and Small Business Technology Transfer (STTR) Programs.

<sup>d</sup> Totals may not appear to add due to rounding.

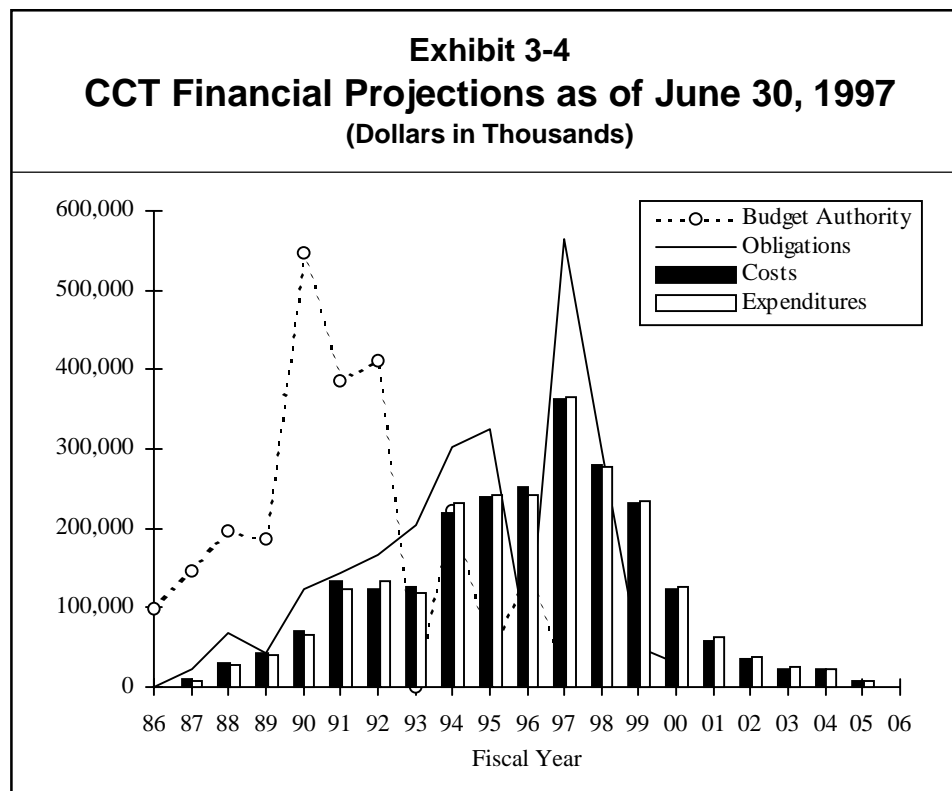
- **Obligations.** The cooperative agreement for each project establishes funding increments, referred to as budget periods. The cooperative agreement defines the tasks to be performed in each budget period. An obligation occurs in the beginning of each budget period and establishes the incremental amount 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.
- **Expenditures.** Expenditures represent payment amounts to the project participant from checks drawn upon the U.S. Treasury.

The full government cost-share specified in the cooperative agreement is considered committed to each project. 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 the decision to proceed with each major phase of project implementation.

The overall financial profile for the CCT Program is presented in Exhibit 3-4. The graph shows

actual performance for FY 1986 through FY 1996 and DOE estimates for FY 1997 through program completion. Excluded from the graph are SBIR and STTR funds, as these are used and tracked separately from the CCT Program. The financial projections presented in Exhibit 3-4 are based on individual project schedules and budget periods as defined in the cooperative agreements and modifications. The projections reflect approved modifications to the cooperative agreements.

The financial status of the program through June 30, 1997, is presented by subprogram in Exhibit 3-5. SBIR and STTR funds are included in this exhibit to account for all funding. Exhibit 3-5 also indicates the apportionment sequence as modified by Public Laws 104-208 and 105-18. 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 Section 5. An overview of project schedules and funding is presented in Exhibit 3-6.

## **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.

**Exhibit 3-5**  
**Financial Status of the CCT Program as of June 30, 1997**  
(Dollars in Thousands)

Subprogram	Appropriations Allocated to Subprogram <sup>b</sup>	Apportioned to Date	Committed to Date	Obligated to Date	Cost to Date	Apportionment Sequence		
						FY	Annual	Cumulative
CCT-I	318,231	318,231	257,157	251,967	188,787	1986	99,400	99,400
CCT-II	535,704	535,704	171,488	172,317	165,216	1987	149,100	248,500
CCT-III	545,544	545,544	618,947	523,489	416,951	1988	199,100	447,600
CCT-IV	394,935	394,935	474,784	475,598	407,467	1989	190,000	637,600
CCT-V	419,573	419,573	463,328	30,978	5,830	1990	554,000	1,191,600
Projects Subtotal	2,213,987	2,213,987	1,985,704	1,454,349	1,184,251	1991	390,995	1,582,595
SBIR & STTR <sup>a</sup>	31,081	31,081	31,081	31,081	31,081	1992	415,000	1,997,595
Program Direction	162,527	162,527	162,527	150,732	143,928	1993	0	1,997,595
Total	2,407,595	2,407,595	2,179,312	1,636,162	1,359,260	1994	225,000	2,222,595
						1995	37,121	2,259,716
						1996	150,000	2,409,716
						1997	(2,121)	2,407,595

<sup>a</sup> Small Business Innovation Research (SBIR) and Small Business Technology Transfer (STTR) Programs

<sup>b</sup> Totals may not appear to add due to rounding.

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 elements:

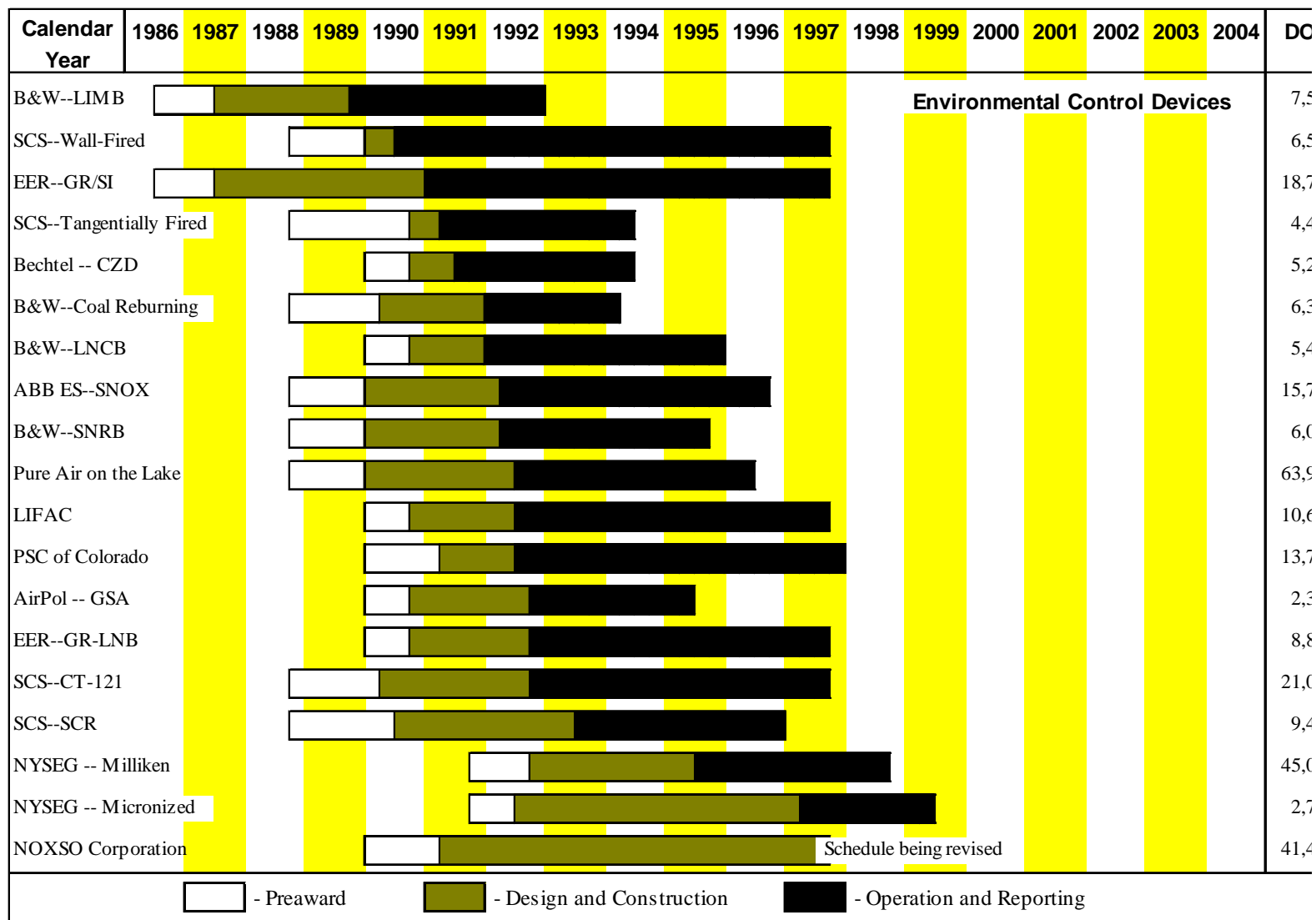
- The federal government may not finance more than 50 percent of the total costs of a project.

- Cost-sharing by the project participants is required throughout the project (design, construction, and operation).
- The federal government may share in project cost growth (within the scope of work defined in the original cooperative agreement) up to 25 percent of the originally negotiated government share of the project.
- The participant's cost-sharing contribution must occur as project expenses are incurred and cannot 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 3-1 summarizes the cost-sharing status by subprogram and by application category for the 39 active or completed projects. In the advanced electric power generation category, which accounts for 56 percent of total project costs, participants are contributing 62 percent of the funds. For the overall program, participants are contributing 66 percent of the total funding, or over \$1.8 billion more than the federal government.

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



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

Year	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	DC	
Tri-State--Nucla			█	█	█	█	█													17,1	
																					<b>Advanced Electric Power Generation</b>
Ohio Power	█	█	█	█	█	█	█	█	█	█	█										66,9
Wabash River							█	█	█	█	█	█	█								219,1
Tampa Electric					█	█	█	█	█	█	█	█	█	█	█	█					150,8
Sierra Pacific							█	█	█	█	█	█	█	█	█						167,9
AIDEA					█	█	█	█	█	█	█	█	█	█	█						117,3
McIntosh 4A					█	█	█	█	█	█	█	█	█	█	█	█	█				93,2
McIntosh 4B								█	█	█	█	█	█	█	█	█	█	█	█	█	109,2
ACFB				█	█	█	█	█	█	█	█	█	█	█	█	█	█				74,7
																					Schedule being revised
ADL--Coal Diesel								█	█	█	█	█	█	█	█						19,1
																					Schedule being revised
Clean Energy								█	█	█	█	█	█	█	█	█	█				183,3
																					Schedule being revised
ABB CE & CQ Inc. -- CQE				█	█	█	█	█	█	█	█	█	█	█	█	█	█				10,8
																					<b>Coal Processing for Clean Fuels</b>
Rosebud SynCoal				█	█	█	█	█	█	█	█	█	█	█	█	█					43,1
ENCOAL				█	█	█	█	█	█	█	█	█	█	█	█	█					45,3
Custom Coals							█	█	█	█	█	█	█	█	█	█					37,9
Air Products -- LPMEOH					█	█	█	█	█	█	█	█	█	█	█	█	█				92,7
Coal Tech	█	█	█	█	█	█	█	█	█	█	█	█	█	█	█	█	█				4
																					<b>Industrial Applications</b>
Passamaquoddy				█	█	█	█	█	█	█	█	█	█	█	█	█					5,9
Bethlehem Steel				█	█	█	█	█	█	█	█	█	█	█	█	█					31,8
CPICOR								█	█	█	█	█	█	█	█	█	█	█	█	█	149,4



## 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 that include net revenue from operation of the demonstration 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 ½ 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.

As of June 30, 1997, five projects have made repayments to the federal government: Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.); Full-Scale Demon-

stration of Low-NO<sub>x</sub> Cell Burner Retrofit (The Babcock & Wilcox Company); Development of the Coal Quality Expert™ (ABB Combustion Engineering, Inc., and CQ Inc.); 10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.); and the Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.).

# 4. CCT Program Accomplishments

## Introduction

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 that are competitive with alternative energy options.

The CCT Program has continued efforts to define and understand the potential domestic and international markets for clean coal technologies. Domestically this activity involved interviews with electric utility executives, public utility commissioners, and financiers. Analyses were made of regional electric capacity requirements, environmental compliance strategies, and the effects of electric utility restructuring on the demand for clean coal technologies. International activities continued, providing information on clean coal technologies and technical support to trade agencies, trade missions, and financial organizations.

A highlight of the continuing CCT Program outreach effort was the Fifth Annual Clean Coal Technology Conference, held in Tampa, Florida, and attended by almost 400 people, including 70 representatives from 16 countries. This conference focused on strategies and approaches that will enable clean coal technol-

ogies to resolve the competing, interrelated demands for power and economic viability in the face of environmental constraints to coal use in the post-2000 era. The program addressed the dynamic changes that will result from utility competition and industry restructuring, while considering the potential of evolving foreign markets.

Throughout the year, the CCT Program staff participated in over 15 domestic and international events involving users and vendors of technologies, regulators, financiers, environmental groups, and other public and private institutions. Five issues of the *Clean Coal Today* newsletter were published in 1996 and early 1997, along with the second annual edition of the *Clean Coal Today Index*, which cross-references all articles published in the newsletter. Publication of the first *Clean Coal Technology Program Bibliography of Publications, Papers, and Presentations* highlighted efforts to document demonstration projects over the past 10 years. DOE also continued expanded coverage of the program by publishing the 10th Anniversary issue of the annual report, *Clean Coal Technology Demonstration Program*:

*Program Update 1995*, and the second mid-year update of project fact sheets, *Clean Coal Technology Demonstration Program: Project Fact Sheets*.

## Marketplace Commitment

The true measure of the CCT Program's success will be the degree to which the clean coal technologies are adopted in the marketplace. The majority of the projects involve demonstrations at full 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 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 government serving as the risk-sharing partner, industry funding has been leveraged to achieve the following goals:

- Create jobs
- Improve the environment



- Reduce the cost of compliance with environmental regulations
- Reduce the cost of electricity generation
- Improve power generation efficiencies
- Position U.S.-based industry to export innovative services and equipment

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—environmental control devices, advanced electric power generation, coal processing for clean fuels, and industrial applications. Thus, the CCT Program can be viewed from a market perspective. This section highlights some of the program and project accomplishments to date along with commercialization successes by market sector.

### ***Environmental Control Devices***

Because control of SO<sub>2</sub> and NO<sub>x</sub> emissions from existing coal-fired boilers was the initial thrust of the program, 15 of the 19 environmental control device projects, those dealing with retrofit of existing facilities, are completed. The completed demonstrations proved commercial viability of a suite of cost-effective SO<sub>2</sub> and NO<sub>x</sub> control options for the full range of coal-fired boiler types. Risk in successfully applying the technologies commercially was significantly mitigated by the extensive databases and attendant predictive models developed through the demonstrations. Also, projects were leveraged to provide input in formulating NO<sub>x</sub> control requirements under the CAAA and to evaluate the impact of emerging issues, such as air toxics on the existing boiler population and control

options. Extensive air toxics testing was performed in conjunction with 10 of the environmental control projects. To a great extent, the technologies were retained for commercial service at the demonstration sites and many have realized commercial sales.

**SO<sub>2</sub> Control Technologies.** All five SO<sub>2</sub> control technology demonstrations have been completed, evaluating three basic approaches to address the diverse pre-NSPS boiler population:

- Low-capital-cost sorbent injection systems, sponsored by LIFAC–North America and Bechtel Corporation, demonstrated SO<sub>2</sub> capture efficiencies in the range of 50–70 percent. These systems hold particular promise for the older, smaller pre-NSPS units, particularly those with space constraints.
- A moderate-capital-cost gas-suspension-absorption system, sponsored by AirPol, Inc., demonstrated SO<sub>2</sub> capture efficiencies in the range of 60–90 percent. The system has particular applicability to the small to mid-range pre-NSPS units with some space limitations.

- Advanced flue gas desulfurization (AFGD) systems, sponsored by Pure Air and Southern Company Services and having somewhat higher capital costs than the other two approaches, demonstrated SO<sub>2</sub> capture efficiencies in the range of 90–95 percent. These systems are primarily applicable to the larger, newer pre-NSPS units that have some latitude in space availability.

The AFGD projects proved that single absorber modules of advanced design could process large volumes of flue gas and provide the required availability and reliability without the usual spares. This, combined with integration of functions within the absorber module and use of high throughput designs, significantly reduced capital cost and space requirements. AFGD testing also established that wallboard-grade gypsum could be produced in lieu of solid waste; wastewater discharge could be eliminated; and, by mitigating corrosion, fiberglass-reinforced-plastic fabrication could eliminate process steps (e.g., pre-quenching for chloride removal and flue gas reheat).

▼ SO<sub>2</sub> control technologies: AirPol (left), Pure Air (center), and LIFAC (right).



The Chiyoda CT-121 AFGD demonstration by Southern Company Services showed that the system could significantly enhance particulate control.

Pure Air on the Lake, L.P., introduced an innovative business concept whereby the company builds, retains ownership, and operates scrubbers as a contracted service to a utility. Relieving utilities of the burden of ownership and operation has proven to be an attractive approach.

Commercialization successes to date are summarized in Exhibit 4-1.

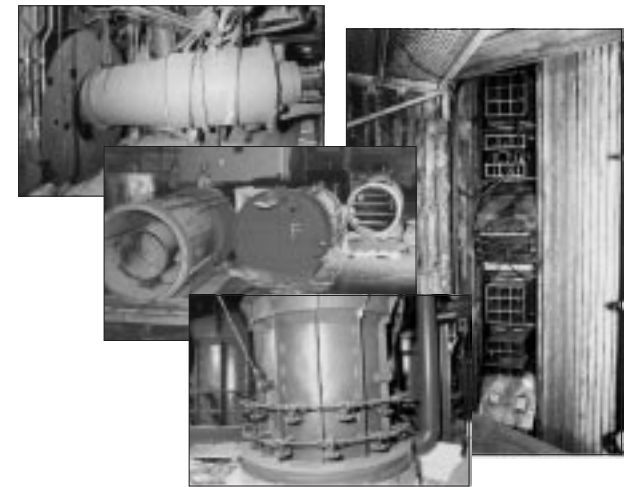
**NO<sub>x</sub> Control Technology.** Five of the seven NO<sub>x</sub> control technology demonstrations have been successfully completed. Actual testing was conducted on the four major boiler types (wall-, tangential-, cyclone-fired, and cell-burner boilers), representing over 90 percent of the pre-NSPS boiler population. Applicability extends to all boiler types.

The database developed during Southern Company Services' evaluation of NO<sub>x</sub> control on wall- and tangential-fired boilers at Plant Smith and Plant Hammond was used by the Environmental Protection Agency in formulating CAAA NO<sub>x</sub> provisions. Babcock & Wilcox's low-NO<sub>x</sub> burner systems, ABB Combustion Engineering's LNCFS™ for tangentially fired boilers, and Foster Wheeler's low-NO<sub>x</sub> burner system for wall-fired boilers have realized commercial acceptance.

Integration of artificial intelligence, neural-network systems into digital boiler controls, such as the Generic NO<sub>x</sub> Control Intelligence System (GNOCIS) installed at Plant Hammond, demonstrated effective optimization of parameters for NO<sub>x</sub> control and boiler performance under load-following operations.

### Exhibit 4-1 Commercial Successes—SO<sub>2</sub> Control Technology

Project and Participant	Commercialization Progress
LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC-North America)	Technology retained for commercial use at host site First high-sulfur coal application 10 commercial units in operation or construction (Canada, China, Finland, Russia, and U.S.)
10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.)	Sale of 50-MWe unit to city of Hamilton, OH – Value—\$10 million – Employment benefit—70 person-years Sale to U.S. Army for hazardous waste disposal – Value—\$1.3 million Sale to Sweden for iron ore sinter plant (no value available) Sales to Taiwan and India – Combined value—\$33 million – Employment benefit—10 person-years
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	Technology retained for commercial use at host site First scrubber installed to comply with CAAA Wallboard manufacturer using all gypsum produced Sale of 1,600 MWe of AFGD capacity to Florida Power & Light – Value—\$200 million – Employment benefit—1,400 person-years
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	Technology retained for commercial use at host site Sale to Canada for tar sands extraction facility Sales of 1,200 MWe of FGD capacity to Czech Republic and Korea



▲ Low-NO<sub>x</sub> burner technologies: Foster Wheeler's low-NO<sub>x</sub> burner for wall-fired boilers (top left), ABB Combustion Engineering's LNCFS™ for tangentially fired boilers (right), Babcock & Wilcox's LNCB® for cell-burner boilers (center), and Babcock & Wilcox's DRB-XCL® for down-fired boilers (bottom).

The Babcock & Wilcox Company's coal reburning technology proved not only to be an effective way to control NO<sub>x</sub> on cyclone boilers, but a means to avoid derating cyclone boilers when switching to low-sulfur, low-rank western coals.

The Babcock & Wilcox Company's low-NO<sub>x</sub> cell burner, LNCB™, provided an effective, low-cost plug-in NO<sub>x</sub> control system for cell-burner boilers known for their inherently high NO<sub>x</sub> emissions.

Energy and Environmental Research Corporation's use of gas reburning with low-NO<sub>x</sub> burners introduced an alternative SCR for high NO<sub>x</sub> emission reduction.

Comparative analyses conducted on a range of SCR catalysts operated on high-sulfur U.S. coals provided needed insight as to the environmental and economic performance potential of the approach and the various options tested under U.S. conditions.

Commercialization successes to date are summarized in Exhibit 4-2.

**Combined SO<sub>2</sub>/NO<sub>x</sub> Control Technologies.**

Five of seven combined SO<sub>2</sub>/NO<sub>x</sub> control technology demonstrations have been successfully completed, testing a multiplicity of complementary and synergistic control methods to achieve cost-effective SO<sub>2</sub> and NO<sub>x</sub> emissions reductions.

SNOX™, a catalytic process developed by Haldor Topsoe a/s, consistently achieved 95 and 94 percent SO<sub>2</sub> and NO<sub>x</sub> control, respectively, as well as excellent particulate control, while producing a salable by-product in lieu of solid waste.

In a project sponsored by Public Service Company of Colorado, complementary use of low-NO<sub>x</sub> burners with SNCR was shown to increase NO<sub>x</sub> emission reduction to greater than 80 percent (comparable

to SCR). SNCR interacted synergistically with sorbent injection to reduce ammonia slip and NO<sub>2</sub> emissions. Sodium-based sorbent injection achieved 70 percent SO<sub>2</sub> removal at high sorbent utilization rates.

The Babcock & Wilcox Company's SO<sub>x</sub>-NO<sub>x</sub>-Rox Box™, integration of a newly developed high-temperature fabric-filter bag (for baghouse installation) with SCR and sorbent injection, proved to be an easily installed, high-efficiency control system for SO<sub>2</sub>, NO<sub>x</sub>, and particulates.

LIMB and Coolside demonstrations proved that sorbent injection methods could achieve up to 70 percent SO<sub>2</sub> reduction while Babcock & Wilcox DRB-XCL® advanced low-NO<sub>x</sub> burners alone could maintain NO<sub>x</sub> emission reductions of 45 percent.

Energy and Environmental Research Corporation's demonstration of gas reburning and sorbent injection showed that NO<sub>x</sub> reductions greater than 60 percent could be achieved with only 13 percent gas heat input and SO<sub>2</sub> removal could be greatly enhanced by use of special sorbents.

**Exhibit 4-2  
Commercial Successes—NO<sub>x</sub> Control Technology**

Project and Participant	Commercialization Progress
Demonstration of Coal Reburning for Cyclone Boiler NO <sub>x</sub> Control (The Babcock & Wilcox Company)	Technology retained for commercial use at host site
Full-Scale Demonstration of Low-NO <sub>x</sub> Cell Burner Retrofit (The Babcock & Wilcox Company)	Technology retained for commercial use at host site Seven commercial contracts awarded for 144 burners – Value—\$27 million – Employment benefit—27 person-years
Evaluation of Gas Reburning and Low-NO <sub>x</sub> Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)	Technology retained for commercial use at host site
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)	Technology retained for commercial use at host site Sales of Foster Wheeler's low-NO <sub>x</sub> burners – Value—\$20 million – Employment benefit—140 person-years Sales of 6 GNOCIS neural-network controls Projected 11 additional GNOCIS sales by end of 1997 Organizations selected to market GNOCIS in U.S. and abroad
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques (Southern Company Services, Inc.)	Technology retained for commercial use at host site Sales of 10 ABB Combustion Engineering LNCFS™ systems to 8 utilities

Commercialization successes to date are summarized in Exhibit 4-3.

### **Advanced Electric Power Generation**

Early in the CCT Program, technologies were sought that could effectively repower those plants that were aging and faced with both the need to install pollutant controls and respond to growing power demands. Contributing to this approach was recogni-

tion that existing power generation sites had significant value and warranted investment given the permitting problems associated with siting new plants. This led to award of two key repowering projects, now completed—an atmospheric fluidized-bed combustion (AFBC) project and a pressurized fluidized-bed combustion (PFBC) project.

As the CCT Program unfolded, a number of energy and environmental issues combined to change

the emphasis toward seeking very high-efficiency, very low-emission power generation technologies both for repowering and new power generation. This was deemed requisite to coal fulfilling its projected contribution to the nation’s energy mix well into the 21st century. Key to this was the growing concern over greenhouse gas emissions. In addition, SO<sub>2</sub> emissions had been capped under the CAAA at year 2000 levels; NO<sub>x</sub> continued to receive increased attention in ozone nonattainment areas; and particulate emissions were identified as carriers of air toxics. This prompted follow-on projects in PFBC, initiation of projects in integrated gasification combined cycle (IGCC), and projects in advanced combustion and heat engines.

The Tri-State Generation and Transmission Association, Inc., repowering project provided the database and operating experience requisite to making AFBC a commercial technology option at utility scale. At 110 MWe, the Nucla circulating fluidized-bed (CFB) unit was more than 40 percent larger than any other AFBC at that time. The thrust of the effort was to fully evaluate the environmental, operational, and

▼ Nucla Station, repowered with a circulating fluidized-bed boiler, was the world’s first utility-scale AFBC unit in commercial service.



<b>Exhibit 4-3 Commercial Successes—Combined SO<sub>2</sub>/NO<sub>x</sub> Control Technology</b>	
<b>Project and Participant</b>	<b>Commercialization Progress</b>
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	Technology retained for commercial use at host site 305-MWe unit operating in Denmark on coal 30-MWe unit operating in Sicily on petroleum coke
LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)	Sale of LIMB to independent power project in Canada
Enhancing the Use of Coals by Gas Reburning Sorbent Injection (Energy and Environmental Research Corporation)	Illinois Power retained gas reburning for commercial use City Water, Light & Power retained full technology for commercial use
Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Corporation)	One sale of DHR Technologies’ Plant Emission Optimization Advisor (PEOA™) and another 4 bids pending Derivative of SNCR system sold to Pennsylvania Electric Company and Mitsubishi Heavy Industries of America – Value—\$1.9 million U.S. company, SHN, established to market scrubber
Integrated Dry NO <sub>x</sub> /SO <sub>2</sub> Emissions Control System (Public Service Company of Colorado)	Technology retained for commercial use at host site Sale of Babcock & Wilcox DRB-XCL® low-NO <sub>x</sub> burners for 101 boilers (55 domestic and 46 international) – Quantity—1,829 burners for 23,664 MWe capacity – Value—\$240 million – Employment—1,670 person-years

economic performance potential of AFBC. As a result, the most comprehensive database on AFBC technology available to date was developed. From this knowledge, commercial units were offered and built. Up to 95 percent SO<sub>2</sub> removal was achieved during the 15,700 hours of demonstration and NO<sub>x</sub> emissions averaged a very low 0.18 pound per million Btu.

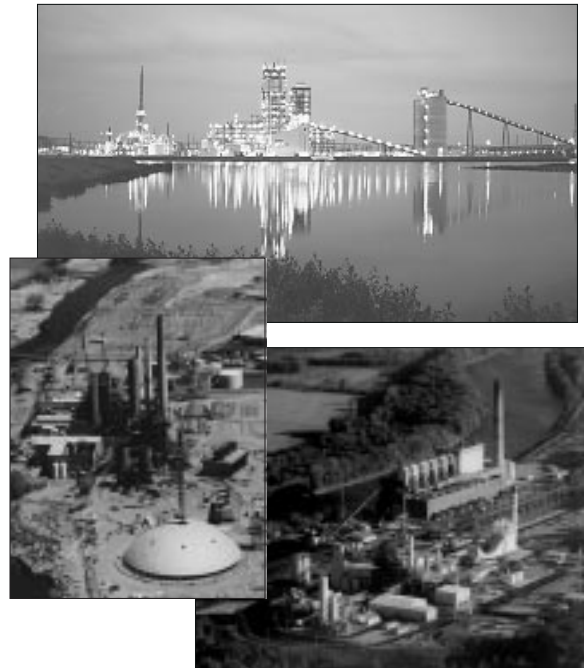
Under the Ohio Power Company repowering of the Tidd Plant (70 MWe), the potential of PFBC as a highly efficient, very low pollutant emission technology was established and the foundation laid for commercialization. The PFBC system constructed was the first utility-scale system in the United States. Efforts were focused on fully evaluating the performance potential. Over 11,444 hours of operation, the technology successfully demonstrated SO<sub>2</sub> removal efficiencies up to 95 percent with very high sorbent utilization (calcium-to-sulfur molar ratio of 1.5) and NO<sub>x</sub> emissions in the range of 0.15–0.33 pound per million Btu. Two ongoing interrelated projects, McIntosh 4A and McIntosh 4B, will take PFBC to a larger scale than the Tidd Plant and introduce second-generation PFBC.

By the end of 1996, three IGCC units were in various stages of operation at three separate utilities. PSI Energy's 262-MWe Wabash River Generating Station Unit 1 IGCC system began operation in November 1995 and by year-end 1996 had produced over 360,000 MWh of electricity using coal-derived syngas. The Tampa Electric Company's 250-MWe Polk Power Station Unit 1 IGCC system began operation in July 1996 and was placed into commercial service in September. Sierra Pacific Power Company's 99-MWe Tracy Station IGCC system initiated startup activities during 1996, and the project began its operational phase in February 1997.

Commercial configurations resulting from the current IGCC and PFBC demonstrations will typically (1) have efficiencies at least 20 percent greater than conventional coal-fired systems (with like CO<sub>2</sub> emission reductions), (2) remove 95–99 percent of the SO<sub>2</sub>, (3) reduce NO<sub>x</sub> emissions to levels equivalent to 90 percent reduction, (4) reduce particulate emissions to 1/3 to 1/10 that currently allowed under the CAAA, and (5) produce salable by-products as opposed to waste from solid residues.

Commercialization successes to date are summarized in Exhibit 4-4.

▼ Three IGCC plants are in various stages of operation: Tampa Electric (top), Piñon Pine (lower left), and Wabash River (lower right).



### ***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, enabling them to comply with the CAAA. In addition, coal processing creates the capability to generate substitute liquid fuels from coal that can replace petroleum and petroleum-based fuels in a wide range of applications, 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. Both the prod-

▼ Coal processing technologies remove barriers to the use of low-energy-density western coal resources: Rosebud (top) and ENCOAL® (bottom).



ucts and the processes have a great deal of market potential both domestically and internationally.

The barrier to using the nation's vast low-sulfur, low-energy-density western coal resource is being addressed through projects sponsored by ENCOAL® and the Rosebud SynCoal Partnership. The resultant fuels, undergoing test burns, have particular application domestically for CAAA compliance and internationally for Pacific Rim Energy markets. Energy density for the

solid fuels averages 12,000 Btu per pound, and sulfur content averages 1.0 percent. ENCOAL®'s liquid fuel product is the equivalent of No. 6 fuel oil. Total sales of Rosebud's SynCoal® product have exceeded 900,000 tons, with 130,000 tons delivered over an extended period to industrial users. ENCOAL® has delivered 15 unit trains of solid fuel to 5 utilities and 3 million gallons of liquid fuel to 8 industrial users.

Many high-energy-density, high-sulfur eastern/midwestern bituminous coals are amenable to significant sulfur removal using an advanced separation process being demonstrated by Custom Coals International. The process can remove up to 90 percent of the inorganic sulfur, which is an integral part of the ash. For coals in which the organically bound sulfur content is low, the process can produce a fuel that enables users to comply with CAAA SO<sub>2</sub> requirements. Addition of a sorbent and other additives to coals less amenable to sulfur extraction also produces a compliance fuel. Products are undergoing test burns.

ABB Combustion Engineering, Inc., and CQ Inc. developed PC-based software, CQE™, to assist utilities in assessing environmental and operational performance of their systems for the range of coal fuels available to determine the least-cost option. The CQE™ software has been distributed to 41 utility members of EPRI and is being marketed commercially worldwide. Two U.S. utilities also have been licensed to use copies of CQE™'s stand-alone Acid Rain Advisor.

Commercialization successes to date are summarized in Exhibit 4-5.

### ***Industrial Applications***

There are significant environmental issues and barriers associated with coal use in industrial applications. Production of steel has been dependent upon coke. However, coke making is an inherently large producer of not only SO<sub>2</sub> and NO<sub>x</sub>, but hazardous air pollutants. Cement production often relies on coal fuel because production costs are largely driven by fuel costs, precipitating the need for effective SO<sub>2</sub> control measures. Because of its low, stable price, coal is an

<b>Exhibit 4-4 Commercial Successes—Advanced Electric Power Generation</b>	
<b>Project and Participant</b>	<b>Commercialization Progress</b>
Tidd PFBC Demonstration Project (The Ohio Power Company)	First utility-scale PFBC in U.S. – Laid foundation for commercialization of PFBC
Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.)	Technology retained for commercial use at host site – World's first large utility-scale AFBC Demonstration commercialized utility-scale AFBC – Quantity—22 AFBC units larger than 100 MWe planned, in construction, or in operation worldwide – Estimated capacity—3,800 MWe – Estimated value—\$5 billion
Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	First greenfield IGCC unit in commercial service 400-MWe minemouth project proposed by Britain's RJB Mining Plc. and Texaco, Inc. Texaco, Inc., and ASEA Brown Boveri signed an agreement forming an alliance to market IGCC technology in Europe
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	First repowered IGCC unit in commercial service – World's largest single train IGCC in commercial service – Preferentially dispatched over other coal-fired units in PSI Energy's system because of high efficiency
Piñon Pine IGCC Power Project (Sierra Pacific Power Company)	Technology to be engaged in commercial service in 1997
Healy Clean Coal Project (Alaska Industrial Development and Export Authority)	Technology to be engaged in commercial service in 1998 TRW offering licensing of combustor worldwide (China agreement in place)



## Exhibit 4-5 Commercial Successes—Coal Processing for Clean Fuels

Project and Participant	Commercialization Progress
Development of the Coal Quality Expert™ (ABB Combustion Engineering, Inc., and CQ Inc.)	CQ Inc. and Black & Veatch working collaboratively to commercialize CQE™ worldwide CQE's Acid Rain Advisor licensed to 2 U.S. users 40 U.S. and 1 U.K. utilities have CQE™ through EPRI membership Other foreign and domestic utilities pursuing access to CQE™ CQE™ Home Page posted on World Wide Web ( <a href="http://www.fuels.bv.com:80/cqe/cqe.htm">http://www.fuels.bv.com:80/cqe/cqe.htm</a> )
Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International)	Proposed agreement to purchase 1 million tons/yr in U.S. Proposed agreement with China to build a coal-cleaning plant, slurry pipeline, and port facility – Value—\$450 million Letter of intent for 3 additional pipelines in China – Value—\$3 billion Letters of intent from Polish utilities for 5 million tons/yr – Value—\$50 million
Advanced Coal Conversion Process Demonstration (Rosebud SynCoal Partnership)	Total sales of SynCoal® product exceeds 900,000 tons – 130,000 tons delivered over extended period to industrial users A semi-commercial project being developed – Stand-alone minemouth design in Wyoming
ENCOAL® Mild Gasification Project (ENCOAL® Corporation)	75,000 tons of solid fuel delivered to 5 major utilities and metallurgical customers 3 million gallons of liquid fuel delivered to 8 industrial users ENCOAL Corporation's newly formed company, NuCoal, L.L.C., signed a contract with Mitsubishi International Corporation for construction of 15,000-metric-ton/day commercial plant in Wyoming – Value—\$460 million Completed feasibility studies for two Indonesian projects Completed first phase of feasibility study for Russian coal group

attractive substitute for oil and gas in industrial boilers, but concerns over increased SO<sub>2</sub> and NO<sub>x</sub> emissions and boiler tube fouling have impeded coal use.

Under a project with Bethlehem Steel Corporation, British Steel's blast furnace granular-coal injection technology demonstrated that 40 percent of the coke

can be replaced with coal injected directly into a blast furnace where emissions from coal combustion/processing are effectively controlled.

The Passamaquoddy Tribe successfully demonstrated a unique recovery scrubber that uses cement kiln dust otherwise disposed of as waste, to remove

▼ SO<sub>2</sub> emissions from this cement kiln are controlled by the Passamaquoddy Technology Recovery Scrubber™.



90 percent of the SO<sub>2</sub>, produce fertilizer and distilled water, and convert the kiln dust to feedstock. (No waste was generated.)

Coal Tech Corporation moved closer to commercializing a combustor for industrial boilers that slags the ash in the combustor to prevent boiler tube fouling, controls NO<sub>x</sub> (70–80 percent reduction) through staged combustion, and controls SO<sub>2</sub> (90 percent) with sorbent injection.

Commercialization successes to date are summarized in Exhibit 4-6.

## 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 the Innovative Control Technology Advisory Panel. As a part of the panel's activities, the state and federal incentive subcommittee prepared a report (*Report to the Secretary of Energy Concerning Commercialization Incentives*) on the 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 CCT-II.

An effort has been under way since 1992 to gain greater understanding of the potential domestic market for clean coal technologies and the organization and factors that will influence what and when facilities get built as well as the technologies that are used.

DOE has been conducting a series of Executive Seminars with leaders in the utility, independent power production, regulatory, and financial communities. The objective of the Executive Seminar series is to establish and maintain a dialogue with corporate officials and key decisionmakers to determine how DOE can enhance the climate wherein clean coal technologies and other advanced technologies will be given serious consideration in electric power generation planning and implementation. The Executive Seminars seek to enlist the views of the key decision-makers on a number of issues relevant to the CCT

Program and the Coal RD&D Program, including (1) perspectives on the pending changes in the utility industry and new opportunities for integrated advanced technologies; (2) risk assessments and risk mitigation, including the adoption of advanced technologies; (3) potential incentives that could be implemented by the government to accelerate commercial acceptance of advanced technologies; and (4) potential impacts of reduced R&D funding resulting from growing competition. Through 1996, three Executive Seminar series had been initiated, with two completed and a total of 60 seminars conducted with utilities, independent power producers, power marketers, state regulators, financial institutions/investment bankers, equipment manufacturers, insurance carriers, and associations. The focus of the current seminar series is on the impacts of utility industry restructuring and its effect on clean coal technology deployment, the opportunities for advanced technologies in international markets, and the outlook for environment compliance, particularly with respect to global climate change issues. Priorities for participation in the seminars are (1) utilities with significant coal utilization, projected load growth, and 25 percent of their coal plants at least 30 years old or older and (2) nonutility generators utilizing coal-based technologies and plants up to 300 MWe of capacity. Representatives of states where coal is a major resource, growth is projected for electric power generation, or advanced regulatory issues predominate are also participants in the seminars.

Additionally, a series of regional studies of key utilities and utility systems is under way. The purpose of these studies is to gain a better understanding of the domestic markets for clean coal technologies and the regional and state factors that have a bearing on com-

### Exhibit 4-6 Commercial Successes—Industrial Applications

Project and Participant	Commercialization Progress
Blast Furnace Granular-Coal Injection System Demonstration Project (Bethlehem Steel Corporation)	British Steel granted exclusive marketing rights to technology co-developer, CPC-Macawber Commercial sale of technology to United States Steel Corporation
Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)	Technology retained for commercial use at host site Completed feasibility study for Taiwanese cement plant

mercial deployment. Regions selected for study account for most of the U.S. coal-fired generating capacity. The regional, utility-specific, state, and other data are collected and analyzed for insights into environmental compliance strategies, capacity planning, industry restructuring, deregulation and competition, and other stakeholder issues affecting the domestic power generation market and the deployment of clean coal technologies.

Studies for three regions have been completed:

- Region 3—Mid-Atlantic, encompassing Pennsylvania, Delaware, Maryland, Virginia, and West Virginia; published.
- Region 4—South Atlantic, encompassing Kentucky, Tennessee, North Carolina, South Carolina, Georgia, Alabama, Mississippi, and Florida; published.
- Region 5—Midwest, encompassing Ohio, Illinois, Indiana, Michigan, Minnesota, and Wisconsin; updated in 1996.

Two studies are in progress:

- Region 6—Southeast, encompassing Texas, Louisiana, Oklahoma, and Arkansas.
- Regions 1 and 2—Northeast, encompassing Maine, Vermont, New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, and New Jersey.

Also completed in 1996 was an assessment of the impact of environmental compliance on coal-fired power plants. The assessment addressed various CAAA requirements, National Ambient Air Quality Standards (NAAQS), Prevention of Significant Deteri-

oration (PSD), New Source Performance Standards (NSPS), the Acid Rain Program, and the air toxics control program, as well as efforts to control global warming by reducing emissions of greenhouse gases. Emission trends, proposed regulations, and options for attaining regulatory compliance were considered for the major air pollutants: SO<sub>2</sub>, NO<sub>x</sub>, particulate matter, CO<sub>2</sub>, and the various air toxics defined as hazardous air pollutants. The report, *U.S. Coal-Fired Plants and Environmental Compliance*, also identifies the technologies for controlling SO<sub>2</sub>, NO<sub>x</sub>, and particulate matter that have been installed at each U.S. coal-fired power plant.

The insights contributed by these efforts identify many significant factors and trends affecting domestic markets for CCTs and relating to the contributions of CCT demonstration projects to these markets, such as issues associated with restructuring the electric industry and new limits on environmental emissions.

## An Emerging International Market

Internationally, clean coal technologies represent a major opportunity for U.S. industries to improve their position in world exports. Worldwide, the market for power generation technologies could reach \$1 trillion by 2015. Capturing just 20 percent of this market would bring in revenues of \$200 billion and support more than 100,000 jobs over three decades in the U.S. power equipment industry alone. Aggressive action by U.S. companies to capture this market share with technologies proven under the CCT Program would

lead to a significant reduction in the U.S. balance-of-trade deficit.

Further, the export of coal amounted to 89 million tons in 1995 and contributed \$3.5 billion to the U.S. balance of payments. By 2015, the Energy Information Administration has projected that U.S. coal exports will increase to more than 120 million tons. Thus, there is enormous incentive to expand U.S. clean coal technology exports so that U.S. industry and the world markets it serves can take advantage of the technical, environmental, efficiency, and economic benefits of these coal-based technologies.

During 1996, clean coal technologies gained recognition as having an important role in enhancing “environmental security.” This term describes a federal interagency policy initiative to coordinate the resources of the Departments of Defense and Energy and the Environmental Protection Agency to focus on selected acute international environmental problems that, by their serious nature, threaten to impact the local health and welfare and hence may destabilize the political or social structure to the detriment of American interests. Because coal is available worldwide, clean coal technologies are now viewed as essential to affordable and reliable electrification that leads directly to sustainable development and enhanced quality of life.

Activities in the Pacific Rim have been in support of the deployment of clean coal technology in this region. The Pacific Rim represents the largest regional user of coal and the largest market for power generation and other coal use technologies. Correspondingly, coal use is the major source of the air and water pollution of the region, and the Pacific Rim is rapidly becoming the largest source of pollution in the world. DOE’s Office of Fossil Energy has developed a program to address

the needs of the region. The program was developed in conjunction with the governments and multilateral organizations active in the Pacific Rim. Activities in the region have had three purposes: (1) education and training in the performance and cost of clean coal technologies as well as the issues pertaining to obtaining commercial financing for projects using these technologies, (2) where possible to support the activities of U.S. developers for projects using clean coal technologies, and (3) when requested, to assist governments with the development of responsible energy and related environmental policy and practices.

DOE's Office of Fossil Energy continued its long relationship with China by supporting the Ministry of Electric Power with an assessment of IGCC projects in China. China issued a plan for sustainable development and identified IGCC and PFBC technologies as the top priorities for the future. China has shown a keen interest in the U.S. clean coal technologies as a means to reduce SO<sub>2</sub>. At the Conference on Energy and Sustainable Development held in Beijing, China characterized its environmental issues as follows: pollution from coal use and heavy transport in urban areas; serious acid rain in South China; and high overall CO<sub>2</sub> emissions. The importance of clean coal technologies in addressing these issues is illustrated by the fact that SO<sub>2</sub> emissions from China constitute 70 percent of the SO<sub>2</sub> emissions in Asia and 90 percent of these emissions are related to those from coal. A similar situation exists for NO<sub>x</sub>: emissions from China represent over 60 percent of the NO<sub>x</sub> emissions in Asia with 70 percent of the Chinese emissions being related to coal use. The introduction of clean coal technologies, which have a minimum power plant efficiency of 33–35 percent as compared to the current China aver-

▼ U.S. International Technical Assistance Program identifies opportunities for clean coal technologies in Brazil.



age of 25–30 percent, could reduce emissions by 20 percent by taking advantage of the more efficient power generation inherent in these advanced systems. The main barrier to the introduction of clean coal technologies is capital costs. Through the efforts of DOE's Office of Fossil Energy, the Asian Development Bank has become a participant in the development and the ultimate financing of the first projects in China.

A second round of the U.S.-India Bilateral Energy Consultations was held in New Delhi in August 1996 and resulted in the creation of a Coal Advisory Group that will serve as a sounding board, problem identifier, and coordinating mechanism relating to coal and coal technology, including coal cleaning, power plant efficiency improvement, and other technical issues. A unique feature of these bilateral talks was the private sector input. A business roundtable was held prior to the talks and developed recommendations for the government of India for reforms in the electric power sector intended to streamline the energy permitting

process, improve financing mechanisms, and restructure state electricity boards to operate more independently and speed privatization. In a related activity, DOE's Office of Fossil Energy and the Electric Power Research Institute cosponsored the Workshop on U.S. Clean Coal Technologies at the Energy Summit '96 Conference and Exhibition in Madras, India, in September. Technical sessions were conducted on advanced power generation and advanced industrial and clean fuels technologies. The sessions focused on describing how U.S. coal and clean coal technologies could contribute to economically meeting India's energy needs while addressing environmental issues. Following the Energy Summit, DOE showcased the latest CCT Program information through an exhibit, technical session, and paper presented at the Power-Gen Asia Conference and Exhibition in New Delhi.

DOE's Office of Fossil Energy participated in a number of other workshops and missions in 1996. A fact-finding mission to Australia was conducted to investigate opportunities and obstacles to U.S. exports of clean coal technologies and to explore opportunities for cooperation on R&D. The goal was to develop a strategy for a government/industry partnership to develop the Australian market for U.S. clean coal technologies. The Office of Fossil Energy cosponsored a workshop with the United States Energy Association at the Independent Power Production Conference in Rio de Janeiro, Brazil. This workshop dealt with the roles, responsibilities, and regulatory functions of state utility commissions. Further, the Office of Fossil Energy continued to participate in a leadership capacity in the Asia Pacific Economic Cooperation Expert Working Group on Clean Coal Technology, which has as its objective the development of multilateral policies

for the development and implementation of clean coal technologies.

A Clean Coal Technology Finance Seminar was held in 1996 with the purpose of receiving views and advice from the U.S. clean coal technology industry on the international marketplace, as well as gaining better insight and understanding on how to strengthen the relationship between the coal industry and the financial community on technologies, markets, and projects.

## Market Communications

Public involvement has been a hallmark of the CCT Program since its inception. Programmatic interest was evaluated, first at the direction of Congress, in two informational solicitations preceding the CCT-I and CCT-II solicitations. Strong and broad industry interest covering a wide range of clean coal technologies was found to exist. Numerous public meetings were held prior to issuing each of the CCT-II through CCT-V project solicitations. The 12 public meetings that were held helped to sharpen the solicitation objectives and procedures, enabling industry to propose a technical agenda that met each of the solicitations' broad objectives.

The clean coal technology outreach program continued to build a broad constituency for the CCT Program and to identify the needs of that constituency for information and data. The support of outreach was reemphasized in the National Energy Strategy in 1991. As a result, a formal outreach program was established with DOE's Office of Fossil Energy.

The purpose of the outreach program is to impart 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 follow:

- Achieve public and government awareness of advanced coal-using technologies as viable energy options
- Provide potential technology users with information that is timely and relevant to their decision-making process
- Provide policy makers and regulators with information about the advantages of clean coal technologies
- Increase the confidence of financial institutions that these technologies are viable options

A vigorous outreach program continues to be pursued in the form of dissemination of program information, publication of materials (including quarterly newsletters and annual program reports), cosponsorship of the Annual Clean Coal Technology Conference, attendance at trade shows and other high-visibility events, conduct of executive seminars, and providing electronic access to project information via the Internet as well as a fax-on-demand system and a computer bulletin board. The outreach program has been expanded into the international arena through sponsorship and participation in trade missions and overview conferences and more specifically as part of the Asia Pacific Economic Cooperation initiative.

The outreach activities conducted by DOE have been directed toward reaching targeted audiences, including users and vendors of the technology, regula-

tors, public educators, environmental organizations, and export markets. Currently, the CCT Program has more than 4,000 priority stakeholders/customers. Stakeholders represent about 275 organizations that are participating in the CCT Program, about 15 of which provide independent and objective program assessments and guidance and/or provide cosponsorship and inputs to the formulation and planning of outreach materials and the annual conferences. Support of this outreach program also comes from well established relationships with major organizations representing the coal industry (e.g., Center for Energy & Economic Development, Council of Industrial Boiler Owners, Clean Coal Technology Coalition, Electric Power Research Institute, and National Mining Association).

The CCT Program mails newsletters, annual program updates, and a variety of other outreach materials to almost 4,000 stakeholders/customers, 80 percent of whom have indicated overall satisfaction with the information and data received from the program. These mailings are made on a periodic basis (quarterly or annually) and as special publications become available. The outreach program has participated in over 185 technical conferences, professional meetings, and trade missions since 1991.

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.

Outreach assets include four traveling exhibits, interactive videos, broadcast videos, printed publications, an extensive photographic library, and a mailing list of stakeholders/customers.

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*, the *Investment Pays Off*, and a series of project-specific topical reports to highlight project events or to capture progress at particular points driven by project-specific considerations. The following key publications were prepared and disseminated:

- *Reducing Emissions of Nitrogen Oxides via Low-NO<sub>x</sub> Burner Technology* (Topical Report Number 5) discusses CCT demonstration projects that reduce NO<sub>x</sub> emissions by combustion modifications using low-NO<sub>x</sub> burners.
- *The Tampa Electric Integrated Gasification Combined-Cycle Project* (Topical Report Number 6) describes the greenfield IGCC unit at Polk Power Plant.
- *The Wabash River Coal Gasification Repowering Project* (Topical Report Number 7) describes the world's largest single-train IGCC power plant.
- *The Piñon Pine Power Project* (Topical Report Number 8) describes Sierra Pacific Power Company's IGCC unit at Tracy Power Station.

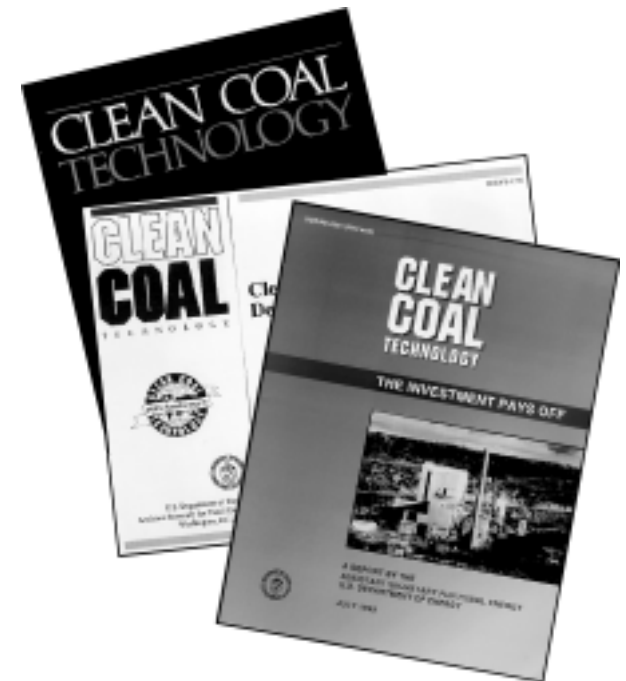
- *Clean Coal Technology Demonstration Program: Program Update 1995*, which marks the program's 10-year anniversary, provides a thorough review of the status of the program as well as updates on each project.
- *Clean Coal Technology Demonstration Program: Project Fact Sheets* provides a mid-year update on each project.
- *CCT Program Bibliography of Publications, Papers and Presentations* identifies the material published during the 10 years of the CCT Program.
- *Fifth Annual Clean Coal Technology Conference: Powering the Next Millennium; Technical Papers* contains the technical papers submitted in advance of the conference.
- *Fifth Annual Clean Coal Technology Conference: Powering the Next Millennium; Proceedings* contains the papers presented during plenary and panel sessions as well as the luncheon addresses.

Five issues of the *Clean Coal Today* newsletter were published in 1996 and early 1997, along with the second annual edition of the *Clean Coal Today Index*, which cross-references all articles published in the newsletter to date by both project title and participant. The newsletter is distributed to approximately 4,000 domestic and international readers. In 1996, the newsletter was re-designed and coverage expanded to include regular features on international activities, commercialization briefs, and information on state activities relating to clean coal technologies.

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. A computer bulletin board also provides updates.

DOE continued to expand its computer network, accessible through the Internet, which provides information on federal fossil energy programs and serves as a "gateway" to other related information throughout the United States and the world. Once into the network,

▼ The CCT Program reports progress and accomplishments through several publications distributed to almost 4,000 stakeholders.



## Exhibit 4-7 How to Obtain Updated CCT Program Information

Media	Description and Action
<i>Clean Coal Today</i>	Subscription to quarterly newsletter: Send name and address to U.S. Department of Energy, FE-22, Washington, DC 20585.
Fossil Energy TechLine	Fax-on-demand system for news announcements and status reports: Call (202) 586-4300 from a tone phone and follow voice instructions. (Call 202-586-6503 for additional TechLine information.)
Computer Bulletin Board	Dial 202-586-6495 via modem.
Fossil Energy Home Page	Primary gateway to extensive information on DOE's Fossil Energy Program and to relevant Web links: On the Internet, access <a href="http://www.fe.doe.gov">http://www.fe.doe.gov</a> and use menu and/or search options.

users can obtain general information and follow links to increasingly detailed information, ultimately accessing specific data on individual projects and facilities. Internet electronic links allow users to move seamlessly between headquarters and field sites. Users can also access technical abstracts and reports maintained by DOE's Office of Scientific and Technical Information at Oak Ridge, Tennessee. The gateways link to more than a hundred energy-related computer servers and networks operated by private companies, trade associations, and other agencies worldwide. Exhibit 4-7 provides instructions on how to obtain updates on the CCT Program.

The Fifth Annual Clean Coal Technology Conference was held in Tampa, Florida, in January 1997, and was cosponsored by the Center for Energy & Economic Development, Council of Industrial Boiler Owners, Electric Power Research Institute, and National Mining Association. There were almost 400 participants, including 70 representatives from 16 countries. The

theme, "Powering the Next Millennium," focused on presenting strategies and approaches that will enable clean coal technologies to resolve the competing, interrelated demands for power, economic viability, and environmental constraints associated with the use of coal in the post-2000 era. The conference provided a forum to review the status of CCT projects here and abroad and provided an opportunity to evaluate CCT Program directions.

The conference was launched at an International Business Forum Brunch, which provided an opportunity to meet and network with the international delegations. This was followed by a panel on options for financing projects and feasibility studies. That afternoon featured a tour of Tampa Electric Company's 250-MWe IGCC project located near Mulberry, Florida, which started operations in October 1996. The project is using a Texaco pressurized, oxygen-blown, entrained-flow gasifier, hot-gas and conventional cold-gas cleanup, and an advanced gas turbine with nitrogen injection for power augmentation and

NO<sub>x</sub> control. This project is unique also in that it recovered and converted some 1,500 acres of phosphate mining spoils to usable wetlands and uplands for native plants and animals.

A tour also was given of Tampa Electric Company's Electric Technology Resource Center, which is the only full-service demonstration facility displaying interactive testing centers in advanced technology, lighting display, and food service.

The conference program was designed to develop sequentially four key conference issues: (1) International Markets for CCTs, which focused on the opportunities and obstacles for CCTs to compete in the international marketplace; (2) Role of CCTs in the Evolving Domestic Electricity Market, which addressed the need to understand and follow the power production industry as it moves into an era of deregulation and competition; (3) Environmental Issues Affecting CCT Deployment, which explored both domestic and international requirements to broaden the understanding of how clean coal technologies can be used to



▲ The Fifth Annual Clean Coal Technology Conference, held in Tampa, FL, focused on issues affecting clean coal deployment into the 21st century.

ensure that solutions are available to accomplish environmental goals while achieving benefits that outweigh the costs; and (4) Deployment—From Today into the Next Millennium, which focused on the opportunities and obstacles to clean coal technology deployment as well as strategies and approaches to enhance deployment.

The four conference issues were developed through three steps over the course of three conference days. First, the issues were identified and articulated in the opening plenary session. The next day consisted of panel sessions during which the key issues were expanded and explored, and resolutions were formulated. During this day, technical papers also were presented on the clean coal projects. On the final day, during the closing plenary session, the issues were summarized, and where possible, conclusions were drawn.



▲ Then Energy Secretary Hazel O'Leary and Representative Ralph Regula dedicate Tampa Electric's 250-MWe IGCC plant following the Fifth Annual Clean Coal Technology Conference.

Several parallel themes emerged from the panels. To encourage clean coal technologies internationally, it was recommended that businesses focus on a few key regions, rather than over the entire globe. Greater attention must be paid to understanding country-specific barriers, be they economic, environmental, political, or social; then strategies must be developed to overcome these barriers. On the domestic front, electric utility restructuring continues to pose great uncertainties. However, coal is still seen as a major energy provider, and clean coal technologies, such as washing and beneficiation, can provide less variable fuel suitable for standard power plant design. Blending coal with other fuels to mitigate the environmental impact of coal and use of IGCC technology were other options emphasized at the conference.

The closing plenary session was followed by a featured speaker, The Honorable Ralph Regula, who chairs the House Appropriations Subcommittee on Interior and Related Agencies and is one of the original supporters of the CCT Program. Representative Regula (and other speakers) emphasized the need for continued and greater outreach efforts, interacting with legislators to convince them of the beneficial effects of CCT development on jobs, economic growth, and U.S. competitiveness, and broadening the reach of information dissemination on clean coal technologies.

Another conference highlight was a featured appearance by departing Secretary of Energy Hazel

▼ Exhibits communicate the progress of the CCT Program at worldwide conferences and trade shows.



O'Leary, who praised the CCT Program as the most successful government/industry partnership—one that has become a model for government/industry cooperation that even GAO applauds. She noted that the program has succeeded because it is environmentally beneficial, industry-driven in terms of portfolio and performance standards, and awarded on the basis of competition.

From January 1996 through June 1997, 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 20 domestic and international events: World Coal Conference, Coal Utilization and Fuel Systems Conference and Exhibition (1996 and



---

1997), Annual American Power Conference (1996 and 1997), Power-Gen Asia '96, Energy Summit '96 Conference and Exhibition, Air & Waste Management Association Annual Conference and Exhibition (1996 and 1997), ASME International Joint Power Generation Conference and Exhibition, Power-Gen International '96, Association of Energy Engineers Competitive Power Congress, Virginia Coal Council Conference & Exposition (1996 and 1977), NASA Technology 2006, Fifth Annual Clean Coal Technology Conference, Pacific Coal Forum, Power Projects in Central and Eastern Europe Conference, NECA Power Markets of the Future: Risks and Rewards Conference, and U.S. DOE American Energy Month.

# 5. CCT Projects

## Summary

CCT Program demonstrations provide a portfolio of technologies that will enable coal to continue to provide low-cost, secure energy vital to the nation's economy while satisfying energy and environmental goals well into the 21st century. This is being carried out by addressing four basic market sectors: (1) environmental control devices for existing and new power plants, (2) advanced electric power generation for repowering existing facilities and providing new generating capacity, (3) coal processing for clean fuels to convert the nation's vast coal resources to clean fuels, and (4) industrial applications dependent upon coal use.

In response to the initial thrust of the program, 15 of 19 projects have been completed that address SO<sub>2</sub> and NO<sub>x</sub> control for coal-fired boilers. The resultant technologies provide a suite of cost-effective control options for the full range of boiler types. The 19 environmental control device projects are valued at more than \$704 million. These include seven NO<sub>x</sub> emission control systems installed in more than 1,700 MWe of utility generating capacity, five SO<sub>2</sub> emissions systems installed on approximately 770 MWe, and seven combined SO<sub>2</sub>/NO<sub>x</sub> emission control systems installed on approximately 800 MWe of capacity.

To respond to load growth as well as growing environmental concerns, the program provides a range

of advanced electric power generation options for both repowering and new power generation. These advanced options offer greater than 20 percent reductions in greenhouse gas emissions; SO<sub>2</sub>, NO<sub>x</sub>, and particulate emissions far below New Source Performance Standards (NSPS); and salable solid and liquid by-products in lieu of solid wastes. Nearly 900 MWe of new capacity and more than 800 MWe of repowered capacity are represented by 11 projects valued at more than \$3.2 billion. These projects include five fluidized-bed combustion (FBC) systems, four integrated gasification combined-cycle (IGCC) systems, and two advanced combustion/heat engine systems. (In addition, a fact sheet for a twelfth project, the externally fired combined-cycle demonstration project is included in this section even though the project was concluded on May 31, 1997.) These projects will not only provide environmentally sound electric generation in the mid- to late 1990s, but also will provide the demonstrated technology base necessary to meet new capacity requirements in the 21st century.

Also addressed are approaches to converting raw, run-of-mine coals to high-energy-density, low-sulfur products. These products have application domestically for compliance with the Clean Air Act Amendments of 1990. Internationally, both the products and processes have excellent market potential. Valued at more than \$519 million, the five projects in the coal processing for clean fuels category represent a diversified portfolio of technologies. Three projects

involve the production of high-energy-density solid fuels, one of which also produces a liquid product equivalent to No. 6 fuel oil. A fourth project is demonstrating a new methanol production process. A fifth complementary effort to the process demonstrations has provided an expert computer software system that enables a utility to assess the environmental, operational, and cost impact of utilizing coals not previously burned at a facility, including upgraded coals and coal blends.

Projects were undertaken as well to address pollution problems associated with coal use in the industrial sector. These included dependence of the steel industry on coke and the inherent pollutant emissions in coke-making; reliance of the cement industry on low-cost indigenous, and often high-sulfur, coal fuels; and the need for many industrial boiler operators to consider switching to coal fuels to reduce operating costs. The four industrial applications projects have a combined value of nearly \$1.3 billion. Projects encompass substitution of coal for 40 percent of coke in iron-making, integration of a direct iron-making process with the production of electricity, reduction of cement kiln emissions and solid waste generation, and demonstration of an industrial-scale slagging combustor. (A fifth industrial project fact sheet, the pulse combustor/gasifier project, is included in this section even though it was concluded on March 3, 1997.)

Section 5 contains a discussion of the technologies being demonstrated and fact sheets for each

project. Two types of facts sheets are provided: (1) a brief, two-page overview for ongoing (or concluded) projects and (2) an expanded four-page summary for projects that have successfully completed operational testing. The expanded fact sheets for completed projects contain a summary of the major results from the demonstration as well as sources for obtaining further information, specifically, contact persons and key references. Information provided in the fact sheets includes the project participant and team members, project objectives, significant project features, process description, major milestones, progress (if ongoing) or summary of results (if completed), and commercial applications. A key to interpreting the milestone charts is provided on the right. To prevent the release of project-specific information of a proprietary nature, process flow diagrams contained in the fact sheets are highly simplified and presented only as illustrations of the concepts involved in the demonstrations. The portion of the process or facility central to the demonstration is demarcated by the shaded area.

An index to project fact sheets is provided in Exhibit 5-1. Projects are listed by application category and alphabetically by participant, and the page numbers for each fact sheet are provided. In addition, Exhibit 5-1 indicates the solicitation under which the project was selected; its status as of June 30, 1997; and the geographic location of the demonstration. Exhibit 5-2 highlights those projects that have successfully completed operational testing and for which expanded, four-page fact sheets, including a summary of results, are provided.

### 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 5-1**  
**Project Fact Sheets, by Application Category and Participant**

Project	Participant	Solicitation/Status	Page
<b>Environmental Control Devices</b>			
<b>SO<sub>2</sub> Control Technologies</b>			
10-MWe Demonstration of Gas Suspension Absorption	AirPol, Inc.	CCT-III/completed	5-10
Confined Zone Dispersion Flue Gas Desulfurization Demonstration	Bechtel Corporation	CCT-III/completed	5-14
LIFAC Sorbent Injection Desulfurization Demonstration Project	LIFAC-North America	CCT-III/completed	5-18
Advanced Flue Gas Desulfurization Demonstration Project	Pure Air on the Lake, L.P.	CCT-II/completed	5-22
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	Southern Company Services, Inc.	CCT-II/completed	5-26
<b>NO<sub>x</sub> Control Technologies</b>			
Demonstration of Coal Reburning for Cyclone Boiler NO <sub>x</sub> Control	The Babcock & Wilcox Company	CCT-II/completed	5-32
Full-Scale Demonstration of Low-NO <sub>x</sub> Cell Burner Retrofit	The Babcock & Wilcox Company	CCT-III/completed	5-36
Evaluation of Gas Reburning and Low-NO <sub>x</sub> Burners on a Wall-Fired Boiler	Energy and Environmental Research Corporation	CCT-III/completed	5-40
Micronized Coal Reburning Demonstration for NO <sub>x</sub> Control	New York State Electric & Gas Corporation	CCT-IV/operational	5-44
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	Southern Company Services, Inc.	CCT-II/operational	5-46
Demonstration of Selective Catalytic Reduction Technology for the Control of NO <sub>x</sub> Emissions from High-Sulfur-Coal-Fired Boilers	Southern Company Services, Inc.	CCT-II/completed	5-48
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO <sub>x</sub> Emissions from Coal-Fired Boilers	Southern Company Services, Inc.	CCT-II/completed	5-52
<b>Combined SO<sub>2</sub>/NO<sub>x</sub> Control Technologies</b>			
SNOX <sup>TM</sup> Flue Gas Cleaning Demonstration Project	ABB Environmental Systems	CCT-II/completed	5-58
LIMB Demonstration Project Extension and Coolside Demonstration	The Babcock & Wilcox Company	CCT-I/completed	5-62
SO <sub>x</sub> -NO <sub>x</sub> -Rox Box <sup>TM</sup> Flue Gas Cleanup Demonstration Project	The Babcock & Wilcox Company	CCT-II/completed	5-66
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	Energy and Environmental Research Corporation	CCT-I/completed	5-70
Milliken Clean Coal Technology Demonstration Project	New York State Electric & Gas Corporation	CCT-IV/operational	5-74
Commercial Demonstration of the NOXSO SO <sub>2</sub> /NO <sub>x</sub> Removal Flue Gas Cleanup System	NOXSO Corporation	CCT-III/restructuring	5-76
Integrated Dry NO <sub>x</sub> /SO <sub>2</sub> Emissions Control System	Public Service Company of Colorado	CCT-III/completed	5-78
<b>Advanced Electric Power Generation</b>			
<b>Fluidized-Bed Combustion</b>			
McIntosh Unit 4A PCFB Demonstration Project	City of Lakeland, Department of Electric & Water Utilities	CCT-III/design	5-86
McIntosh Unit 4B Topped PCFB Demonstration Project	City of Lakeland, Department of Electric & Water Utilities	CCT-V/design	5-88
Tidd PFBC Demonstration Project	The Ohio Power Company	CCT-I/completed	5-90
ACFB Demonstration Project	York County Energy Partners, L.P.	CCT-I/restructuring	5-94
Nucla CFB Demonstration Project	Tri-State Generation and Transmission Association, Inc.	CCT-I/completed	5-96

**Exhibit 5-1 (continued)**  
**Project Fact Sheets, by Application Category and Participant**

Project	Participant	Solicitation/Status	Page
<b>Integrated Gasification Combined Cycle</b>			
Clean Energy Demonstration Project	Clean Energy Partners Limited Partnership	CCT-V/restructuring	5-100
Piñon Pine IGCC Power Project	Sierra Pacific Power Company	CCT-IV/operational	5-102
Tampa Electric Integrated Gasification Combined-Cycle Project	Tampa Electric Company	CCT-III/operational	5-104
Wabash River Coal Gasification Repowering Project	Wabash River Coal Gasification Repowering Project Joint Venture	CCT-IV/operational	5-106
<b>Advanced Combustion/Heat Engines</b>			
Healy Clean Coal Project	Alaska Industrial Development and Export Authority	CCT-III/construction	5-108
Clean Coal Diesel Demonstration Project	Arthur D. Little, Inc.	CCT-V/restructuring	5-110
Externally Fired Combined-Cycle Demonstration Project	Pennsylvania Electric Company	CCT-V/concluded	5-112
<b>Coal Processing for Clean Fuels</b>			
<b>Coal Preparation Technologies</b>			
Development of the Coal Quality Expert™	ABB Combustion Engineering, Inc., and CQ Inc.	CCT-I/completed	5-116
Self-Scrubbing Coal™: An Integrated Approach to Clean Air	Custom Coals International	CCT-IV/operational	5-120
Advanced Coal Conversion Process Demonstration	Rosebud SynCoal Partnership	CCT-I/operational	5-122
<b>Mild Gasification</b>			
ENCOAL® Mild Coal Gasification Project	ENCOAL® Corporation	CCT-III/operational	5-124
<b>Indirect Liquefaction</b>			
Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process	Air Products Liquid Phase Conversion Company, L.P.	CCT-III/operational	5-126
<b>Industrial Applications</b>			
Blast Furnace Granular-Coal Injection System Demonstration Project	Bethlehem Steel Corporation	CCT-III/operational	5-130
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	Coal Tech Corporation	CCT-I/completed	5-132
Clean Power from Integrated Coal/Ore Reduction (CPICOR™)	CPICOR™ Management Company, L.L.C.	CCT-V/design	5-136
Cement Kiln Flue Gas Recovery Scrubber	Passamaquoddy Tribe	CCT-II/completed	5-138
Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal	ThermoChem, Inc.	CCT-IV/concluded	5-142

**Exhibit 5-1 (continued)**  
**Project Fact Sheets, by Application Category and Participant**

<b>Participant</b>	<b>Project</b>	<b>Location</b>	<b>Page</b>
ABB Combustion Engineering, Inc., and CQ Inc.	Development of the Coal Quality Expert™	Homer City, PA	5-116
ABB Environmental Systems	SNOX™ Flue Gas Cleaning Demonstration Project	Niles, OH	5-58
Air Products Liquid Phase Conversion Company, L.P.	Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process	Kingsport, TN	5-126
AirPol, Inc.	10-MWe Demonstration of Gas Suspension Absorption	West Paducah, KY	5-10
Alaska Industrial Development and Export Authority	Healy Clean Coal Project	Healy, AK	5-108
Arthur D. Little, Inc.	Clean Coal Diesel Demonstration Project	Fairbanks, AK	5-110
The Babcock & Wilcox Company	Demonstration of Coal Reburning for Cyclone Boiler NO <sub>x</sub> Control	Cassville, WI	5-32
The Babcock & Wilcox Company	Full-Scale Demonstration of Low-NO <sub>x</sub> Cell Burner Retrofit	Aberdeen, OH	5-36
The Babcock & Wilcox Company	LIMB Demonstration Project Extension and Coolside Demonstration	Lorain, OH	5-62
The Babcock & Wilcox Company	SO <sub>x</sub> -NO <sub>x</sub> -Rox Box™ Flue Gas Cleanup Demonstration Project	Dilles Bottom, OH	5-66
Bechtel Corporation	Confined Zone Dispersion Flue Gas Desulfurization Demonstration	Seward, PA	5-14
Bethlehem Steel Corporation	Blast Furnace Granular-Coal Injection System Demonstration Project	Burns Harbor, IN	5-130
City of Lakeland, Department of Electric & Water Utilities	McIntosh Unit 4A PCFB Demonstration Project	Lakeland, FL	5-86
City of Lakeland, Department of Electric & Water Utilities	McIntosh Unit 4B Topped PCFB Demonstration Project	Lakeland, FL	5-88
Clean Energy Partners Limited Partnership	Clean Energy Demonstration Project	East coast site	5-100
Coal Tech Corporation	Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	Williamsport, PA	5-132
CPICOR™ Management Company, L.L.C.	Clean Power from Integrated Coal/Ore Reduction (CPICOR™)	Vineyard, UT	5-136
Custom Coals International	Self-Scrubbing Coal™: An Integrated Approach to Clean Air	Central City, PA Lower Mt. Bethel, PA Richmond, IN Astabula, OH	5-120
ENCOAL® Corporation	ENCOAL® Mild Coal Gasification Project	Gillette, WY	5-124
Energy and Environmental Research Corporation	Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	Hennepin, IL Springfield, IL	5-70
Energy and Environmental Research Corporation	Evaluation of Gas Reburning and Low-NO <sub>x</sub> Burners on a Wall-Fired Boiler	Denver, CO	5-40
LIFAC–North America	LIFAC Sorbent Injection Desulfurization Demonstration Project	Richmond, IN	5-18
New York State Electric & Gas Corporation	Micronized Coal Reburning Demonstration for NO <sub>x</sub> Control	Lansing, NY	5-44

**Exhibit 5-1 (continued)**  
**Project Fact Sheets, by Application Category and Participant**

<b>Participant</b>	<b>Project</b>	<b>Location</b>	<b>Page</b>
New York State Electric & Gas Corporation	Milliken Clean Coal Technology Demonstration Project	Lansing, NY	5-74
NOXSO Corporation	Commercial Demonstration of the NOXSO SO <sub>2</sub> /NO <sub>x</sub> Removal Flue Gas Cleanup System	NOXSO site under negotiation Charleston, TN	5-76
The Ohio Power Company	Tidd PFBC Demonstration Project	Brilliant, OH	5-90
Passamaquoddy Tribe	Cement Kiln Flue Gas Recovery Scrubber	Thomaston, ME	5-138
Pennsylvania Electric Company	Externally Fired Combined-Cycle Demonstration Project	Not applicable	5-112
Public Service Company of Colorado	Integrated Dry NO <sub>x</sub> /SO <sub>2</sub> Emissions Control System	Denver, CO	5-78
Pure Air on the Lake, L.P.	Advanced Flue Gas Desulfurization Demonstration Project	Chesterton, IN	5-22
Rosebud SynCoal Partnership	Advanced Coal Conversion Process Demonstration	Colstrip, MT	5-122
Sierra Pacific Power Company	Piñon Pine IGCC Power Project	Reno, NV	5-102
Southern Company Services, Inc.	Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	Coosa, GA	5-46
Southern Company Services, Inc.	Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	Newnan, GA	5-26
Southern Company Services, Inc.	Demonstration of Selective Catalytic Reduction Technology for the Control of NO <sub>x</sub> Emissions from High-Sulfur-Coal-Fired Boilers	Pensacola, FL	5-48
Southern Company Services, Inc.	180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO <sub>x</sub> Emissions from Coal-Fired Boilers	Lynn Haven, FL	5-52
Tampa Electric Company	Tampa Electric Integrated Gasification Combined-Cycle Project	Mulberry, FL	5-104
ThermoChem, Inc.	Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal	Not applicable	5-142
Tri-State Generation and Transmission Association, Inc.	Nucla CFB Demonstration Project	Nucla, CO	5-96
Wabash River Coal Gasification Repowering Project Joint Venture	Wabash River Coal Gasification Repowering Project	West Terre Haute, IN	5-106
York County Energy Partners, L.P.	ACFB Demonstration Project	To be determined	5-94

**Exhibit 5-2**  
**CCT Projects that Completed Operational Testing by June 30, 1997**

Project	Participant	End Date	Solicitation	Page
<b>Environmental Control Devices</b>				
<b>SO<sub>2</sub> Control Technologies</b>				
10-MWe Demonstration of Gas Suspension Absorption	AirPol, Inc.	3/94	CCT-III	5-10
Confined Zone Dispersion Flue Gas Desulfurization Demonstration	Bechtel Corporation	6/93	CCT-III	5-14
LIFAC Sorbent Injection Desulfurization Demonstration Project	LIFAC-North America	6/94	CCT-III	5-18
Advanced Flue Gas Desulfurization Demonstration Project	Pure Air on the Lake, L.P.	6/95	CCT-II	5-22
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	Southern Company Services, Inc.	12/94	CCT-II	5-26
<b>NO<sub>x</sub> Control Technologies</b>				
Demonstration of Coal Reburning for Cyclone Boiler NO <sub>x</sub> Control	The Babcock & Wilcox Company	12/92	CCT-II	5-32
Full-Scale Demonstration of Low-NO <sub>x</sub> Cell Burner Retrofit	The Babcock & Wilcox Company	4/93	CCT-III	5-36
Evaluation of Gas Reburning and Low-NO <sub>x</sub> Burners on a Wall-Fired Boiler	Energy and Environmental Research Corporation	1/95	CCT-III	5-40
Demonstration of Selective Catalytic Reduction Technology for the Control of NO <sub>x</sub> Emissions from High-Sulfur-Coal-Fired Boilers	Southern Company Services, Inc.	7/95	CCT-II	5-48
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO <sub>x</sub> Emissions from Coal-Fired Boilers	Southern Company Services, Inc.	12/92	CCT-II	5-52
<b>Combined SO<sub>2</sub>/NO<sub>x</sub> Control Technologies</b>				
SNOX <sup>TM</sup> Flue Gas Cleaning Demonstration Project	ABB Environmental Systems	12/94	CCT-II	5-58
LIMB Demonstration Project Extension and Coolside Demonstration	The Babcock & Wilcox Company	8/91	CCT-I	5-62
SO <sub>x</sub> -NO <sub>x</sub> -Rox Box <sup>TM</sup> Flue Gas Cleanup Demonstration Project	The Babcock & Wilcox Company	5/93	CCT-II	5-66
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	Energy and Environmental Research Corporation	10/94	CCT-I	5-70
Integrated Dry NO <sub>x</sub> /SO <sub>2</sub> Emissions Control System	Public Service Company of Colorado	12/96	CCT-III	5-78
<b>Advanced Electric Power Generation</b>				
<b>Fluidized-Bed Combustion</b>				
Tidd PFBC Demonstration Project	The Ohio Power Company	3/95	CCT-I	5-90
Nucla CFB Demonstration Project	Tri-State Generation and Transmission Association, Inc.	1/91	CCT-I	5-96
<b>Coal Processing for Clean Fuels</b>				
<b>Coal Preparation Technologies</b>				
Development of the Coal Quality Expert <sup>TM</sup>	ABB Combustion Engineering, Inc., and CQ Inc.	12/95	CCT-I	5-116
<b>Industrial Applications</b>				
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	Coal Tech Corporation	5/90	CCT-I	5-132
Cement Kiln Flue Gas Recovery Scrubber	Passamaquoddy Tribe	9/93	CCT-I	5-138



## Environmental Control Devices

Environmental control devices are those technologies applied (retrofitted) to existing or new facilities for the purpose of controlling SO<sub>2</sub> and NO<sub>x</sub> emissions. Although boilers may be modified and combustion affected, the basic boiler configuration and function remains unchanged in retrofitting these technologies.

## SO<sub>2</sub> Control Technology

Sulfur dioxide (SO<sub>2</sub>) is an acid gas formed during coal combustion, which oxidizes the inorganic, pyritic sulfur (Fe<sub>2</sub>S), and organically bound sulfur in the coal. Identified as a precursor to formation of acid rain, SO<sub>2</sub> was targeted in Title IV of the Clean Air Act Amendments of 1990 (CAAA). Phase I of Title IV, effective in 1995, affected 261 coal-fired units nationwide. The required SO<sub>2</sub> reduction was moderate and largely met by switching to low-sulfur fuels. In year 2000, Phase II of Title IV will come into effect, impacting all fossil-fuel-fired units, but most of all, the approximately 900 pre-NSPS coal-fired units. Under the stricter Phase II requirements, compliance by fuel switching alone is unlikely. But, the CAAA provides utilities flexibility in control strategies through SO<sub>2</sub> allowance trading. This permits a range of control options to be applied by a utility, as well as allowance purchasing. Recognizing this, the CCT Program has sought to provide a portfolio of SO<sub>2</sub> control technologies.

SO<sub>2</sub> control devices embody those technologies that condition and act upon the flue gas resulting from combustion, not the combustion itself, for the purpose of removing only SO<sub>2</sub>. Three basic approaches evolved, driven primarily by different conditions that exist within the pre-NSPS boiler population impacted by the CAAA. There is a tremendous range in critical factors, such as size, type, age, and space availability.

On one end of the spectrum are the smaller, older boilers with limited space for adding equipment. For these, sorbent injection techniques hold promise. Sorbent is injected into the boiler or the ductwork, and humidification is incorporated in some fashion to properly condition the flue gas for efficient SO<sub>2</sub> capture. Equipment size and complexity are held to a minimum to keep capital costs and space requirements low. Both limestone and lime sorbents are used. Limestone costs are about one-third that of hydrated lime; but limestone must be conditioned (calcined), and even then it is less effective in SO<sub>2</sub> capture (under simple sorbent injection conditions) than hydrated lime. Where limestone is used, it is injected in the boiler to produce calcium oxide, which reacts with SO<sub>2</sub> to form solid compounds of calcium sulfite and calcium sulfate. Both limestone and lime injection require the presence of water (humidification) and a calcium-to-sulfur molar ratio (Ca/S) of about 2.0 for sulfur capture efficiencies of 50–70 percent.

In the mid-range of the spectrum are 100–300-MWe boilers less than 30 years old and somewhat space constrained. For many of these, an increase in front-end control cost is justified by enhanced performance. The approach involves introduction of a reactor vessel in the flue gas stream to create conditions to enhance SO<sub>2</sub> capture beyond that

achievable with the simpler sorbent injection systems. Lime, as opposed to limestone, is used and sulfur capture efficiencies up to 90 percent can be achieved at a Ca/S of 1.3–2.0. This category of control device is called a spray dryer (because the solid by-product from the reaction is dry).

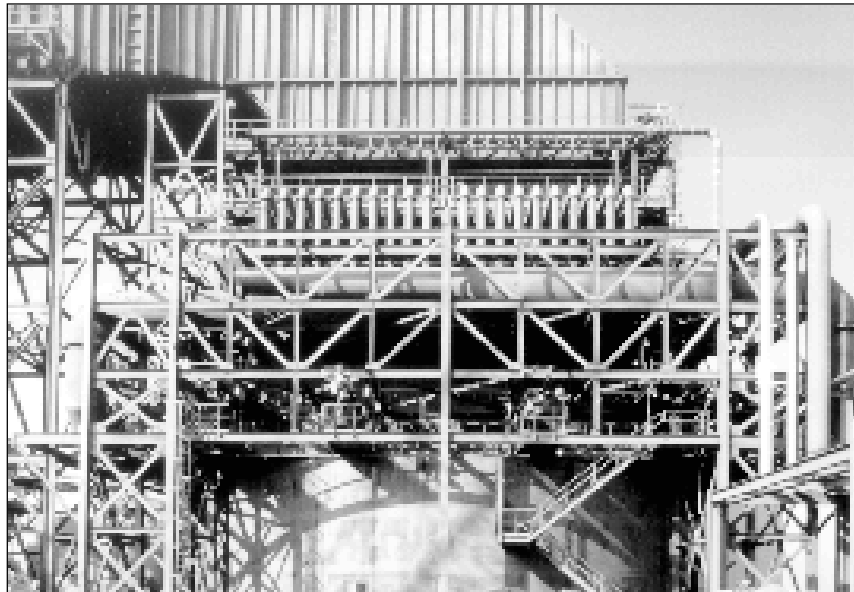
At the other end of the spectrum are the larger (300-MWe and more) boilers with some latitude in space availability, as well as new capacity additions. For these, advanced flue gas desulfurization (AFGD) wet scrubbers, with higher capital cost, but higher sulfur capture efficiency than other approaches, become cost effective. These systems apply larger and somewhat more complex reactors that drive up the capital cost. However, the sorbent is limestone and SO<sub>2</sub> removal efficiencies greater than 90 percent are achieved at a Ca/S of about 1.0, making operating costs significantly lower than those of the other two approaches. Furthermore, although the initial AFGD solid by-product is in slurry form, it is dewatered to produce gypsum—a salable product.

Under the CCT Program, two sorbent injection systems, one spray dryer, and two AFGD processes were successfully demonstrated. All have completed testing. Exhibit 5-3 briefly summarizes the characteristics and performance of the technologies that are described in more detail in the project fact sheets.

### Exhibit 5-3 CCT Program SO<sub>2</sub> Control Technology Characteristics

Project	Process	Coal Sulfur Content	SO <sub>2</sub> Reduction	Fact Sheet
Confined Zone Dispersion Flue Gas Desulfurization Demonstration	Sorbent injection—in-duct lime sorbent injection and humidification	1.5–2.5%	50%	5-14
LIFAC Sorbent Injection Desulfurization Demonstration Project	Sorbent injection—furnace sorbent injection (limestone) with vertical humidification vessel and sorbent recycle	2.0–2.9%	70%	5-18
10-MWe Demonstration of Gas Suspension Absorption	Spray dryer—vertical, single-nozzle reactor with integrated sorbent particulate recycle (lime sorbent)	2.7–3.5%	60–90%	5-10
Advanced Flue Gas Desulfurization Demonstration Project	AFGD—co-current flow, integrated quench absorber tower and reaction tank with combined agitation/oxidation (gypsum by-product)	2.25–4.7%	94%	5-22
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	AFGD—forced flue gas injection into reaction tank (Jet Bubbling Reactor <sup>®</sup> ) for combined SO <sub>2</sub> and particulate capture (gypsum by-product)	1.2–3%	90+%	5-26

▼ This side view of Pure Air’s advanced flue gas desulfurization absorber module shows air inlet ducts and sorbent injection piping.



▼ This view shows the sorbent (top) and water (bottom) inlet connections to the Pure Air absorber module.



## 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)

### Plant Capacity/Production

10-MWe equivalent slipstream of flue gas from a 175-MWe wall-fired boiler

### Coals

Western Kentucky bituminous—

Peabody Martwick, 3.05% sulfur

Emerald Energy, 2.61% sulfur

Andalax, 3.06% sulfur

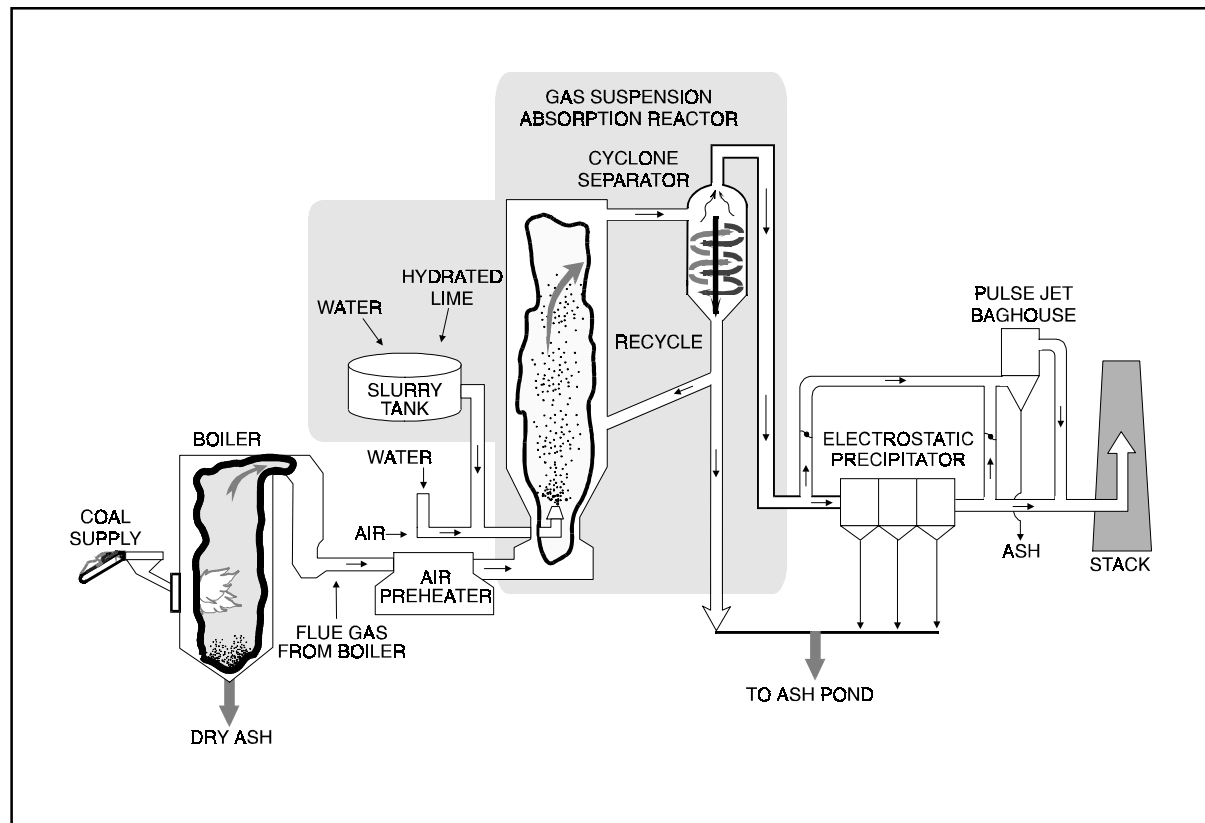
Warrior Basin, 3.5% sulfur (used intermittently)

### Project Funding

Total project cost	\$7,717,189	100%
DOE	2,315,259	30
Participant	5,401,930	70

### Project Objective

To demonstrate the applicability of Gas Suspension Absorption as an economic option for achieving Phase II



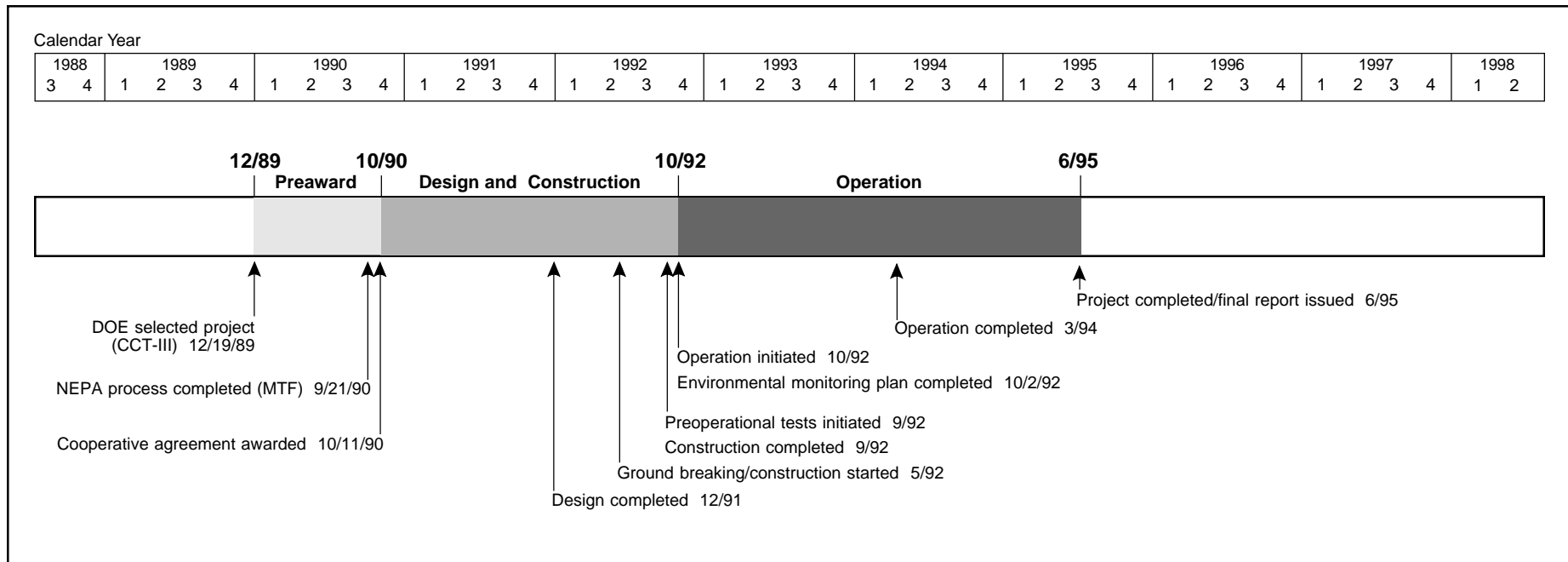
CAAA SO<sub>2</sub> compliance on pulverized-coal-fired boilers using high-sulfur coal.

### 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) or pulse jet baghouse (PJBH) 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.

A test program was structured to (1) optimize design of the GSA reactor for reduction of SO<sub>2</sub> emissions from boilers using high-sulfur coal and (2) evaluate the environmental control capability, economic potential, and mechanical performance of GSA. A statistically designed parametric (factorial) test plan was developed involving six variables. Beyond evaluation of the basic GSA unit to control SO<sub>2</sub>, air toxic control tests were conducted, and the effectiveness of a GSA/ESP and GSA/PJBH to control both SO<sub>2</sub> and particulate were tested. Factorial tests were followed by continuous runs to verify consistency of performance over time.



## Results Summary

### Environmental

- Ca/S molar ratio had the greatest effect on SO<sub>2</sub> removal, with approach-to-saturation temperature next, followed closely by chloride content.
- GSA/ESP achieved
  - 90% sulfur capture at a Ca/S of 1.3 with 8 °F approach-to-saturation and 0.04% chloride,
  - 90% sulfur capture at a Ca/S of 1.4 with 18 °F approach-to-saturation and 0.12% chloride, and
  - 99.9+% average particulate removal efficiency.
- GSA/PJBH achieved
  - 96% sulfur capture at a Ca/S of 1.4 with 18 °F approach-to-saturation and 0.12% chloride,
  - 3–5% increase in SO<sub>2</sub> reduction relative to GSA/ESP, and
  - 99.99+% average particulate removal efficiency.

- GSA/ESP and GSA/PJBH removed 98% of the hydrogen chloride (HCl), 96% of the hydrogen fluoride (HF), and 99% on more of most trace metals, except cadmium, antimony, mercury, and selenium. (GSA/PJBH removed 99+% of the selenium.)
- The solid by-product was usable as low-grade cement.

### Operational

- GSA/ESP lime utilization averaged 66.1% and GSA/PJBH averaged 70.5%.
- The reactor achieved the same performance as a conventional spray dryer, but at <sup>1</sup>/<sub>4</sub>–<sup>1</sup>/<sub>3</sub> the size.
- GSA generated lower particulate loading than a spray dryer, enabling compliance with a lower ESP efficiency.
- Special steels were not required in construction, and only a single spray nozzle is needed
- High availability and reliability similar to other commercial applications were demonstrated, reflecting simple design.

### Economic

- Capital and levelized (15-year) costs for GSA installed in a 300-MWe plant using 2.6% sulfur coal are compared below to costs for a wet limestone scrubber with forced oxidation (WLFO scrubber). EPRI's cost methodology was employed. Based on EPRI cost studies of FGD processes, the capital cost (1990\$) for a conventional spray dryer was \$172/kW.

	Capital Cost (1990\$/kW)	Levelized Cost (mills/kWh)
GSA—3 units at 50% capacity	\$149	10.35
WLFO	\$216	13.04

## Project Summary

The GSA capability of suspending a high concentration of solids, effectively drying the solids, and recirculating the solids at a high rate with precise control results in SO<sub>2</sub> control comparable to that of wet scrubbers and high lime utilization. The high concentration of solids provides the sorbent/SO<sub>2</sub> contact area. The drying enables low approach-to-saturation temperature and chloride usage. The rapid, precise, integral recycle system sustains the high solids concentration. The high lime utilization mitigates the largest operating cost (lime) and further reduces costs by reducing the amount of by-product generated. The GSA is distinguished from the average spray dryer by its modest size, simple means of introducing reagent to the reactor, direct means of recirculating unused lime, and low reagent consumption. Also, injected slurry coats recycled solids, not the walls, avoiding corrosion and enabling use of carbon steel in fabrication.

## Environmental Performance

Exhibit 5-4 lists the six variables used in the factorial tests and the levels at which they were applied. Inlet flue gas temperature was held constant at 320 °F. Factorial testing showed that lime stoichiometry had the greatest effect on SO<sub>2</sub> removal. Approach-to-saturation temperature was the next most important factor, followed closely by chloride levels. Although an approach-to-saturation temperature of 8 °F was achieved without plugging the system, the test was conducted at a very low chloride level (0.04%). Because water evaporation rates decrease as chloride levels increase, an 18 °F approach-to-saturation temperature was chosen for the higher 0.12% coal chloride level. Exhibit 5-5 summarizes key results from factorial testing.

A 28-day continuous run to evaluate the GSA/ESP configuration was made with bituminous coals averaging 2.7% sulfur, 0.12% chloride levels,

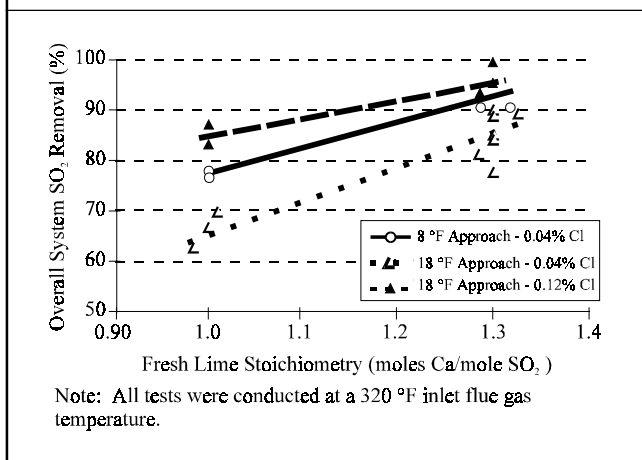
0.12%, and 18 °F approach-to-saturation temperature. A subsequent 14-day continuous run to evaluate the GSA/PJBH configuration was performed under the same conditions as those of the 28-day run, except for adjustments in flyash injection rate from 1.5 to 1.0 gr/ft<sup>3</sup> (actual).

### Exhibit 5-4 Variables and Levels Used in GSA Factorial Testing

Variable	Level
Approach-to-saturation temperature (°F)	8*, 18, 28
Ca/S (moles Ca(OH) <sub>2</sub> /mole inlet SO <sub>2</sub> )	1.00 and 1.30
Flyash loading (gr/ft <sup>3</sup> , actual)	0.50 and 2.0
Coal chloride level (%)	0.04 and 0.12
Flue gas flow rate (10 <sup>3</sup> std ft <sup>3</sup> /min)	14 and 20
Recycle screw speed (rpm)	30 and 45

\*8 °F was only run at the low coal chloride level.

### Exhibit 5-5 GSA Factorial Testing Results



The 28-day run on the GSA/ESP system showed that the overall SO<sub>2</sub> removal efficiency averaged slightly more than 90%, very close to the set point of 91%, at an average Ca/S ratio of 1.40–1.45 moles Ca(OH)<sub>2</sub>/mole inlet SO<sub>2</sub>. The system was able to adjust rapidly to the surge in inlet SO<sub>2</sub> caused by switching to 3.5% sulfur Warrior Basin coal for a week. Lime utilization averaged 66.1%. The particulate removal efficiency averaged 99.9+% and emission rates were maintained below 0.015 lb/10<sup>6</sup> Btu. The 14-day run on the GSA/PJBH system showed that the SO<sub>2</sub> removal efficiency averaged more than 96% at an average Ca/S ratio of 1.34–1.43 moles Ca(OH)<sub>2</sub>/mole inlet SO<sub>2</sub>. Lime utilization averaged 70.5%. The particulate removal efficiency averaged 99.99+% and emission rates ranged from 0.001 to 0.003 lb/10<sup>6</sup> Btu.

All air toxic tests were conducted with 2.7% sulfur, low-chloride coal with a 12 °F approach-to-saturation temperature and a high flyash loading of 2.0 gr/ft<sup>3</sup> (actual). The GSA/ESP arrangement indicated average removal efficiencies of greater than 99% for arsenic, barium, chromium, lead, and vanadium; somewhat less for manganese; and less than 99% for antimony, cadmium, mercury, and selenium. The GSA/PJBH configuration showed 99+% removal efficiencies for arsenic, barium, chromium, lead, manganese, selenium, and vanadium; with cadmium removal much lower and mercury removal lower than that of the GSA/ESP system. The removal of HCl and HF was dependent upon the utilization of lime slurry and was relatively independent of particulate control configuration. The removal efficiencies were greater than 98% and 96% for HCl and HF, respectively.

## Operational Performance

Because the GSA system has suspended recycle solids to provide a contact area for SO<sub>2</sub> capture, multiple high-pressure atomizer nozzles or high-speed rotary nozzles to achieve uniform, fine droplet size are not required. Also, recycle of solids is direct and avoids recycling material in

the feed slurry, which necessitates expensive abrasion-resistant materials in the atomizer(s).

The high heat and mass transfer characteristics of the GSA enable the GSA system to be significantly smaller than a conventional spray dryer for the same capacity— $\frac{1}{4}$  to  $\frac{1}{3}$  the size. This makes retrofit feasible for space-confined plants and reduces installation cost. The GSA system slurry is sprayed on the recycled solids, not the reactor walls, avoiding direct wall contact and the need for corrosion-resistant alloy steels. Furthermore, the high concentration of rapidly moving solids scours the reactor walls and mitigates scaling. The GSA system generates a significantly lower grain loading than a spray dryer— $2\text{--}5\text{ gr/ft}^3$  for GSA versus  $6\text{--}10\text{ gr/ft}^3$  for a spray dryer—enabling compliance even with lower ESP particulate removal efficiency. The GSA system produces a solid by-product containing very low moisture. This material contains both fly ash and unreacted lime. With the addition of water, the by-product undergoes a pozzolanic reaction, essentially providing the characteristics of a low-grade cement.

### Economic Performance

Using the EPRI costing methodology applied to 30–35 other FGD processes, economics were estimated for a moderately difficult retrofit of a 300-MWe boiler burning 2.6% sulfur coal. The design  $\text{SO}_2$  removal efficiency was 90% at a lime feed rate equivalent to 1.30 moles of Ca/mole inlet  $\text{SO}_2$ . Lime was assumed to be 2.8 times the cost of limestone. It was determined that (1) capital cost (1990\$) was \$149/kW with three units at 50% capacity and (2) levelized cost (15-year) was 10.35 mills/kWh with three units at 50% capacity.

A cost comparison run for a WLFO scrubber showed the capital and levelized costs to be \$216/kW and 13.04 mills/kWh, respectively. The capital cost listed in EPRI cost tables for a conventional spray dryer at 300 MWe and 2.6% sulfur coal was \$172/kW (1990\$). Also, because the GSA requires less power and has better



▲ AirPol successfully demonstrated the GSA system at TVA's Center for Emissions Research.

lime utilization than a spray dryer, the GSA will have a lower operating cost.

### Commercial Applications

The low capital cost, moderate operating cost, and high  $\text{SO}_2$  capture efficiency make the GSA system particularly attractive as a CAAA compliance option for boilers in the 50–250-MWe range. Other major advantages include the modest space requirements comparable to duct injection systems, high availability/reliability owing to design

simplicity, and low dust loading, minimizing particulate upgrade costs.

GSA market entry was significantly enhanced with the sale of a 50-MWe unit to the city of Hamilton, OH, subsidized by the Ohio Coal Development Office. This will enable AirPol, Inc., to refine the commercial design and provide a solid design base for a 100-MWe unit, which will be the module size for larger plants. In addition to positioning GSA for market penetration into larger plant sizes, the experience at the first commercial site will increase utility sector confidence in the GSA system. This should be further bolstered by an award to FLS miljo of a major project in Sweden for a high-performance GSA system to remove 90–95% sulfur from the flue gas of a 4-million-ton/yr iron ore sinter plant.

### Contacts

Frank E. Hsu, Vice President, Operations, (201) 490-6400  
AirPol, Inc.  
3 Century Drive  
Parssippany, NJ 07054-4610  
Lawrence Saroff, DOE/HQ, (301) 903-9483  
Sharon K. Marchant, FETC, (412) 892-6008

### References

- *10-MWe Demonstration of Gas Suspension Absorption Final Project Performance and Economics Report.* Report No. DOE/PC/90542-T9. AirPol, Inc. June 1995. (Available from NTIS as DE95016681.)
- *10-MW Demonstration of the Gas Suspension Absorption Final Public Design Report.* Report No. DOE/PC/90542-T10. AirPol, Inc. June 1995. (Available from NTIS as DE960003270.)
- *SO<sub>2</sub> Removal Using Gas Suspension Absorption Technology.* Topical Report No. 4. U.S. Department of Energy and AirPol, Inc. April 1995.

## Confined Zone Dispersion Flue Gas Desulfurization Demonstration

**Project completed.**

### Participant

Bechtel Corporation

### Additional Team Members

Pennsylvania Electric Company—cofunder and host  
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

### Plant Capacity/Production

73.5 MWe

### Coal

Pennsylvania bituminous, 1.2–2.5% sulfur

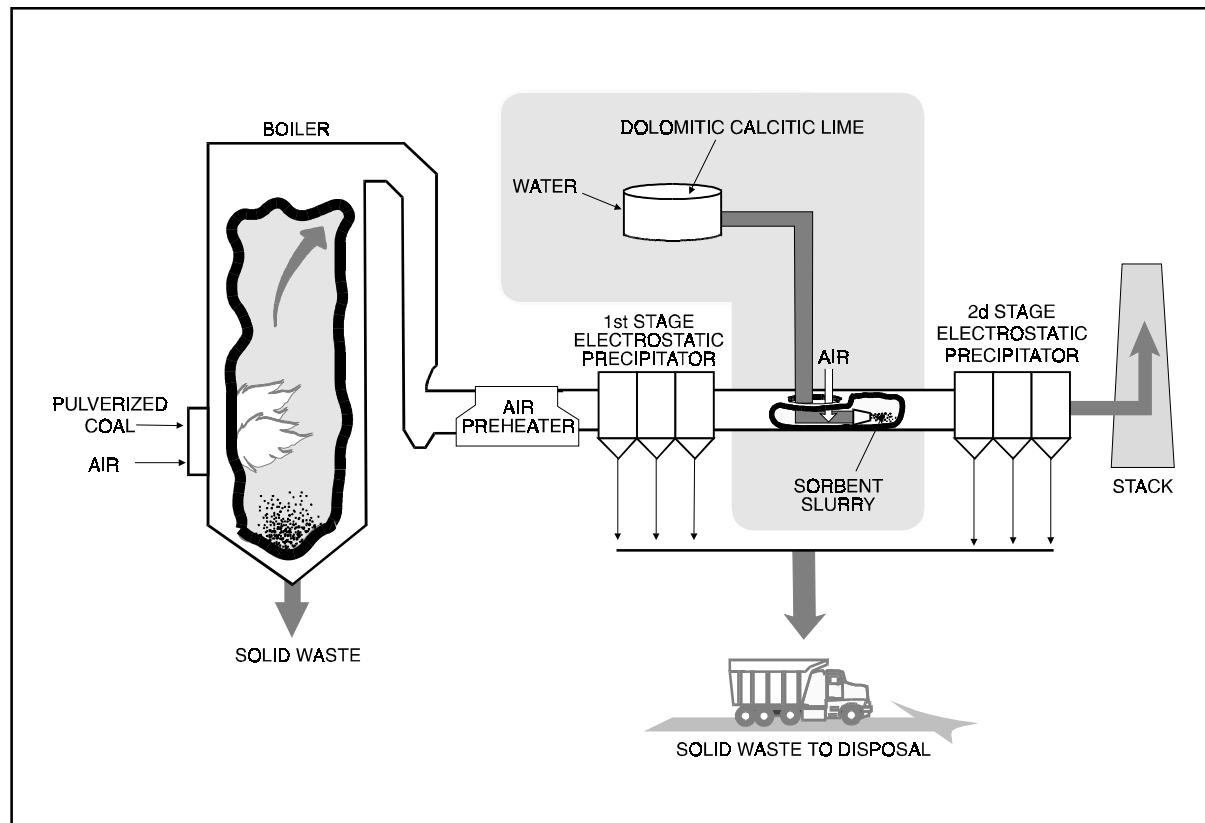
### Project Funding

Total project cost*	\$10,411,600	100%
DOE	5,205,800	50
Participant	5,205,800	50

### Project Objective

To demonstrate SO<sub>2</sub> removal capabilities of in-duct CZD/FGD technology; specifically, to define the optimum process operating parameters and to determine

\*Additional project overrun costs were funded 100% by the participant for a final total project cost of \$12,173,000.

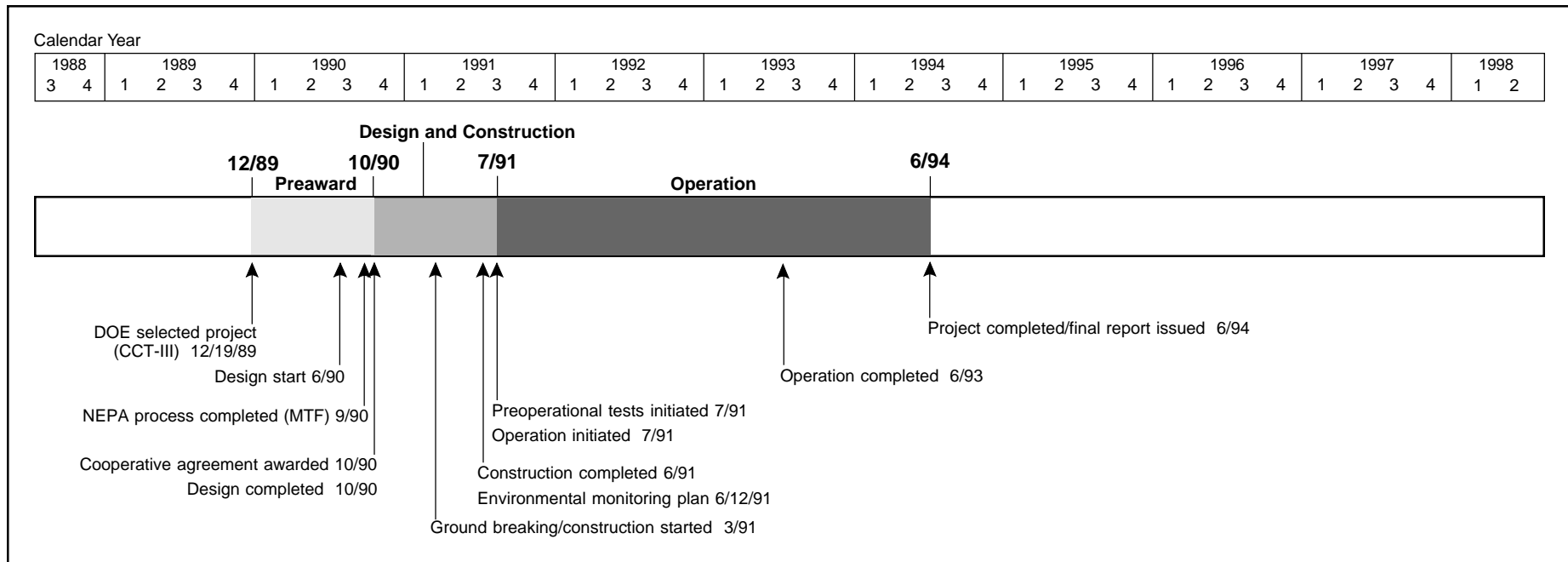


CZD/FGD's operability, reliability, and cost-effectiveness during long-term testing and its impact on downstream operations and emissions.

### 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<sub>2</sub> is quickly 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.

This project included 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<sub>2</sub> removal and the capability of the ESP to control particulates. The demonstration was conducted at Pennsylvania Electric Company's Seward Station in Seward, PA. 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-stage ESPs.



## Results Summary

### Environmental

- Pressure-hydrated dolomitic lime proved to be a more effective sorbent than either dry hydrated calcitic lime or freshly slaked calcitic lime.
- Sorbent injection rate was the most influential parameter on SO<sub>2</sub> capture. Flue gas temperature was the limiting factor on injection rate. For SO<sub>2</sub> capture efficiency of 50% or more, a flue gas temperature of 300 °F or more was needed.
- Slurry concentration for a given sorbent did not increase SO<sub>2</sub> removal efficiency beyond a certain threshold concentration.
- Testing indicated that SO<sub>2</sub> removal efficiencies of 50% or more were achievable with flue gas temperatures of 300–310 °F (full load), sorbent injection rate of 52–57 gal/min, residence time of 2 seconds, and a pressure-hydrated dolomitic-lime concentration of about 9%.

- For operating conditions at Seward Station, data indicated that for 40–50% SO<sub>2</sub> removal, a 6–8% lime or dolomitic lime slurry concentration, and a stoichiometric ratio of 2–2.5 resulted in a 40–50% lime utilization rate. That is, 2–2.5 moles of CaO or CaO•MgO were required for every mole of SO<sub>2</sub> removed.
- Assuming 92% lime purity, 1.9–2.4 tons of lime was required for every ton of SO<sub>2</sub> removed.

### Operational

- About 100 ft of straight duct was required to assure the 2-second residence time needed for effective CZD/FGD operation.
- At Seward Station, stack opacity was not detrimentally affected by CZD/FGD.
- Availability of CZD/FGD was very good.
- Some CZD/FGD modification will be necessary to assure consistent SO<sub>2</sub> removal and avoid deposition of solids within the ductwork during upsets.

### Economic

- Capital cost of a 500-MWe system operating on 4% sulfur coal and achieving 50% SO<sub>2</sub> reduction was estimated at less than \$30/kW and operating cost at \$300/ton of SO<sub>2</sub> removed.



## Project Summary

The principle of the CZD/FGD is to form a wet zone of slurry droplets in the middle of a duct confined in an envelope of hot gas between the wet zone and the hot gas. The lime slurry reacts with part of the SO<sub>2</sub> in the gas and the reaction products dry to form solid particles. An ESP, downstream from the point of injection, captures the reaction products along with the fly ash entrained in the flue gas.

CZD/FGD did not require a special reactor, simply a modification to the ductwork. Use of the commercially available Type S pressure-hydrated dolomitic lime reduced residence time requirements for CZD/FGD and enhanced sorbent utilization. The increased humidity of CZD/FGD processed flue gas enhanced ESP performance, eliminating the need for upgrades to handle the increased particulate load.

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. The new atomizing nozzles were thoroughly tested both outside and inside the duct prior to testing. The SO<sub>2</sub> removal parametric test program, which began in October 1991, was completed in August 1992.

Specific objectives were as follows:

- Achieve projected SO<sub>2</sub> removal of 50%
- Realize SO<sub>2</sub> removal costs of less than \$300/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,



▲ Bechtel's demonstration showed that 50% SO<sub>2</sub> removal efficiency was possible using CZD/FGD technology. The extended duct into which lime slurry was injected is in the foreground.

freshly slaked calcitic lime, and pressure-hydrated dolomitic lime. All three reagents remove SO<sub>2</sub> from the flue gas but require different feed concentrations of lime slurry for the same percentage of SO<sub>2</sub> removed. The most efficient removals and easiest to operate system were obtained using pressure-hydrated dolomitic lime.

### Environmental Performance

Sorbent injection rate proved to be the most influential factor on SO<sub>2</sub> capture. The rate of injection possible was limited by the flue gas temperature. This impacted a portion of the demonstration when air leakage caused flue gas temperature to drop from 300–310 °F to 260–280 °F. At 300–310 °F, injection rates of 52–57 gal/min were possible and SO<sub>2</sub> reductions greater than 50% were achieved. At 260–280 °F, injection rates had to be dropped to 30–40 gal/min, resulting in a 15–30% drop in SO<sub>2</sub> removal efficiency. Slurry concentration for a given sorbent did not increase SO<sub>2</sub> removal efficiency beyond a certain threshold concentration. For example, with pressure-hydrated dolomitic lime, slurry concentrations above 9% did not increase SO<sub>2</sub> capture efficiency.

Parametric tests indicated that SO<sub>2</sub> removals above 50% are possible under the following conditions: 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 gal/min.

### Operational Performance

The percentage of lime utilization in the CZD/FGD significantly affected the total cost of SO<sub>2</sub> removal. An analysis of the continuous operational data indicated that the percentage of lime utilization was directly dependent on two key factors:

- Percentage of SO<sub>2</sub> removed
- Lime slurry feed concentration

For operating conditions at Seward Station, data indicated that for 40–50% SO<sub>2</sub> removal, a 6–8% lime or dolomitic lime slurry concentration, and a stoichiometric ratio of 2–2.5 resulted in a 40–50% lime utilization rate. That is, 2–2.5 moles of CaO or CaO•MgO were required for every mole of SO<sub>2</sub> removed; or assuming 92% lime purity, 1.9–2.4 tons of lime were required for every ton of SO<sub>2</sub> removed. In summary, the demonstration showed the following results:

- A 50% SO<sub>2</sub> removal efficiency with CZD/FGD was possible.
- Drying and SO<sub>2</sub> absorption required a residence time of 2 seconds, which required a long and straight horizontal gas duct of about 100 feet.
- 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 were required to assure consistent SO<sub>2</sub> 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.

## Economic Performance

The CZD/FGD process can achieve costs of \$300/ton of SO<sub>2</sub> removed when operating a 500-MWe unit burning 4% sulfur coal. Based on a 500-MWe plant retrofitted with CZD/FGD for 50% SO<sub>2</sub> removal, the total capital cost is estimated to be less than \$30/kW.

## Commercial Applications

After the conclusion of the DOE-funded CZD/FGD demonstration project at Seward Station, the CZD/FGD system was modified to improve SO<sub>2</sub> removal during continuous operation while following daily load cycles. Bechtel and the host utility, Pennsylvania Electric Company, continued the CZD/FGD demonstration for an additional year. Results showed that CZD/FGD operation at SO<sub>2</sub> removal rates lower than 50% could be sustained over long periods without significant process problems.

CZD/FGD can be used for retrofit of existing plants and installation in new utility boiler flue gas facilities to remove SO<sub>2</sub> from a wide variety of sulfur-containing coals. A CZD/FGD system can be added to a utility boiler with a capital investment of about \$25–50/kW of

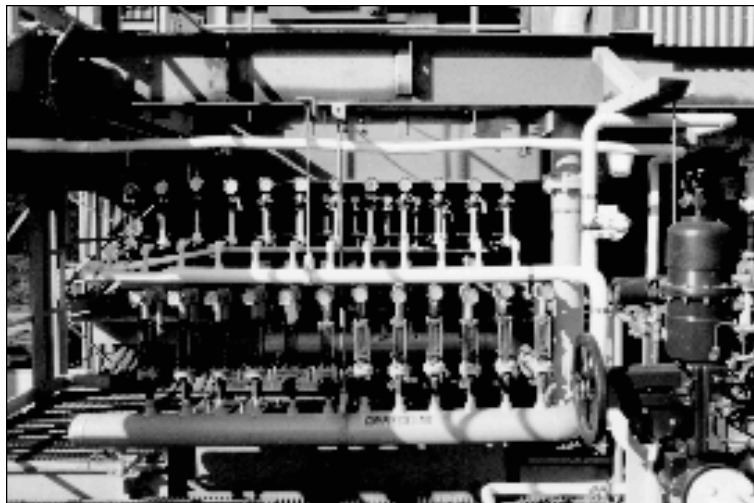
installed capacity, or approximately one-fourth the cost of building a conventional wet scrubber. In addition to low capital cost, other advantages include small space requirements, ease of retrofit, low energy requirements, fully automated operation, and production of only nontoxic, disposable waste. The CZD/FGD technology is particularly well suited for retrofitting existing boilers, independent of type, age, or size. The CZD/FGD installation does not require major power station alterations and can be easily and economically integrated into existing power plants.

## Contacts

Joseph T. Newman, Project Manager, (415) 768-1189  
Bechtel Corporation  
P.O. Box 193965  
San Francisco, CA 94119-3965  
Lawrence Saroff, DOE/HQ, (301) 903-9483  
James U. Watts, FETC, (412) 892-5991

## References

- *Confined Zone Dispersion Project: Final Technical Report.* Bechtel Corporation. June 1994.
- *Confined Zone Dispersion Project: Public Design Report.* Bechtel Corporation. October 1993.
- *Comprehensive Report to Congress on the Clean Coal Technology Program: Confined Zone Dispersion Flue Gas Desulfurization Demonstration.* Bechtel Corporation. Report No. DOE/FE-0203P. U.S. Department of Energy. September 1990. (Available from NTIS as DE91002564.)



▲ This photo shows the CZD/FGD lime slurry injector control system.

## 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.—cofounder and project manager  
Tampella Power Corporation—cofounder  
Tampella, Ltd.—technology owner  
Richmond Power and Light—cofounder and host utility  
Electric Power Research Institute—cofounder  
Black Beauty Coal Company—cofounder  
State of Indiana—cofounder

### 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

### Plant Capacity/Production

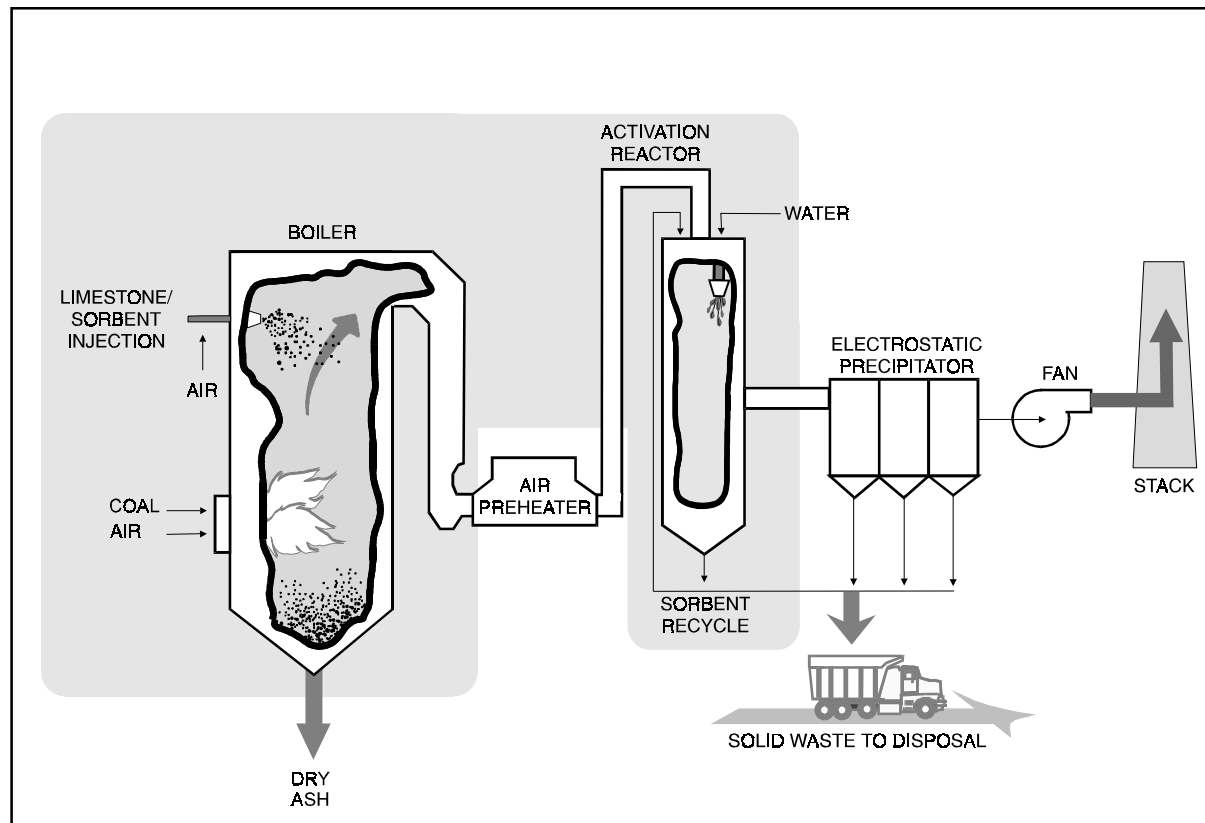
60 MWe

### Coal

Bituminous, 2.0–2.8% sulfur

### Project Funding

Total project cost	\$21,393,772	100%
DOE	10,636,864	50
Participants	10,756,908	50



### Project Objective

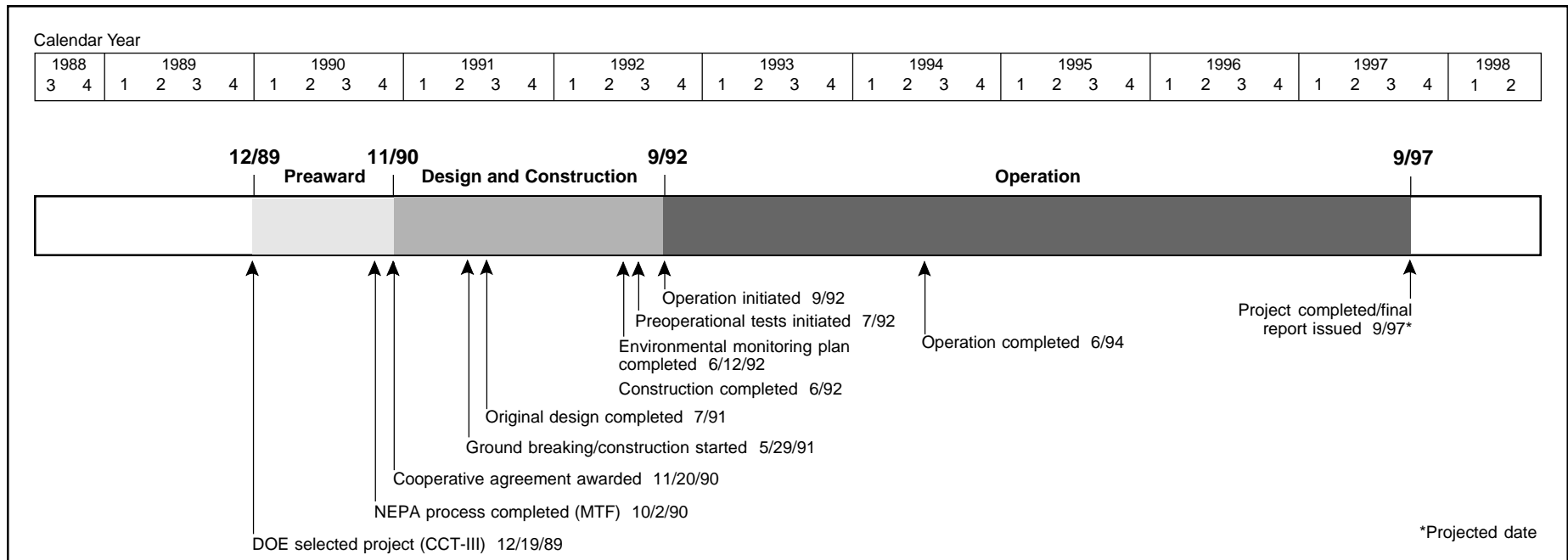
To demonstrate that electric power plants—especially those with space limitations and burning high-sulfur coals—can be retrofitted successfully with the LIFAC limestone injection process to remove 75–85% of the SO<sub>2</sub> from flue gas and produce a dry solid waste product for disposal in a landfill.

### 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<sub>2</sub> in the boiler flue gas. The limestone is calcined into calcium oxide and is available for capture of additional SO<sub>2</sub> downstream in the activation, or humidification, reactor. In the vertical chamber, water sprays initiate a series of chemical reactions leading to

SO<sub>2</sub> 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 are 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<sub>2</sub> from flue gas and produces a dry solid waste product suitable for disposal in a landfill.



## Results Summary

### Environmental

- SO<sub>2</sub> removal efficiency was 70% at a calcium-to-sulfur (Ca/S) molar ratio of 2.0, approach-to-saturation temperature of 7–12 °F, and limestone fineness of 80% minus 325 mesh.
- SO<sub>2</sub> removal efficiency with limestone fineness of 80% minus 200 mesh was 15% lower at a Ca/S of 2.0 and 7–12 °F approach to saturation.
- The four parameters having the greatest influence on sulfur removal efficiency were limestone quality, Ca/S molar ratio, approach-to-saturation temperature, and ESP ash recycle rate.
- ESP ash recycle rate was limited in the demonstration system configuration. Increasing the recycle rate and sustaining a 5 °F approach-to-saturation temperature was projected to increase SO<sub>2</sub> removal efficiency to 85% at a Ca/S of 2.0 (fine limestone).

- ESP efficiency and operating levels were essentially unaffected by LIFAC operation during steady-state operation.
- Fly and bottom ash were dry and readily disposed of at a local landfill. The quantity of additional solid waste can be determined by assuming that approximately 4.3 tons of limestone is required to remove 1.0 ton of SO<sub>2</sub>.

### Operational

- When operating with fine limestone (80% minus 325 mesh), the soot-blowing cycle had to be reduced from 6.0 to 4.5 hours.
- Automated programmable logic and simple design make the LIFAC system easy to operate in start-up, shutdown, or normal duty cycles.
- The amount of bottom ash increased slightly, but there was no negative impact on the ash-handling system.

### Economic

- 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).
- Operating cost—\$65/ton of SO<sub>2</sub> removal, assuming 75% SO<sub>2</sub> capture, Ca/S of 2.0, limestone composed of 95% CaCO<sub>3</sub>, and \$15/ton.

## Project Summary

The LIFAC technology was designed to enhance the effectiveness of dry sorbent injection systems for SO<sub>2</sub> control and to maintain the desirable aspects of low capital cost and compactness for ease of retrofit. Furthermore, limestone was used as the sorbent (about 1/3 of the cost of lime) and a sorbent recycle system was incorporated to reduce operating costs.

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

- Baseline tests characterized the operation of the host boiler and associated subsystems prior to LIFAC operations.
- Parametric tests were designed to evaluate the many possible combinations of LIFAC process parameters and their effect on SO<sub>2</sub> removal.
- 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 were performed to demonstrate LIFAC's performance under commercial operating conditions.
- Post-LIFAC tests involved repeating the baseline test to identify any changes caused by the LIFAC system.

The coals used during the demonstration varied in sulfur content from 1.4% to 2.8%. However, most of the testing was conducted with the higher sulfur coals (2.0–2.8% sulfur).

### Environmental Performance

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<sub>2</sub> capture was about 15% better when injecting fine limestone (80 minus 325 mesh) than it was with coarse limestone (80 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% SO<sub>2</sub> 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<sub>2</sub> 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 was found to affect SO<sub>2</sub> capture. During a brief test, it was found that increasing the recycle rate by 50% resulted in a 5% increase in SO<sub>2</sub> removal efficiency. It was estimated 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<sub>2</sub> reduction of 85% could be maintained.

### Operational Performance

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 molar ratio of 2.0 was selected to attain SO<sub>2</sub> 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 humidifica-



▲ 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 Canada, China, Finland, Russia, and the United States.

tion, grind size of the high-calcium-content limestone, and recycle of spent sorbent from the ESP.

Long-term testing showed that SO<sub>2</sub> 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 amount of boiler bottom ash increased slightly during testing, but there was no negative impact on the power plant's bottom and



▲ The top of the LIFAC reactor is shown being lifted into place. During 2,800 hours of operation, long-term testing showed that SO<sub>2</sub> reductions of 70% or more could be sustained under normal boiler operation.

flyash removal system. The solid waste generated was a mixture of fly ash and calcium compounds and was readily disposed of at a 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 personal computers located in the host utility's control room.

### Economic Performance

The economic evaluation indicated that the capital cost of a LIFAC installation is lower than for either a spray dryer or wet scrubber. 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<sub>2</sub>, assuming 75% SO<sub>2</sub> capture, a Ca/S ratio of 2.0, and limestone containing 95% CaCO<sub>3</sub>. Assuming limestone costs of \$15/ton, LIFAC's operating cost would be \$65/ton of SO<sub>2</sub> removed.

### Commercial Applications

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%) 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 are using bituminous and lignite coals having lower sulfur contents (0.6–1.5%).

### Contacts

Jim Hervol, Project Manager, (412) 497-2235  
 ICF Kaiser Engineers, Inc.  
 Gateway View Plaza  
 1600 West Carson Street  
 Pittsburgh, PA 15219-1031  
 Lawrence Saroff, DOE/HQ, (301) 903-9483  
 James U. Watts, FETC, (412) 892-5991

### References

- "LIFAC Nearing Marketability." *Clean Coal Today*. Report No. DOE/FE-0215P-21. Spring 1996.
- Viiala, J., et al. "Commercialization of the LIFAC Sorbent Injection Process in North America." *Third Annual Clean Coal Technology Conference: Technical Papers*. September 1994.
- *Comprehensive Report to Congress on the Clean Coal Technology Program: LIFAC Sorbent Injection Desulfurization Demonstration Project*. LIFAC-North America. Report No. DOE/FE-0207P. U.S. Department of Energy, October 1990. (Available from NTIS as DE91001077.)

## Advanced Flue Gas Desulfurization Demonstration Project

*Project completed.*

### 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.)

### Additional Team Members

Northern Indiana Public Service Company—cofunder and host

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

### Plant Capacity/Production

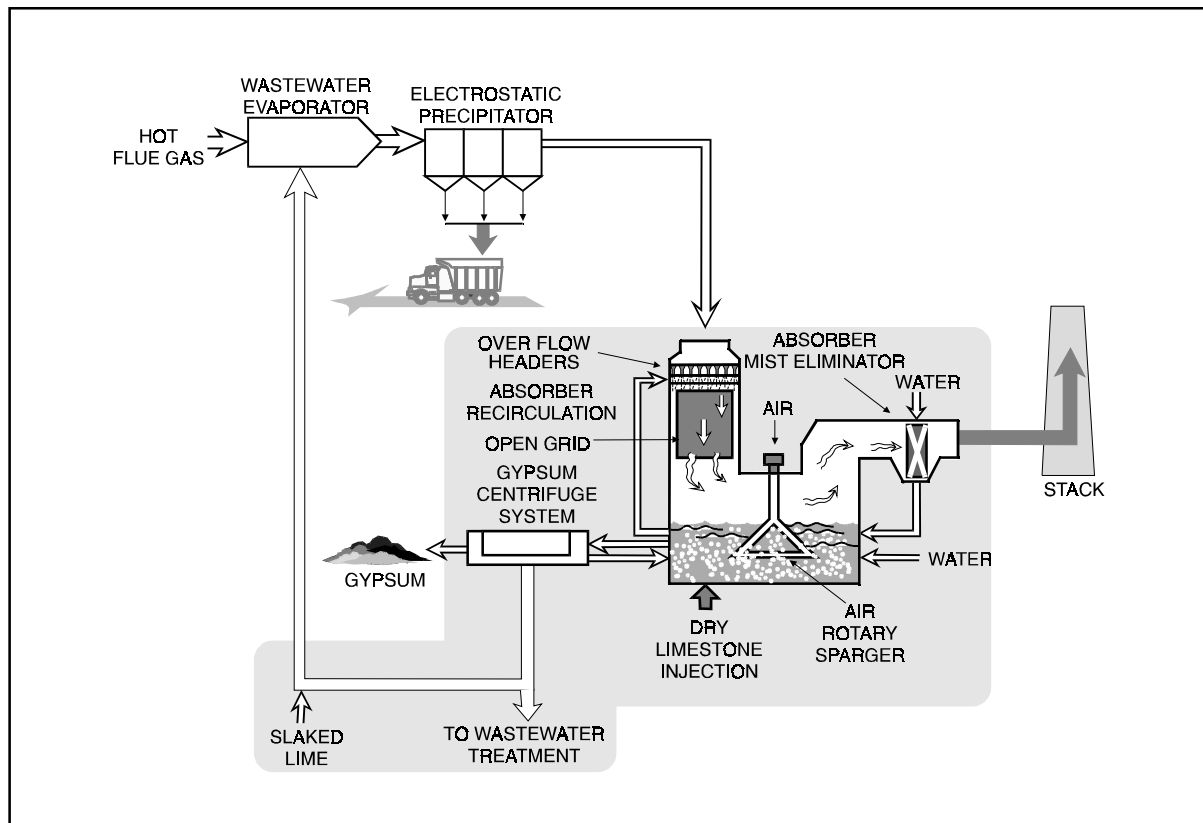
528 MWe

### Coal

Bituminous, 2.0–4.5% sulfur

### Project Funding

Total project cost	\$151,707,898	100%
DOE	63,913,200	42
Participant	87,794,698	58



### Project Objective

To reduce SO<sub>2</sub> emissions by 95% or more at approximately one-half the cost of conventional scrubbing technology, significantly reduce space requirements, and create no new waste streams.

### Technology/Project Description

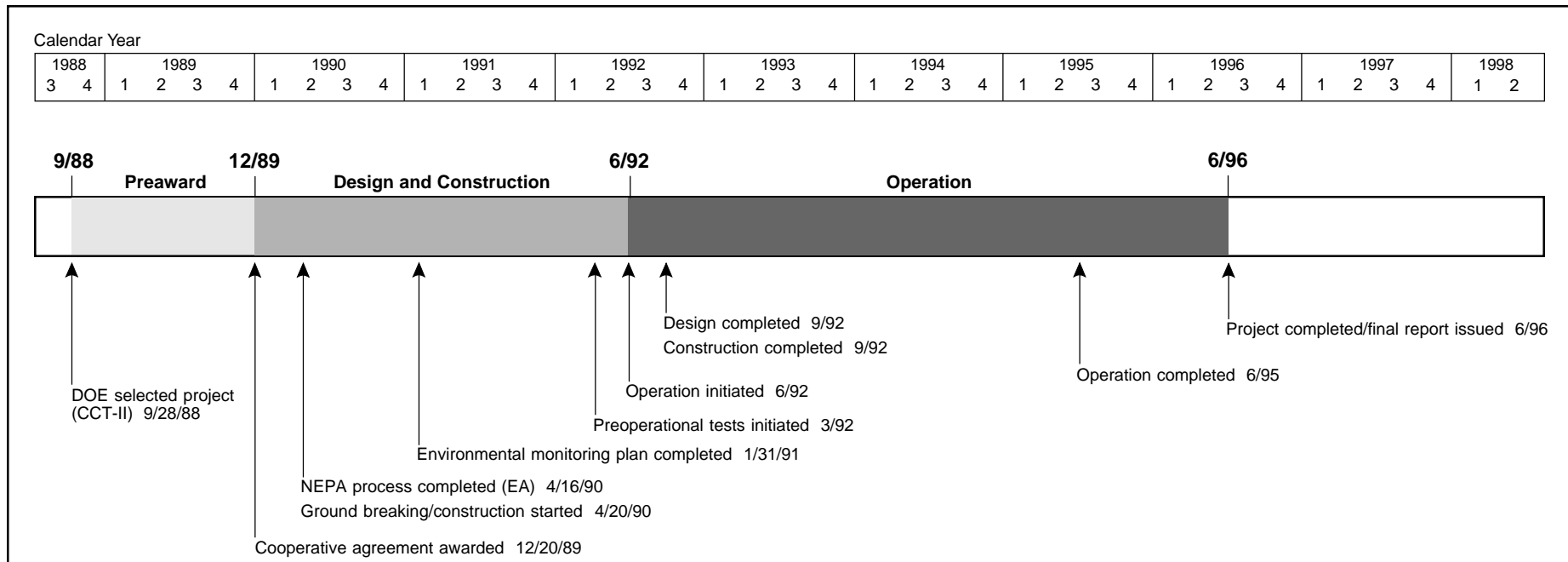
Pure Air built a single SO<sub>2</sub> absorber for a 528-MWe power plant. Although the largest capacity absorber module of its time in the United States, space requirements were modest because no spare or backup absorber modules were required. The absorber performed three functions in a single vessel: prequenching, absorbering, and oxidation of sludge to gypsum. Additionally, the absorber was of a co-current design, in which the flue gas and scrubbing slurry move in the same direction and

at a relatively high velocity compared to that in conventional scrubbers. These features all combined to yield a state-of-the-art SO<sub>2</sub> absorber that was more compact and less expensive than contemporary conventional scrubbers.

Other technical features included 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 combined the functions of agitation and air distribution into one piece of equipment to facilitate the oxidation of calcium sulfite to gypsum.

Pure Air also demonstrated a unique gypsum agglomeration process, PowerChip®, to significantly enhance handling characteristics of AFGD-derived gypsum.

PowerChip is a registered trademark of Pure Air on the Lake, L.P.



## Results Summary

### Environmental

- AFGD design enabled a single 600-MWe absorber module without spares to remove 95% or more SO<sub>2</sub> at availabilities of 99.5% when operating with high-sulfur coals.
- Wallboard-grade gypsum was produced in lieu of solid waste, and all gypsum produced was sold commercially.
- The wastewater evaporation system (WES) mitigated expected increases in wastewater generation associated with gypsum production and showed the potential for achieving zero wastewater discharge (only a partial-capacity WES was installed).
- PowerChip® increased the market potential for AFGD-derived gypsum by cost effectively converting it to a product with the handling characteristics of natural rock gypsum.

- Air toxics testing established that all acid gases were effectively captured and neutralized by the AFGD. Trace elements largely became constituents of the solids streams (bottom ash, fly ash, gypsum product). Some boron, selenium, and mercury passed to the stack gas in a vapor state.

### Operational

- AFGD use of co-current, high-velocity flow; integration of functions; and a unique air rotary sparger proved to be highly efficient, reliable (to the exclusion of requiring a spare module), and compact. The compactness, combined with no need for a spare module, significantly reduced space requirements.
- The own-and-operate contractual arrangement whereby Pure Air took on the turnkey, financing, operating and maintenance risks through performance guarantees was successful.

### Economic

- Capital costs and space requirements for AFGD were about half those of contemporary systems.

## Project Summary

The project proved that single absorber modules of advanced design could process large volumes of flue gas and provide the required availability and reliability without the usual spares. The major performance objectives were met.

Over the 3-year demonstration, the AFGD unit accumulated 26,280 hours of operation with an availability of 99.5%. Approximately 237,000 tons of SO<sub>2</sub> were removed, with capture efficiencies of 95% or more, and over 210,000 tons of salable gypsum were produced. The AFGD continues commercial service, which includes sale of all by-product gypsum to U.S. Gypsum's East Chicago, IN, wallboard production plant.

### Environmental Performance

Testing over the 3-year period clearly established that AFGD operating within its design parameters (without additives) could consistently achieve 95% SO<sub>2</sub> reduction or more with 2.0–4.5% sulfur coals. The design range for the calcium-to-sulfur stoichiometric ratio was

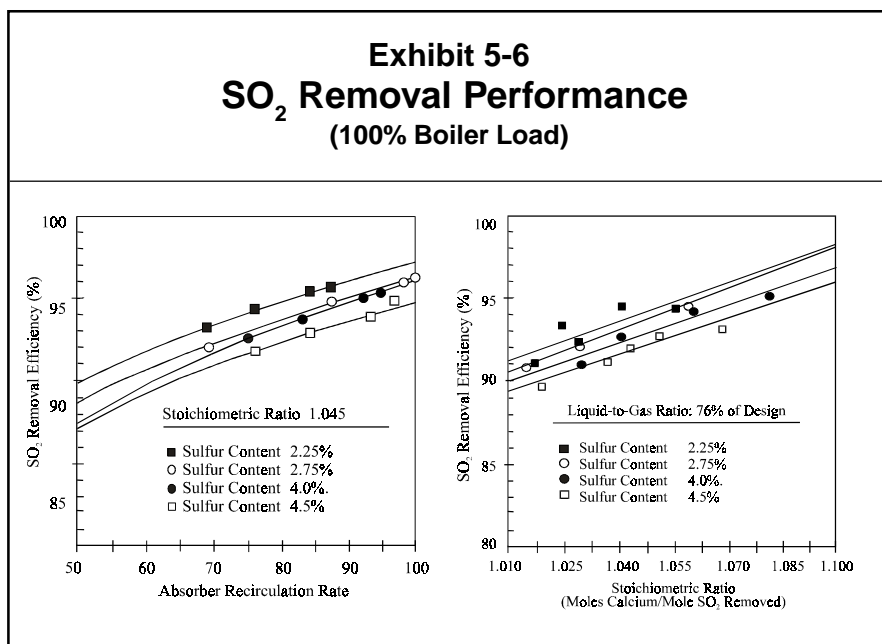


1.01–1.07, with the upper value set by gypsum purity requirements (i.e., amount of unreacted reagent allowed in the gypsum). Another key control parameter was the ratio (L/G) of the amount of reagent slurry injected into the absorber grid (L) to the volume of flue gas (G). The design L/G range was 50–128 gal/10<sup>3</sup> ft<sup>3</sup>. The lower end was determined by solids settling rates in the slurry and the requirement for full wetting of the grid packing. The high end was determined by where performance leveled out.

Five coals with differing sulfur contents were selected for parametric testing to examine SO<sub>2</sub> removal efficiency as a function of load, sulfur content, stoichiometric ratio, and L/G. Loads tested were 33%, 67%, and 100%. High removal efficiencies, well above 95%, at loads of 33% and 67% were possible with low to moderate stoichiometric ratio and L/G settings, even for 4.5% sulfur coal. Exhibit 5-6 summarizes the results of parametric testing at full load.

In the AFGD process, chlorides that would have been released to the air are captured and potentially become a wastewater problem. This was mitigated by the addition of the WES which takes a portion of the wastewater stream with high chloride and sulfate levels and injects it into the ductwork upstream of the ESP. The hot flue gas evaporated the water and the dissolved solids were captured in the ESP. Problems were experienced early on, with the WES nozzles failing to provide adequate atomization and plugging as well. This was resolved by replacing the original single-fluid nozzles with dual fluid systems employing air as the second fluid.

Commercial-grade gypsum quality (95.6–99.7%) was maintained throughout testing, even at the lower sulfur concentrations where the ratio of fly ash to gypsum increases due to lower sulfate availability. The primary importance of producing a commercial-grade gypsum is avoidance of the environmental and economic consequences of disposal. The marketability of the gypsum is dependent upon whether users are in range of economic



transport and whether they can handle the gypsum by-product. For these reasons, PowerChip<sup>®</sup> technology was demonstrated as part of the project. This technology uses a compression mill to convert the highly cohesive AFGD gypsum cake into a flaked product with handling characteristics equivalent to natural rock gypsum. The process avoids use of binders, pre-drying or pre-calcining normally associated with briquetting and is 30–55% cheaper at \$2.50–\$4.10/ton.

Air toxics testing established that all acid gases are effectively captured and neutralized by the AFGD. Trace elements largely become constituents of the solids streams (bottom ash, fly ash, gypsum product). Some boron, selenium, and mercury pass to the stack gas in a vapor state.

#### Operational Performance

Availability over the 3-year operating period averaged 99.5% while maintaining an average SO<sub>2</sub> removal effi-

ciency of 94%. This was attributable to the simple, effective design and an effective operating/maintenance philosophy. Modifications were also made to the AFGD system. An example was the implementation of new alloy technology, C-276 alloy over carbon steel clad material, to replace alloy wallpaper construction within the absorber tower wet/dry interface. Also, use of co-current rather than conventional counter-current flow resulted in lower pressure drops across the absorber and afforded the flexibility to increase gas

flow without an abrupt drop in removal efficiency. AFGD SO<sub>2</sub> capture efficiency with limestone was comparable to that in wet scrubbers using lime, which is far more expensive. Twenty-four-hour power consumption was 5,275 kW, or 61% of expected consumption, and water consumption was 1,560 gal/min, or 52% of expected consumption.

#### Economic Performance

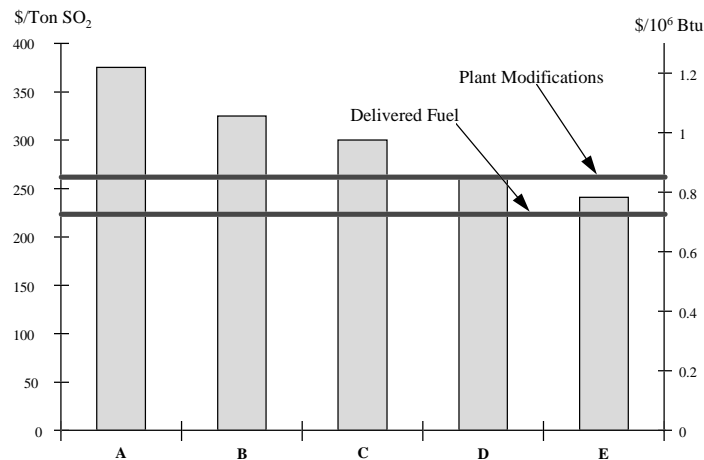
Exhibit 5-7 summarizes capital and levelized current dollar cost estimates for nine cases with varying plant capacity and coal sulfur content. A capacity factor of 65% and a sulfur removal efficiency of 90% were assumed. The calculation of levelized cost followed guidelines established in the Electric Power Research Institute's Technical Assessment Guide.

The incremental benefits of the own-and-operate arrangement, by-product utilization, and emission allowances were also evaluated. Exhibit 5-8 depicts the rela-

### Exhibit 5-7 Estimated Costs for an AFGD System

Cases:	1	2	3	4	5	6	7	8	9
Plant size (MWe)	100	100	100	300	300	300	500	500	500
Coal sulfur content (%)	1.5	3.0	4.5	1.5	3.0	4.5	1.5	3.0	4.5
Capital cost (\$/kW)	193	210	227	111	121	131	86	94	101
Levelized cost (\$/ton SO <sub>2</sub> )									
15-year life	1,518	840	603	720	401	294	536	302	223
20-year life	1,527	846	607	716	399	294	531	300	223
Levelized cost (mills/kWh)									
15-year life	16.39	18.15	19.55	7.78	8.65	9.54	5.79	6.52	7.24
20-year life	16.49	18.28	19.68	7.73	8.62	9.52	5.74	6.48	7.21

### Exhibit 5-8 Flue Gas Desulfurization Economics



500-MWe plant, 30-yr levelized costs, allowance value of \$300/ton

Incremental cases:

A—Conventional FGD (EPRI model)

B—AFGD, own-and-operate arrangement

C—Adds gypsum sales

D—Adds emission allowance credits at \$300/ton, for 90% SO<sub>2</sub> removal

E—Increases SO<sub>2</sub> removal to 95%

tive costs of a hypothetical 500-MWe generating unit in the Midwest burning 4.3% sulfur coal with a base case conventional FGD system and four incremental cases. The horizontal lines in Exhibit 5-8 show the range of costs for a fuel-switching option. The lower bar is the cost of fuel delivered to the

hypothetical Midwest unit and the upper bar allows for some plant modifications to accommodate the compliance fuel.

#### Commercial Applications

AFGD is positioned well to compete in the pollution control arena of year 2000 and beyond. AFGD has markedly reduced cost and demonstrated the ability to compete with fuel switching under certain circumstances even with a first-generation system. Advances in technology, e.g., in materials and components, should improve costs for AFGD. The own-and-operate business approach has done much to mitigate risk on the part of prospective users. High-SO<sub>2</sub>-capture efficiency places an AFGD user in the possible position of trading allowances or applying credits to other units within the utility. WES and PowerChip® mitigate or eliminate otherwise serious environmental concerns. AFGD effectively deals with hazardous air pollutants.

Pure Air of Manatee, L.P., entered into a contract with Florida Power & Light Company to process 1,600 MWe of flue gas with two 800-MWe AFGD modules and incorporate WES.

#### Contacts

Don Vymazal, Manager, Contract Administration  
(601) 481-3687

Pure Air on the Lake, L.P.  
7201 Hamilton Boulevard  
Allentown, PA 18195-1501

Lawrence Saroff, DOE/HQ, (301) 903-9483

James U. Watts, FETC, (412) 892-5991

#### References

- *Advanced Flue Gas Desulfurization (AFGD) Demonstration Project: Final Technical Report*. Pure Air on the Lake, L.P. April 1996.
- *Advanced Flue Gas Desulfurization Project: Public Design Report*. Pure Air on the Lake, L.P. March 1990.
- *Comprehensive Report to Congress on the Clean Coal Technology Program: Advanced Flue Gas Desulfurization (AFGD) Demonstration Project*. (Pure Air on the Lake, L.P.) DOE/FE Report No. 0150. U.S. Department of Energy. November 1989. (Available from NTIS as DE90004460.)
- *Summary of Air Toxics Emissions Testing at Sixteen Utility Power Plants*. Prepared by Burns and Roe Services Corporation for U.S. Department of Energy, Pittsburgh Energy Technology Center. July 1996.

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

*Project completed.*

### Participant

Southern Company Services, Inc.

### Additional Team Members

Georgia Power Company—host

Electric Power Research Institute—cofunder

Radian Corporation—environmental and analytical consultant

Ershigs, Inc.—fiberglass fabricator

Composite Construction and Equipment—fiberglass sustainment consultant

Acentech—flow modeling consultant

Ardaman—gypsum stacking consultant

University of Georgia Research Foundation—by-product utilization studies consultant

### 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

### Plant Capacity/Production

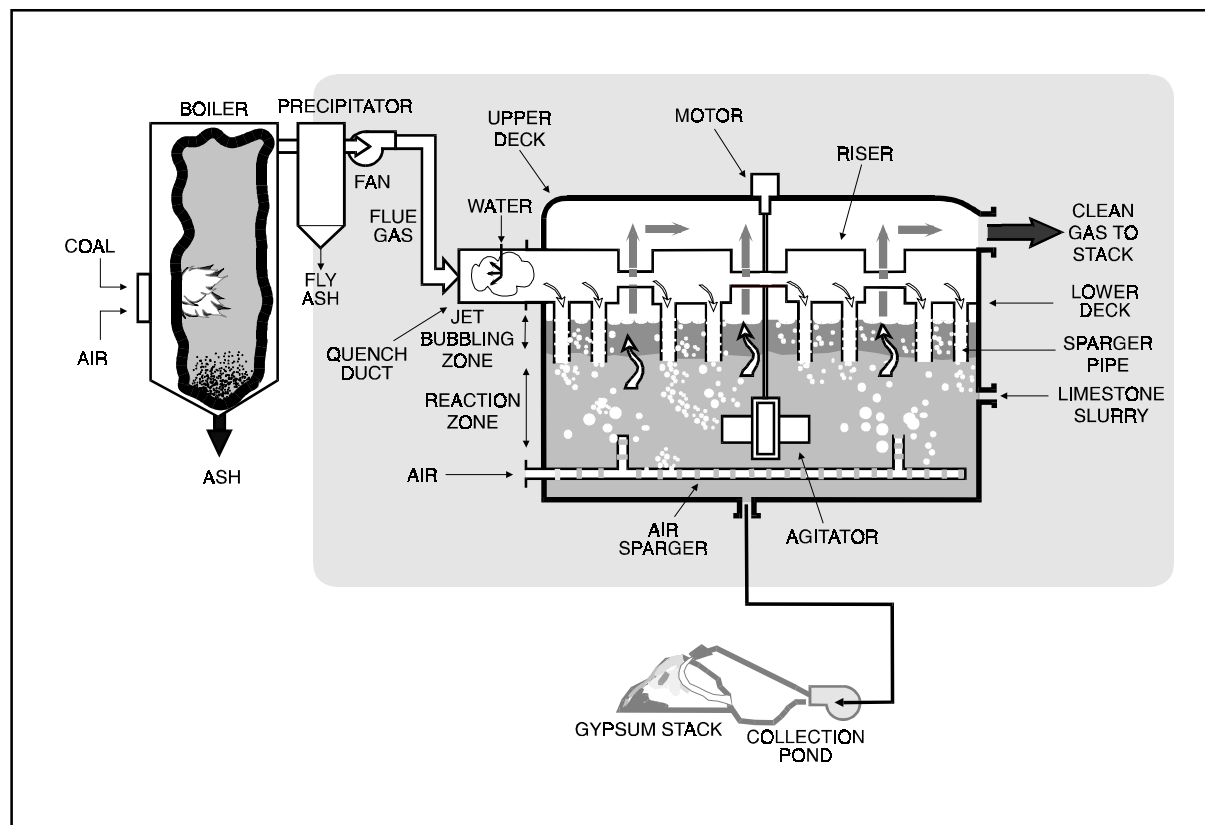
100 MWe

### Goals

Illinois No. 5 & No. 6 blend, 2.4% sulfur

Compliance, 1.2% sulfur

Jet Bubbling Reactor is a registered trademark of the Chiyoda Corporation.



### Project Funding

Total project cost	\$43,074,996	100%
DOE	21,085,211	49
Participant	21,989,785	51

### Project Objective

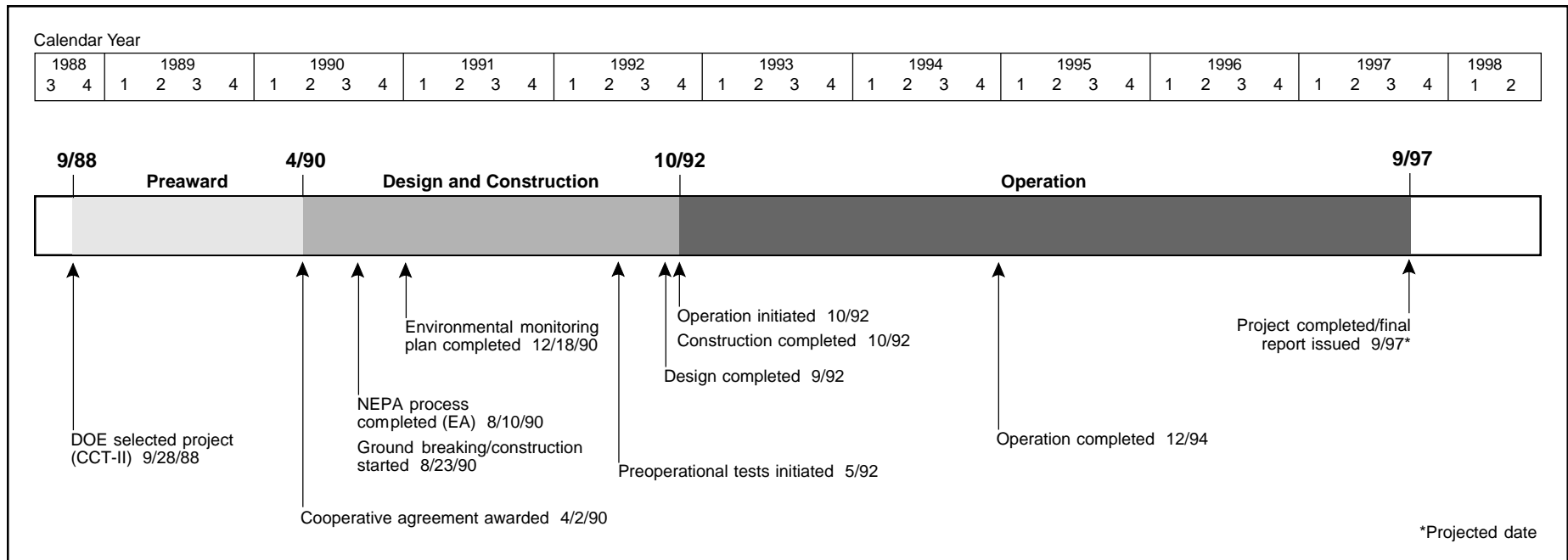
To demonstrate 90% SO<sub>2</sub> control at high reliability with and without simultaneous particulate control; to evaluate use of fiberglass-reinforced-plastic (FRP) vessels to eliminate flue gas reheat and spare absorber modules; and to evaluate use of gypsum to reduce waste management costs.

### Technology/Project Description

The project demonstrated the CT-121 FGD process, which uses a unique absorber design known as the Jet Bubbling Reactor® (JBR). The process combines lime-

stone 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<sub>2</sub> in the flue gas is absorbed and forms calcium sulfite (CaSO<sub>3</sub>). 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.



## Results Summary

### Environmental

- Over 90% SO<sub>2</sub> removal efficiency was achieved at SO<sub>2</sub> inlet concentrations of 1,000–3,500 ppm with limestone utilization over 97%.
- JBR achieved particulate removal efficiencies of 97.7–99.3% for inlet mass loadings of 0.303–1.392 lb/10<sup>6</sup> Btu over a load range of 50–100 MWe.
- Capture efficiency was a function of particle size:
  - >10 microns—99% capture
  - 1–10 microns—90% capture
  - 0.5–1 micron—negligible capture
  - <0.5 micron—90% capture
- Hazardous air pollutant (HAP) testing showed greater than 95% capture of hydrogen chloride (HCl) and fluoride (HF) gases, 80–98% capture of most trace metals, less than 50% capture of mercury and cadmium, and less than 70% capture of selenium.

- Gypsum stacking proved effective for producing wall-board/cement-grade gypsum.

### Operational

- FRP-fabricated equipment proved durable both structurally and chemically, eliminating the need for a flue gas prescrubber and reheat.
- FRP construction combined with simplicity of design resulted in 97% availability at low ash loadings and 95% at high ash loadings, precluding the need for a spare reactor module.
- Simultaneous SO<sub>2</sub> and particulate control were achieved at flyash loadings reflective of an ESP with marginal performance.

### Economic

- Final results are not yet available. However, elimination of the need for flue gas prescrubbing, reheat, and spare module requirement should result in capital requirements far below those of conventional FGD systems.

## Project Summary

The CT-121 process differs from the more common spray tower type of flue gas desulfurization systems in that a single process vessel is used in place of the usual spray tower/reaction tank/thickener arrangement. Pumping of reacted slurry to a gypsum transfer tank is intermittent. This allows crystal growth to proceed essentially uninterrupted resulting in large, easily dewatered gypsum crystals (conventional systems employ large centrifugal pumps to move reacted slurry causing crystal attrition and secondary nucleation).

The demonstration spanned 27 months, including start-up and shakedown, during which approximately 19,000 hours were logged. Exhibit 5-9 summarizes operating statistics. Elevated particulate loading included a short test with the electrostatic precipitator (ESP) completely deenergized, but the long-term testing was conducted with the ESP partially deenergized to simulate a more realistic scenario, i.e., a CT-121 retrofit to a boiler with a marginally performing particulate collection device. The SO<sub>2</sub> removal efficiency was measured under

five different inlet concentrations with coals averaging 2.4% and ranging 1.2– 4.3% sulfur (as burned).

### Operating Performance

Use of FRP construction proved very successful. Because their large size precluded shipment, the JBR and limestone slurry storage tanks were constructed on site. Except for some erosion experienced at the JBR inlet transition duct, the FRP-fabricated equipment proved to be durable both structurally and chemically. Because of the high corrosion resistance, the need for a flue gas pre-scrubber to remove chlorides was eliminated. Similarly, the FRP-constructed chimney proved resistant to the corrosive condensates in wet flue gas, precluding the need for flue gas reheat.

Availability of the CT-121 scrubber during the low-ash test phase was 97%. It dropped to 95% under the elevated ash-loading conditions due largely to sparger tube plugging problems precipitated by flyash agglomeration on the sparger tube walls during high ash loading when the ESP was deenergized. The high reliability

demonstrated verified that a spare JBR is not required in a commercial design offering.

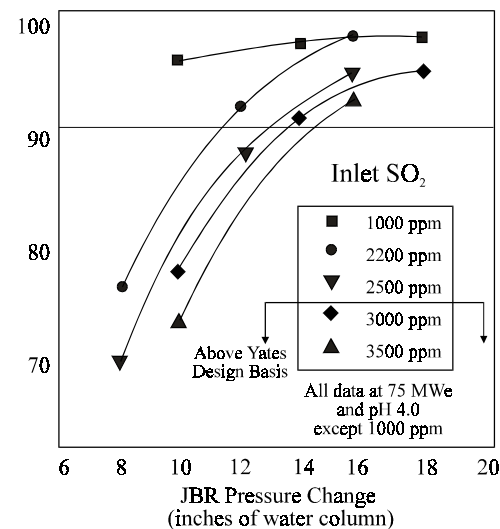
### Environmental Performance

Exhibit 5-10 shows SO<sub>2</sub> removal efficiency as a function of pressure drop across the JBR for five different inlet concentrations. The greater the pressure drop, the greater the depth of slurry traversed by the flue gas. As the SO<sub>2</sub> concentration increased, removal efficiency decreased, but adjustments in JBR fluid level could maintain the efficiency above 90% and, at lower SO<sub>2</sub> concentration levels, above 98%. Limestone utilization remained above 97% throughout the demonstration.

Long-term particulate capture performance was tested with a partially deenergized ESP (approximately 90% efficiency) and is summarized in Exhibit 5-11.

Analysis indicated that a large percentage of the outlet particulate matter is sulfate, likely a result of acid mist and gypsum carryover. This reduces the estimate of ash mass loading at the outlet to approximately 70% of the measured outlet particulates.

**Exhibit 5-10**  
**SO<sub>2</sub> Removal Efficiency**



**Exhibit 5-9**  
**Operation of CT-121 Scrubber**

	Low-Ash Phase	Elevated-Ash Phase	Cumulative for Project
Total test period (hr)	11,750	7,250	19,000
Scrubber available (hr)	11,430	6,310	18,340
Scrubber operating (hr)	8,600	5,210	13,810
Scrubber called upon (hr)	8,800	5,490	14,290
Reliability <sup>a</sup>	0.98	0.95	0.96
Availability <sup>b</sup>	0.97	0.95	0.97
Utilization <sup>c</sup>	0.73	0.72	0.75

<sup>a</sup> Reliability = hours scrubber operated divided by the hours called upon to operate  
<sup>b</sup> Availability = hours scrubber available divided by the total hours in the period  
<sup>c</sup> Utilization = hours scrubber operated divided by the total hours in the period

**Exhibit 5-11**  
**Particulate Capture Performance**  
**(ESP Marginally Operating)**

JBR Pressure Change (inches of water column)	Boiler Load (MWe)	Inlet Mass Loading (lb/10 <sup>6</sup> Btu)	Outlet Mass Loading* (lb/10 <sup>6</sup> Btu)	Removal Efficiency (%)
18	100	1.288	0.02	97.7
10	100	1.392	0.010	99.3
18	50	0.325	0.005	98.5
10	50	0.303	0.006	98.0

\*Federal NSPS is 0.03 lb/10<sup>6</sup> Btu for units constructed after September 18, 1978. Plant Yates permit limit is 0.24 lb/10<sup>6</sup> Btu as an existing unit.

For particulate sizes greater than 10 microns, capture efficiency was consistently greater than 99%. In the 1–10- micron range, capture efficiency was over 90%. Between 0.5 and 1 micron, the particulate removal dropped at times to negligible values possibly due to acid mist carryover entraining particulates in this size range. Below 0.5 micron, the capture efficiency increased to over 90%. Calculated HAP removals across the CT-121 JBR, based on the measurements taken during the demonstration, are shown in Exhibit 5-12.

As to solids handling, the gypsum stacking method proved effective in the long term. Although chloride content was initially high in the stack due to the closed loop nature of the process (with concentrations often exceeding 35,000 ppm), a year later the chloride concentration in the gypsum dropped to less than 50 ppm, suitable for wallboard and cement applications. The predominant cause of the initial high chloride content was attributed to rainwater washing the stack.

### Economic Performance

Although the final economic analyses are not yet available, it appears as though CT-121 technology offers significant economic advantages. FRP construction eliminates the need for prescrubbing and reheating flue gas. High system availability eliminates the need for a spare absorber module. Particulate removal capability precludes the need for expensive (capital-intensive) ESP upgrades to meet increasingly tough environmental regulations.

### Commercial Applications

Involvement of Southern Company (which owns Southern Company Services, Inc.),

with more than 20,000 MWe of coal-fired generating capacity, is expected to enhance confidence in the CT-121 process among other large high-sulfur-coal boiler users. This process will be applicable to 370,000 MWe of new

and existing generating capacity by the year 2010. A 90% reduction in SO<sub>2</sub> emissions from only the retrofit portion of this capacity represents more than 10,500,000 tons/yr of potential SO<sub>2</sub> control.

Plant Yates continues to operate with the CT-121 scrubber as an integral part of the site's CAAA compliance strategy.

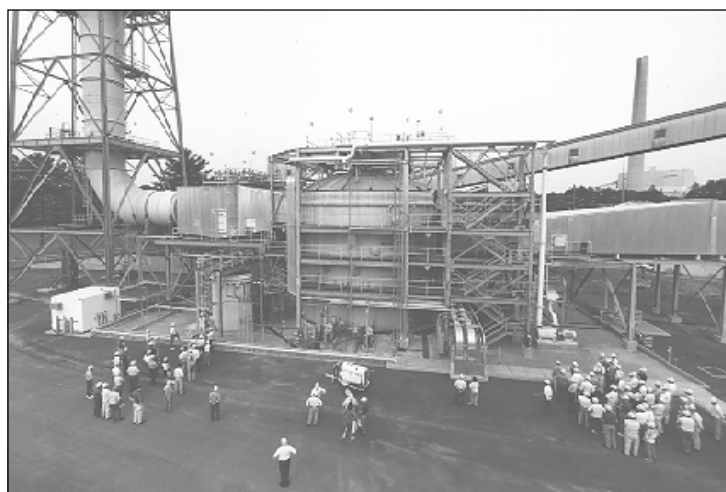
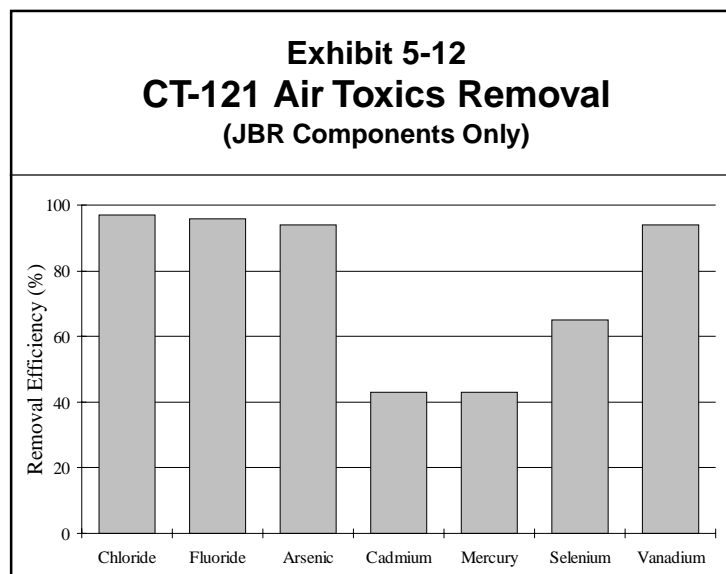
### Contacts

David P. Burford, Project Manager, (205) 992-6329  
Southern Company Services, Inc.  
P.O. Box 2625  
Birmingham, AL 35202-2625  
Lawrence Saroff, DOE/HQ, (301) 903-9483  
James U. Watts, DOE/FETC, (412) 892-5991

### References

- Final technical, economic, and public design reports are expected to be available by September 1997.
- *A Study of Toxic Emissions from a Coal-Fired Power Plant Utilizing an ESP while Demonstrating the CCT CT-121 FGD Project. Final Report.* Report No. DOE/PC/93253-T1. Radian Corporation. June 1994. (Available from NTIS as DE94016053.)
- *Comprehensive Report to Congress on the Clean Coal Technology Program: Demonstration of Innovative Applications of Technology for the CT-121 FGD Process.* Southern Company Services, Inc. Report No. DOE/FE-0158. U.S. Department of Energy. February 1990. (Available from NTIS as DE9008110.)

**Exhibit 5-12**  
**CT-121 Air Toxics Removal**  
**(JBR Components Only)**



▲ The unique Jet Bubbling Reactor® (center) was constructed from fiberglass-reinforced plastic.

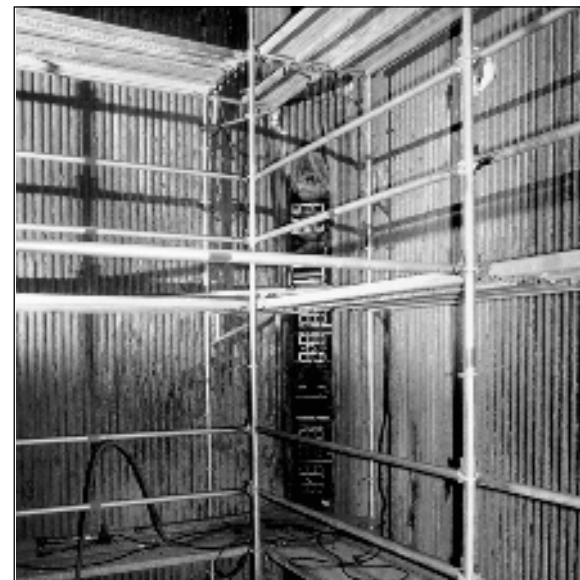
## NO<sub>x</sub> Control Technology

Nitrogen oxides (NO<sub>x</sub>) are formed from oxidation of nitrogen contained within the coal (fuel-bound nitrogen) and oxidation of the nitrogen in the air at high temperatures of combustion (thermal NO<sub>x</sub>). Rapid formation of NO<sub>x</sub> at the flame front can occur; but usually, this reaction of hydrocarbon fragments with atmospheric nitrogen represents a small fraction of total NO<sub>x</sub> emissions. To control fuel-NO<sub>x</sub> formation, it is important to limit oxygen at the early stages of combustion. To control thermal NO<sub>x</sub>, it is important to limit peak temperatures.

NO<sub>x</sub> was identified both as a precursor to acid rain, targeted under Title IV of the CAAA, and as a contributor to ozone formation, targeted under Title I. Phase I of Title IV, effective in 1995, required some 169 wall- and tangentially fired coal units to reduce emissions to 0.50 and 0.45 pound per million Btu, respectively. In 2000, Phase II of Title IV will come into effect, impacting all fossil-fueled units, but most of all, the balance of the 900 pre-NSPS coal-fired units (see Exhibit 5-13). The proposed new NSPS for NO<sub>x</sub> emissions reduces the limit for new or modified utility units to 1.35 pounds per megawatt-hour, regardless of fuel type, or as an alternate, 0.15 pounds per million Btu. In 1998, the largest sources

of NO<sub>x</sub> in 13 eastern states will be required to monitor and report their NO<sub>x</sub> emissions during ozone season, and additional rules pertaining to ozone transport are expected. Further, final revisions to NAAQS for ozone drop the limit to 80 parts per billion over 8 hours. In anticipation of these stricter NO<sub>x</sub> limits, the CCT Program has sought to provide a number of NO<sub>x</sub> control options to cover the range of boiler types and emission reduction requirements.

Control of NO<sub>x</sub> emissions can be accomplished by either modifying the combustion process or acting upon the products of combustion (or combinations thereof). Combustion modification technologies include low-NO<sub>x</sub> burners (LNBs), advanced overfire air (AOFA), and reburning



▲ A portion of ABB Combustion Engineering's Low-NO<sub>x</sub> Concentric Firing System (LNCFS™) is shown being installed on a tangentially fired boiler.

processes using either gas or coal. Processes used to act upon flue gas include selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR).

LNBs regulate the initial fuel-air mixture, velocities, and turbulence to create a fuel-rich flame core and control the rate at which additional air required to complete combustion is mixed. This staging of combustion avoids a highly oxidized environment and hot spots conducive to fuel-NO<sub>x</sub> and thermal-NO<sub>x</sub> formation. LNBs alone typically can achieve 40–50 percent NO<sub>x</sub> reduction. But no LNBs have been developed for cyclone-fired boilers.

AOFA involves injection of air above the primary combustion zone to allow the primary combustion to occur without the amount of oxygen needed for complete combustion. This oxygen deficiency mitigates fuel-NO<sub>x</sub> formation. AOFA injected at high

### Exhibit 5-13 Group I and 2 Boiler Statistics and Phase II NO<sub>x</sub> Emission Limits

Boiler Types	No. of Boilers	Phase II NO <sub>x</sub> Emission Limits (lb/10 <sup>6</sup> Btu)
<b>Group 1</b>		
Tangentially fired	299	0.40
Dry-bottom, wall-fired	308	0.46
<b>Group 2</b>		
Cell burner	36	0.68
Cyclone >155 MWe	55	0.86
Wet-bottom, wall-fired >65 MWe	26	0.84
Vertically fired	28	0.80

Source: Environmental Protection Agency, Nitrogen Oxides Emission Reduction Program, Final Rule for Phase II, Group 1 and Group 2 Boilers (downloaded from <http://www.epa.gov/docs/acidrain/nofxs3.html>).

**Exhibit 5-14**  
**CCT Program NO<sub>x</sub> Control Technology Characteristics**

<b>Project</b>	<b>Process</b>	<b>Boiler Size/ Type</b>	<b>NO<sub>x</sub> Reduction</b>	<b>Fact Sheet</b>
Demonstration of Coal Reburning for Cyclone Boiler NO <sub>x</sub> Control	Coal reburning—30% heat input	100 MWe/cyclone	52–62%	5-32
Evaluation of Gas Reburning and Low-NO <sub>x</sub> Burners on a Wall-Fired Boiler	LNB/gas reburning/AOFA—13–18% gas heat input	172 MWe/wall	37–65%	5-40
Micronized Coal Reburning Demonstration for NO <sub>x</sub> Control	Coal reburning—30% heat input	148 MWe/tangential 50 MWe/cyclone	50–60% (goal)	5-44
Full-Scale Demonstration of Low-NO <sub>x</sub> Cell Burner Retrofit	LNB—separation of coal and air ports on plug-in unit	605 MWe/cell burner	48–58%	5-36
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	LNB/AOFA—advanced LNB with separated AOFA and artificial intelligence controls	500 MWe/wall	50% (goal)	5-46
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO <sub>x</sub> Emissions from Coal-Fired Boilers	LNB/AOFA—advanced LNB with close-coupled and separated overfire air	180 MWe/tangential	37–45%	5-52
Demonstration of Selective Catalytic Reduction Technology for the Control of NO <sub>x</sub> Emissions from High-Sulfur-Coal-Fired Boilers	SCR—eight catalysts with different shapes and chemical compositions	8.7 MWe/various	80%	5-48

velocity creates turbulent mixing to complete the combustion in a gradual fashion at lower temperatures to mitigate thermal-NO<sub>x</sub> formation. Usually, AOFA is used in combination with LNBs, but alone, AOFA can achieve 10–25 percent NO<sub>x</sub> emission reductions. LNB/AOFA systems generally can achieve NO<sub>x</sub> emission reductions of 60–67 percent.

In reburning, a percentage of the fuel input to the boiler is diverted to injection ports above the primary combustion zone. Either gas or coal is typically used as the reburning fuel to provide 10–30 percent of the heat input to the boiler. The reburning fuel is injected to create a fuel-rich zone deficient in oxygen (a reducing

rather than oxidizing zone). NO<sub>x</sub> entering this zone is stripped of oxygen, forming elemental nitrogen. Combustion is completed in a burnout zone where air is injected by an AOFA system. Reburning has application to all boiler types, including cyclone boilers, and can achieve NO<sub>x</sub> emission reductions of 50–67 percent.

SCR and SNCR can be used alone or in combination with combustion modification. These processes use ammonia or urea in a reducing reaction with NO<sub>x</sub> to form elemental nitrogen and water. SNCR can only be used at high temperatures (1,600–2,200 °F) where a catalyst is not needed. SCR is typically

applied at temperatures between 600–800 °F. Generally, SNCR and SCR systems alone can achieve NO<sub>x</sub> emission reductions of 30–50 percent and 80–90+ percent, respectively.

Under the CCT Program, seven NO<sub>x</sub> control technologies were addressed, encompassing LNBs, AOFA, reburning, SNCR, SCR, and combinations thereof. Five of the projects have been completed, one is nearing completion, and one is in construction. Exhibit 5-14 briefly summarizes the characteristics and performance of the technologies that are described in more detail in the project fact sheets.



## Demonstration of Coal Reburning for Cyclone Boiler NO<sub>x</sub> Control

*Project completed.*

### Participant

The Babcock & Wilcox Company

### Additional Team Members

Wisconsin Power and Light Company—cofunder and host

Sargent and Lundy—engineer for coal handler

Electric Power Research Institute—cofunder

State of Illinois, Department of Energy and Natural Resources—cofunder

Utility companies (14 cyclone boiler operators)—cofundors

### 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, Coal Reburn

### Plant Capacity/Production

100 MWe

### Coals

Illinois Basin bituminous (Lamar), 1.15% sulfur,

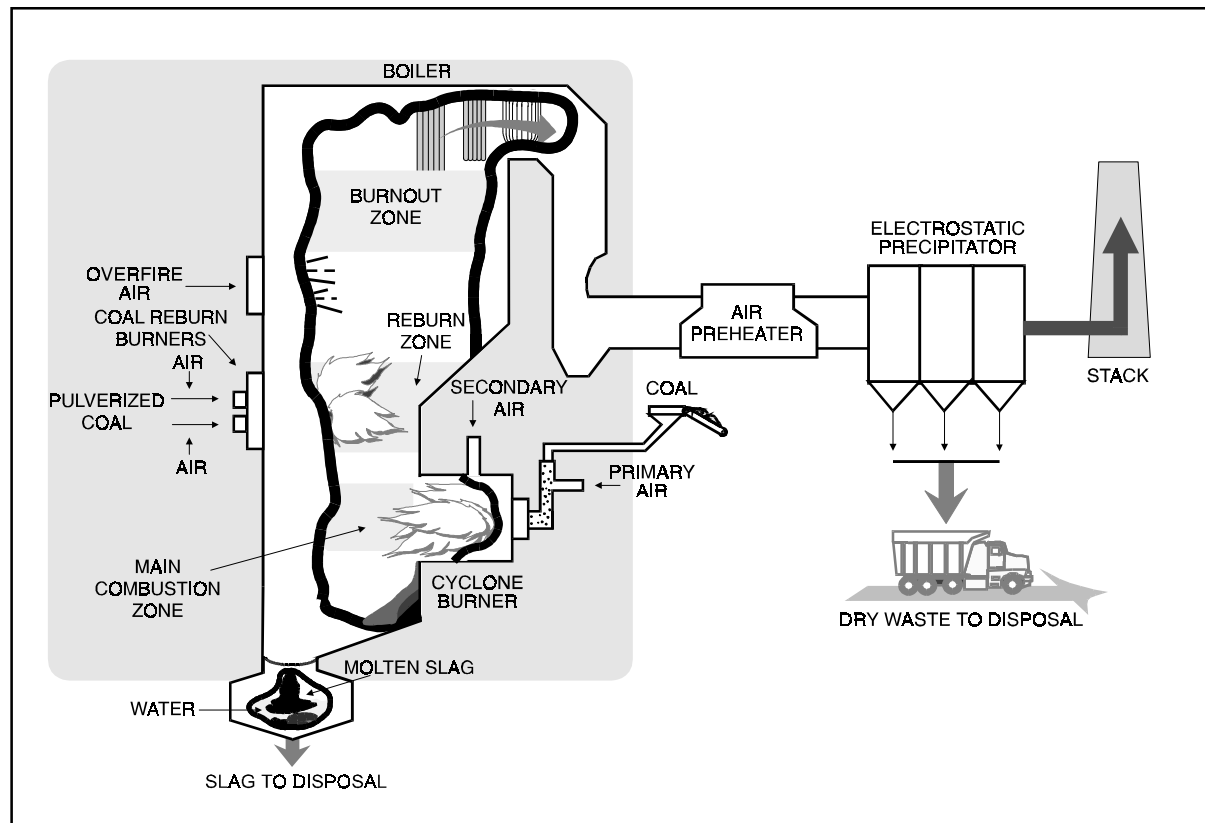
1.24% nitrogen

Powder River Basin (PRB) subbituminous, 0.27% sulfur,

0.55% nitrogen

### Project Funding

Total project cost	\$13,646,609	100%
DOE	6,340,788	46
Participant	7,305,821	54



### Project Objective

To demonstrate the technical and economic feasibility of achieving greater than 50% reduction in NO<sub>x</sub> emissions with no serious impact on cyclone combustor operation, boiler performance, or other emission streams.

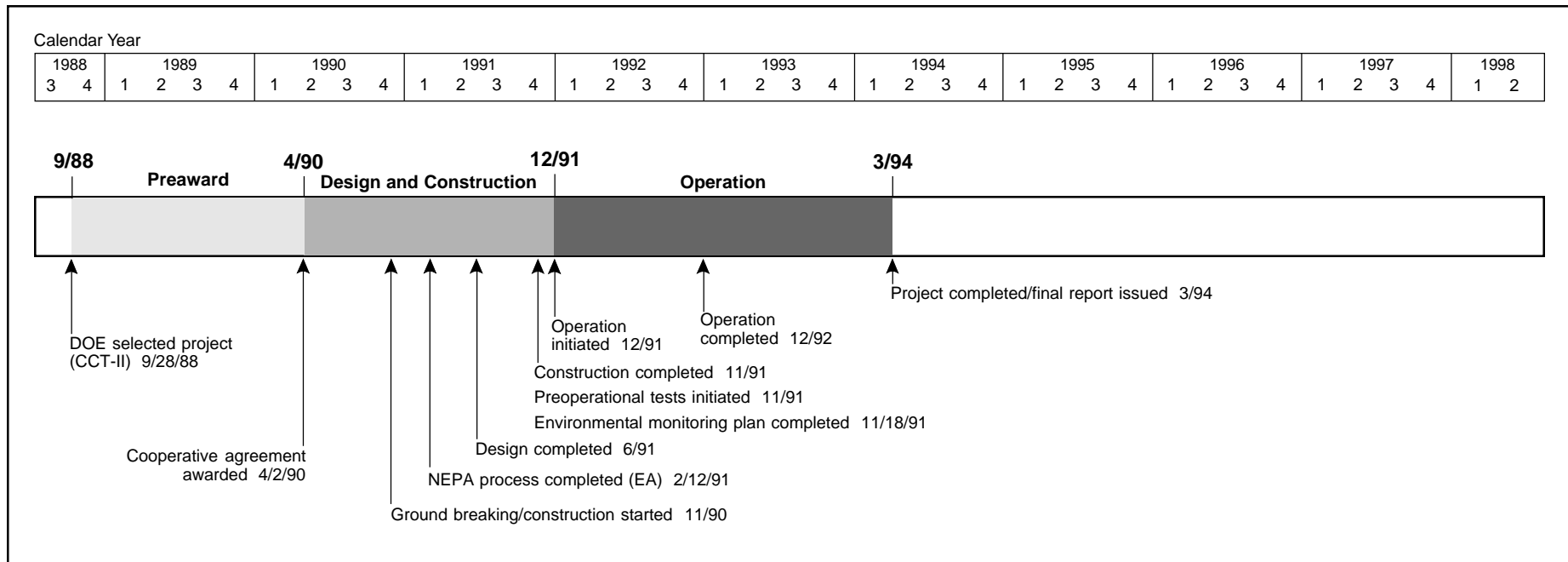
### Technology/Project Description

Babcock & Wilcox Coal Reburn reduces NO<sub>x</sub> 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<sub>x</sub> 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.

Coal Reburn can be applied with the cyclone burners operating within their normal, noncorrosive, 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.



## Results Summary

### Environmental

- Coal Reburn achieved greater than 50% NO<sub>x</sub> reduction at full load with Lamar bituminous and PRB subbituminous coals.
- Reburn-zone stoichiometry had the greatest effect on NO<sub>x</sub> control.
- Gas recirculation was vital to maintaining reburn-zone stoichiometry while providing necessary burner cooling, flame penetration, and mixing.
- Opacity levels and electrostatic precipitator (ESP) performance were not affected by Coal Reburn with either coal tested.
- Optimal Coal Reburn heat input was 29–30% at full load and 33–35% at half to moderate loads.

### Operational

- No major boiler performance problems were experienced with Coal Reburn operations.

- Boiler turndown capability was 66%, exceeding the 50% goal.
- ESP efficiency improved slightly during Lamar coal testing and did not change with PRB coal.
- Coal fineness levels above the nominal 90% through 200 mesh were maintained, reducing unburned carbon losses (UBCL).
- UBCL was the only major contributor to boiler efficiency loss, which was 0.1%, 0.25%, and 1.5% at loads of 110-, 82-, and 60-MWe, respectively, when using Lamar coal. With PRB coal, the efficiency loss ranged from zero at full load to 0.3% at 60 MWe.
- Superior flame stability was realized with PRB coal, contributing to better NO<sub>x</sub> control than with Lamar coal.
- Expanded volumetric fuel delivery with reburn burners enabled switching to PRB low-rank coal without boiler derating.

### Economic

- Capital costs for 110- and 605-MWe plants were \$66/kW and \$43/kW, respectively. Levelized 10- and 30-year busbar power costs for a 110-MWe plant were 2.4 and 2.3 mills/kWh, respectively. Levelized 10- and 30-year busbar power costs for a 605-MWe plant were 1.6 and 1.5 mills/kWh, respectively.

## Project Summary

Although cyclone boilers represent only 15% of the pre-NSPS coal-fired generating capacity, they contribute 21% of the NO<sub>x</sub> formed by pre-NSPS coal-fired units. This is due to the cyclone combustor's inherent turbulent, high-temperature combustion process. Consequently, cyclone boilers are targeted for NO<sub>x</sub> reduction under the CAAA and state implementation plans. However, at the time of this demonstration, there was no cost-effective combustor modification available for NO<sub>x</sub> control.

Babcock & Wilcox Coal Reburn offers an economic and operationally sound response to the environmental impetus. This technology avoids cyclone combustor modification and associated performance complications and provides an alternative to other cyclone boiler NO<sub>x</sub>-control options having relatively higher capital and/or operating costs.

The majority of the testing was performed firing Illinois Basin bituminous coal (Lamar), as it is typical of the coal used by many utilities operating cyclones. Subbituminous PRB 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.

### Environmental Performance

Three sequences of testing of Coal Reburn used 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. PRB coal was tested by parametric optimization and performance modes. Exhibit 5-15 shows changes in NO<sub>x</sub> emissions and boiler efficiency using the reburn system for various load conditions and coal types.

Coal Reburn tests on both the Lamar and PRB coals indicated that variation of reburn-zone stoichiometry was

the most critical factor in changing NO<sub>x</sub> 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.

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

### Operational Performance

For Lamar coal, the full-, medium-, and low-load UBCL were 0.1%, 0.25%, and 1.5% higher, respectively, than the baseline. Full-, medium-, and low-load UBCL with PRB coal were 0.0%, 0.2%, and 0.3% higher, respectively, than the baseline. Coal Reburn burner flame stability improved with PRB coal.



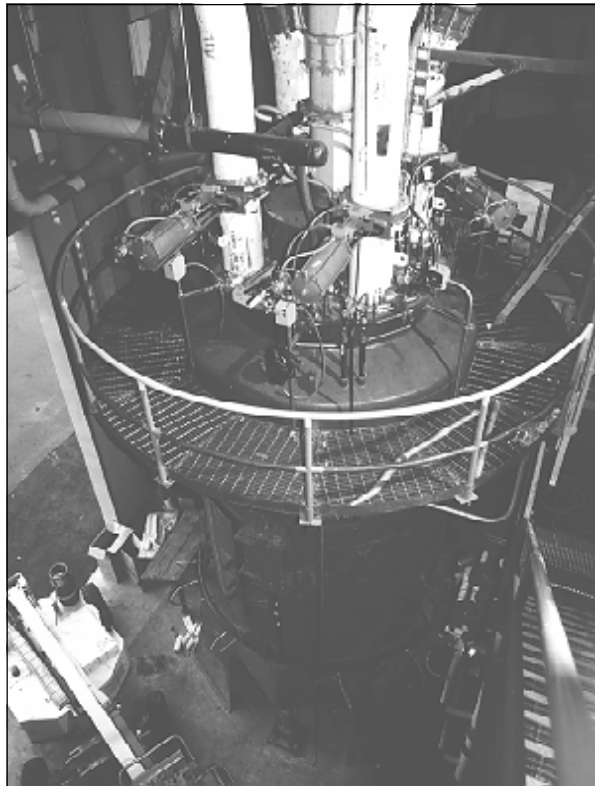
▲ Wisconsin Power and Light Company's Nelson Dewey Station hosted the successful demonstration of Coal Reburn.

During Coal Reburn 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 ultrasonic thickness measurements were taken of the furnace wall tubes. No observable decrease in wall tube thickness was measured.

Another significant finding was that Coal Reburn minimizes and possibly eliminated a 0–25% derating normally associated with switching to subbituminous coal in a cyclone unit. This derating was a result of using a lower Btu fuel in a cyclone with a limited coal feed capacity. The reburn system transferred about 30% of the

**Exhibit 5-15  
Coal Reburn Test Results**

	Boiler Load		
	110 MWe	82 MWe	60 MWe
<b>Lamar coal</b>			
NO <sub>x</sub> (lb/10 <sup>6</sup> Btu/% reduction)	0.39/52	0.36/50	0.44/36
Boiler efficiency losses due to unburned carbon (%)	0.1	0.25	1.5
<b>Powder River Basin coal</b>			
NO <sub>x</sub> (lb/10 <sup>6</sup> Btu/% reduction)	0.34/55	0.31/52	0.30/53
Boiler efficiency losses due to unburned carbon (%)	0.0	0.2	0.3



▲ The coal pulverizer is part of Babcock & Wilcox Coal Reburn. This system has been retained by Wisconsin Power and Light for NO<sub>x</sub> emission control at the Nelson Dewey Station.

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.

### Economic Performance

An economic analysis of total capital and levelized revenue requirements was conducted using the “Electric Power Research Institute Economic Premises” for retrofit of 110- and 605-MWe plants. In addition, annualized costs per ton of NO<sub>x</sub> removed were developed for 110- and 605-MWe plants over both 10 and 30 years. The results of these analyses are shown in Exhibit 5-16. These values assumed typical retrofit conditions and did not

take into account any fuel savings from use of low-rank coal. The pulverizers and associated coal handling were taken into account. Site-specific parameters that can significantly impact these retrofit costs included the state of the existing control system, availability of flue gas recirculation, space for coal pulverizers, space for reburn burners and overfire air ports within the boiler, scope of coal-handling modification, sootblowing capacity, ESP capacity, steam temperature control capacity, and boiler circulation considerations.

### Commercial Applications

Coal Reburn is a retrofit technology applicable to a wide range of utility and industrial cyclone boilers. The current U.S. Coal 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.

### Contacts

Tony Yagiela, (216) 829-7403

The Babcock & Wilcox Company  
1562 Beeson Street  
Alliance, OH 44601

Lawrence Saroff, DOE/HQ, (301) 903-9483

John C. McDowell, FETC, (412) 892-6237

### References

- *Demonstration of Coal Reburning for Cyclone Boiler NO<sub>x</sub> Control: Final Project Report.* Report No. DOE/PC/89659-T16. The Babcock & Wilcox Company. February 1994. (Available from NTIS as DE94013052, Appendix 1 as DE94013053, Appendix 2 as DE94013054.)
- *Public Design Report: Coal Reburning for Cyclone Boiler NO<sub>x</sub> Control.* The Babcock & Wilcox Company. August 1991. (Available from NTIS as DE92012554.)

## Exhibit 5-16 Coal Reburn Economics

Costs	Plant Size	
	110 MWe	605 MWe
Total capital cost (\$/kW)	66	43
Levelized busbar power cost (mills/kWh)		
10-year life	2.4	1.6
30-year life	2.3	1.5
Annualized cost (\$/ton of NO <sub>x</sub> removed)		
10-year life	1,075	408
30-year life	692	263

- *Comprehensive Report to Congress on the Clean Coal Program: Demonstration of Coal Reburning for Cyclone Boiler NO<sub>x</sub> Control.* (The Babcock & Wilcox Company). Report No. DOE/FE-0157. U.S. Department of Energy. February 1990. (Available from NTIS as DE90008111.)

## Full-Scale Demonstration of Low-NO<sub>x</sub> Cell Burner Retrofit

**Project completed.**

### Participant

The Babcock & Wilcox Company

### Additional Team Members

The Dayton Power and Light Company—cofunder and host

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<sub>x</sub> cell burner (LNCB®) system

### Plant Capacity/Production

605 MWe

### Coal

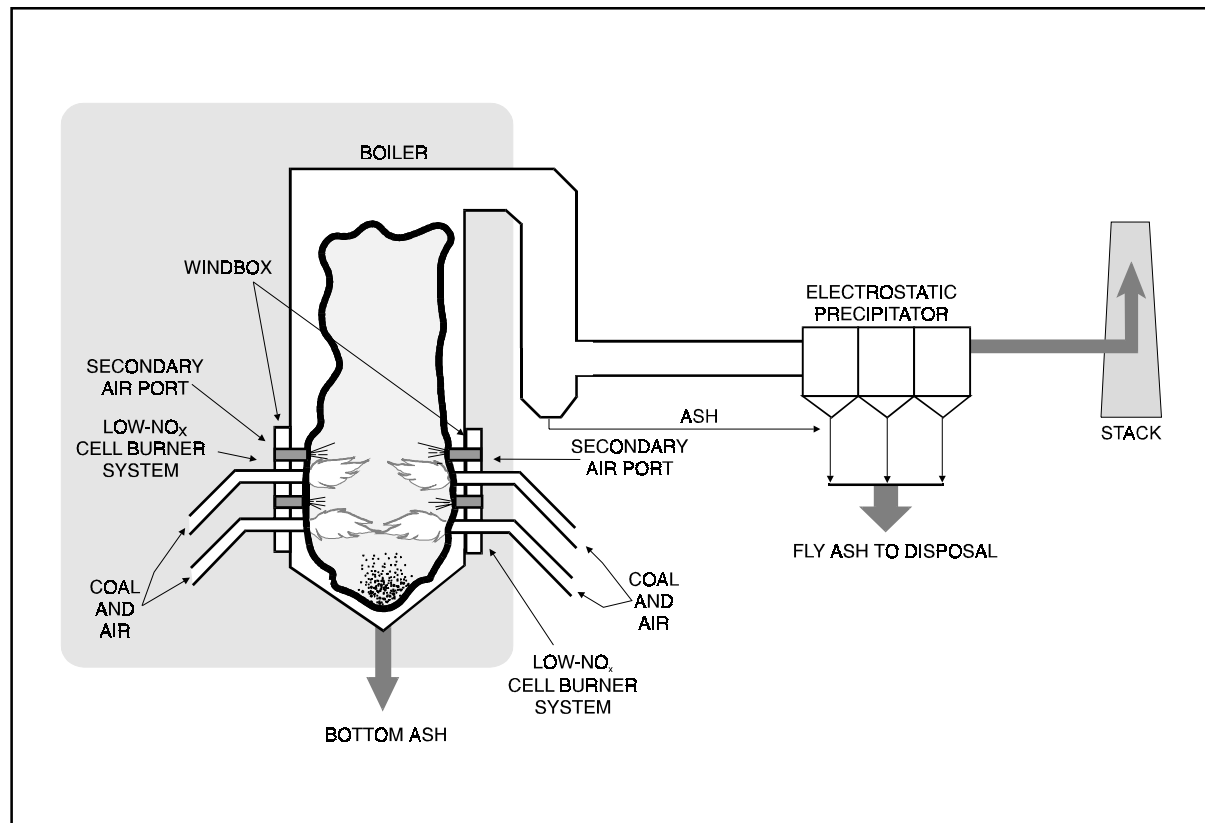
Bituminous, medium sulfur

### Project Funding

Total project cost	\$11,233,392	100%
DOE	5,442,800	48
Participant	5,790,592	52

### Project Objective

To demonstrate, through the first commercial-scale full burner retrofit, the cost-effective reduction of NO<sub>x</sub> from a



large baseload coal-fired utility boiler with LNCB® technology; to achieve at least a 50% NO<sub>x</sub> reduction without degradation of boiler performance at less cost than that of conventional low-NO<sub>x</sub> burners.

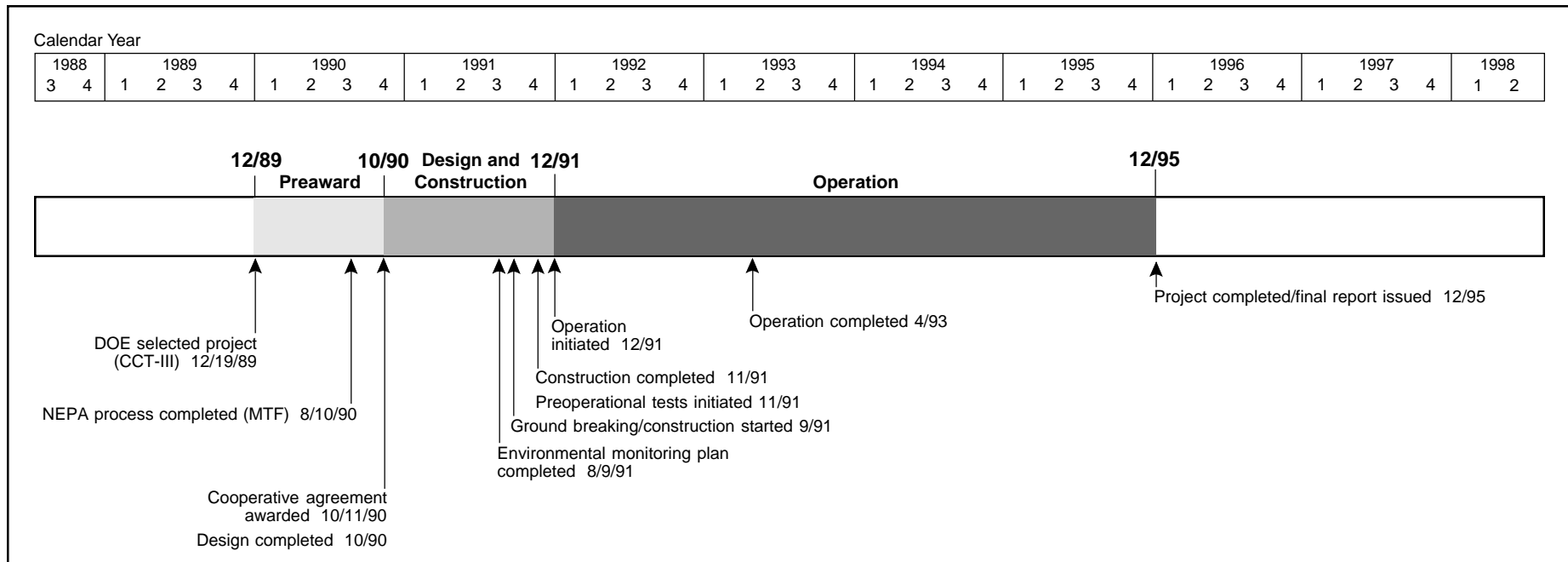
### Technology/Project Description

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<sub>x</sub> 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 nitro-

LNCB is a registered trademark of The Babcock & Wilcox Company.

gen compounds are converted to nitrogen gas, and the reduced flame temperature minimizes the formation of thermal NO<sub>x</sub>.

The demonstration was conducted on a Babcock & Wilcox-designed, supercritical, once-through boiler equipped with an electrostatic precipitator (ESP). This unit, which is typical of cell burner boilers, 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 ensure complete combustion in the lower furnace.



## Results Summary

### Environmental

- Short-term optimization testing (all mills in service) showed NO<sub>x</sub> reductions in the range of 53.0–55.5%, 52.5–54.7%, and 46.9–47.9% at loads of 605 MWe, 460 MWe, and 350 MWe, respectively.
- Long-term testing at full load (all mills in service) showed an average NO<sub>x</sub> reduction of 58% (over 8 months).
- Long-term testing at full load (one mill out of service) showed an average NO<sub>x</sub> reduction of 60% (over 8 months).
- CO emissions averaged 28–55 ppm at full load with LNCB<sup>®</sup> in service.
- Fly ash increased, but ESP performance remained virtually unchanged.

### Operational

- Unit efficiency remained essentially unchanged.
- Unburned carbon losses (UBCL) increased by approximately 28% for all tests, but boiler efficiency loss was offset by a decrease in dry gas loss due to a lower boiler economizer outlet gas temperature.
- Boiler corrosion with LNCB<sup>®</sup> was roughly equivalent to boiler corrosion rates prior to retrofit.

### Economic

- Capital cost for a 600-MWe plant was \$9/kW (1994\$).
- Levelized cost for a 600-MWe plant was estimated at 0.284 mills/kWh and \$96.48/ton of NO<sub>x</sub> removed.

## Project Summary

Utility boilers equipped with cell burners currently comprise 13% or approximately 23,000 MWe of pre-NSPS coal-fired generating capacity. Cell burners are designed for rapid mixing of the fuel and air. The tight burner spacing and rapid mixing minimize the flame size while maximizing the heat release rate and unit efficiency. Combustion efficiency is good, but the rapid heat release produces relatively large quantities of NO<sub>x</sub>.

To reduce NO<sub>x</sub> emissions, the LNCB<sup>®</sup> has been designed to stage mixing of the fuel and combustion air. A key design criterion was accomplishing delayed fuel-air mixing with no modifications to waterwall panels. A plug-in design reduces material costs and outage time required to complete the retrofit, compared to installing conventional, internally staged low-NO<sub>x</sub> burners. LNCB<sup>®</sup> provides a lower cost alternative to address NO<sub>x</sub> reduction requirements for cell burners.



▲ Dayton Power and Light Company's J.M. Stuart Plant hosted the successful demonstration of LNCB® technology.

### Environmental Performance

The initial LNCB® configuration resulted in excessive CO and H<sub>2</sub>S emissions. Through modeling, a revised configuration was developed to address the problem without compromising boiler performance. The modification was incorporated and validated model capabilities.

Following parametric testing to establish optimal operating modes, a series of optimization tests were conducted on the LNCB® to assess environmental and operational performance. Two sets of measurements were taken, one by Babcock & Wilcox and the other by an independent company, to validate data accuracy. Consequently, the data provided is a range reflecting the two measurements.

The average NO<sub>x</sub> emissions reduction achieved at full load with all mills in service ranged from 53.0% to 55.5%. With one mill out of service at full load, the average NO<sub>x</sub> reduction ranged from 53.3% to 54.5%.

Average NO<sub>x</sub> reduction at intermediate load (about 460 MWe) ranged from 52.5% to 54.7%. At low loads (about 350 MWe), average NO<sub>x</sub> reduction ranged from 46.9% to 47.9%.

NO<sub>x</sub> emissions were monitored over the long-term at full load for all mills in service and one mill out of service. Each test spanned an 8-month period. NO<sub>x</sub> emission reductions realized were 58% for all mills in service and about 60% for one mill out of service.

Complications arose in assessing CO emissions relative to baseline because baseline calibration was not refined enough. However, accurate measurements were made with LNCB® in service.

CO emissions were corrected to 3.0% O<sub>2</sub> and measured at full, intermediate, and low loads. The range of CO emissions at full load with all mills in service was 28–55 ppm and 20–38 ppm with one mill out of service. At intermediate loads (about 460 MWe), CO emissions were 28–45 ppm and at low loads (about 350 MWe), 5–27 ppm.

Particulate emissions were minimally impacted. The LNCB® had little effect on flyash resistivity, largely due to SO<sub>3</sub> injection, and therefore ESP removal efficiency remained very high. Baseline ESP collection efficiencies for full load with all mills in service, full load with one mill in service, and intermediate load with one mill out of service were 99.5%, 99.49%, and 99.81%, respectively. For the same conditions, in the same sequence with LNCB® in operation, ESP collection efficiencies were 99.43%, 99.12%, and 99.35%, respectively.



▲ The LNCB® is viewed from within the boiler.

### Operational Performance

Furnace exit gas temperature, or secondary superheater inlet temperature, initially decreased by 100 °F but eventually rose to within 10 °F of baseline conditions.

The UBCL increased by approximately 28% for all tests. The most significant increase from baseline data occurred for a test with one mill out of service. A 52% increase in UBCL resulted in an efficiency loss of 0.69%.

Boiler efficiency showed very little change from baseline. The average for all mills in service increased by 0.16%. The higher post-retrofit efficiency was attributed to a decrease in dry gas loss with lower economizer gas

outlet temperature (and subsequent lower air heater gas outlet temperature), offsetting UBCL and CO emission losses. Also, increased coal fineness mitigated UBCL.

Because sulfidation is the primary corrosion mechanism in substoichiometric combustion of sulfur-containing coal, H<sub>2</sub>S levels were monitored in the boiler. After optimizing LNCB<sup>®</sup> operation, levels were largely at the lower detection limit. There were some higher local readings, but corrosion panel tests established that corrosion rates with LNCB<sup>®</sup> were roughly equivalent to pre-retrofit rates.

Ash sample analyses indicated that ash deposition would not be a problem. The LNCB<sup>®</sup> ash was little different from baseline ash. Furthermore, the small variations observed in furnace exit gas temperature between baseline and LNCB<sup>®</sup> indicated little change in furnace slagging. Start-up and turndown of the unit were unaffected by conversion to LNCB<sup>®</sup>.

### Economic Performance

The economic analyses were performed for a 600-MWe nominal unit size and typical location in the midwest United States. A medium-sulfur, medium-volatile bituminous coal was chosen as the typical fuel. For a baseline NO<sub>x</sub> emission level of 1.2 lb/10<sup>6</sup> Btu and a 50% reduction target, the estimated capital cost was \$9/kW (1994\$). The levelized cost of electricity was estimated at 0.284 mills/kWh or \$96.48/ton of NO<sub>x</sub> removed.

### Commercial Applications

The low cost and short outage time for retrofit make the LNCB<sup>®</sup> design the most cost-effective NO<sub>x</sub> control technology available today for cell burner boilers. The LNCB<sup>®</sup> system can be installed at about half the cost and time of other commercial low-NO<sub>x</sub> burners. Dayton Power & Light has retained the LNCB<sup>®</sup> for use in commercial service. There have been eight commercial sales of LNCB<sup>®</sup>.

### Contacts

Tony Yagiela, (216) 829-7403

The Babcock & Wilcox Company

1562 Beeson Street

Alliance, OH 44601

Lawrence Saroff, DOE/HQ, (301) 903-9483

John C. McDowell, FETC, (412) 892-6237

### References

- *Final Report: Full-Scale Demonstration of Low-NO<sub>x</sub> Cell Burner Retrofit.* Report No. DOE/PC/90545-T2. The Babcock & Wilcox Company. December 1995. (Available from NTIS as DE96003766.)
- *Public Design Report: Full-Scale Demonstration of Low-NO<sub>x</sub> Cell Burner Retrofit.* Report No. DOE/PC/90545-T4. The Babcock & Wilcox Company. August 1991. (Available from NTIS as DE92009768.)

- *Comprehensive Report to Congress on the Clean Coal Technology Program: Full-Scale Demonstration of Low-NO<sub>x</sub> Cell-Burner Retrofit.* The Babcock & Wilcox Company. Report No. DOE/FE-0197P. U.S. Department of Energy. July 1990. (Available from NTIS as DE90018026.)



▲ The connections to the LNCB<sup>®</sup> are viewed from outside the boiler.



## Evaluation of Gas Reburning and Low-NO<sub>x</sub> Burners on a Wall-Fired Boiler

**Project completed.**

### Participant

Energy and Environmental Research Corporation

### Additional Team Members

Public Service Company of Colorado—cofounder and host  
 Gas Research Institute—cofounder  
 Colorado Interstate Gas Company—cofounder  
 Electric Power Research Institute—cofounder  
 Foster Wheeler Energy Corp.—technology supplier

### 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 (GR) system  
 Foster Wheeler Energy Corp.'s low-NO<sub>x</sub> burners (LNB)

### Plant Capacity/Production

172 MWe

### Coal

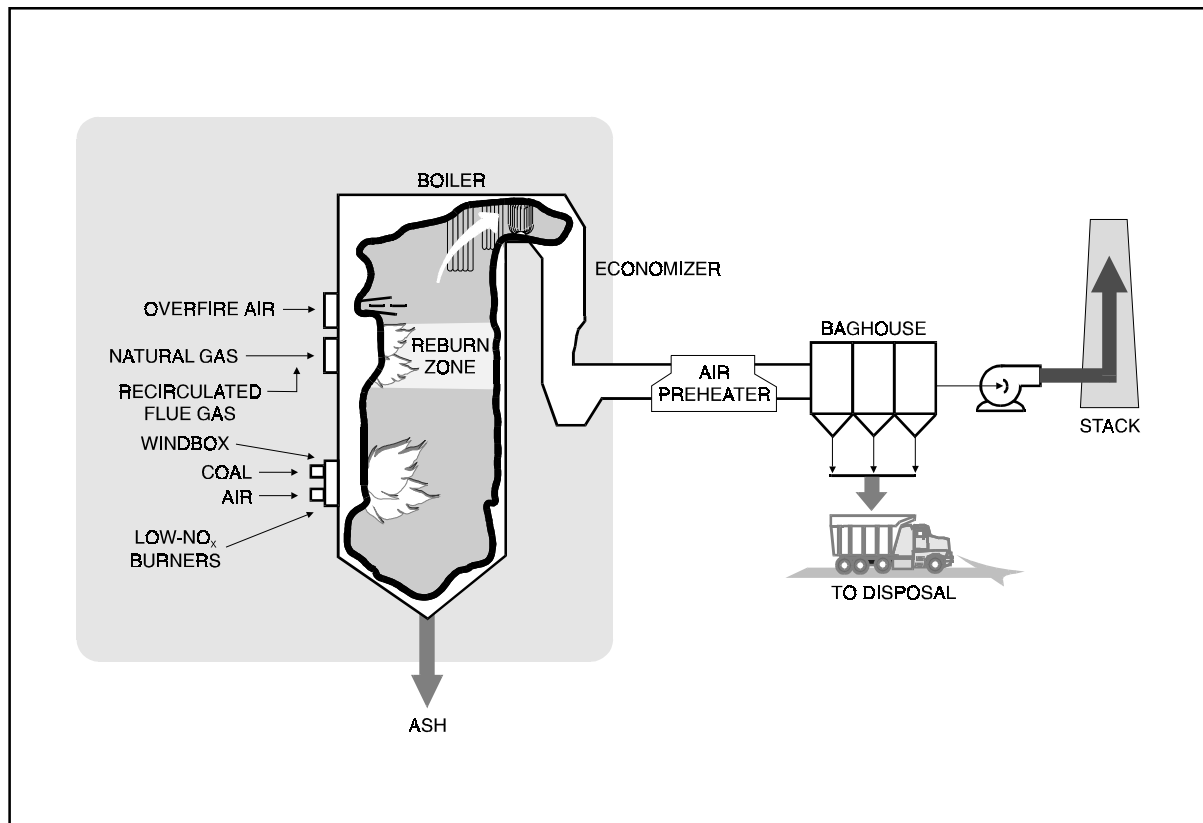
Western bituminous, 0.35–0.66% sulfur

### Project Funding

Total project cost	\$17,807,258	100%
DOE	8,895,790	50
Participant	8,911,468	50

### Project Objective

To attain up to a 70% decrease in the emissions of NO<sub>x</sub> from an existing wall-fired utility boiler firing low-sulfur coal using both gas reburning and low-NO<sub>x</sub> burners

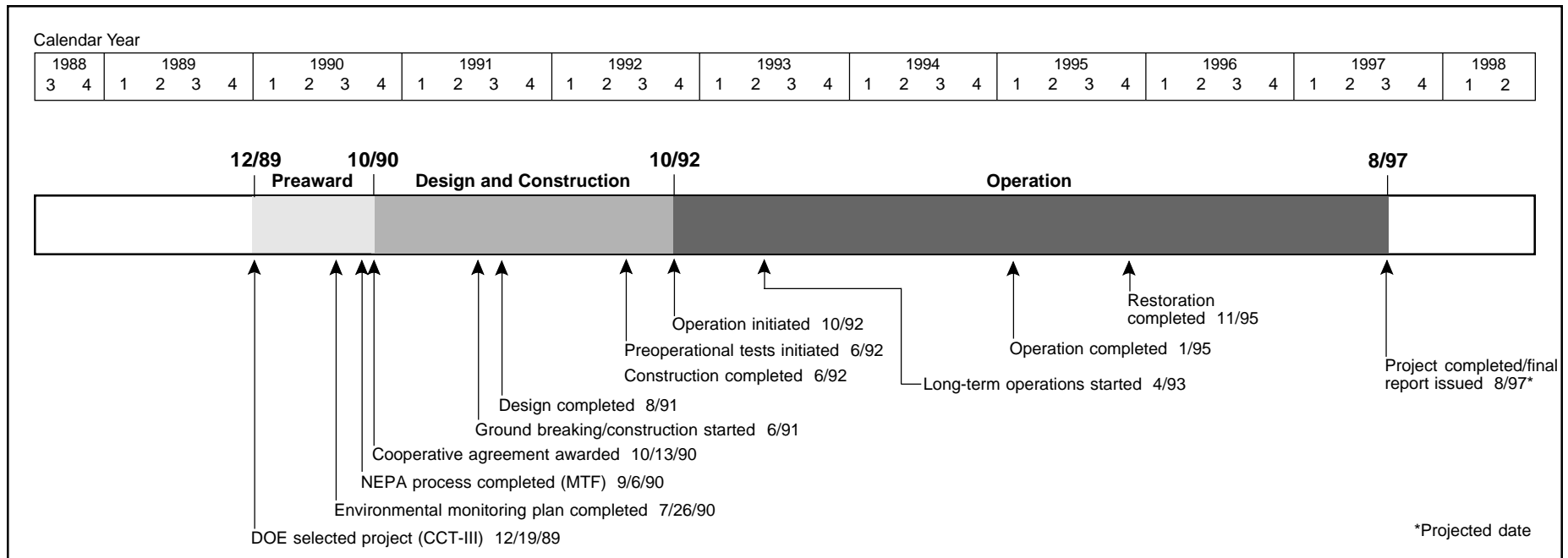


(GR-LNB); and to assess the impact of GR-LNB on boiler performance.

### Technology/Project Description

Gas reburning involves firing natural gas (up to 25% of total heat input) above the main coal combustion zone in a boiler. This upper-level firing creates a slightly fuel-rich zone. NO<sub>x</sub> drifting upward from the lower region of the furnace is "reburned" in this zone and converted to molecular nitrogen. Low-NO<sub>x</sub> burners positioned in the coal combustion zone retard the production of NO<sub>x</sub> 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<sub>x</sub> burners was intended to lower NO<sub>x</sub> emissions by up to 70%. Gas reburning was demonstrated with and without the use of recirculated flue gas and with optimized overfire air.

A series of parametric tests were performed on the gas reburning system, varying operational control parameters, and assessing the effect on boiler emissions, completeness of combustion (carbon-in-ash), thermal efficiency, and heat rate. A 1-year long-term testing program was performed in order to judge the consistency of system outputs, assess the impact of long-term operation on the boiler equipment, gain experience in operating GR-LNB in a normal load-following environment, and develop a database for use in subsequent GR-LNB applications. Both first- and second-generation gas-reburning tests were performed.



## Results Summary

### Environmental

- LNB alone achieved a 37% NO<sub>x</sub> reduction.
- First-generation GR, which incorporated flue gas recirculation, in combination with LNB achieved a 65% NO<sub>x</sub> reduction at an 18% gas heat input rate.
- Second-generation GR, without flue gas recirculation, in combination with LNB achieved 64% NO<sub>x</sub> reduction at 13% gas heat input.
- Both first- and second-generation GR with LNB were capable of reducing NO<sub>x</sub> emissions by up to 70%.
- After modifying the overfire air system to enhance penetration and turbulence (as part of second-generation GR), CO emissions were controlled to acceptable levels at low gas heat input rates (5–10%).
- SO<sub>2</sub> emissions and particulate loadings were reduced by the percentage heat input supplied by GR.

### Operational

- Boiler efficiency decreased by approximately 1.0%.
- There was no measurable boiler tube wear and only a small amount of slagging.

### Economic

- Capital cost for GR was approximately \$15/kW (1993\$) plus the gas pipeline cost, if not in place, for 100-MWe plants or larger.
- Operating costs were related to the gas/coal cost differential and the value of SO<sub>2</sub> emission allowances (because GR reduces SO<sub>2</sub> emissions when displacing coal).

## Project Summary

The demonstration established that GR–LNB offers a cost-effective option for deep NO<sub>x</sub> reduction on wall-fired boilers. GR–LNB NO<sub>x</sub> control performance approached that of selective catalytic reduction (SCR) but at significantly lower cost. SCR typically achieves 70–80% NO<sub>x</sub> reduction at capital costs in the range of \$100–\$150/kW for retrofit applications. GR–LNB achieved 60–70% NO<sub>x</sub> reduction at a capital cost of approximately \$35–\$45/kW (derived from GR capital cost of \$15/kW according to the demonstration and \$20–30/kW for low-NO<sub>x</sub> burners according to the literature). The importance of cost-effective technology for deep NO<sub>x</sub> reduction is reflected in ongoing deliberations on the need for NO<sub>x</sub> reduction in ozone nonattainment areas beyond what is currently projected in Title IV of the CAAA. Title I of the CAAA deals with ozone nonattainment and is currently the driving force for deep NO<sub>x</sub> reduction in many regions of the country.

GR-LNB was installed and evaluated on a 172-MWe (gross) wall-fired boiler—a balanced-draft pulverized-coal unit supplied by Babcock & Wilcox. The GR system, including an overfire air system, was designed and installed by Energy and Environmental Research Corporation. The LNBs were designed and installed by Foster Wheeler Energy Corp.

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 stoichiometric ratio, percent gas heat input, percent overfire air, and load) and the effects of these variables on NO<sub>x</sub> reduction, SO<sub>2</sub> reduction, CO emissions, carbon-in-ash, and heat rates were analyzed. The baseline condition of the LNB was also established.



▲ A worker inspects the support ring for the Foster Wheeler low-NO<sub>x</sub> burner installed in the boiler wall.

### Environmental Performance

At a constant load (150 MWe) and a constant oxygen level at the boiler exit, both NO<sub>x</sub> and SO<sub>2</sub> emissions decreased when natural gas was introduced in the GR operation. In general, the NO<sub>x</sub> emissions were reduced with increasing gas heat input. At gas heat inputs greater than 10%, NO<sub>x</sub> emissions were reduced marginally as gas heat input increased. Natural gas also reduced SO<sub>2</sub> emissions in proportion to the gas heat input. At Cherokee Station, low-sulfur (0.35–0.66%) coal was used, and typical SO<sub>2</sub> emissions were 0.65 lb/10<sup>6</sup> Btu. With a gas heat input of 20%, SO<sub>2</sub> emissions decreased by 20% to 0.52 lb/10<sup>6</sup> Btu.

The CO<sub>2</sub> emissions were also reduced as a result of using natural gas because it has a lower carbon-to-hydrogen ratio than coal. At a gas heat input of 20%, the CO<sub>2</sub> emissions were reduced by 8%.

Long-term testing was initiated in April 1993 and completed in January 1995. The objectives of the test were to obtain operating data over an extended period when the unit was under routine commercial service, determine the effect of GR-LNB operation on the unit, and obtain incremental maintenance and operating costs with GR.

During long-term testing, it was determined that flue gas recirculation had minimal effect on NO<sub>x</sub> emissions. A second series of tests were added to the project to evaluate a modified or second-generation system. Modifications are summarized below:

- The flue gas recirculation system, originally designed to provide momentum to the natural gas, was removed. (This change significantly reduced capital costs.)
- Natural gas injection was optimized at 10% gas heat input compared to the initial design value of 18%. The removal of the flue gas recirculation system required installation of high-velocity injectors, which made greater use of available natural gas pressure. (This modification reduced natural gas usage and thus operating costs.)

### Exhibit 5-17 NO<sub>x</sub> Data from Cherokee Station, Unit 3

	GR Generation	
	First	Second
Baseline (lb/10 <sup>6</sup> Btu)	0.73	0.73
Avg NO <sub>x</sub> reduction (%)		
LNB	37	37
GR-LNB	65	64
Avg gas heat input (%)	18	13

- Overfire air ports were modified to provide higher jet momentum, especially at low total flows.

Over 4,000 hours of operation were achieved, with the results as shown in Exhibit 5-17.

Although the NO<sub>x</sub> reduction performance of LNB (37% NO<sub>x</sub> reduction) was less than the expected 45%, the overall objectives of the demonstration were met. Boiler efficiency decreased by only 1% during gas reburning due to increased moisture in the fuel resulting from natural gas use. Further, there was no measurable tube wear, and only small amounts of slagging occurred during the GR-LNB demonstration.

### Economic Performance

GR-LNB is a retrofit technology in which the costs are dependent on the following site-specific factors:

- Gas availability at the site
- Gas/coal cost differential
- SO<sub>2</sub> removal requirements
- Value of SO<sub>2</sub> emission credits

Based on the demonstration, GR-LNB is expected to achieve at least 60% NO<sub>x</sub> control with a gas heat input of 10–15%. The capital cost estimate for a 100-MWe or

larger installation was about \$15/kW (1993\$) plus gas pipeline costs, if required. Operating costs were almost entirely related to the differential cost of natural gas and coal as reduced by the value of the SO<sub>2</sub> emission credits received due to absence of sulfur in the gas.

### Commercial Applications

Public Service Company of Colorado, the host utility, decided to retain the low-NO<sub>x</sub> burners and the gas-reburning system for immediate use; however, a restoration was required to remove the flue gas recirculation system.

Current estimates indicate that about 35 existing wall-fired utility installations, plus industrial boilers, could make immediate use of this technology. The technology can be used in retrofit, repowering, or greenfield installations. There is no known limit to the size or scope of the application of this technology combination.

GR-LNB is expected to be less capital intensive, or less costly, than a scrubber, selective catalytic reduction, or other technologies. GR-LNB functions equally well with any kind of coal.

### Contacts

Blair A. Folsom, Senior Vice President, (714) 859-8851  
Energy and Environmental Research Corporation  
18 Mason  
Irvine CA 92718

Lawrence Saroff, DOE/HQ, (301) 903-9483  
Jerry L. Hebb, FETC, (412) 892-6079

### References

- *Evaluation of Gas Reburning and Low NO<sub>x</sub> Burners on a Wall-Fired Boiler (Long-Term Testing, April 1993–January 1995)*. Report No. DOE/PC/90547-T20. Energy and Environmental Research Corporation. June 1995. (Available from NTIS as DE95017755.)
- *Evaluation of Gas Reburning and Low NO<sub>x</sub> Burners on a Wall-Fired Boiler (Optimization Testing, Novem-*

*ber 1992–April 1993)*. Report No. DOE/PC/90547-T19. Energy and Environmental Research Corporation. June 1995. (Available from NTIS as DE95017754.)

- *Reduction of NO<sub>x</sub> and SO<sub>2</sub> Using Gas Reburning, Sorbent Injection and Integrated Technologies*. Topical Report No. 3, Revision 1. U.S. Department of Energy and Energy and Environmental Research Corporation. September 1993. (Available from NTIS as DE94007444.)
- *Comprehensive Report to Congress on the Clean Coal Technology Program: Evaluation of Gas Reburning and Low-NO<sub>x</sub> Burners on a Wall-Fired Boiler*. Energy and Environmental Research Corporation. Report No. DOE/FE-0204P. U.S. Department of Energy. September 1990. (Available from NTIS as DE9100253.)



▲ The Public Service Company of Colorado has retained the gas-reburning and low-NO<sub>x</sub> burner system for commercial use.

## Micronized Coal Reburning Demonstration for NO<sub>x</sub> Control

### Participant

New York State Electric & Gas Corporation

### Additional Team Members

Eastman Kodak Company—host and cofunder

Consolidation Coal Company—tester

D.B. Riley—technology supplier

Fuller Company—technology supplier

Energy and Environmental Research Corporation—reburn system designer

ABB Combustion Engineering, Inc.—technology supplier

### Locations

Lansing, Tompkins County, NY (New York State Electric & Gas Corporation's Milliken Station, Unit 1)

Rochester, Monroe County, NY (Eastman Kodak Company's Utility Power House, Unit 15)

### Technology

ABB Combustion Engineering's Low-NO<sub>x</sub> Concentric Firing System (LNCFS™)

D.B. Riley's MPS mill (at Milliken Station)

Fuller's MicroMill™ technologies for producing micronized coal (at Eastman Kodak)

### Plant Capacity/Production

Milliken Station: 148-MWe tangentially fired boiler

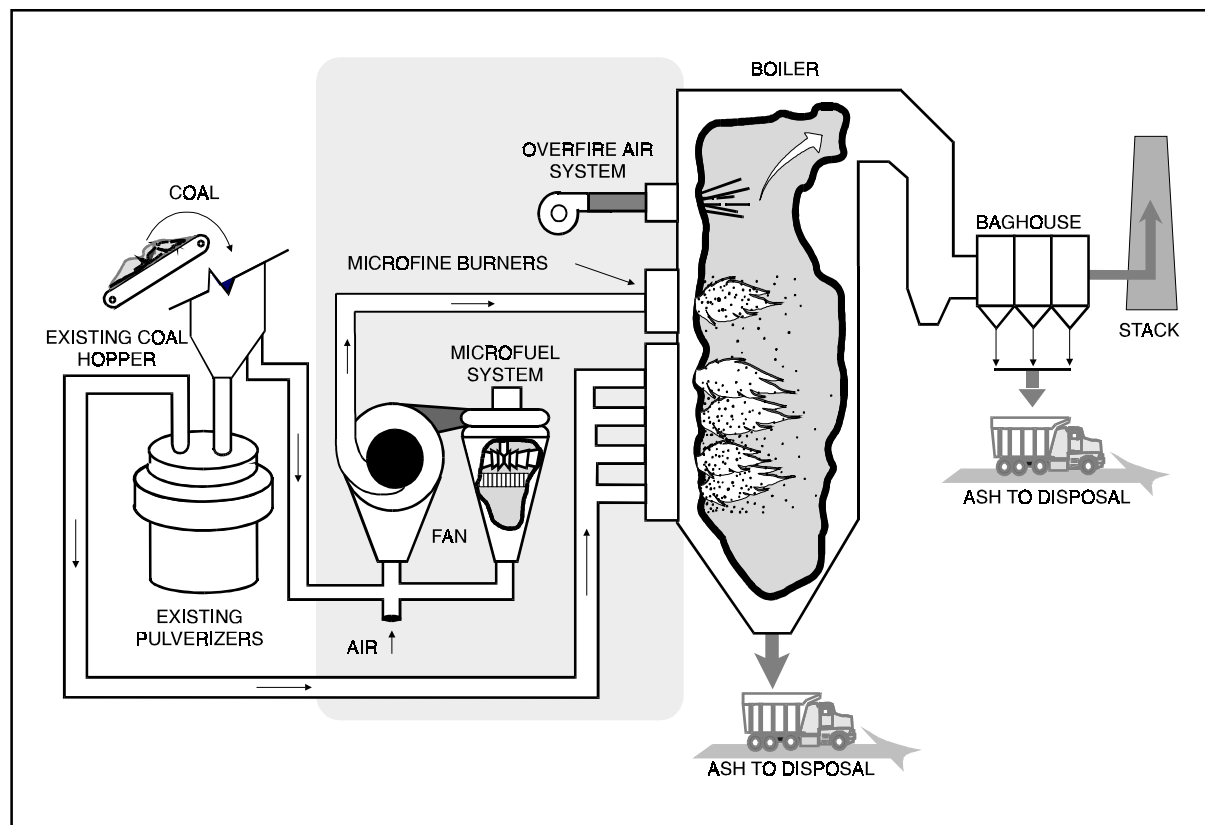
Eastman Kodak Company: 50-MWe cyclone boiler

### Project Funding

Total project cost	\$9,096,486	100%
DOE	2,701,011	30
Participant	6,395,475	70

MicroMill is a trademark of the Fuller Company.

LNCFS is a trademark of ABB Combustion Engineering, Inc.



### Project Objective

To reduce NO<sub>x</sub> emissions by 50–60% using micronized coal as the reburning fuel combined with advanced coal-reburning technology.

### Technology/Project Description

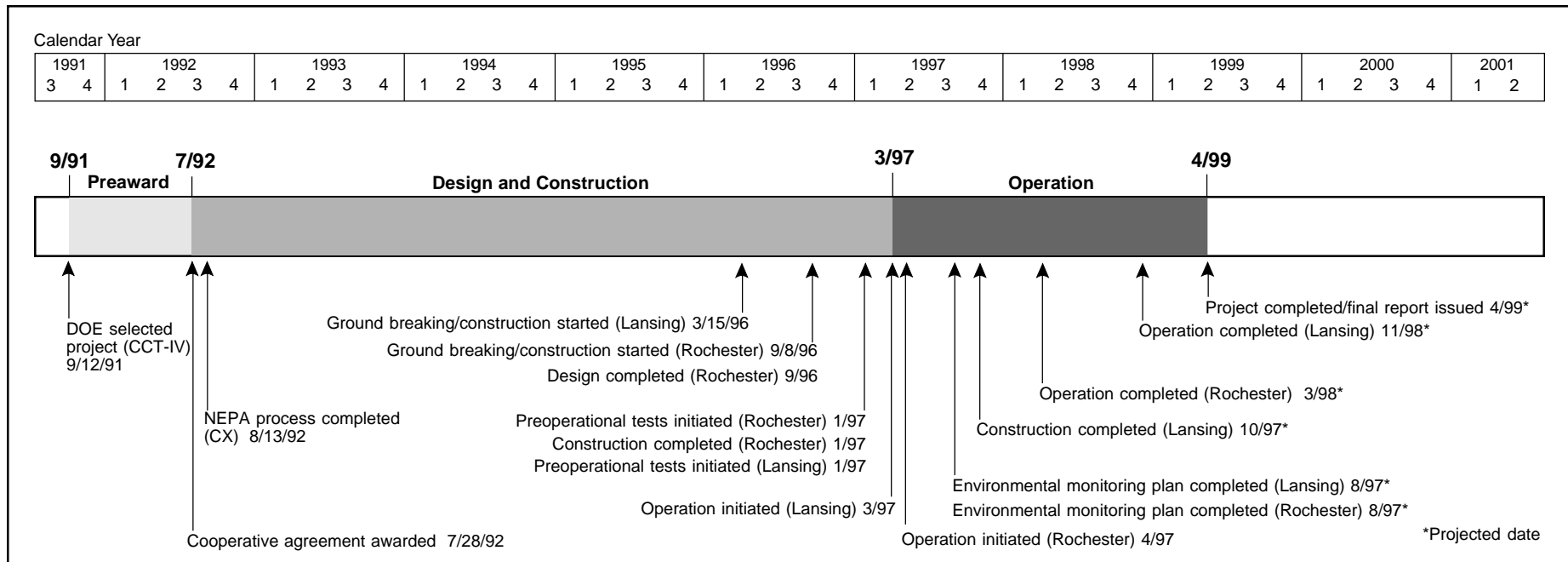
The reburning coal, which can comprise up to 30% of the total fuel, is micronized (80% below 325 mesh) and injected into a pulverized-coal-fired furnace above the main burner, the region where NO<sub>x</sub> formation occurs.

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<sub>x</sub> 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.

At the Milliken site, coal will be reburned for NO<sub>x</sub> control using the following methods: (1) close-coupled overfire air (CCOFA) reburning in which the top burner of the existing LNCFS™ burners are used for burning the micronized coal and the remaining burners are re-aimed, (2) use of the burners in a deep stage combustion mode



and re-aiming them to create burn and reburn zones, and (3) a more standard method using injectors to input micronized coal into the boiler. At the Eastman Kodak site, the Fuller MicroMill™ will be used to produce the micronized coal, and injectors or burners, depending on boiler characteristics, will be used for the reburning. Overfire air also will be installed. Both the injectors/burners and the overfire air will be installed at the optimal point downstream of the cyclone burners.

### Project Status/Accomplishments

Construction at the Kodak site in Rochester continued into 1997. Operational testing began in April 1997 and will continue into March 1998.

Preoperational testing of the reburn system at Milliken Station near Lansing began in March 1997. In late 1997, testing of CCOFA reburning at Milliken will be completed, and injector reburn testing will begin. Reburn testing at Milliken is scheduled to be completed in late 1998.

### 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<sub>x</sub> 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 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 and burner capacity would be able to reach their maximum continuous rating. NO<sub>x</sub> 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.

This demonstration will provide methods for NO<sub>x</sub> control at a low capital cost for utilities and industrial users to meet the current and upcoming NO<sub>x</sub> regulations. Utilities that install low-NO<sub>x</sub> burners to meet CAAA Title I requirements and must also meet Title IV requirements will have a low-cost option. Industrial users being pressured by states to reduce NO<sub>x</sub> also will be provided a low-cost option, particularly cyclone boiler users who have been without low-NO<sub>x</sub> burners.

## 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

### Location

Coosa, Floyd County, GA (Georgia Power Company's Plant Hammond, Unit No. 4)

### Technology

Foster Wheeler's low-NO<sub>x</sub> burner (LNB) with advanced overfire air (AOFA)  
 EPRI's Generic NO<sub>x</sub> Control Intelligence System (GNOCIS) for plant optimization

### Plant Capacity/Production

500 MWe

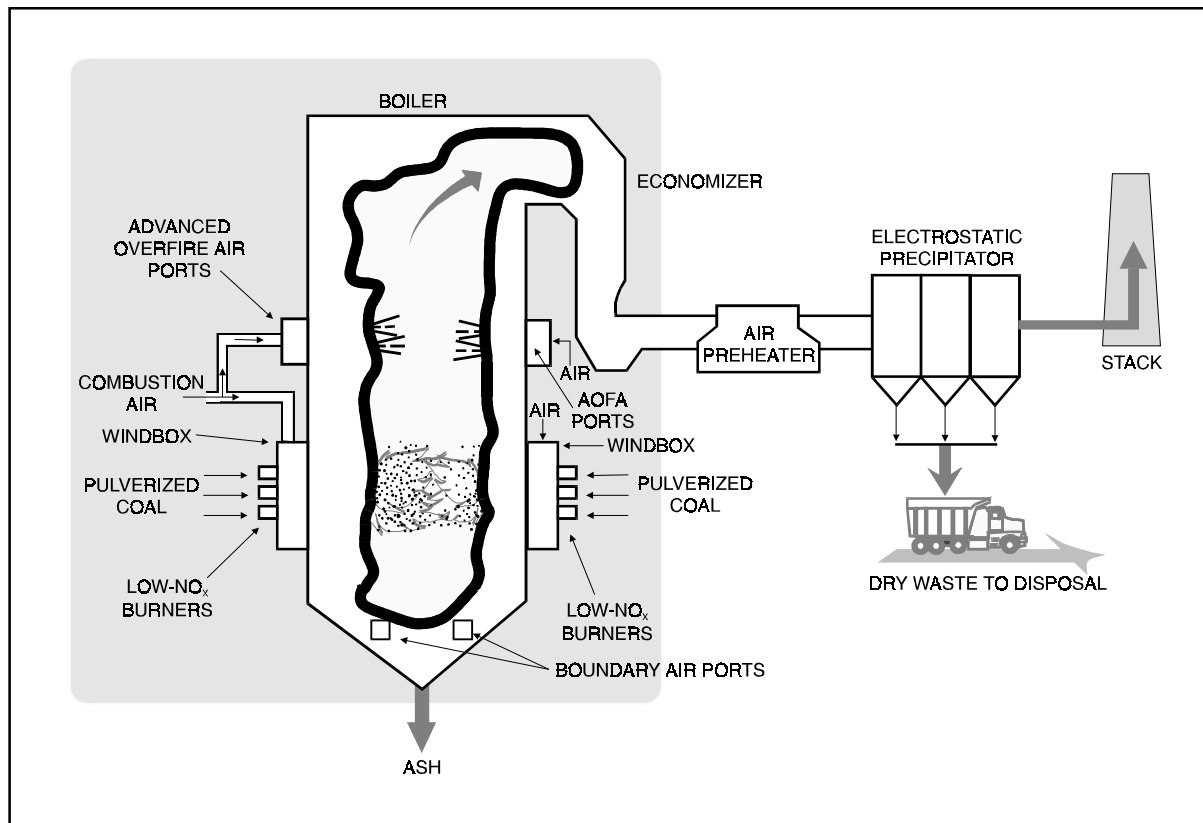
### Project Funding

Total project cost	\$15,853,900	100%
DOE	6,553,526	41
Participant	9,300,374	59

(Of the total project cost, \$523,680 is for toxics testing.)

### Project Objective

To achieve 50% NO<sub>x</sub> reduction with the AOFA/LNB system; to determine the contributions of AOFA and the LNB to NO<sub>x</sub> reduction and the parameters determining optimal AOFA/LNB system performance; and to assess the long-term effects of AOFA, LNB, and combined



AOFA/LNB and advanced digital controls on NO<sub>x</sub> reduction and boiler performance.

### Technology/Project Description

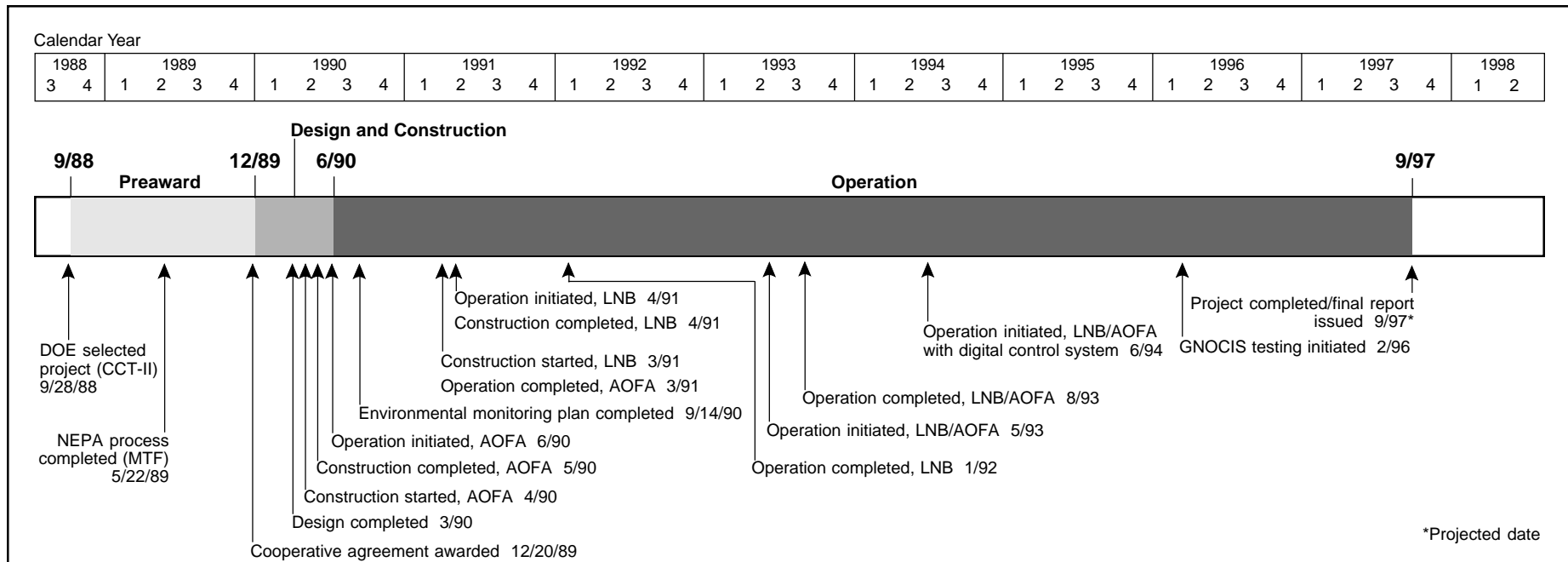
AOFA involves (1) improving the mixing of overfire air with the furnace gases to achieve complete combustion, (2) depleting the air from the burner zone to minimize NO<sub>x</sub> formation, and (3) supplying air over furnace wall tube surfaces to prevent slagging and furnace corrosion. The AOFA technique was expected to reduce NO<sub>x</sub> emissions by about 35%.

In an LNB, fuel and air mixing is controlled to preclude the formation of NO<sub>x</sub>. 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<sub>x</sub> emissions by about 45%.

Based on earlier experience, the use of AOFA in conjunction with LNB can reduce NO<sub>x</sub> 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, opposed wall-fired unit, which is representative of many existing pre-NSPS wall-fired utility boilers in the United States. The project also includes installation and testing of an advanced digital control system that optimizes LNB/AOFA performance using artificial intelligence techniques. 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<sub>x</sub> 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<sub>x</sub> emission levels to be approximately 0.65 lb/10<sup>6</sup> Btu. This NO<sub>x</sub> level represents a 48% reduction when compared to the baseline, full-load value of 1.23 lb/10<sup>6</sup> 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 (LOI) values in the LNB configuration were near 8%, compared to 5% for baseline. Results from LNB/AOFA testing indicate that full-load NO<sub>x</sub> emissions were approximately 0.41 lb/10<sup>6</sup> Btu with a corresponding flyash loss-on-ignition value of nearly 8%. Full-load, long-term NO<sub>x</sub> emission reductions in the LNB/AOFA configuration were about 63%. However, analysis of emissions data showed that the incremental NO<sub>x</sub> reduction

effectiveness of the AOFA system (beyond the use of the LNB) was approximately 17% with additional reductions resulting from other operational changes.

GNOICIS testing for optimizing NO<sub>x</sub> reduction and boiler efficiency began in February 1996. Although narrow parameters were placed on the recommendations that GNOICIS could provide, preliminary data analysis is encouraging, with an observed efficiency gain of 0.5%, a reduction in LOI levels of 1–3%, and a reduction in NO<sub>x</sub> emissions by 10–15% at full load. Short-term testing of the GNOICIS, in both open- and closed-loop configurations, and long-term closed-loop testing were planned for early fall 1996; however, low dispatch priority and problems with the unit have impacted GNOICIS testing. The final project report and a report on testing of several on-line carbon-in-ash monitors are being prepared.

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 was issued in December 1993.

### Commercial Applications

The technology is applicable to the 422 existing pre-NSPS wall-fired boilers; these boilers burn a variety of coals. The GNOICIS technology is applicable to all fossil-fuel-fired boilers.

Based on the success of GNOICIS at Georgia Power's Plant Hammond and the early demonstrations at PowerGen's Kingsnorth 1 and Alabama Power's Gaston 4, Southern Company has installed GNOICIS software in six other power plants, including several of its own units, i.e., Georgia Power's Branch 3 and Wansley 1 and Alabama Power's Gaston 3. The three other installations include Duquesne Light & Power's Cheswick unit, Entergy's Nelson Unit 4, and PowerGen's Kingsnorth 3. Of the 9 current installations, 5 units burn coal; 1, gas; 2, a combination of coal and gas; and 1, a combination of coal and oil. The units encompass a wide variety of boiler types and all major U.S. vendors. A total of 20 installations is anticipated by year-end 1997, including several in foreign countries.



## Demonstration of Selective Catalytic Reduction Technology for the Control of NO<sub>x</sub> Emissions from High-Sulfur-Coal-Fired Boilers

*Project completed.*

### Participant

Southern Company Services, Inc.

### Additional Team Members

Electric Power Research Institute—cofunder

Ontario Hydro—cofunder

Gulf Power Company—host

### Location

Pensacola, Escambia County, FL (Gulf Power Company's Plant Crist, Unit 4)

### Technology

Selective catalytic reduction (SCR)

### Plant Capacity/Production

8.7-MWe equivalent (three 2.5-MWe and six 0.2-MWe equivalent SCR reactor plants)

### Coal

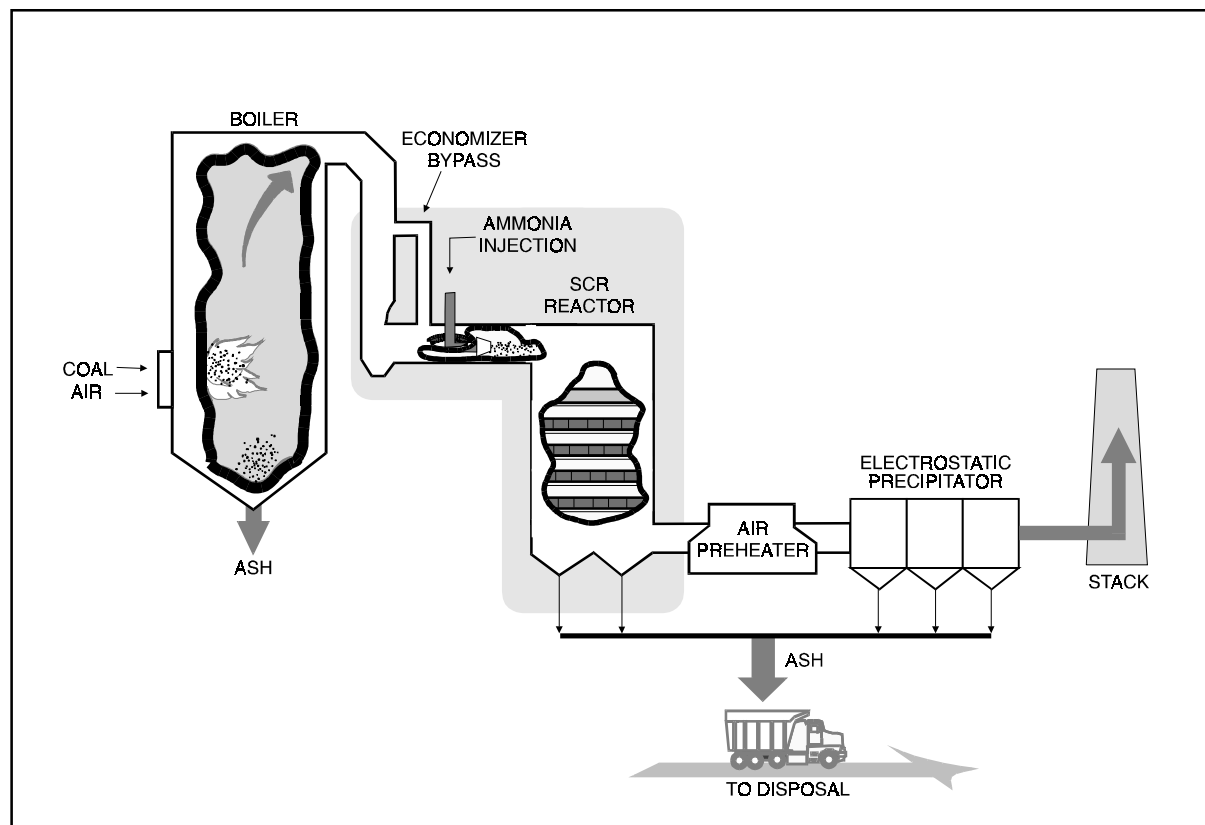
Illinois bituminous, 2.7% sulfur

### Project Funding

Total project cost	\$23,229,729	100%
DOE	9,406,673	40
Participant	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 high-sulfur U.S. coal under various operating conditions while achieving as much as 80% NO<sub>x</sub> removal.



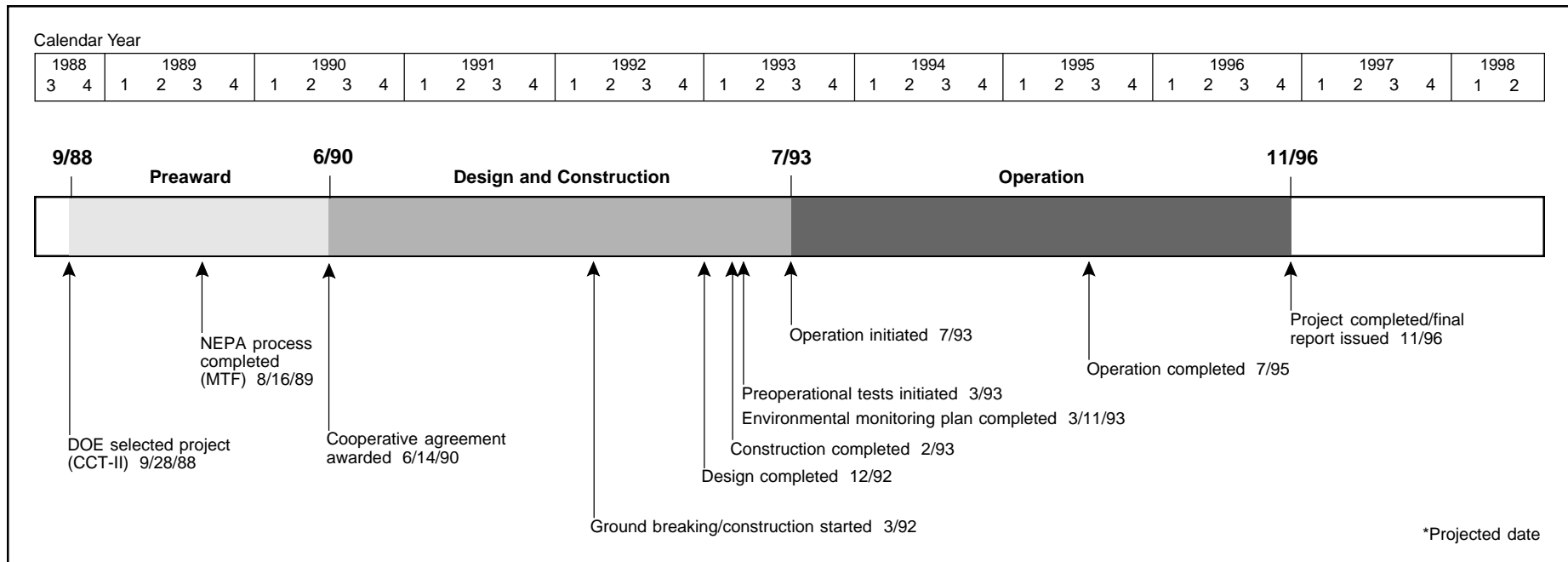
### Technology/Project Description

The SCR technology consists of injecting ammonia into boiler flue gas and passing it through a catalyst bed where the NO<sub>x</sub> and ammonia react to form nitrogen and water vapor.

In this demonstration project, the SCR facility consisted of three 2.5-MWe-equivalent SCR reactors, supplied by separate 5,000 std ft<sup>3</sup>/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 demonstration.

The project demonstrated, at high- and low-dust loadings of flue gas, the applicability of SCR technology to provide a cost-effective means of reducing NO<sub>x</sub> emissions from power plants burning high-sulfur U.S. coal.

The demonstration plant, which was located at Gulf Power Company's Plant Crist near Pensacola, FL, utilized flue gas from the burning of 2.7% sulfur coal under various NO<sub>x</sub> and particulate levels.



## Results Summary

### Environmental

- NO<sub>x</sub> reductions of over 80% were achieved at an ammonia slip well under the 5 ppm acceptable for commercial operation.
- Flow rates could be increased to 150% of design without exceeding the ammonia slip design level of 5 ppm at 80% NO<sub>x</sub> reduction.
- While catalyst performance increased above 700 °F, the benefit did not outweigh the heat rate penalties.
- The increase for ammonia slip, a sign of catalyst deactivation, went from less than 1 ppm to approximately 3 ppm over 12,000 hours of operation, thus demonstrating deactivation in coal-fired units was in line with worldwide experience.
- SO<sub>2</sub> oxidation was within or below the design limits necessary to protect downstream equipment.

### Operational

- Fouling of catalysts was controlled by adequate sootblowing procedures.
- Catalyst erosion was not considered to be a problem.
- Air preheater performance was degraded because of ammonia slip and subsequent by-product formation; however, problem solutions were identified.
- The SCR process does not significantly affect the results of toxicity-characteristic-leaching-procedure analysis of the fly ash.

### Economic

Levelized costs for various NO<sub>x</sub> removal levels for a 250-MWe unit at 0.35 lb/10<sup>6</sup> Btu inlet follow:

	40%	60%	80%
1996 levelized cost (mills/kWh)	2.39	2.57	2.79
1996 levelized cost (\$/ton)	3,502	2,500	2,036

## Project Summary

The demonstration tests were designed to address several uncertainties, including potential catalyst deactivation due to poisoning by trace metals species in U.S. coals, performance of technology and effects on the balance-of-plant equipment in the presence of high amounts of SO<sub>2</sub> and SO<sub>3</sub>, and performance of the SCR catalyst under typical U.S. high-sulfur coal-fired utility operating conditions. Catalyst suppliers were required to design the catalyst baskets to match predetermined reactor dimensions, provide a maximum of four catalyst layers, and meet the following reactor baseline conditions:

Parameter	Minimum	Baseline	Maximum
Temperature (°F)	620	700	750
NH <sub>3</sub> /NO <sub>x</sub> molar ratio	0.6	0.8	1.0
Space velocity (1% design flow)	60	100	150
Flow rate (std ft <sup>3</sup> /min)			
Large reactor	3,000	5,000	7,500
Small reactor	240	400	600

## Exhibit 5-18 Catalysts Tested

Catalyst	Reactor Size*	Catalyst Configuration
Nippon/Shokubai	Large	Honeycomb
Siemens AG	Large	Plate
W.R. Grace/Noxeram	Large	Honeycomb
W.R. Grace/Synox	Small	Honeycomb
Haldor Topsoe	Small	Plate
Hitachi/Zosen	Small	Plate
Cormetech/High dust	Small	Honeycomb
Cormetech/Low dust	Small	Honeycomb

\* Large = 2.5 MWe; 5,000 std ft<sup>3</sup>/min    Small = 0.2 MWe; 400 std ft<sup>3</sup>/min

The catalysts tested are listed in Exhibit 5-18. Catalyst suppliers were given great latitude in providing the amount of catalyst for this demonstration.

### Environmental Results

Ammonia slip, the controlling factor in the long-term operation of commercial SCR, was usually  $\leq 5$  ppm because of plant and operational considerations. Ammonia slip was dependent on catalyst exposure time, flow rate, temperature,  $\text{NH}_3/\text{NO}_x$  distribution, and  $\text{NH}_3/\text{NO}_x$  ratio ( $\text{NO}_x$  reduction). Changes in  $\text{NH}_3/\text{NO}_x$  ratio and consequently  $\text{NO}_x$  reduction generally produced the most significant changes in ammonia slip. The ammonia slip at 60%  $\text{NO}_x$  reduction was at or near the detection limit of 1 ppm. As  $\text{NO}_x$  reduction was increased above 80%, ammonia slip also increased and remained at reasonable levels up to  $\text{NO}_x$  reductions of 90%. Over 90%, the ammonia slip levels increased dramatically.

The flow rate and temperature effects on  $\text{NO}_x$  reduction were also measured. In general, flows could be increased to 150% of design without the ammonia slip exceeding 5 ppm at 80%  $\text{NO}_x$  reduction and design temperature. With respect to temperature, most catalysts

exhibited fairly significant improvements in overall performance as temperatures increased from 620 °F to 700 °F but relatively little improvement as temperature increased from 700 °F to 750 °F. The conclusion was that the benefits of high-temperature operation probably do not outweigh the heat rate penalties involved in operating SCR at the higher temperatures.

Catalyst deactivation was generally observed by an increase in ammonia slip over time, assuming the  $\text{NO}_x$  reduction efficiency was held constant. Over the 12,000 hours of the demonstration tests, the ammonia slip did, in fact, increase from less than 1 ppm to approximately 3 ppm.

These results demonstrated the maturity of catalyst design and that deactivation was in line with prior worldwide experience.

It has been observed that the catalytic active species that results in  $\text{NO}_x$  reduction often contributed to  $\text{SO}_2$  oxidation (i.e.,  $\text{SO}_3$  formation), which can be detrimental to downstream equipment. In general,  $\text{NO}_x$  reduction can be increased as the tolerance for  $\text{SO}_3$  is also increased. The upper bound for  $\text{SO}_2$  oxidation for the demonstration catalyst was set at 0.75% at baseline conditions. The average  $\text{SO}_2$  oxidation rate for each of the catalysts is shown in Exhibit 5-19. These data reflect baseline conditions over the life of the demonstration. All of the catalysts were within design limits, with most exhibiting oxidation rates below the design limit. Other factors affecting  $\text{SO}_2$  oxidations are listed below:

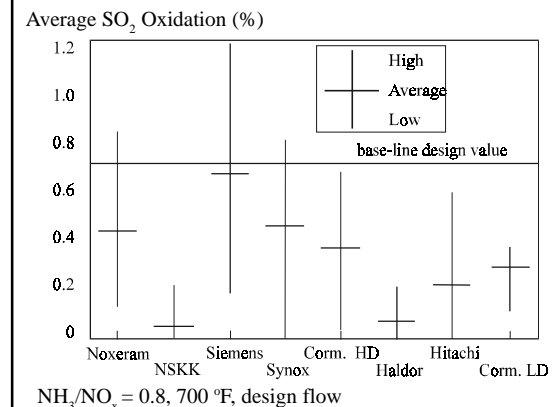
- **Flow Rate.** Most of the catalysts exhibited fairly constant  $\text{SO}_2$  oxidation with respect to flow rate (i.e., space velocity). In theory,  $\text{SO}_2$  oxidation should be inversely proportional to flow rate.
- **Temperature.** Theoretically the relationship between  $\text{SO}_2$  oxidation and temperature should be exponential

as temperature increases; however, measurements showed the relationship to be linear with little difference in  $\text{SO}_2$  oxidation between 620 °F and 700 °F. However, between 700 °F and 750 °F, the  $\text{SO}_2$  oxidation increased more significantly.

### Other Findings

- **Pressure Drop.** Overall reactor pressure drop was a function of the catalyst geometry and volume, but tests to determine which one was controlling were inconclusive.
- **Fouling.** The fouling characteristics of the catalyst were important to long-term operation. During the demonstration, measurements showed relatively level pressure drop over time, indicating that sootblowing procedures were effective. The plate-type configurations had somewhat less fouling potential than did the honeycomb configuration, but both were acceptable for application.
- **Erosion.** Catalyst erosion was not considered to be a significant problem because most of the erosion was

## Exhibit 5-19 Avg $\text{SO}_2$ Oxidation Rate (Baseline)



attributed to aggressive sootblowing.

- **Air Preheater Performance.** The demonstration showed that the SCR process exacerbated performance degradation of the air preheaters mainly due to ammonia slip and subsequent by-product formation. Regenerator-type air heaters outperformed recuperators in SCR applications in terms of both thermal performance and fouling.
- **Ammonia Volatilization.** The ammonia volatilized from the SCR flyash when a significant amount of water was absorbed by the ash. This was caused by the formation of a moist layer on the ash with a pH high enough to convert the ammonia compounds in the ash to gas-phase ammonia.
- **Toxicity-Characteristic-Leaching-Procedure (TCLP) Analysis.** TCLP analyses were performed on flyash samples. The SCR process did not significantly affect the toxics leachability of the fly ash.

### Economic Results

An economic evaluation was performed for full-scale applications of SCR technology to a new 250-MWe pulverized coal-fired plant located in a rural area with minimal space limitations. The fuel considered was high-sulfur Illinois No. 6 coal. Other key base case design criteria are shown in Exhibit 5-20.

Results of the economic analysis of capital, operating and maintenance (O&M), and levelized cost based on a 30-year project life for various unit sizes for an SCR

	125 MWe	250 MWe	700 MWe
Capital cost (\$/kW)	61	54	45
Operating cost (\$)	580,000	1,045,000	2,667,000
1996 levelized cost			
mills/kWh	2.89	2.57	2.22
\$/ton	2,811	2,500	2,165

system with a NO<sub>x</sub> removal efficiency of 60% follow:

Results of the economic analysis of capital, O&M, and levelized cost for various NO<sub>x</sub> removal efficiencies for a 250-MWe unit with 0.35 lb of inlet NO<sub>x</sub>/10<sup>6</sup> Btu

	40%	60%	80%
Capital cost (\$/kW)	52	54	57
Operating costs (\$)	926,000	1,045,000	1,181,000
1996 levelized cost			
mill/kWh	2.39	2.57	2.79
\$/ton	3,502	2,500	2,036

follow:

For retrofit applications, the estimated capital costs were \$59–112/kW, depending on the size of the installation and the difficulty and scope of the retrofit. The levelized costs for the retrofit applications were

Exhibit 5-20 Design Criteria	
Parameter	Specification
Type of SCR	Hot side
Number of reactors	One
Reactor configuration	3 catalyst support layers
Initial catalyst load	2 of 3 layers loaded
Range of operation	35–100% boiler load
NO <sub>x</sub> inlet concentration	0.35 lb/10 <sup>6</sup> Btu
Design NO <sub>x</sub> reduction	60%
Design ammonia slip	5 ppm
Catalyst life	16,000 hr
Ammonia cost	\$250/ton
SCR cost	\$400/ft <sup>3</sup>

\$1,850–5,100/ton (current \$).

### Commercial Applications

As a result of this demonstration, SCR technology has been shown to be applicable to existing and new utility generating capacity for removal of NO<sub>x</sub> from the flue gas of virtually any size boiler. There are approximately 1,041 coal-fired utility boilers in active commercial service in the United States; these boilers represent a total generating capacity of 296,000 MWe.

### Contacts

Robert R. Hardman, (205) 257-7772

Southern Company Services, Inc.

P.O. Box 2625

Birmingham, AL 35202-2625

Lawrence Saroff, DOE/HQ, (301) 903-9483

Arthur L. Baldwin, FETC, (412) 892-6011

### References

- Maxwell, J. D., et al. "Demonstration of SCR Technology for the Control of NO<sub>x</sub> Emissions from High-Sulfur Coal-Fired Utility Boilers." *Fifth Annual Clean Coal Technology Conference: Technical Papers*, January 1997.
- *Demonstration of SCR Technology for the Control of NO<sub>x</sub> Emissions from High-Sulfur Coal-Fired Utility Boilers: Final Report*. Vol. 1. Southern Company Services. October 1996. (Appendixes in Vol. 2–3.)
- *Economic Evaluation of Commercial-Scale SCR Applications for Utility Boilers*. Southern Company Services. September 1996.

## 180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO<sub>x</sub> Emissions from Coal-Fired Boilers

**Project completed.**

### Participant

Southern Company Services, Inc.

### Additional Team Members

Gulf Power Company—cofunder and host

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<sub>x</sub> Concentric Firing System (LNCFS™) with advanced overfire air (AOFA), clustered coal nozzles, and offset air

### Plant Capacity/Production

180 MWe

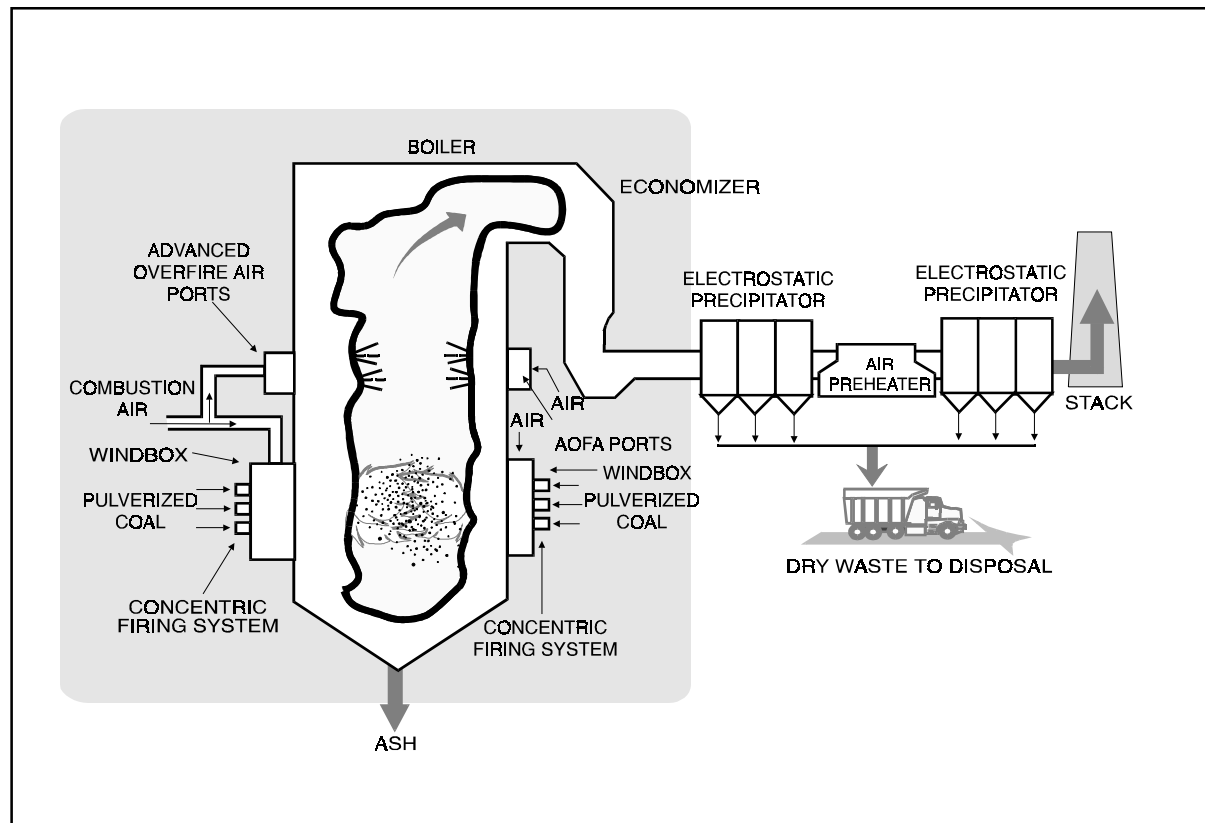
### Coal

Eastern bituminous, high reactivity

### Project Funding

Total project cost	\$9,153,383	100%
DOE	4,440,184	49
Participant	4,713,199	51

LNCFS is a trademark of ABB Combustion Engineering, Inc.



### Project Objective

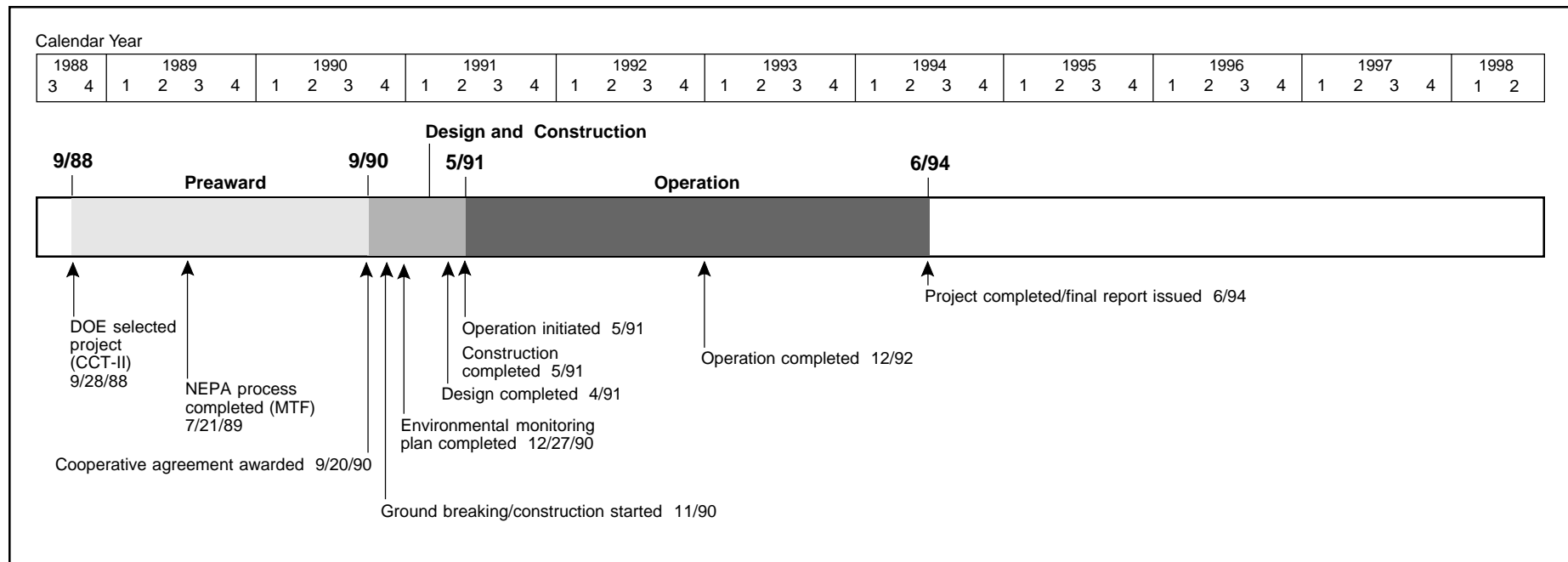
To demonstrate in a stepwise fashion the short- and long-term NO<sub>x</sub> reduction capabilities of Low-NO<sub>x</sub> Concentric Firing System levels I, II, and III on a single reference boiler.

### Technology/Project Description

Technologies demonstrated included the Low-NO<sub>x</sub> Concentric Firing System (LNCFS™), levels I, II, and III. Each level of the LNCFS™ used different combinations of overfire air and clustered coal nozzle positioning to achieve NO<sub>x</sub> 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™ I used a close-coupled overfire air (CCOFA) system integrated directly into the windbox of the boiler. A separated overfire air (SOFA) system located above

the combustion zone was featured in the LNCFS™ II system. This was an advanced overfire air system that incorporates back pressuring and flow measurement capabilities. CCOFA and SOFA were both used in the LNCFS™ III tangential-firing approach.

Carefully controlled short-term tests were conducted followed by long-term testing under normal load dispatch conditions. Long-term tests, which typically lasted 2–3 months for each phase, best represent the true emissions characteristics of each technology. Results presented are based on long-term test data.



## Results Summary

### Environmental

- At full load, the NO<sub>x</sub> emissions using LNCFS™ I, II, and III were 0.39, 0.39, and 0.34 lb/10<sup>6</sup> Btu, respectively, which represent reductions of 37%, 37%, and 45% from the baseline emissions.
- Emissions with LNCFS™ were not sensitive to power outputs between 100- and 200-MWe, but emissions increased significantly below 100 MWe, reaching baseline emission levels at 70 MWe.
- Because of reduced effectiveness at low loads, LNCFS™ proved marginal as a compliance option for peaking load conditions.
- Average CO emissions increased at full load.
- Air toxics testing found LNCFS™ to have no clear-cut effect on the emissions of trace metals or acid gases. Volatile organic compounds (VOCs) appeared to be reduced and semi-volatile compounds increased.

### Operational

- Loss-on-ignition (LOI) was not sensitive to the LNCFS™ retrofits but very sensitive to coal fineness.
- Furnace slagging was reduced but back-pass fouling was increased for LNCFS™ II and III.
- Boiler efficiency and unit heat rate were impacted minimally.
- Unit operation was not significantly affected, but operating flexibility of the unit was reduced at low loads with LNCFS™ II and III.

### Economic

- The capital cost estimate for LNCFS™ I was \$5–15/kW and for LNCFS™ II and III, \$15–25/kW.
- The cost effectiveness for LNCFS™ I was \$103/ton of NO<sub>x</sub> removed; LNCFS™ II, \$444/ton; and LNCFS™ III, \$400/ton.

## Project Summary

At the time of the demonstration, specific NO<sub>x</sub> emission regulations were being formulated under the CAAA. The data developed over the course of this project provided needed real-time input to regulation development.

LNCFS™ technology was designed for tangentially fired boilers, which represent a large percentage of the pre-NSPS coal-fired generating capacity. The technology reduces NO<sub>x</sub> by staging combustion in the boiler vertically by separating coal and air injectors and horizontally by creating fuel-rich and lean zones with offset air nozzles. The objective was to determine NO<sub>x</sub> emission reductions and impact on boiler performance over the long-term under normal dispatch and operating conditions. By using the same boiler, the demonstration provided direct comparative performance analysis of the three configurations. Short-term parametric testing enabled extrapolation of results to other tangentially fired units by evaluating the relationship between NO<sub>x</sub> emissions and key operating parameters.

### Exhibit 5-21 LNCFS™ Configurations

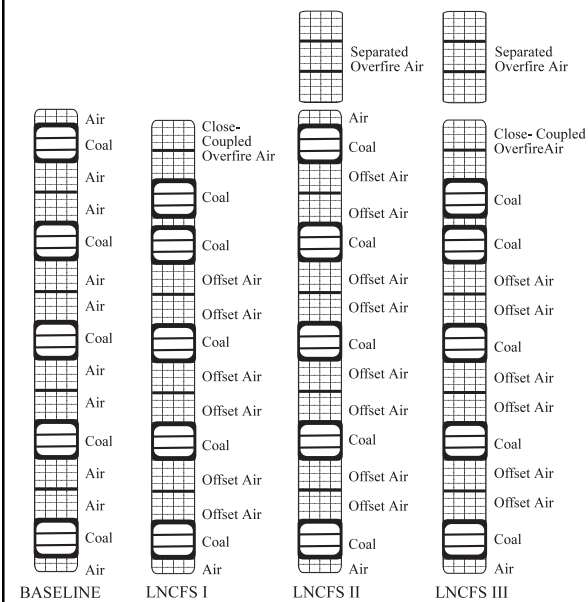
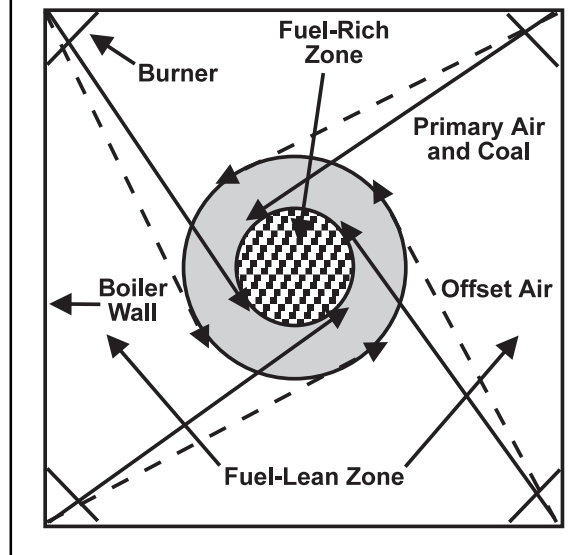


Exhibit 5-21 shows the various LNCFS™ configurations used to achieve staged combustion. In addition to overfire air, as shown in Exhibit 5-22, the LNCFS™ incorporates other NO<sub>x</sub>-reducing techniques into the combustion process. Using offset air, two concentric circular combustion regions are 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 annulus of combustion air can be varied using adjustable offset air nozzles.

#### Operational Performance

Exhibit 5-23 summarizes the impacts of LNCFS™ on unit performance.

### Exhibit 5-22 Concentric Firing Concept



#### Environmental Performance

At full load, LNCFS™ I, II, and III reduced NO<sub>x</sub> emissions by 37%, 37%, and 45%, respectively.

Exhibit 5-24 presents the NO<sub>x</sub> emission estimates obtained in the assessment of the average annual NO<sub>x</sub> emissions for three dispatch scenarios.

Air toxics testing found LNCFS™ to have no clear-cut effect on the emission of trace metals or acid gases. The data provided marginal evidence for a decreased emission of chromium. The effect on aldehydes/ketones could not be assessed because baseline data were compromised. VOCs appeared to be reduced and semi-volatile compounds increased. The increase in semi-volatile compounds was deemed to be consistent with increases in the amount of unburned carbon in the ash.

#### Economic Performance

LNCFS™ II was the only complete retrofit (LNCFS™ I and III were modifications of LNCFS™ II), and therefore capital cost estimates were based on the Lansing Smith Unit No. 2 retrofit as well as other tangentially fired LNCFS™ retrofits. The capital cost ranges follow:

- LNCFS™ I—\$5–15/kW
- LNCFS™ II—\$15–25/kW
- LNCFS™ III—\$15–25/kW

Site-specific considerations have a significant effect on capital costs; however, the above ranges reflect recent experience and are planning estimates. The actual capital cost for LNCFS™ II at Lansing Smith Unit No. 2 was \$3 million, or \$17/kW, which falls within the projected range.

The cost effectiveness of the LNCFS™ technologies is based on the capital and operating and maintenance costs and the NO<sub>x</sub> removal efficiency of the technologies. The cost effectiveness of the LNCFS™ technologies is listed below (based on a levelization factor of 0.144):

- LNCFS™ I—\$103/ton of NO<sub>x</sub> removed
- LNCFS™ II—\$444/ton of NO<sub>x</sub> removed
- LNCFS™ III—\$400/ton of NO<sub>x</sub> removed

#### Commercial Applications

LNCFS™ technology has been adopted by eight other utilities in eight separate retrofits over a range of capacities. Further, potential commercial applications of this technology include nearly 600 U.S. pulverized coal, tangentially fired utility units. These units are 25–950 MWe in size and fire a wide range of coals, from low-volatile bituminous through lignite.

### Exhibit 5-23 Unit Performance Impacts Based on Long-Term Testing

	Baseline	LNCFS™ I	LNCFS™ II	LNCFS™ III
Avg CO at full load (ppm)	10	12	22	33
Avg excess O <sub>2</sub> at full load (%)	3.7	3.2	4.5	4.3
LOI at full load (%)	4.8	4.6	4.2	5.9
O <sub>2</sub> (%)	4.0	3.9	5.3	4.7
Steam outlet conditions	Satisfactory at full load; low temperatures at low loads	Full load: 5–10 °F lower than baseline Low loads: 10–30 °F lower than baseline	Same as baseline	160–200 MWe: OK 80 MWe: 15–35 °F lower than baseline
Furnace slagging and backpass fouling	Medium	Medium	Reduced slagging, but increased fouling	Reduced slagging, but increased fouling
Operating flexibility	Normal	Same as baseline	More care required at low loads	More difficult to operate than other systems
Boiler efficiency (%)	90	90.2	89.7	89.85
Efficiency change	N/A	+0.2	-0.3	-0.15
Turbine heat rate (Btu/kWh)	9,000	9,011	9,000	9,000
Unit net heat rate (Btu/kWh)	9,995	9,986	10,031	10,013
Change (%)	N/A	-0.1	+0.36	+0.18

### Exhibit 5-24 Average Annual NO<sub>x</sub> Emissions and % Reduction

Boiler Duty Cycle	Units	Baseline	LNCFS™ I	LNCFS™ II	LNCFS™ III
Baseload (161.8 MWe avg)	Avg NO <sub>x</sub> emissions (lb/10 <sup>6</sup> Btu)	0.62	0.41	0.41	0.36
	Avg reduction (%)		38.7	38.7	42.2
Intermediate load (146.6 MWe avg)	Avg NO <sub>x</sub> emissions (lb/10 <sup>6</sup> Btu)	0.62	0.40	0.41	0.34
	Avg reduction (%)		39.2	35.9	45.3
Peaking load (101.8 MWe avg)	Avg NO <sub>x</sub> emissions (lb/10 <sup>6</sup> Btu)	0.59	0.45	0.47	0.43
	Avg reduction (%)		36.1	20.3	28.0

#### Contacts

Robert R. Hardman, Project Manager, (205) 877-7772  
Southern Company Services, Inc.  
P.O. Box 2625  
Birmingham, AL 35202-2625  
Lawrence Saroff, DOE/HQ, (301) 903-9483  
Scott M. Smouse, FETC, (412) 892-5725

#### References

- *180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO<sub>x</sub>) Emissions from Coal-Fired Boilers: Final Report and Key Project Findings.* Report No. DOE/PC/89653-T14. Southern Company Services, Inc. February 1994. (Available from NTIS as DE94011174.)
- *180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO<sub>x</sub>) Emissions from Coal-Fired Boilers—Plant Lansing Smith—Phase III and Final Environmental Monitoring Program Report.* Southern Company Services, Inc. December 1993.
- *Measurement of Chemical Emissions under the Influence of Low-NO<sub>x</sub> Combustion Modifications.* Report No. DOE/PC/89653-T12. Southern Company Services, Inc. October 1993. (Available from NTIS as DE94005038.)
- *180-MW Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO<sub>x</sub>) Emissions from Coal-Fired Boilers: Public Design Report.* Report No. DOE/PC/89652-T13. Southern Company Services, Inc. September 1993. (Available from NTIS as DE94000218.)



## Combined SO<sub>2</sub>/NO<sub>x</sub> Control Technology

Combined SO<sub>2</sub>/NO<sub>x</sub> control systems encompass those technologies that combine previously described control methods and those that apply other, synergistic techniques. Three of the projects combine either LNBs or gas reburning with sorbent injection. In one of these, SNCR is used with LNBs to enhance performance. Another project combines a number of techniques to improve overall system performance, such as LNBs with SNCR, unique space-saving and durable wet-scrubber design, sorbent additive, and artificial intelligence controls. The balance of the seven projects use synergistic methods not previously described.

SO<sub>x</sub>-NO<sub>x</sub>-Rox Box™ incorporates an SCR catalyst in a high-temperature filter bag for NO<sub>x</sub> control and applies sorbent injection for SO<sub>2</sub> control. The high-temperature filter bag, operated in a standard pulsed jet baghouse, protects the SCR catalyst, allows operation at optimal NO<sub>x</sub> control temperatures, forms a sorbent cake on the surface to enhance SO<sub>2</sub> capture, and provides high-efficiency particulate capture.

SNOX™ uses SCR followed by catalytic oxidation of SO<sub>2</sub> to SO<sub>3</sub> with condensation of the SO<sub>3</sub> in the presence of water to produce sulfuric acid. Following the SCR with the catalytic oxidation allows the SCR to operate at optimal ammonia concentration without worry of ammonia slip (ammonia passing to the second catalyst is broken down). Furthermore, most particulates passing through the upstream baghouse are captured in the sulfuric acid condens-



▲ New York State Electric & Gas Corporation's Milliken Station is hosting the demonstration of a combination of unique SO<sub>2</sub> and NO<sub>x</sub> control technologies.

ing unit. The system produces no solid waste.

NOXSO uses a single, regenerable adsorber (spherical alumina beads impregnated with sodium carbonate) to capture both SO<sub>2</sub> and NO<sub>x</sub>. The adsorber is used in a fluidized bed to achieve effective mixing with the flue gas. The flue gas is then processed through a regenerator system to release the NO<sub>x</sub> and SO<sub>2</sub> before return to the fluidized bed.

Five of the seven combined SO<sub>2</sub>/NO<sub>x</sub> control technology projects have been completed, one is in operation, and one is in the project definition and design phase. Exhibit 5-25 briefly summarizes the characteristics and performance of the technologies that are described in more detail in the project fact sheets.

**Exhibit 5-25**  
**CCT Program Combined SO<sub>2</sub>/NO<sub>x</sub> Control Technology Characteristics**

<b>Project</b>	<b>Process</b>	<b>Coal Sulfur Content</b>	<b>SO<sub>2</sub>/NO<sub>x</sub> Reduction</b>	<b>Fact Sheet</b>
LIMB Demonstration Project Extension and Coolside Demonstration	LNB/sorbent injection—furnace and duct injection, calcium-based sorbents	1.6–3.8%	60–70%/40–50%	5-62
Integrated Dry NO <sub>x</sub> /SO <sub>2</sub> Emissions Control System	LNB/SNCR/sorbent injection—calcium- and sodium-based sorbents used in duct injection	0.4%	70%/62–80%	5-78
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	Gas reburning/sorbent injection—calcium-based sorbents used in duct injection	3.0%	50–60%/67%	5-70
Milliken Clean Coal Technology Demonstration Project	LNB/SNCR/wet scrubber—sorbent additive and space-saving, durable scrubber design	1.5–4.0%	95%/53–58% (goal)	5-74
SO <sub>x</sub> -NO <sub>x</sub> -Rox Box™ Flue Gas Cleanup Demonstration Project	SCR/high temperature baghouse/sorbent injection—SCR in high-temperature filter bag and calcium-based sorbent injection	3.4%	80–90%/90%	5-66
SNOX™ Flue Gas Cleaning Demonstration Project	SCR/oxidation catalyst/sulfuric acid condenser—synergistic catalyst effect and no solid waste	3.4%	95%/94%	5-58
Commercial Demonstration of the NOXSO SO <sub>2</sub> /NO <sub>x</sub> Removal Flue Gas Cleanup System	Regenerable adsorbent—spherical alumina beads impregnated with sodium carbonate in fluidized-bed adsorber	3.4% (planned)	98% (goal)/75% (goal)	5-76

## 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

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

### Plant Capacity/Production

35-MWe equivalent slipstream from a 108-MWe boiler

### Coal

Ohio bituminous, 3.4% sulfur

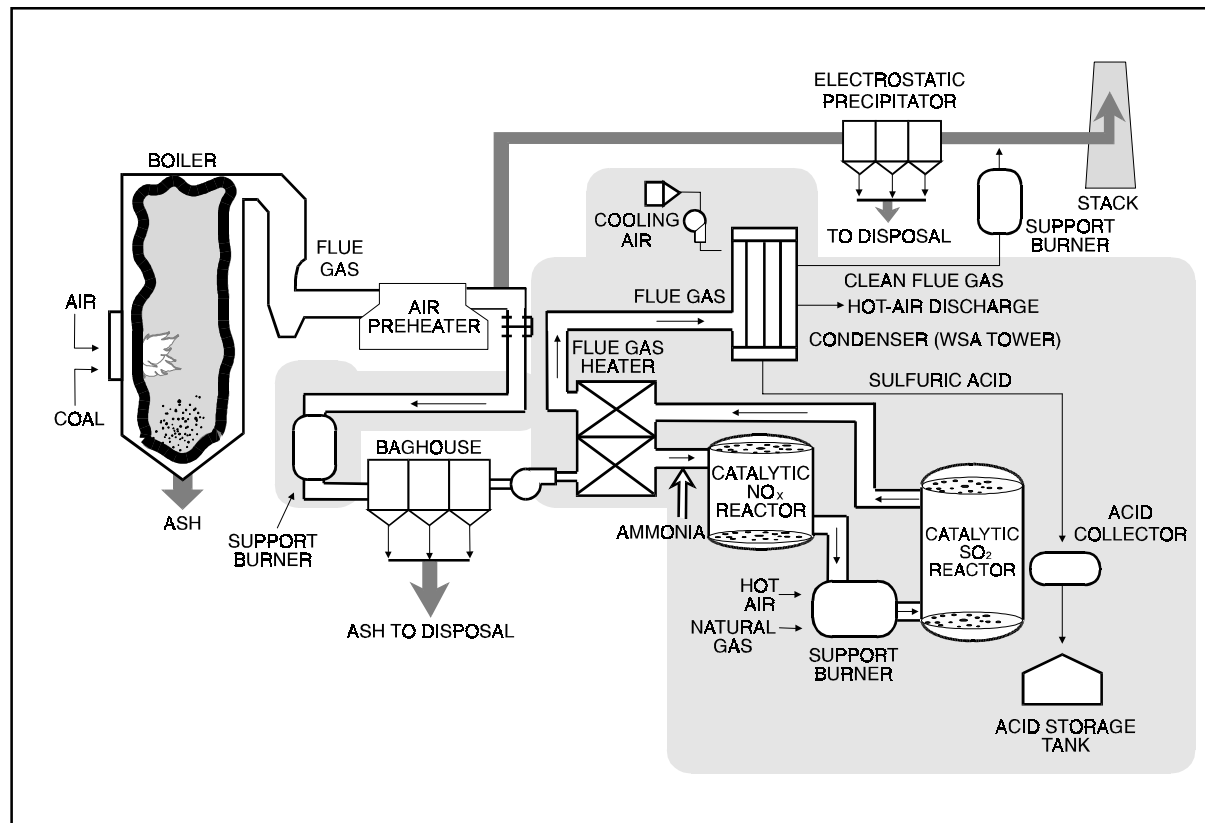
### Project Funding

Total project cost	\$31,438,408	100%
DOE	15,719,200	50
Participant	15,719,208	50

### Project Objective

To demonstrate at an electric power plant using U.S. coals that SNOX™ technology will catalytically remove 95% of SO<sub>2</sub> and more than 90% of NO<sub>x</sub> from flue gas and produce a salable by-product of concentrated sulfuric acid.

SNOX is a trademark of Haldor Topsoe a/s.



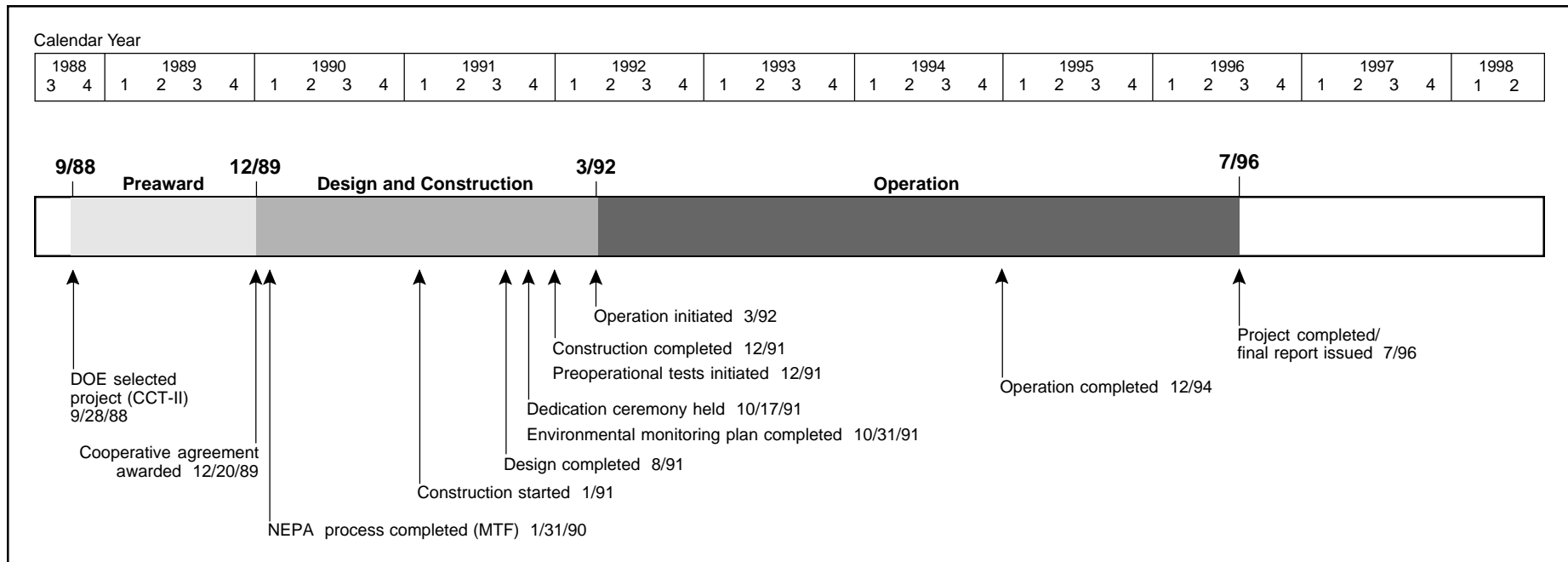
### Technology/Project Description

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<sub>2</sub> converter. The ash-free gas is reheated, and NO<sub>x</sub> is reacted with small quantities of ammonia in the first of two catalytic reactors where the NO<sub>x</sub> is converted to harmless nitrogen and water vapor. The SO<sub>2</sub> is oxidized to SO<sub>3</sub> in a second catalytic converter. The gas then passes through a novel glass-tube condenser that allows SO<sub>3</sub> to hydrolyze to concentrated sulfuric acid.

The technology, while using U.S. coals, was designed to remove 95% of the SO<sub>2</sub> and more than 90% of the NO<sub>x</sub> from flue gas and produce a salable sulfuric acid

by-product. This was 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.



## Results Summary

### Environmental

- SO<sub>2</sub> removal efficiency was normally in excess of 95% for inlet concentrations averaging about 2,000 ppm.
- NO<sub>x</sub> reduction averaged 94% for inlet concentrations of approximately 500–700 ppm.
- Particulate removal efficiency for the high-efficiency fabric filter baghouse with SNOX™ system was greater than 99%.
- Sulfuric acid purity exceeded federal specifications for Class I acid.
- Air toxics testing showed high capture efficiency of most trace elements in the baghouse. A significant portion of the boron and almost all of the mercury escaped to the stack. But selenium and cadmium, normally a problem, were effectively captured in the acid drain, as were organic compounds.

- Absence of an alkali reagent contributed to having no secondary pollution streams or increases in CO<sub>2</sub> emissions.
- SO<sub>2</sub> catalyst virtually eliminated CO and hydrocarbon emissions.

### Operational

- SO<sub>2</sub> catalyst downstream of the NO<sub>x</sub> catalyst eliminated ammonia slip and allowed the SCR to function more efficiently.
- Heat developed in the SNOX™ process was used to enhance thermal efficiency.

### Economic

- Capital cost was estimated at \$305/kW for a 500-MWe unit firing 3.2% sulfur coal. The levelized incremental cost was estimated at 6.1 mills/kWh or \$21/ton of SO<sub>2</sub> removal on a constant dollar basis. Comparable current dollar costs were 7.8 mills/kWh and \$284/ton of SO<sub>2</sub>.

## Project Summary

Because the SNOX™ process utilized an oxidation catalyst to convert SO<sub>2</sub> to SO<sub>3</sub> and ultimately to sulfuric acid, no reagent was required for the SO<sub>2</sub> removal step. As a result, the process produced no other waste streams.

In order to demonstrate and evaluate the performance of the SNOX™ process, general operating data were collected and parametric tests conducted to characterize the process and equipment. The system has operated for approximately 8,000 hours and produced more than 5,600 tons of commercial-grade sulfuric acid. Many tests for the SNOX™ system were conducted at three loads—75%, 100%, and 110% of design capacity.

### Environmental Performance

Particulate emissions from the process were very low (<1 mg/Nm<sup>3</sup>) due to the characteristics of the SO<sub>2</sub> catalyst and the sulfuric acid condenser (WSA Condenser). Although the Niles SNOX™ plant was fitted with a baghouse (rather than an ESP) on its inlet, this was not necessary for low particulate emissions, but the baghouse

was needed to maintain an acceptable cleaning frequency of the SO<sub>2</sub> catalyst. At operating temperature, the SO<sub>2</sub> catalyst, because of its sticky surface, retained about 90% of the dust that entered the catalyst vessel. Dust that passed through was subsequently removed in the WSA Condenser, which acted as a condensing particulate removal device (utilizing the dust particulates as nuclei).

Minimal or no increase in CO<sub>2</sub> emissions by the process was tied to two features—the lack of a carbonate-based alkali reagent that releases CO<sub>2</sub> and the fact that the process recovered additional heat from the flue gas to offset its parasitic energy requirements. This heat recovery, under most design conditions, results in the net heat rate of the boiler being the same or better after addition of the SNOX™ process, and consequently no increase in CO<sub>2</sub> generation per unit of power.

With respect to CO and hydrocarbons, the SO<sub>2</sub> catalyst acted to virtually eliminate these compounds as well. This aspect also positively affected the interaction of the NO<sub>x</sub> and SO<sub>2</sub> catalysts. Because the SO<sub>2</sub> catalyst followed the NO<sub>x</sub> catalyst, any unreacted ammonia (slip) was oxidized in the SO<sub>2</sub> catalyst to nitrogen, water vapor, and a small amount of NO<sub>x</sub>. As a result, downstream fouling by ammonia compounds was eliminated and the SCR was operated at slightly higher than typical ammonia stoichiometries. These higher stoichiometries allowed smaller SCR catalyst volumes and permitted the attainment of very high reduction efficiencies (>95%).

Sulfur dioxide removal in the SNOX™ process was controlled by the efficiency of the SO<sub>2</sub>-to-SO<sub>3</sub> oxidation, which occurred as the flue gas passes through the oxidation catalyst beds. The efficiency was controlled by two factors—space velocity and bed temperature. Space velocity governed the amount of catalyst necessary at design flue gas flow conditions, and gas and bed temperature had to be high enough to activate the SO<sub>2</sub> oxidation, reaction. During the test program, SO<sub>2</sub> removal efficiency was normally in excess of 95% for inlet concentrations averaging about 2,000 ppm.

The SCR portion of the SNOX™ process was able to operate at higher than typical ammonia stoichiometries due to its location ahead of the SO<sub>2</sub> catalyst beds. Normal operating stoichiometries for the SCR system were in the range of 1.02–1.05 and system reduction efficiencies averaged 94% with inlet NO<sub>x</sub> levels of approximately 500–700 ppm.

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.

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 (hydrogen chloride, hydrogen fluoride, chloride, fluoride, phosphate, sulfate)
- Ammonia and cyanide
- Elemental carbon
- Radionuclides
- Volatile organic compounds
- Semi-volatile compounds including polynuclear aromatic hydrocarbons
- Aldehydes

Most trace elements were captured in the baghouse along with the particulate. A significant portion of the boron and almost all of the mercury escaped to the stack. But selenium and cadmium, normally a problem, were effectively captured in the acid drain, as were organic compounds.



▲ The bottom portion of the SO<sub>2</sub> converter catalyst, with the catalyst dust collector hopper mounted on steel rails (center), is shown.

### Operational Performance

Heat recovery was accomplished by the SNOX™ process. In a commercial configuration, it can be utilized in the thermal cycle of the boiler. The process generated recoverable heat in several ways. All of the reactions that took place with respect to NO<sub>x</sub> and SO<sub>2</sub> removal were exothermic and increased the temperature of the flue gas. This heat plus fuel-fired support heat added in the high-temperature SCR/SO<sub>2</sub> catalyst loop was recovered in the WSA Condenser cooling air discharge for use in the furnace as combustion air. Because the WSA Condenser

lowered the temperature of the flue gas to about 210 °F, compared to approximately 300 °F for a typical power plant, additional thermal energy was recovered along with that from the heats of reaction.

### Economic Performance

The economic evaluation of the SNOX™ process showed a capital cost of approximately \$305/kW for a 500-MWe unit firing 3.2% sulfur coal. The levelized incremental cost was 6.1 mills/kWh on a constant dollar basis and 7.8 mills/kWh on a current dollar basis. The equivalent costs per ton of SO<sub>2</sub> removed were \$219/ton (constant dollars) and \$384 (current dollars).

### 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<sub>x</sub> and SO<sub>2</sub> makes 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 is a significant problem.

The host utility, Ohio Edison, is retaining the SNOX™ technology as a permanent part of the pollution control system at Niles Station to help Ohio Edison meet its overall SO<sub>2</sub>/NO<sub>x</sub> reduction goals.

Commercial SNOX™ plants also are operating in Denmark and Sicily. In Denmark, a 305-MWe plant has operated since August 1991. The boiler at this plant burns coals from various 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.

### Contacts

Paul Yosick, Project Manager, (423) 653-7550  
ABB Environmental Systems  
1400 Center Port Boulevard  
Knoxville, TN 37932  
Lawrence Saroff, DOE/HQ, (301) 903-9483  
James U. Watts, FETC, (412) 892-5991

### References

- *A Study of Toxic Emissions from a Coal-Fired Power Plant Utilizing the SNOX™ Innovative Clean Coal Technology Demonstration. Volume 1, Sampling/Results/Special Topics: Final Report.* Report No. DOE/PC/93251-T3-Vol. 1. Battelle Columbus Operations. July 1994. (Available from NTIS as DE94018832.)
- *A Study of Toxic Emissions from a Coal-Fired Power Plant Utilizing the SNOX™ Innovative Clean Coal Technology Demonstration. Volume 2, Appendices: Final Report.* Report No. DOE/PC/93251-T3-Vol. 2. Battelle Columbus Operations. July 1994. (Available from NTIS as DE94018833.)

- *A Study of Toxic Emissions from a Coal-Fired Power Plant: Niles Station Boiler No. 2. Volume 1, Sampling/Results/Special Topics: Final Report.* Report No. DOE/PC/93251-T1-Vol. 1. Battelle Columbus Operations. July 1994. (Available from NTIS as DE94016050.)
- *A Study of Toxic Emissions from a Coal-Fired Power Plant: Niles Station Boiler No. 2. Volume 2, Appendices: Final Report.* Report No. DOE/PC/93251-T1-Vol. 2. Battelle Columbus Operations. July 1994. (Available from NTIS as DE94016051.)
- *Comprehensive Report to Congress on the Clean Coal Technology Program: WSA-SNOX™ Flue Gas Cleaning Demonstration Project.* ABB Combustion Engineering, Inc. Report No. DOE/FE-0151. U.S. Department of Energy. November 1989. (Available from NTIS as DE90004461.)



◀ The SNOX™ demonstration at Ohio Edison's Niles Station Unit No. 2 achieved SO<sub>2</sub> removal efficiencies exceeding 95% and NO<sub>x</sub> reduction effectiveness averaging 94%. Ohio Edison is retaining the SNOX™ technology as part of its environmental control system.

## 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

### Location

Lorain, Lorain County, OH (Ohio Edison's Edgewater Station, Unit 4)

### Technology

The Babcock & Wilcox Company's (B&W) limestone injection multistage burner (LIMB) system; Babcock & Wilcox DRB-XCL® low-NO<sub>x</sub> burners

Consolidation Coal Company's Coolside duct injection of lime sorbents

### Plant Capacity/Production

105 MWe

### Coal

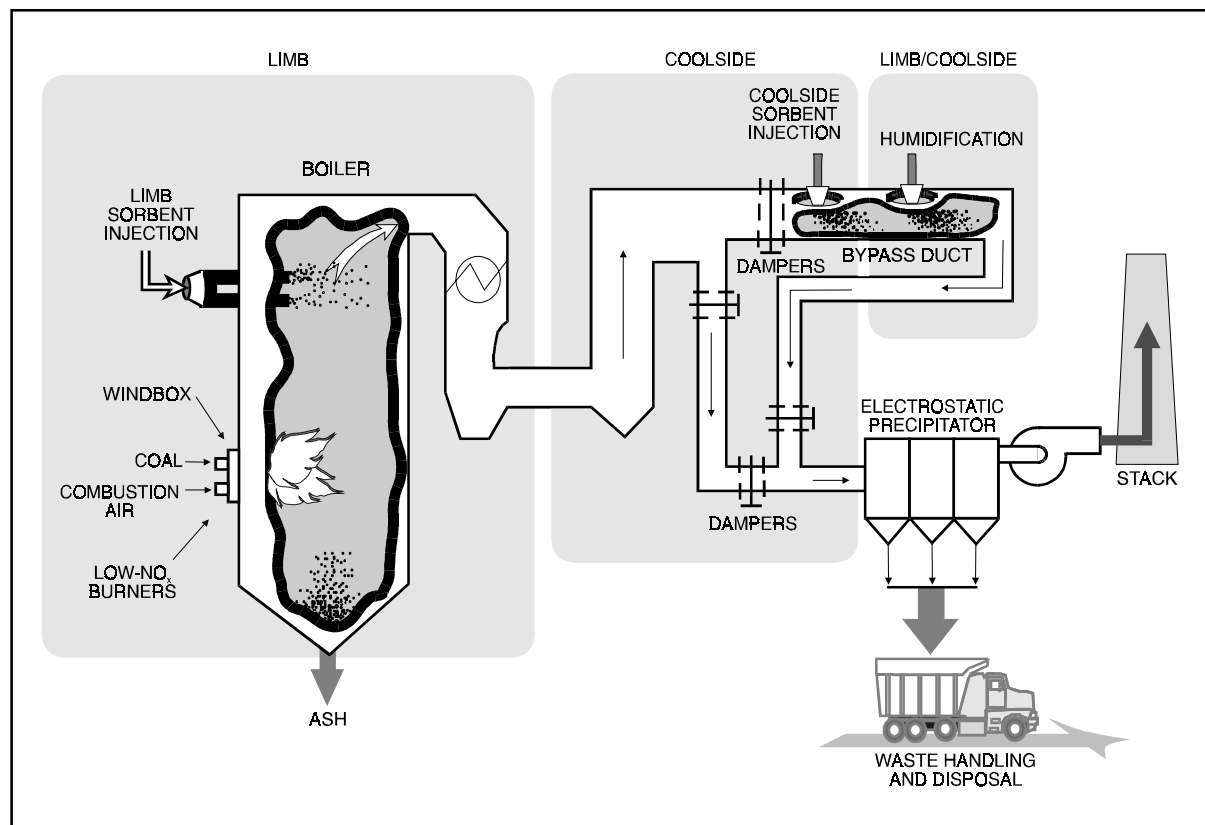
Ohio bituminous, 1.6%, 3.0%, and 3.8% sulfur

### Project Funding

Total project cost	\$19,404,940	100%
DOE	7,597,026	39
Participant	11,807,914	61

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

TAG is a trademark of the Electric Power Research Institute.



### Project Objective

To demonstrate, with a variety of coals and sorbents, the LIMB process as a retrofit system for simultaneous control of NO<sub>x</sub> and SO<sub>2</sub> in the combustion process, and that LIMB can achieve up to 70% NO<sub>x</sub> and SO<sub>2</sub> 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<sub>2</sub> removal of up to 70%.

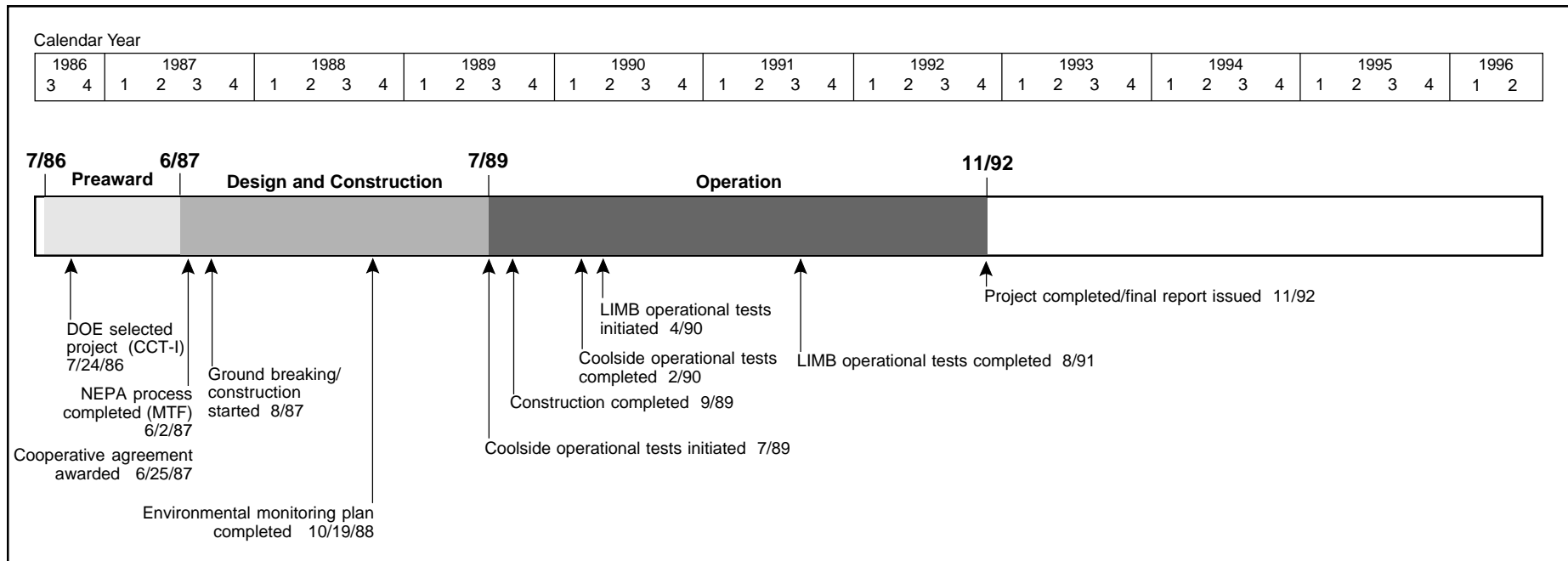
### Technology/Project Description

The LIMB process reduces SO<sub>2</sub> 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<sub>2</sub> removal. Combinations of three 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<sub>2</sub> absorption. SO<sub>2</sub> absorption is improved by dissolving NaOH or Na<sub>2</sub>CO<sub>3</sub> in the humidification water. The spent sorbent is collected with the fly ash, as in the LIMB process. Bituminous coal with 3.0% sulfur was used in testing.

Babcock & Wilcox DRB-XCL® low-NO<sub>x</sub> burners, which control NO<sub>x</sub> through staged combustion, were used in demonstrating both LIMB and Coolside technologies.



## Results Summary

### Environmental

- LIMB SO<sub>2</sub> removal efficiencies at a calcium-to-sulfur (Ca/S) molar ratio of 2.0 and minimal humidification across the range of coal sulfur contents were 53–61% for ligno lime, 51–58% for calcitic lime, 45–52% for dolomitic lime, and 22–25% for limestone ground to 80% less than 44 microns (325 mesh).
- LIMB SO<sub>2</sub> removal efficiency increased to 32% using limestone ground to 100% minus 325 mesh and increased an additional 5–7% when ground to 100% less than 10 microns.
- LIMB SO<sub>2</sub> removal efficiencies were enhanced by about 10% when humidification down to 20 °F approach-to-saturation temperature was used.
- LIMB, which incorporated Babcock & Wilcox DRB-XCL<sup>®</sup> low-NO<sub>x</sub> burners, achieved 40–50% NO<sub>x</sub> reduction.

- Coolside SO<sub>2</sub> removal efficiency was 70% at a Ca/S molar ratio of 2.0, a sodium-to-calcium (Na/Ca) ratio of 0.2, and 20 °F approach-to-adiabatic-saturation temperature using commercial hydrated lime and 2.8–3.0% sulfur coal.
- Sorbent recycle tests demonstrated the potential to improve sorbent utilization.

### Operational

- Humidification enhanced ESP performance, which enabled opacity levels to be kept well within limits.
- LIMB availability was 95%. Coolside did not undergo testing of sufficient length to establish availability.
- Humidifier performance indicated that operation in a vertical rather than horizontal mode would be better.

### Economic

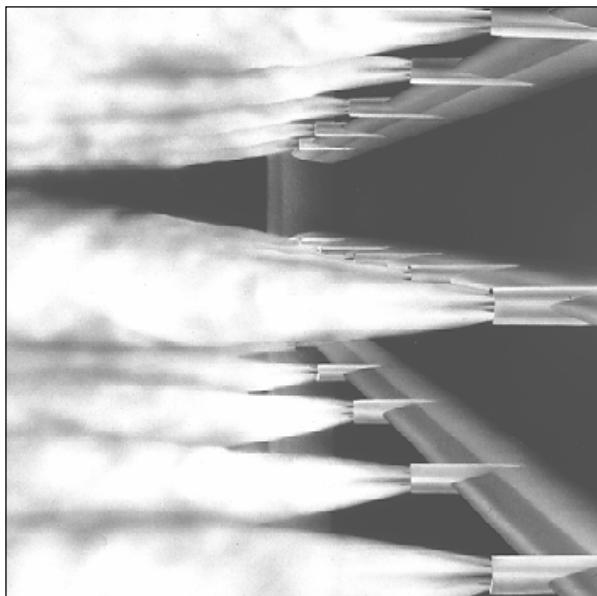
- LIMB capital costs were \$31–102/kW for plants 100–500 MWe and coals with 1.5–3.5% sulfur, with a target SO<sub>2</sub> reduction of 60%. Annual levelized costs (15-year) for this range of conditions were \$392–791/ton of SO<sub>2</sub> removed (1992\$).
- Coolside capital costs were \$69–160/kW for plants 100–500 MWe and coals with 1.5–3.5% sulfur, with a target SO<sub>2</sub> reduction of 70%. Annualized levelized costs (15-year) for this range of conditions were \$482–943/ton of SO<sub>2</sub> removed (1992\$).



## Project Summary

The initial expectation with LIMB technology was that limestone calcined by injection into the furnace would achieve adequate SO<sub>2</sub> capture. Use of limestone in lieu of the significantly more expensive lime would keep operating costs relatively low. However, the demonstration showed that even with fine grinding of the limestone and deep humidification, performance with limestone was marginal. As a result, a variety of hydrated limes were evaluated in the LIMB configuration, demonstrating enhanced performance. Although LIMB performance was enhanced by applying humidification to the point of approaching adiabatic saturation temperatures, performance did not rely on this deep humidification.

Coolside design was dependent upon deep humidification to improve sorbent reactivity and use of hydrated lime. Sorbent injection was downstream of the furnace. In addition, sorbent activity was enhanced by dissolving



▲ Water mist sprayed into the flue gas enhanced sulfur capture by the sorbent by approximately 10% in the LIMB process when 20 °F approach-to-saturation was used.

sodium hydroxide (NaOH) or sodium carbonate (Na<sub>2</sub>CO<sub>3</sub>) in the humidification water.

### Environmental Performance (LIMB)

LIMB 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% by weight. Each of four different sorbents was injected while burning each of the three different coals. Other variables examined were stoichiometry, humidifier outlet temperature, and injection level. Exhibit 5-26 summarizes SO<sub>2</sub> removal efficiencies for the range of sorbents and coals tested.

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 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% higher than that obtained at similar conditions for limestone with particles all sized less than 44 microns.

During the design phase, it was expected that injection at the 181-ft 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<sub>2</sub> removal. Injection was also performed at the 187-ft level and similar removals were observed. Removal efficiencies while injecting at these levels were about 5% higher than while injecting sorbent at the 191-ft level.

Removal efficiencies were enhanced by approximately 10% over the range of stoichiometries tested when humidification down to a 20 °F approach-to-saturation temperature was used.

## Exhibit 5-26 LIMB SO<sub>2</sub> Removal Efficiencies (Percent)

Sorbent	Nominal Coal Sulfur Content		
	3.8%	3.0%	1.6%
Ligno lime	61	63	53
Commercial calcitic lime	58	55	51
Dolomitic lime	52	48	45
Limestone (80% <44 microns)	NT	25	22

NT = Not tested  
Test conditions: injection at 181 ft, Ca/S of 2.0, minimal humidification.

The continued use of the low-NO<sub>x</sub> burners resulted in an overall average NO<sub>x</sub> emissions level of 0.43 lb/10<sup>6</sup> Btu, which is about a 45% reduction.

### Operational Performance (LIMB)

Long-term test data showed that the LIMB system was available about 95% of the time it was called upon to operate. Even with minimal humidification, ESP performance was adequately enhanced to keep opacity levels well below the permitted limit. Opacity was generally in the 2–5% range while the limit was 20%.

### Environmental Performance (Coolside)

The Coolside process was tested while burning compliance (1.2–1.6% sulfur) and noncompliance (2.8–3.2% sulfur) coals. 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.

**Exhibit 5-27**  
**Capital Cost Comparison**  
(\$/kW)

Coal (%S)	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO
	<b>100 MWe</b>			<b>150 MWe</b>		
1.5	93	150	413	66	116	312
2.5	95	154	421	71	122	316
3.5	102	160	425	73	127	324
	<b>250 MWe</b>			<b>500 MWe</b>		
1.5	46	96	228	31	69	163
2.5	50	101	235	36	76	169
3.5	54	105	240	40	81	174

**Exhibit 5-28**  
**Annual Levelized Cost Comparison**  
(\$/Ton of SO<sub>2</sub> Removed)

Coal (%S)	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO
	<b>100 MWe</b>			<b>150 MWe</b>		
1.5	791	943	1418	653	797	1098
2.5	595	706	895	520	624	692
3.5	525	629	665	461	570	527
	<b>250 MWe</b>			<b>500 MWe</b>		
1.5	549	704	831	480	589	623
2.5	456	567	539	416	502	411
3.5	419	526	413	392	482	321

The test program demonstrated that the Coolside process routinely achieved 70% SO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> removal with recycled sorbent alone was 22% at 0.5 available Ca/S and 18 °F approach-to-adiabatic-saturation. The observed SO<sub>2</sub> 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.

performance were SO<sub>2</sub> removal efficiencies of 60%, 70%, and 95% for LIMB, Coolside, and LSFO, respectively. EPRI TAG™ methodology was used. Exhibits 5-27 and 5-28 summarize results.

available hydrated lime. Coolside SO<sub>2</sub> 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<sub>2</sub> removal with recycled sorbent alone was 22% at 0.5 available Ca/S and 18 °F approach-to-adiabatic-saturation. The observed SO<sub>2</sub> 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.

**Operational Performance (Coolside)**

Floor deposits experienced in the ductwork with the horizontal humidification led designers to consider a vertical unit in a commercial configuration. Short-term testing did not permit evaluation of Coolside system availability.

**Economic Performance (LIMB & Coolside)**

Economic comparisons were made between LIMB, Coolside, and a wet scrubber with limestone injection and forced oxidation (LSFO). Assumptions on perfor-

**Commercial Application**

Both LIMB and Coolside technologies are applicable to most utility and industrial coal-fired units and provide alternatives to conventional wet flue gas desulfurization processes. LIMB and Coolside can be retrofitted with modest capital investment and downtime, and their space requirements are substantially less than for conventional flue gas sulfurization processes.

**Contacts**

Paul Nolan, (216) 860-1074  
The Babcock & Wilcox Company  
P.O. Box 351  
Barberton, OH 44203-0351  
Lawrence Saroff, DOE/HQ, (301) 903-9483  
James U. Watts, FETC, (412) 892-5991

**References**

- 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 DE93005979.)
- 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 DE93001722.)
- *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*. Report No. DOE/PC/79798-T2. The Babcock & Wilcox Company. December 1988. (LIMB/Coolside demonstration.) (Available from NTIS as DE92016131.)
- *Comprehensive Report to Congress on the Clean Coal Technology Program: LIMB Demonstration Project Extension*. The Babcock & Wilcox Company. Report No. DOE/FE-0085. U.S. Department of Energy. April 1987. (Available from NTIS as DE87009793.)

## SO<sub>x</sub>-NO<sub>x</sub>-Rox Box™ Flue Gas Cleanup Demonstration Project

**Project completed.**

### Participant

The Babcock & Wilcox Company

### Additional Team Members

Ohio Edison Company—cofunder and host  
 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 SO<sub>x</sub>-NO<sub>x</sub>-Rox Box™ (SNRB™) process

### Plant Capacity/Production

5-MWe equivalent slipstream from a 156-MWe boiler

### Coal

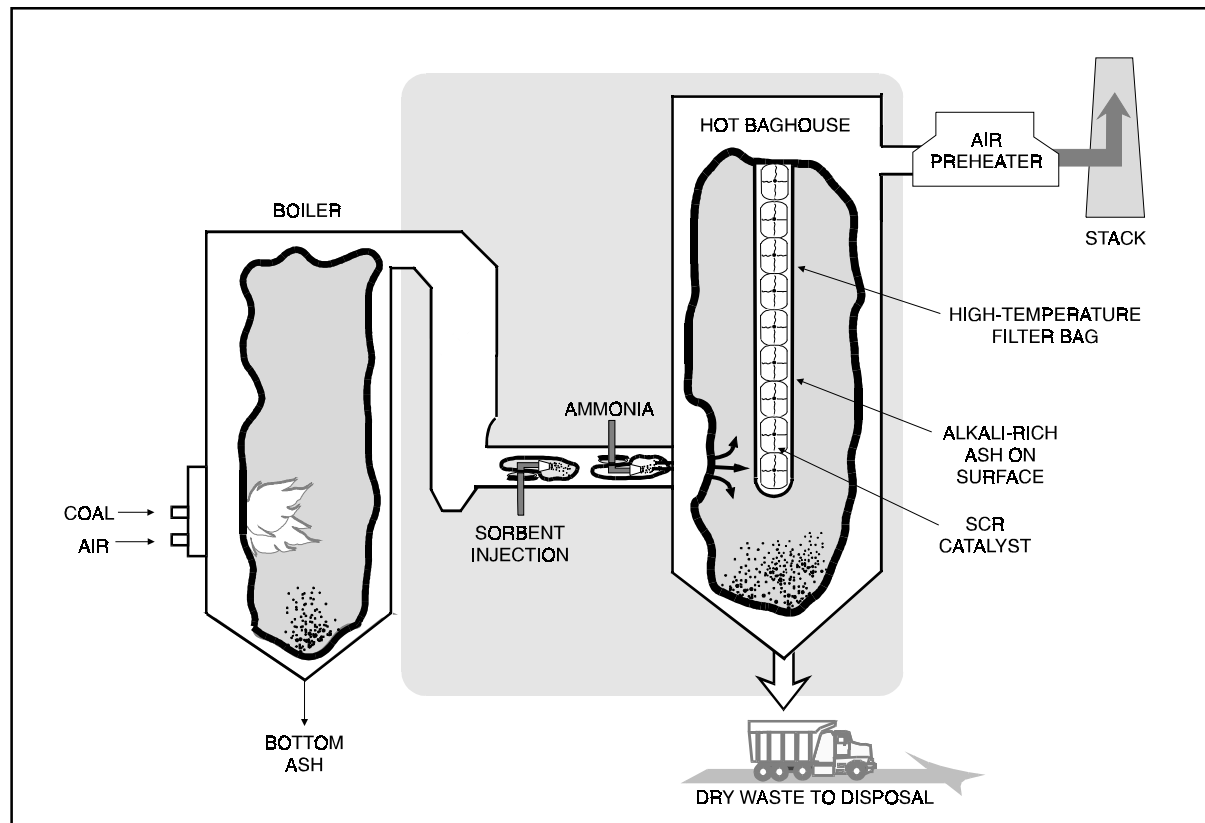
Bituminous coal blend, 3.7% sulfur avg

### Project Funding

Total project cost	\$13,271,620	100%
DOE	6,078,402	46
Participant	7,193,218	54

### Project Objective

To achieve greater 70% SO<sub>2</sub> removal and 90% or higher reduction in NO<sub>x</sub> emissions while maintaining particulate emissions below 0.03 lb/10<sup>6</sup> Btu.



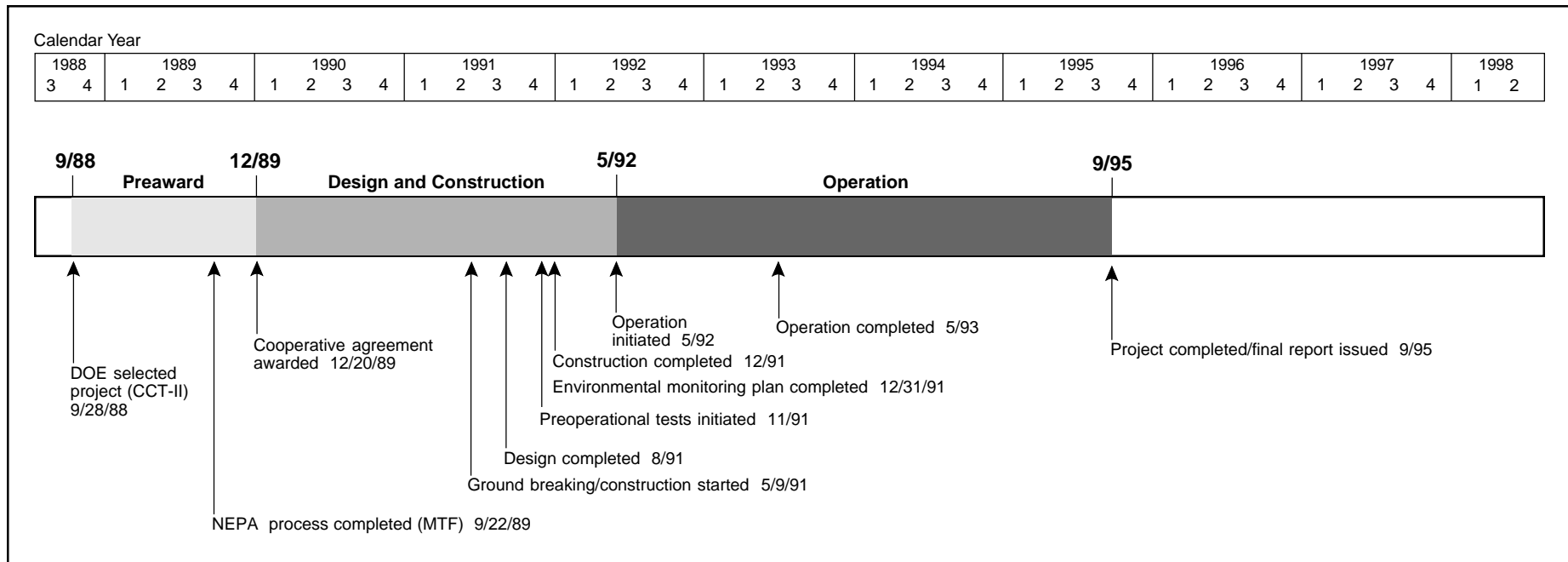
### Technology/Project Description

The SNRB™ process combines the removal of SO<sub>2</sub>, NO<sub>x</sub>, and particulates in one unit—a high-temperature baghouse. SO<sub>2</sub> removal is accomplished using either calcium- or sodium-based sorbent injected into the flue gas. NO<sub>x</sub> removal is accomplished by injecting ammonia (NH<sub>3</sub>) to selectively reduce NO<sub>x</sub> 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 SNRB™ process was operated for approximately 2,300 hours. Through this effort, SNRB™ demonstrated the technical and economic feasibility of achieving more than 80% SO<sub>2</sub> removal, more than 90% NO<sub>x</sub> removal, and 99% particulate removal at lower capital, operating, and maintenance costs than those for a combination of conventional systems. The demonstration was conducted at Ohio Edison Company's R.E. Burger Plant, Unit No. 5, in Dilles Bottom, OH.



## Results Summary

### Environmental

- SO<sub>2</sub> removal efficiency of 80% was achieved with commercial-grade lime at a calcium-to-sulfur (Ca/S) molar ratio of 2.0 and temperature of 800–850 °F.
- SO<sub>2</sub> removal efficiency of 90% was achieved with sugar hydrated and lignosulfonate hydrated lime at a Ca/S ratio of 2.0 and temperature of 800–850 °F.
- SO<sub>2</sub> removal efficiency of 80% was achieved with sodium bicarbonate at a sodium-to-sulfur (Na<sub>2</sub>/S) molar ratio of 1.0 and temperature of 425 °F.
- SO<sub>2</sub> emissions were reduced to less than 1.2 lb/10<sup>6</sup> Btu with 3–4% sulfur coal with a Ca/S molar ratio as low as 1.5 and Na<sub>2</sub>/S ratio of 1.0.
- Injection of calcium-based sorbents directly upstream of the baghouse at 825–900 °F resulted in higher overall SO<sub>2</sub> removal than injection further upstream at temperatures up to 1,200 °F.

- NO<sub>x</sub> reduction of 90% was achieved with an NH<sub>3</sub>/NO<sub>x</sub> ratio of 0.9 and temperature of 800–850 °F.
- Air toxic removal efficiency was comparable to that of an electrostatic precipitator (ESP), except that hydrogen fluoride (HF) was reduced by 84% and hydrogen chloride (HCl) by 95%.

### Operational

- Calcium utilization was 40–45% for SO<sub>2</sub> removals of 85–90%.
- Norton Company's NC-300 zeolite SCR catalyst showed no appreciable physical degradation or change in catalyst activity over the course of the demonstration.
- No excessive wear or failures occurred with the filter bags tested: 3M's Nextel ceramic fiber filter bag and Owens Corning Fiberglas's S-Glass filter bag.

### Economic

- Capital cost for a 250-MWe retrofit was \$233/kW, assuming 3.5% sulfur coal and baseline NO<sub>x</sub> generation of 1.2 lb/10<sup>6</sup> Btu.

## Project Summary

SNRB™ incorporates two successful technology development efforts that offer distinct advantages over other control technologies. High-temperature filter bags and circular monolith catalyst developments enabled multiple emission control in a single component with a low plant-area space requirement. As a postcombustion control system, it is simple to operate. The high-temperature bag provides a clean, high-temperature environment compatible with effective SCR operation and a surface for enhanced SO<sub>2</sub>/sorbent contact (creates a sorbent cake on the surface). Particulate control, which is receiving increasing attention, is typical of the superior performance offered by pulsed jet baghouses.

## Environmental Performance

Four different sorbents were tested for SO<sub>2</sub> capture. Calcium-based sorbents included commercial-grade-hydrated lime, sugar-hydrated lime, and lignosulfonate-hydrated lime. In addition, sodium bicarbonate was tested. The optimal location for injecting the sorbent into the flue gas was immediately upstream of the baghouse. Effectively, the SO<sub>2</sub> was captured by the sorbent in the form of a filter cake on the filter bags (along with fly ash).

With the baghouse operating above 830 °F, injection of commercial-grade hydrated lime at Ca/S molar ratio of 1.8 and above resulted in SO<sub>2</sub> removals of over 80%. At a Ca/S of molar ratio of 2.0, performance of the sugar-hydrated lime and lignosulfonate-hydrated lime increased performance by approximately 8%, for overall removal of approximately 90%. SO<sub>2</sub> removal of 85–90% was obtained with calcium utilization of 40–45%. Injection of the calcium-based sorbents directly upstream of the baghouse at 825–900 °F resulted in higher overall SO<sub>2</sub> removal than injection further upstream at temperatures up to 1,200 °F.

SO<sub>2</sub> removal using sodium bicarbonate was 80% at an Na<sub>2</sub>/S ratio of 1.0 and 98% at an Na<sub>2</sub>/S ratio of 2.0 at a significantly reduced baghouse temperature of 450–460 °F. SO<sub>2</sub> emissions while burning a 3–4% sulfur

coal were reduced to less than 1.2 lb/10<sup>6</sup> Btu with a Ca/S molar ratio as low as 1.5 and Na<sub>2</sub>/S ratio less than 1.0.

To capture NO<sub>x</sub>, ammonia was injected between the sorbent injection point and the baghouse. The ammonia and NO<sub>x</sub> 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.



▲ The demonstration baghouse is installed on the back side of the power plant. Workers stand by the catalyst holder tube prior to lifting it into the penthouse.

NO<sub>x</sub> emissions reduction of 90% was readily achieved with ammonia slip limited to less than 5 ppm. This performance reduced NO<sub>x</sub> emissions to less than 0.10 lb/10<sup>6</sup> Btu. NO<sub>x</sub> 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<sub>x</sub> removal over the range evaluated.

Turndown capability for tailoring the degree of NO<sub>x</sub> reduction by varying the rate of ammonia injection was demonstrated for a range of 50–95% NO<sub>x</sub> 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<sub>2</sub> to SO<sub>3</sub> over the zeolite catalyst appeared to be less than 0.5%. (SO<sub>2</sub> 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.

Particulate emissions were consistently below NSPS standards of 0.03 lb/10<sup>6</sup> Btu, with an average over 30 baghouse particulate emission measurements of 0.018 lb/10<sup>6</sup> Btu, which corresponds to a collective efficiency of 99.89%. Hydrated lime injection increased the baghouse inlet particulate loading from 5.6 to 16.5 lb/10<sup>6</sup> Btu. Emissions 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 lb/in<sup>2</sup> 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. 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. Measurements of mercury speciation, dioxins, and furans were unique

features of this test program. The emissions control efficiencies achieved for various air toxics by the SNRB™ system were generally comparable to those of the conventional ESP at the power plant. However, the SNRB™ system did reduce HCl by an average of 95% and HF emissions by an average of 84%, whereas the ESP had no effect on these constituents.

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). Also, the solids potentially could be used as a partial cement replacement to lower the cost of concrete.

### Operational Performance

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.

### Economic Performance

For a 250-MWe boiler fired with 3.5% sulfur coal and NO<sub>x</sub> emissions of 1.2 lb/10<sup>6</sup> Btu, the projected capital cost of an SNRB™ system is approximately \$233/kW including various 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. Variable operating costs are dominated by the cost of the SO<sub>2</sub> sorbent for a system designed for 85–90% SO<sub>2</sub> removal. Fixed operating costs primarily consist of system operating labor and projected labor and material for the hot baghouse and ash-handling systems.

### Commercial Applications

Commercialization of the technology is expected to develop with an initial larger scale application equivalent to 50–100 MWe. The focus of marketing efforts is being 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 that can be tailored to maximize control of SO<sub>2</sub>, NO<sub>x</sub>, or combined emissions to meet current performance requirements while providing flexibility to address future needs.

### Contacts

Kevin Redinger, (330) 829-7719

The Babcock & Wilcox Company  
1562 Beeson Street  
Alliance, OH 44601

Lawrence Saroff, DOE/HQ, (301) 903-9483

John C. McDowell, FETC, (412) 892-6237

### References

- *SO<sub>x</sub>-NO<sub>x</sub>-Rox Box™ Flue Gas Cleanup Demonstration Final Report*. Report No. DOE/PC/89656-T1. The Babcock & Wilcox Company. September 1995. (Available from NTIS as DE96003839.)
- *5 MWe SNRB™ Demonstration Facility: Detailed Design Report*. The Babcock & Wilcox Company. November 1992.
- *Comprehensive Report to Congress on the Clean Coal Technology Program: SO<sub>x</sub>-NO<sub>x</sub>-Rox Box™ Flue Gas Cleanup Demonstration Project*. The Babcock & Wilcox Company. Report No. DOE/FE-0145. U.S. Department of Energy. November 1989. (Available from NTIS as DE90004458.)



▲ Workers lower one of the catalyst holder tubes into a mounting plate in the penthouse of the high-temperature baghouse.

## 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 Commerce & Community Affairs—cofunder

Illinois Power Company—host

City Water, Light and Power—host

### 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 (GR-SI) process

### Plant Capacity/Production

Hennepin: tangential-fired 80 MWe (gross), 71 MWe (net)

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

### Coal

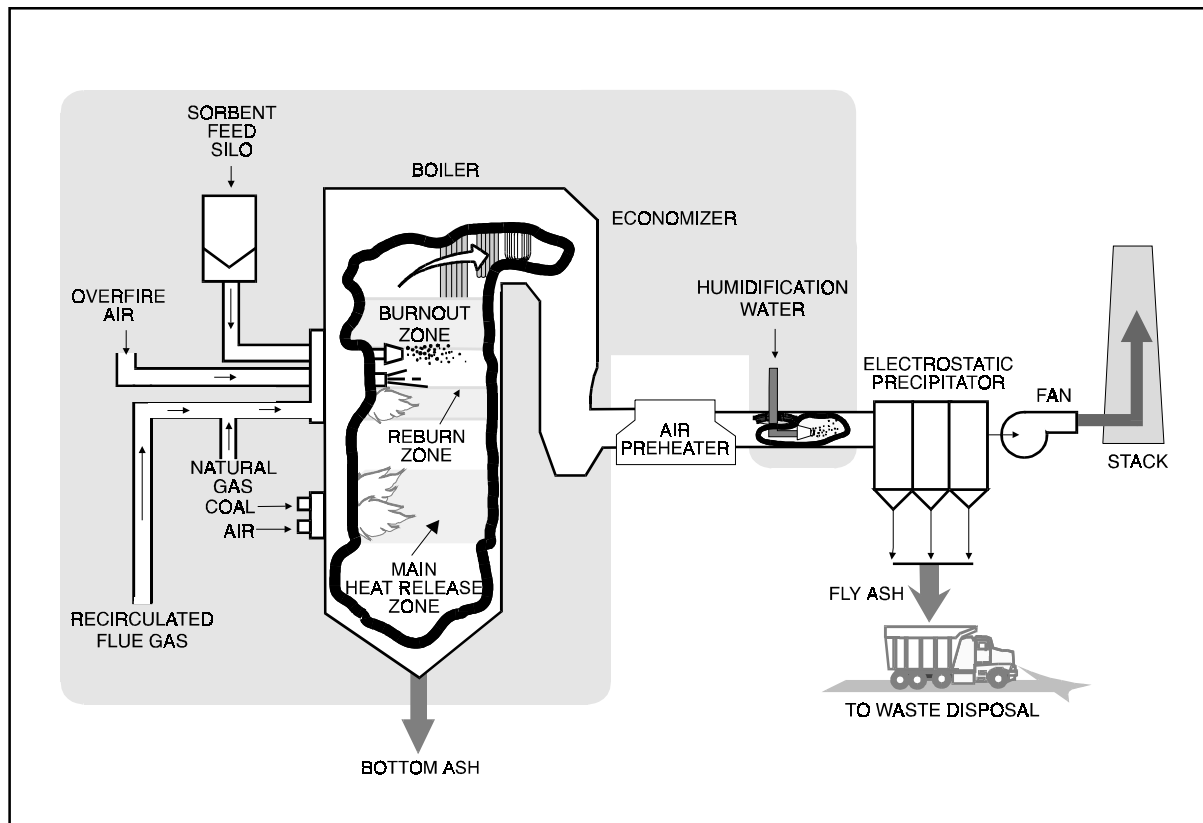
Illinois bituminous, 3.0% sulfur

### Project Funding

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

### Project Objective

To demonstrate gas reburning to attain at least 60% NO<sub>x</sub> reduction along with sorbent injection to capture at least



50% of the SO<sub>2</sub> on two different boiler configurations—tangentially fired and cyclone-fired—while burning high-sulfur midwestern coal.

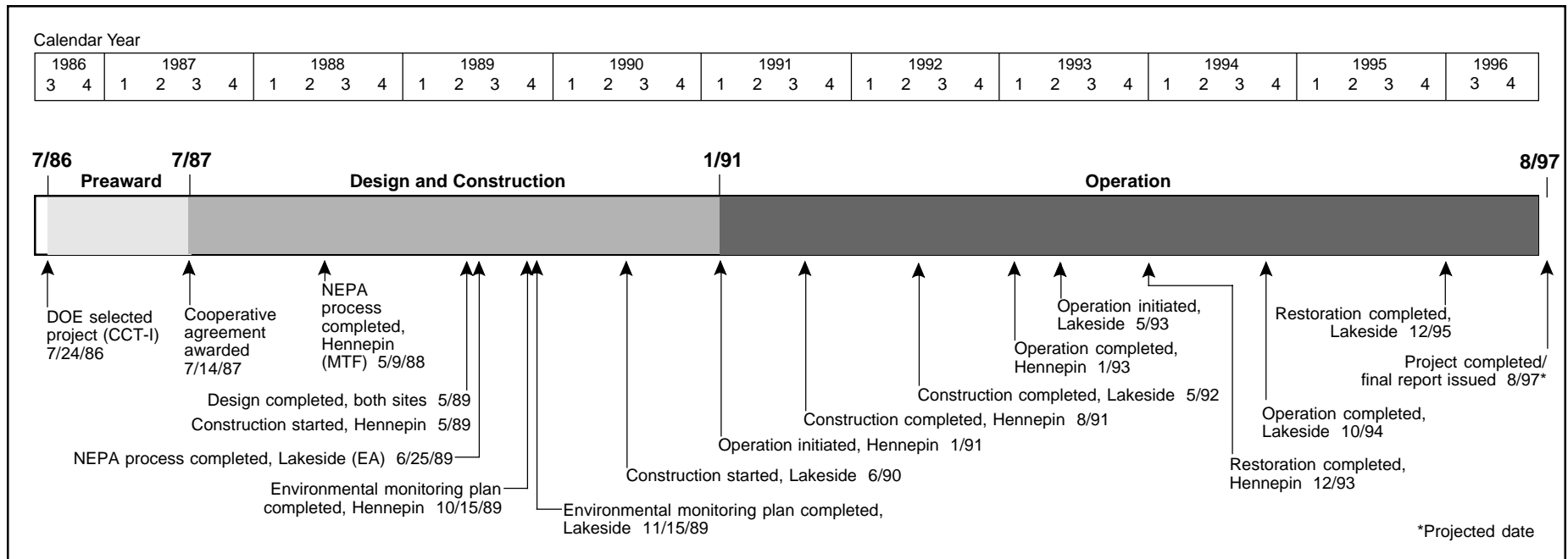
### Technology/Project Description

In this process, 80–85% of the fuel was coal and was supplied to the main combustion zone. The remaining 15–20% of the fuel, provided by natural gas, bypassed the main combustion zone and was injected above the main burners to form a reducing (reburning) zone in which NO<sub>x</sub> was converted to nitrogen. A calcium compound (sorbent) was injected in the form of dry, fine particulates above the reburning zone in the boiler. The calcium compound tested was Ca(OH)<sub>2</sub> (lime). This project demonstrated the 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.

A comprehensive test program was conducted at each of the two sites, operating the equipment over a wide range of boiler conditions. Over 1,500 hours of operation was achieved, enabling a substantial amount of data to be obtained. Intensive measurements were taken to quantify the reductions in NO<sub>x</sub> and SO<sub>2</sub> emissions, the impact on boiler equipment and operability, and all factors influencing costs.

PromiSORB is a trademark of Energy and Environmental Research Corporation.



## Results Summary

### Environmental

- On the tangentially fired boiler, GR-SI NO<sub>x</sub> reductions of up to 75% were achieved, and an average 67% reduction was realized at an average gas heat input of 18%.
- GR-SI SO<sub>2</sub> removal efficiency on the tangentially fired boiler averaged 53% with hydrated lime at a calcium-to-sulfur (Ca/S) molar ratio of 1.75 (corresponding to a sorbent utilization of 24%).
- On the cyclone-fired boiler, GR-SI NO<sub>x</sub> reductions of up to 74% were achieved, and an average 66% reduction was realized at an average gas heat input of 22%.
- GR-SI SO<sub>2</sub> removal efficiency on the cyclone-fired boiler averaged 58% with hydrated lime at a Ca/S molar ratio of 1.8 (corresponding to a sorbent utilization of 24%).

- Particulate emissions were not a problem on either unit undergoing demonstration, but humidification had to be introduced at Hennepin to enhance ESP performance.
- Three advanced sorbents tested achieved higher SO<sub>2</sub> capture efficiencies than the baseline Linwood hydrated lime. PromiSORB™ A achieved 53% SO<sub>2</sub> capture efficiency and 31% utilization without GR at a Ca/S molar ratio of 1.75. Under the same conditions, PromiSORB™ B achieved 66% SO<sub>2</sub> reduction and 38% utilization, and High-Surface-Area Hydrated Lime achieved 60% SO<sub>2</sub> reduction and 34% utilization.

### Operational

- Boiler efficiency decreased by approximately 1% as a result of increased moisture formed in combustion from natural gas use.
- There was no change in boiler tube wastage, tube metallurgy, or projected boiler life.

### Economic

- Capital cost for gas reburning (GR) was approximately \$15/kW plus the gas pipeline cost, if not in place.
- Operating costs for GR were related to the gas/coal cost differential and the value of SO<sub>2</sub> emission allowances (because GR replaces some coal with gas, it also reduces SO<sub>2</sub> emissions).
- Capital cost for sorbent injection (SI) was approximately \$50/kW.
- Operating costs for SI were dominated by the cost of sorbent and sorbent/ash disposal costs. SI was estimated to be competitive at \$300/ton of SO<sub>2</sub> removed.



## Project Summary

The GR-SI project demonstrated the success of gas reburning and sorbent injection technologies in reducing  $\text{NO}_x$  and  $\text{SO}_2$  emissions. The process design conducted early in the project combined with the vast amount of data collected during the testing created a database capable of applying the technology to all major coal-firing configurations (tangential-, cyclone-, and wall-fired) on both utility and industrial units. The emissions control and performance can be accurately projected as can the capital and operating costs.

### Environmental Performance (Hennepin)

Operational testing, which included optimization testing and long-term testing, was conducted between January 1991 and January 1993. 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 long-term demonstration testing, the average  $\text{NO}_x$  reduction was approximately 67%. The average  $\text{SO}_2$  removal efficiency was over 53% at a Ca/S molar ratio of 1.75. (Linwood hydrated lime was used throughout these tests except for a few days when Marblehead lime was used.) CO emissions were below 50 ppm in most cases but were higher during operation at low load.

A significant reduction in  $\text{CO}_2$  was also measured. This was due to partial replacement of coal with natural gas having a lower C/H ratio. This cofiring with 18% natural gas resulted in a theoretical  $\text{CO}_2$  emissions reduction of nearly 8% from the coal-fired baseline level. With flue gas humidification, electrostatic precipitator (ESP) collection efficiencies greater than 99.8% and particulate

emissions less than  $0.025 \text{ lb}/10^6 \text{ Btu}$  were measured even with an increase in inlet particulate loading resulting from sorbent injection. These levels were comparable to measured baseline emissions of  $0.035 \text{ lb}/10^6 \text{ Btu}$  and a collection efficiency greater than 99.5%.

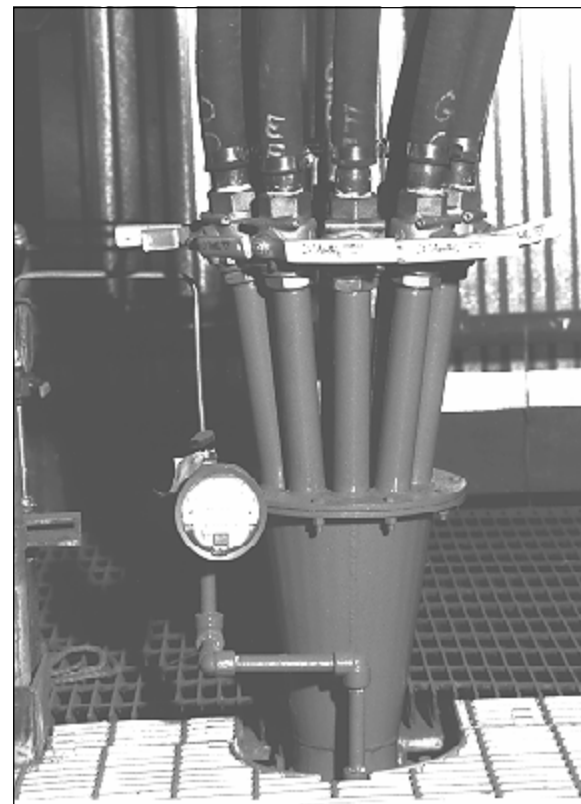
Following the completion of the long-term tests, three specially prepared sorbents were tested. Two were manufactured by the participant and contained proprietary additives to increase their reactivity toward  $\text{SO}_2$  and were referred to as PromiSORB™ A and B. The Illinois State Geological Survey developed the other sorbent—High-Surface-Area Hydrated Lime in which alcohol is used to form a material that gives rise to a much higher surface area than that of conventionally hydrated limes.

The  $\text{SO}_2$  capture without GR, at a nominal 1.75 Ca/S molar ratio, was 53% for PromiSORB™ A, 66% for PromiSORB™ B, 60% for High-Surface-Area Hydrated Lime, and 42% for Linwood lime. At a 2.6 Ca/S molar ratio, the PromiSORB™ B yielded 81%  $\text{SO}_2$  removal efficiency.

### Environmental Performance (Lakeside)

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%. The GR parametric tests achieved a  $\text{NO}_x$  reduction of approximately 60% at a gas heat input of 22–23%. Additional flow modeling and computer modeling studies indicated that smaller reburning fuel jet nozzles could increase reburning fuel mixing and thus improve the  $\text{NO}_x$  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  $\text{SO}_2$  reduction level varied with load because of the effect of temperature on the sulfation reaction. At a Ca/S of 2.0, 44%  $\text{SO}_2$  reduction was achieved at full load (33 MWe); 38%  $\text{SO}_2$  reduction was achieved at mid-load (25 MWe); and 32%  $\text{SO}_2$  reduction was achieved at low load (20 MWe).



▲ The flexible lime-sorbent distribution lines lead from the sorbent splitter to the top of the cyclone-fired boiler at Lakeside Station.

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% to increase the reburning jet's penetration characteristics. The decrease in nozzle diameter increased  $\text{NO}_x$  reduction by an additional 3–5% compared to the initial parametric tests. With GR-SI, total  $\text{SO}_2$  reductions resulted from partial replacement of coal with natural gas and sorbent injection. At a gas heat input of 22% and Ca/S molar ratio of 1.8, average  $\text{NO}_x$  reduction

during the long-term testing of GR-SI was 66% and the average SO<sub>2</sub> reduction was 58%.

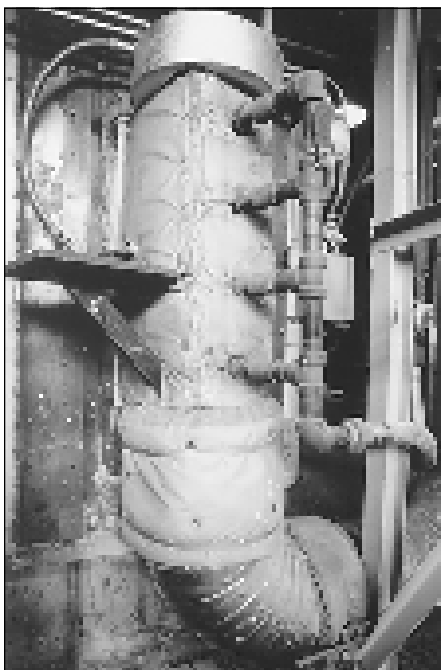
### Operational Performance (Hennepin/Lakeside)

Sorbent injection increased the frequency of sootblower operation but did not adversely affect boiler efficiency or equipment performance. Gas reburning decreased boiler efficiency by approximately 1.0% because of the increase in moisture formed with combustion of natural gas. Examination of the boiler before and after testing showed no measurable change in tube wear or metallurgy. Essentially, the scheduled life of the boiler was not compromised.

The ESPs adequately accommodated the changes in ash loading and resistivity with the presence of sorbent in the ash. No adverse conditions were found to exist. But as mentioned, humidification had to be added at Hennepin to achieve acceptable ESP performance with GR-SI.

### Economic Performance (Hennepin/Lakeside)

Capital and operating costs depend largely on site-specific factors, such as gas availability at the site, coal/gas cost differential, SO<sub>2</sub> removal requirements, and value of SO<sub>2</sub> allowances. It was estimated that for most installation, a 15% gas heat input will achieve 60% NO<sub>x</sub> reduction. The capital cost for such a GR installation was estimated at \$15/kW for 100-MWe and larger plants plus the cost of the gas pipeline (if required). Operating costs were almost entirely related to the differential cost of the gas over the coal as reduced by the value of SO<sub>2</sub> emission allowances.



▲ The natural gas injector was installed on the corner of Hennepin Station's tangentially fired boiler.

The capital cost estimate for SI was \$50/kW. Operating costs for SI were dominated by the cost of the sorbent and sorbent/ash disposal costs. SI was projected to be cost competitive at \$300/ton of SO<sub>2</sub> removed.

### Commercial Applications

The GR-SI process is a 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 more than 900 pre-NSPS utility boilers; the technologies also can be applied to new utility boilers. With NO<sub>x</sub> and SO<sub>2</sub> 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.

### Contacts

Blair A. Folsom, Senior Vice President, (714) 859-8851  
Energy and Environmental Research Corporation  
18 Mason  
Irvine, CA 92718  
Lawrence Saroff, DOE/HQ, (301) 903-9483  
Jerry L. Hebb, FETC, (412) 892-6079

### References

- *Enhancing the Use of Coals by Gas Reburning-Sorbent Injection; Long Term Testing Period, September 1, 1991-January 15, 1993.* Report No. DOE/PC/79796-T40. Energy and Environmental Research Corporation. February 1995. (Available from NTIS as DE95011481.)
- *Enhancing the Use of Coals by Gas Reburning and Sorbent Injection; Volume 2: Gas Reburning-Sorbent Injection at Hennepin Unit 1, Illinois Power Company.* Report No. DOE/PC/79796-T38-Vol. 2. Energy and Environmental Research Corporation. October 1994. (Available from NTIS as DE95009448.)
- *Enhancing the Use of Coals by Gas Reburning and Sorbent Injection; Volume 3: Gas Reburning-Sorbent Injection at Edwards Unit 1, Central Illinois Light Company.* Report No. DOE/PC/79796-T38-Vol. 3. Energy and Environmental Research Corporation. October 1994. (Available from NTIS as DE95009447.)
- *Clean Coal Technology: Reduction of NO<sub>x</sub> and SO<sub>2</sub> Using Gas Reburning, Sorbent Injection, and Integrated Technologies.* Topical Report No. 3, Revision 1. U.S. Department of Energy and Energy and Environmental Research Corporation. September 1993. (Available from NTIS as DE94007444.)
- *Comprehensive Report to Congress on the Clean Coal Technology Program: Enhancing the Use of Coals by Gas Reburning and Sorbent Injection.* Energy and Environmental Research Corporation. Report No. DOE/FE-0087. U.S. Department of Energy. May 1987. (Available from NTIS as DE87010815.)

## 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 of 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<sub>x</sub> Concentric Firing System (LNCFS™) Level III; Nalco Fuel Tech's NOxOUT® urea injection system; Stebbins' tile-lined split-module absorber; and ABB Air Preheater's heat-pipe air-heater system

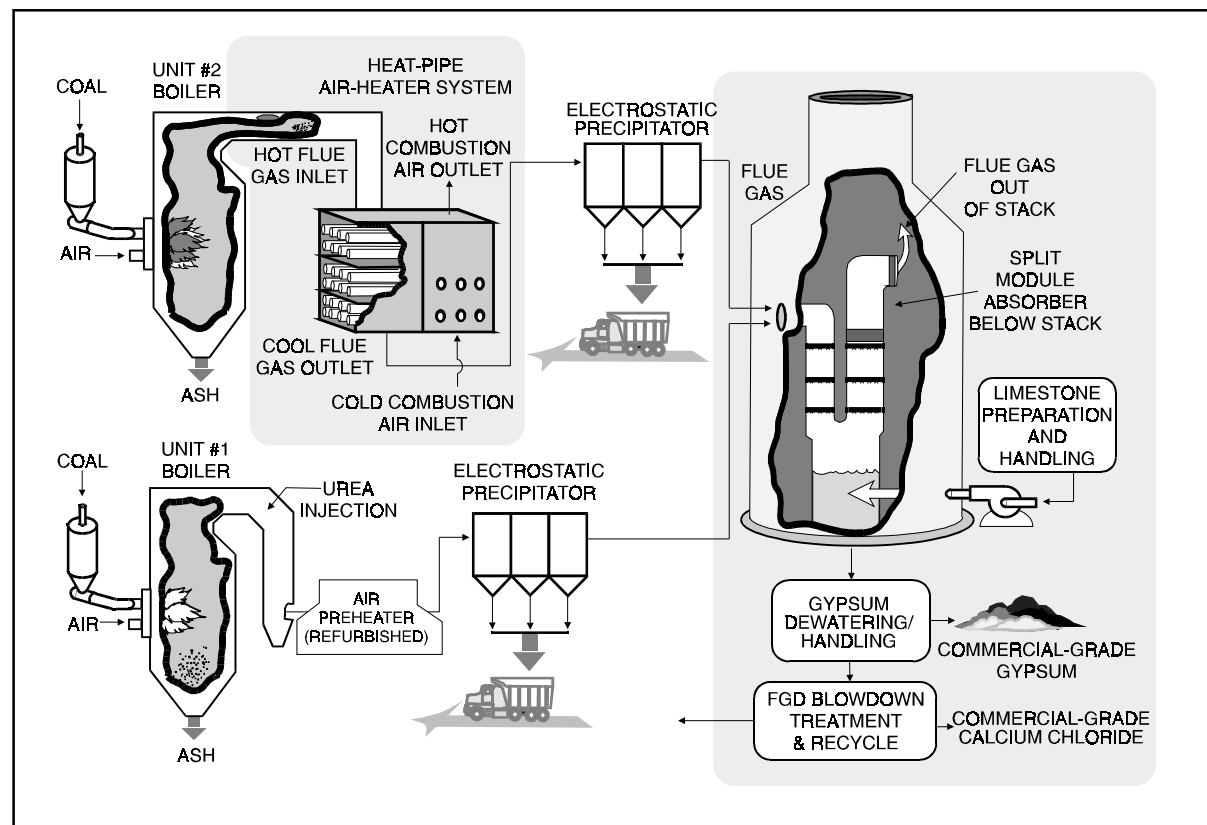
### Plant Capacity/Production

300 MWe

NOxOUT is a registered trademark of Nalco Fuel Tech.

LNCFS is a trademark of ABB Combustion Engineering, Inc.

PEOA is a trademark of DHR Technologies, Inc.



### 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<sub>2</sub> removal in a Stebbins tile-lined scrubber, low-NO<sub>x</sub> burner, urea injection for NO<sub>x</sub> removal, and a heat-pipe air preheater.

### Technology/Project Description

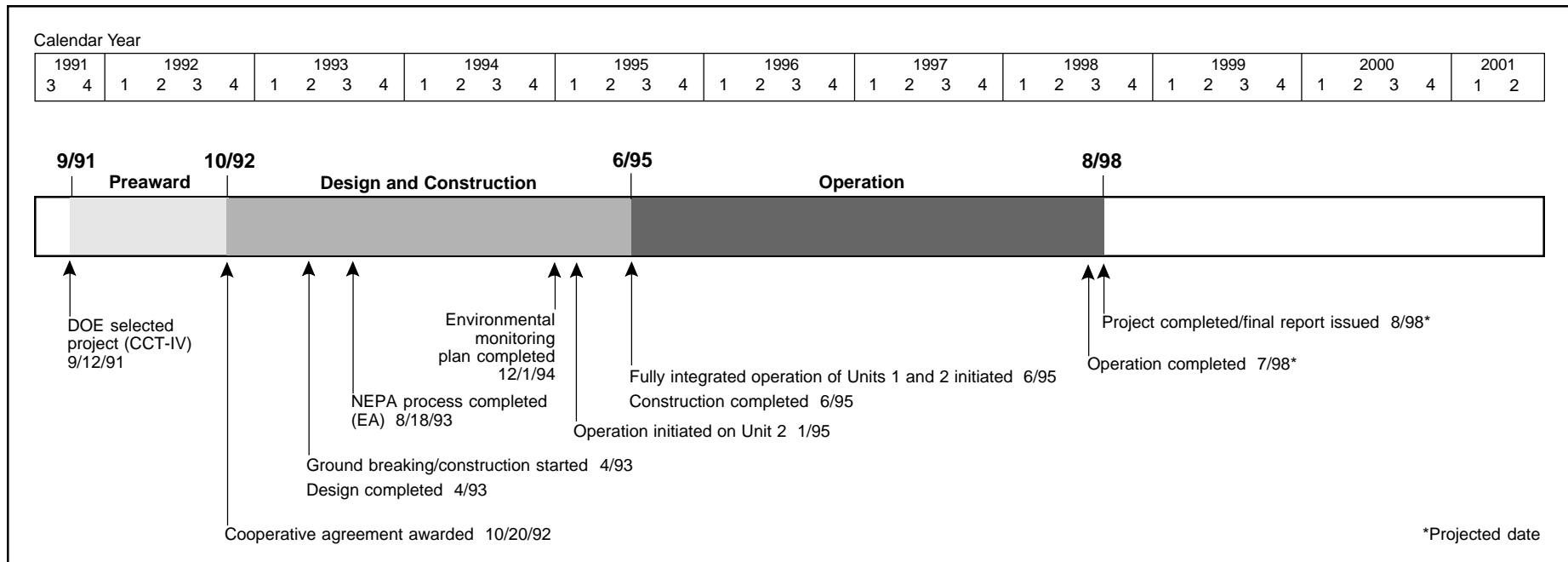
The S-H-U wet flue gas desulfurization process is a formic-acid-enhanced, wet limestone process, which results

in very high SO<sub>2</sub> 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 below the stack to save space and provide operational flexibility.

The Nalco Fuel Tech NOxOUT® system is used to remove NO<sub>x</sub> by injecting urea into the boiler flue gas. This facet of the project, in conjunction with other combustion modifications, including LNCFS™ Level III (low-NO<sub>x</sub> burner system), reduces NO<sub>x</sub> emissions and produces marketable fly ash.

A heat-pipe air-heater system by ABB Air Preheater, Inc., reduces both air leakage and the air heater's flue gas



exit temperature. DHR Technologies, Inc., is providing a state-of-the-art boiler and plant artificial-intelligence-based control system, PEOA™, to enhance emissions reductions and boiler efficiencies.

The project has been 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 has been designed to achieve at least a 95% SO<sub>2</sub> removal efficiency (or up to 98%) using limestone while burning high-sulfur coal. NO<sub>x</sub> reductions have been achieved using selective noncatalytic reduction technology and separate combustion modifications. NO<sub>x</sub> emissions have been reduced from 0.65 to 0.40 lb/10<sup>6</sup> Btu (38%) by retrofitting the two boilers with low-NO<sub>x</sub> burners. NOxOUT® is expected to reduce NO<sub>x</sub> emissions from Unit 1 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.

Pittsburgh, Freeport, and Kittanning coals, with sulfur contents of 1.5%, 2.9%, and 4.0%, are being used in the demonstration.

### Project Status/Accomplishments

The split module scrubber at Milliken Station began scrubbing operations for Unit 2 in January 1995. Full plant operation with Unit 1 incorporated into the split-module scrubber began in June 1995.

Heat pipe performance testing at various loads was completed in July 1996. Further testing on a cleaned heat pipe was completed in November 1996. Test data are being compiled, and a report is being prepared.

Design coal FGD testing began in May 1996. However, the sulfur content of coal received was below design specifications for the scrubber. Testing was halted in September 1996 due to plugging of some slurry spray nozzles. Milliken does not expect to receive any coal with the design sulfur percentage until late summer 1997. Testing has been delayed until design coal can be delivered, after which testing will continue for 6 months.

Mist eliminator testing is complete; a report is expected to be issued in mid-1997.

### Commercial Applications

The S-H-U SO<sub>2</sub> removal process, the Nalco NOxOUT® noncatalytic reduction process, Stebbins’ tile-lined split-module absorber, and ABB Air Preheater’s heat-pipe air-heater technology are applicable to virtually all power plants, in both retrofit and greenfield applications, at any size. The space-saving design features of the technologies, combined with the production of marketable by-products, offer significant incentives to generating stations with limited space.

Wheelabrator is marketing NOxOUT® through a license agreement with Nalco Fuel Tech. DHR Technologies’ Plant Emission Optimization Advisor (PEOA™) has been sold to City Public Service in San Antonio, TX; three bids are outstanding in Korea and one in Israel.

## Commercial Demonstration of the NOXSO SO<sub>2</sub>/NO<sub>x</sub> Removal Flue Gas Cleanup System

### Participant

NOXSO Corporation

### Additional Team Members

Olin Corporation—cofunder and host  
 Gas Research Institute—cofunder  
 Electric Power Research Institute—cofunder  
 W.R. Grace and Company—cofunder  
 Morrison Knudsen-Ferguson—engineer  
 Calabrian Corporation—burn-in-oxygen technology supplier  
 Advanced Petrogas Systems—liquid SO<sub>2</sub> plant fabrication

### Location

NOXSO Plant: site under negotiation  
 SO<sub>2</sub> Plant: Charleston, Bradley County, TN (Olin Corporation's Chlor-alkali facility)

### Technology

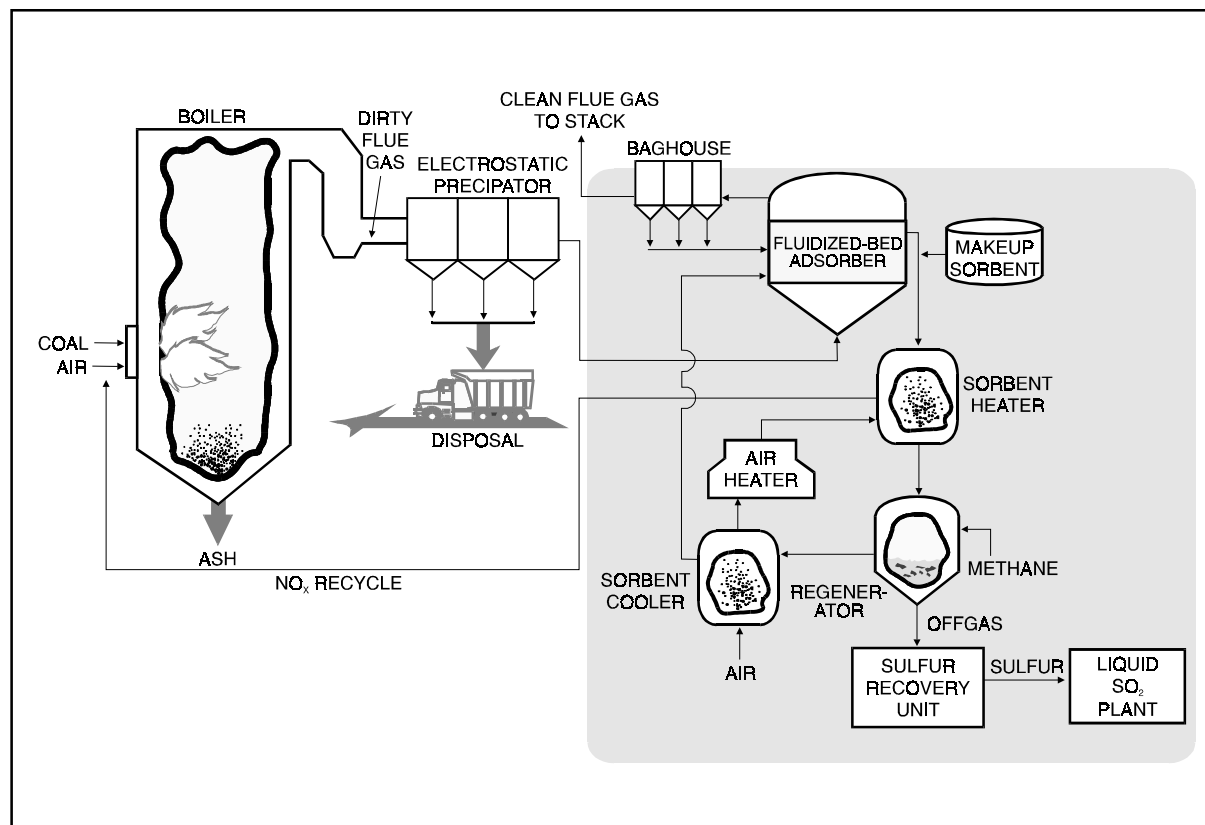
NOXSO Corporation's dry, regenerable flue gas cleanup process  
 Calabrian Corporation's burn-in-oxygen technology for production of liquid SO<sub>2</sub>

### Plant Capacity/Production

NOXSO Plant: 50–100 MWe  
 SO<sub>2</sub> Plant: 45,000 tons/yr of liquid SO<sub>2</sub>

### Project Funding

Total project cost	\$82,812,120	100%
DOE	41,406,060	50
Participant	41,406,060	50



### Project Objective

To demonstrate removal of 98% of the SO<sub>2</sub> and 75% of the NO<sub>x</sub> 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<sub>2</sub> and NO<sub>x</sub> 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; SO<sub>2</sub> and NO<sub>x</sub> are adsorbed by the sorbent, which consists of spherical beads of high-surface-area alumina impregnated with sodium carbonate. Cleaned flue gas then passes through a baghouse to the stack.

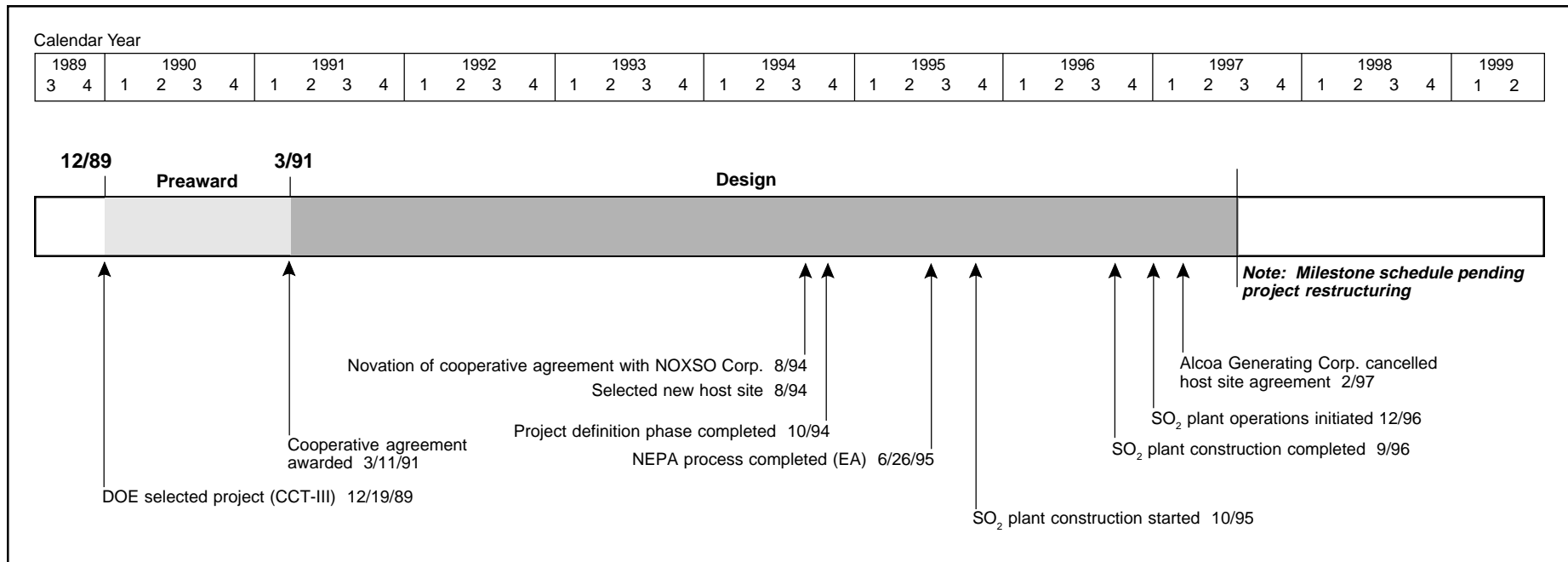
The NO<sub>x</sub> is desorbed from the NOXSO sorbent when heated by a stream of hot air. Hot air containing the des-

orbed NO<sub>x</sub> is recycled to the boiler where equilibrium processes cause destruction of the NO<sub>x</sub>. 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<sub>2</sub> and hydrogen sulfide (H<sub>2</sub>S). This offgas is processed to produce elemental sulfur, which is further processed to produce liquid SO<sub>2</sub>, a higher valued by-product.

The process is expected to achieve SO<sub>2</sub> reductions of 98% and NO<sub>x</sub> reductions of 75%.

A full-scale design based on data from the proof-of-concept facility at Ohio Edison's Toronto power plant is in preparation.

The project will also demonstrate a 45,000-ton/yr liquid SO<sub>2</sub> plant at Olin Corporation's Charleston, TN, facility. The liquid SO<sub>2</sub> plant will use Calabrian's burn-



in-oxygen technology. This technology is a substantial improvement over other existing technologies for producing liquid SO<sub>2</sub>. By manufacturing liquid SO<sub>2</sub> with oxygen rather than air, by-product streams are eliminated, making the technology environmentally friendly. Storage requirements are minimal because the product can be made virtually on demand.

### Project Status/Accomplishments

NOXSO is searching for a new host site to demonstrate the NOXSO process. Alcoa Generating Corporation chose to cancel the host site agreement when NOXSO was unable to obtain full project financing by January 31, 1997, as specified in the agreement.

In June 1997, the court accepted NOXSO's petition for voluntary bankruptcy. NOXSO will continue the process of selecting a new host site for demonstrating the NOXSO technology.

### Commercial Applications

The NOXSO process is applicable for retrofit or new facilities. The process is suitable for utility and industrial

coal-fired boilers of 50 MWe or larger. The process is adaptable to coals with medium- to high-sulfur content.

The process produces one of the following as a salable by-product: elemental sulfur, sulfuric acid, or liquid SO<sub>2</sub>. 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<sub>2</sub> and NO<sub>x</sub>, need to eliminate solid wastes, and/or have inadequate water supply for a wet scrubber.

## Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> Emissions Control System

**Project completed.**

### 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 tester

Western Research Institute—flyash evaluator

Colorado School of Mines—bench-scale engineering researcher and tester

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<sup>®</sup> low-NO<sub>x</sub> burners, in-duct sorbent injection, and furnace (urea) injection

### Plant Capacity/Production

100 MWe

### Coal

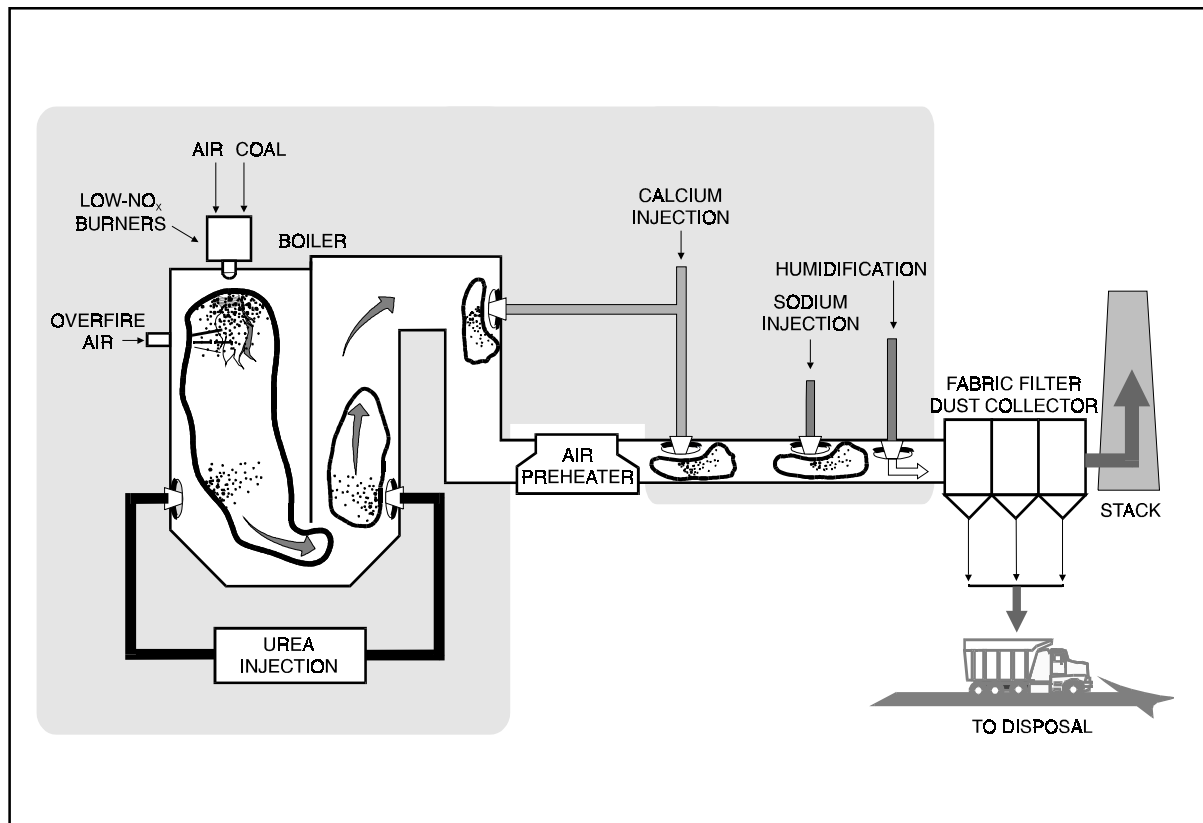
Colorado bituminous, 0.4% sulfur

Wyoming subbituminous (short test), 0.35% sulfur

### Project Funding

Total project cost	\$27,411,462	100%
DOE	13,705,731	50
Participant	13,705,731	50

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



### Project Objective

To demonstrate the integration of five technologies to achieve up to 70% reduction in NO<sub>x</sub> and SO<sub>2</sub> emissions; more specifically, to assess the integration of a down-fired low-NO<sub>x</sub> burner with in-furnace urea injection for additional NO<sub>x</sub> removal and dry sorbent in-duct injection with humidification for SO<sub>2</sub> removal.

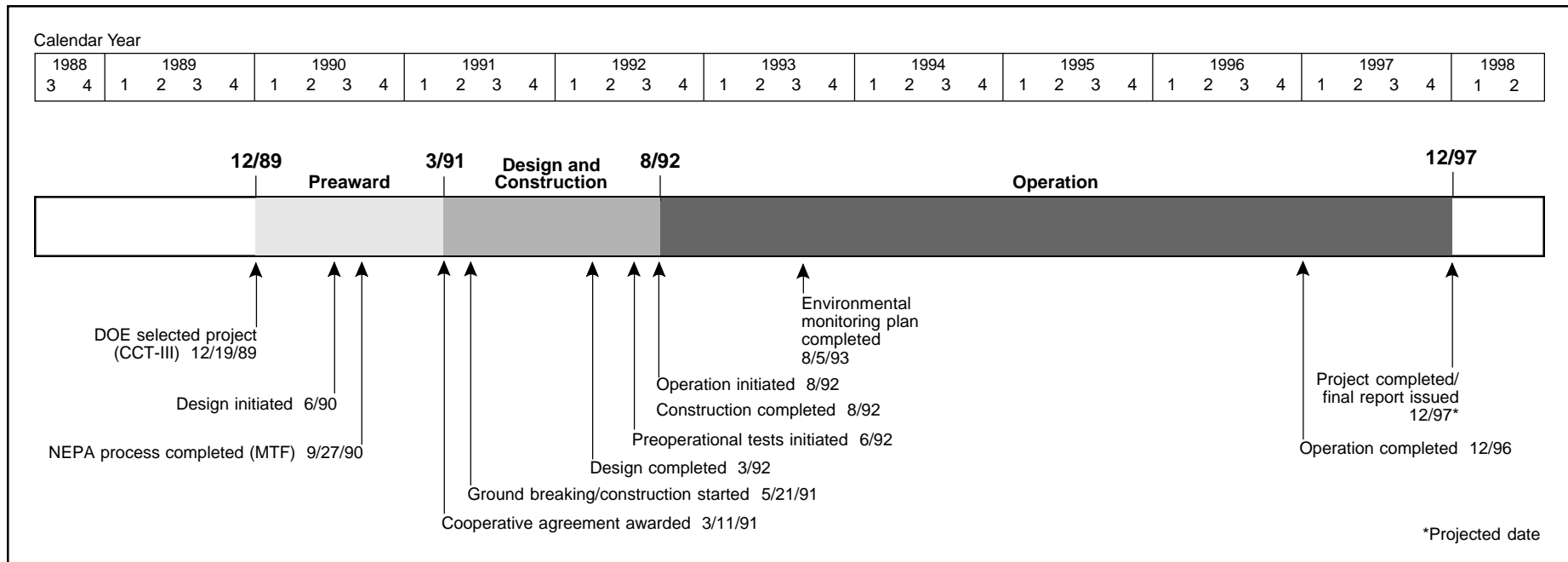
### Technology/Project Description

All of the testing used Babcock & Wilcox's low-NO<sub>x</sub> DRB-XCL<sup>®</sup> down-fired burners with overfire air. These burners control NO<sub>x</sub> by injecting the coal and the combustion air in an oxygen-deficient environment. Additional air was introduced via overfire air ports to complete the combustion process and further enhance NO<sub>x</sub> removal. A urea-based selective noncatalytic reduction

(SNCR) system was tested to determine how much additional NO<sub>x</sub> can be removed from the combustion gas.

Two types of dry sorbents were injected into the ductwork downstream of the boiler to reduce SO<sub>2</sub> emissions. Either calcium was injected upstream of the boiler economizer or sodium downstream of the air heater. Humidification downstream of the dry sorbent injection was incorporated to aid SO<sub>2</sub> capture and lower flue gas temperature and gas flow before entering the fabric filter dust collector.

The systems were 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.



## Results Summary

### Environmental

- With maximum overfire air (24% of total combustion air), a NO<sub>x</sub> reduction of 62–69% was achieved across the 50–110-MWe load range.
- DRB-XCL<sup>®</sup> burners with minimum overfire air reduced NO<sub>x</sub> emissions by more than 63% under steady state conditions.
- NO<sub>x</sub> reductions were decreased by 10–25% under load-following conditions.
- The SNCR system, using both stationary and retractable injection lances in the furnace, provided NO<sub>x</sub> removal of 30–50% at an ammonia (NH<sub>3</sub>) slip of 10 ppm, thus increasing performance of the total NO<sub>x</sub> control system to greater than 80% NO<sub>x</sub> reduction.
- SO<sub>2</sub> removal with calcium-based dry sodium injection into the boiler at approximately 1,000 °F was less than 10%, and with injection into the fabric filter duct, SO<sub>2</sub> removal was less than 40% at a Ca/S ratio of 2.0.

- Sodium bicarbonate injection before the air heater demonstrated a long-term SO<sub>2</sub> removal of approximately 70% at a normalized stoichiometric ratio (NSR) of 1.0.
- Sodium sesquicarbonate injection ahead of the fabric filter achieved 70% SO<sub>2</sub> removal at an NSR of 2.0.
- NO<sub>2</sub> emissions were generally higher when using sodium biocarbonate than when using sodium sesquicarbonate.
- Integrated SNCR and sodium dry sorbent injection tests showed reduced NH<sub>3</sub> and NO<sub>2</sub> emissions.
- During four series of air toxics tests, the fabric filter successfully removed nearly all trace metal emissions and 80% of the mercury.

### Operational

- Arapahoe 4 operated more than 34,000 hours after combustion modifications were complete.
- Availability factor was over 91%.

- Operational test objectives were met or exceeded.
- Control system modifications and additional operator training may be necessary to improve NO<sub>x</sub> control under load-following conditions.
- Buildup of a hard ash cake on the fabric filter occurred during operation of dry sorbent injection of calcium hydroxide with humidification.
- Temperature differential between the top and bottom surfaces of the Advanced Retractable Injection Lances (ARIL) caused the lances to bend downwards 12–18 inches. Alternative designs corrected the problem.
- Concurrent operation of SNCR and the dry sodium injection system caused an NH<sub>3</sub> odor problem around the ash silo, which appeared to be related to the rapid change in pH due to the sodium in the ash.

### Economic

- Data not available.



## Project Summary

The Integrated Dry NO<sub>x</sub>/SO<sub>x</sub> Emissions Control System combines five major control technologies to form an integrated system to control both NO<sub>x</sub> and SO<sub>2</sub>. The low-NO<sub>x</sub> combustion system consists of 12 Babcock & Wilcox DRB-XCL® low-NO<sub>x</sub> burners installed on the roof. The low-NO<sub>x</sub> combustion system also incorporated three Babcock & Wilcox dual-zone NO<sub>x</sub> ports added to each side of the furnace approximately 20 ft below the boiler roof. These ports injected up to 25% of the total combustion air through the furnace sidewalls.

Additional NO<sub>x</sub> control was achieved with the urea-based SNCR system. The SNCR when used with the low-NO<sub>x</sub> combustion system would allow the goal of 70% NO<sub>x</sub> reduction to be reached. Further, the SNCR system was an important part of the integrated system, interacting synergistically with the dry sorbent injection (DSI) system to reduce NO<sub>2</sub> formation and ammonia slip.

Initially the SNCR was designed and installed to incorporate two levels of injectors with 10 injectors at each level, with the exact location being based on temperature profiles that existed with the original combustion system. However, the retrofit low-NO<sub>x</sub> combustion system resulted in a decrease in furnace exit gas temperature by approximately 200 °F, thus moving one injector level out of the temperature regime needed for effective SNCR operation. With only one operational injector level, the load-following performance was compromised.

In order to achieve the desirable NO<sub>x</sub> reduction at low loads, two alternatives were explored. First, it was shown that ammonia was more effective than urea at low loads. An on-line urea-to-ammonia conversion system was installed and resulted in improved low-load performance, but the improvement was not as large as desired for the lowest load (60 MWe). The second approach was to install injectors in the higher temperature regions of the furnace. This was achieved by installing two NOELL ARIL lances into the furnace through two unused sootblower ports. Each lance was nominally 4 inches in diameter and approximately 20 ft in length with a single



▲ Public Service Company of Colorado demonstrated low-NO<sub>x</sub> burners, induct injection, and SNCR at Arapahoe Station near Denver.

row of nine injection nozzles. Each injection nozzle consisted of a fixed air orifice and a replaceable liquid orifice. The ability to change orifices allowed not only for removal and cleaning but adjustment of the injection pattern along the length of the lance in order to compensate for any significant maldistributions of flue gas velocity, temperature, or baseline NO<sub>x</sub> concentration. One of the key features of the ARIL system was its ability to rotate, thus providing a high degree of flexibility in optimizing SNCR performance.

The SO<sub>2</sub> control system was a DSI system that could inject either calcium- or sodium-based reagents into the flue gas upstream of the fabric filter. Sorbent was injected into three locations: (1) air heater exit where the temperature was approximately 260 °F, (2) entrance of the air heater where the temperature was approximately 600 °F, or (3) the boiler economizer region where the flue gas temperature was approximately 1,000 °F. To improve SO<sub>2</sub> removal with calcium hydroxide, a humidification system capable of achieving 20 °F approach-to-saturation was installed approximately 100 ft ahead of the fabric filter. The system designed by Babcock & Wilcox included

84 I-Jet nozzles that can inject up to 80 gal/min into the flue gas duct work.

## Environmental Performance

The combined DRB-XCL® burner and minimum overfire air reduced NO<sub>x</sub> emissions by over 63% under steady-state conditions and with carefully supervised operations. Under load-following conditions, NO<sub>x</sub> emissions were about 10–25% higher. At maximum overfire air (4% of total combustion air), the low-NO<sub>x</sub> combustion system reduced NO<sub>x</sub> emissions by 62–69% across the load range (50–110 MWe). The results indicated that the low-NO<sub>x</sub> burners were responsible for most of the NO<sub>x</sub> reduction.

The original design of two rows of injector nozzles proved relatively ineffective because one row of injectors was in a region where the flue gas temperature was too low for effective operation. At full load, the original design achieved NO<sub>x</sub> reduction of 45%. However, the performance decreased significantly as load decreased; at 60 MWe, NO<sub>x</sub> removal was limited to about 11% with an ammonia slip of 10 ppm. The addition of the retractable lances improved low-load performance of the urea-based SNCR injection system. The ability to follow the temperature window by rotating the ARIL lances proved to be an important feature in optimizing performance. As a result, the SNCR system obtained NO<sub>x</sub> removal of 30–50%, at a NH<sub>3</sub> slip limited to 10 ppm at the fabric filter inlet, thus increasing the total NO<sub>x</sub> control system reduction to greater than 80%, significantly exceeding the goal of 70%.

Testing of calcium hydroxide injection at the economizer without humidification resulted in SO<sub>2</sub> removal in the range of 5–8% at a Ca/S molar ratio of 2.0. Higher SO<sub>2</sub> removal was achieved with duct injection of calcium hydroxide and humidification, with SO<sub>2</sub> removals approaching 40% at a Ca/S molar ratio of 2.0 and approach-to-saturation temperature of 20–30 °F. Sodium-based reagents were found to be much more effective than calcium-based sorbents and achieved significantly higher SO<sub>2</sub> removals during dry injection. Sodium bicarbonate

injection before the air heater demonstrated short-time SO<sub>2</sub> removals of 80%. Long-term reductions of 70% were achieved with an NSR of 1.0. Sodium sesquicarbonate achieved 70% removal at an NSR of 2.0 when injected ahead of the fabric filter. A disadvantage of the sodium-based process was that it converted some existing NO to NO<sub>2</sub>. Even though 5–10% of the NO<sub>x</sub> was reduced during the conversion process, the net NO<sub>2</sub> exiting at the stack was increased. While NO is colorless, small quantities of brown/orange NO<sub>2</sub> caused a visible plume.

A major objective was the demonstration of the integrated performance of the NO<sub>x</sub> emissions control systems and the SO<sub>2</sub> removal technologies. The results showed that a synergistic benefit occurred during the simultaneous operation of the SNCR and the sodium DSI system in that the NH<sub>3</sub> slip from the SNCR process suppressed the NO<sub>2</sub> emissions associated with NO to NO<sub>2</sub> oxidation by dry sodium injection.

Four series of air toxic tests were completed. Results indicated that the fabric filter successfully removed 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 detectable limits.

### Operating Performance

Construction began in July 1991 and was completed in August 1992. The test program began in August 1992 and was scheduled for completion in June 1994. However, the addition of the new SNCR injection location and alternative lance design tests extended the test program through December 1996. The Arapahoe Unit 4 operated more than 34,000 hours after combustion modifications were completed. The availability factor during the period was over 91%.

The operational test objectives were met or exceeded. However, there were operational lessons learned during the demonstration that will be useful in future deployment of the technologies. These “lessons” are summarized below.

It was found that control system modifications and additional operator training may be necessary to more accurately control NO<sub>x</sub> reductions using low-NO<sub>x</sub> burners under load-following conditions.

During the operation of the duct injection of calcium hydroxide and humidification under load-following conditions, fabric filter pressure-drop significantly increased. This was caused by the buildup of a hard ash cake on the fabric filter bags that could not be cleaned under normal reverse-air cleaning. The heavy ash cake was caused by the humidification system, but it was not determined whether the problem was due to operation at 30 °F approach-to-saturation temperature or an excursion caused by a rapid decrease in load.

The performance of the ARIL lances in NO<sub>x</sub> removal was good; however, the location created some operational problems. A large differential heating pattern between the top and bottom of the lance caused a significant amount of thermal expansion along the upper surface of the lance. This caused the lance to bend downwards approximately 12–18 inches after 30 minutes of exposure. Eventually the lances become permanently bent, thus making insertion and retraction difficult. The problem was partially resolved by adding cooling slots at the end of the lance. An alternative lance design provided by Diamond Power Specialty Company (a division of Babcock & Wilcox) was tested and found to have less bending due to evaporative cooling, even though its NO<sub>x</sub> reduction and NH<sub>3</sub> slip performance were slightly less than for the ARIL lance.

When the SNCR and dry sodium systems were operated concurrently, an NH<sub>3</sub> odor problem was encountered around the ash silo. Reducing the NH<sub>3</sub> slip set points to the range of 4–5 ppm reduced the ammonia concentration in the fly ash to the 100–200 ppm range but the odor persisted. It was found that the problem was related to the rapid change in pH due to the presence of sodium in the ash. The rapid development of the high pH level and the attendant release of the ammonia vapor appear to be

related to the wetting of the fly ash necessary to minimize fugitive dust emissions during transportation and handling. Handling ash in dry transport trucks solved this problem.

### Economic Performance

Economic analysis is under way.

### Commercial Applications

Either the entire Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> Emissions Control System or the individual technologies are applicable to most utility and industrial coal-fired units and provide lower capital-cost alternatives 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.

### Contacts

Terry Hunt, Project Manager, (303) 571-1113  
Public Service Company of Colorado  
550 15th Street, Suite 880  
Denver, CO 80202

Lawrence Saroff, DOE/HQ, (301) 903-9483  
Jerry L. Hebb, FETC, (412) 892-6079

### References

- Hunt, Terry, et al. “Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> Emissions Control System: Performance Summary.” *Fifth Annual Clean Coal Technology Conference: Technical Papers*. January 1997.
- *Comprehensive Report to Congress on the Clean Coal Technology Program: Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> Emission Control System*. Public Service Company of Colorado. Report No. DOE/FE-0212P. U.S. Department of Energy. January 1991. (Available from NTIS as DE91008624.)

## Advanced Electric Power Generation Technology

Advanced electric power generating systems employ the technologies that enable the efficient and environmentally superior generation of electric power. The advanced electric power generation projects selected under the CCT Program are responsive to the long-term capacity expansion needs requisite to meeting long-term demand and offsetting nuclear retirements and to the stringent CAAA emission limits effective in 2000. These technologies are characterized by high thermal efficiency, very low pollutant emissions, reduced CO<sub>2</sub> emissions, few solid waste problems, and enhanced economics. Advanced electric power generation systems may be deployed in modules, allowing phased construction to match demand growth more predictably and to meet the requirements of smaller municipal, rural, and nonutility generators.

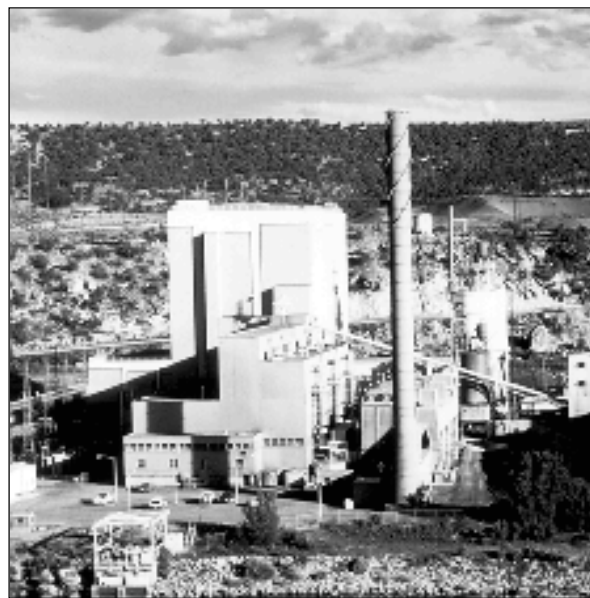
There are five generic technology approaches being used to demonstrate advanced electric power generation systems under the CCT Program. The characteristics of these five technologies are outlined here, and the specific projects and technologies are presented in more detail in the fact sheets. A sixth generic technology project, externally fired combined-cycle, was selected as part of the CCT-V solicitation. Even though this project ended in May 1997, its fact sheet is included for completeness.

### *Fluidized-Bed Combustion*

Fluidized-bed combustion (FBC) reduces emissions of SO<sub>2</sub> and NO<sub>x</sub> 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 the limestone is fluidized on jets of air in the combustion chamber. Sulfur released from the coal as SO<sub>2</sub> is captured by the sorbent in the bed to form a solid calcium compound that is removed with the ash. The resultant waste is a dry, benign solid that can be disposed of easily or used in agricultural or construction applications. More than 90 percent of the SO<sub>2</sub> released can be captured this way.

At combustion temperatures of 1,400–1,600 °F, the fluidized mixing of the fuel and sorbent enhances both combustion and sulfur capture. The operating temperature range is about half that of a conventional boiler and below the temperature which thermally



▲ Tri-State Generation and Transmission Association's Nucla Station was host to demonstration of the world's first utility-scale AFBC.

induced NO<sub>x</sub> is formed. In fact, fluidized-bed NO<sub>x</sub> emissions are about 70–80 percent lower than those for at conventional pulverized coal boilers. Thus, fluidized-bed combustors substantially reduce both SO<sub>2</sub> and NO<sub>x</sub> emissions. Also, fluidized-bed combustion has the capability of utilizing high-ash coal, whereas conventional pulverized coal units must limit ash content to relatively low levels.

Two parallel paths were pursued in fluidized-bed development—bubbling and circulating beds. Bubbling beds use a dense fluid bed and low fluidization velocity to effect good heat transfer and mitigate erosion of an in-bed heat exchanger. Circulating fluidized beds use a relatively high fluidization velocity (entrained bed) in conjunction with hot cyclones to separate and recirculate the particulate from the flue gas before it passes to a heat exchanger. Hybrid systems have since evolved from these two basic approaches.

Fluidized-bed combustion can be either atmospheric (AFBC) or pressurized (PFBC). AFBC operates at atmospheric pressure while PFBC operates at pressure 6–16 times higher. PFBC offers potentially higher efficiency and, consequently, reduced operating costs and waste relative to AFBC.

Second-generation PFBC integrates the combustor with a pyrolyzer (coal gasifier) to fuel a gas turbine (topping cycle), the waste heat from which is used to generate steam for a steam turbine (bottoming cycle). The inherent efficiency of the gas turbine and waste heat recovery in this combined-cycle mode significantly increases overall efficiency. Such advanced PFBC systems have the potential for efficiencies of over 50 percent.

## ***Integrated Gasification Combined Cycle***

The integrated coal gasification combined-cycle process has four basic steps: (1) fuel gas is generated by coal reacting with high-temperature steam and an oxidant (oxygen or air) in a reducing atmosphere; (2) gas is either passed directly to a hot-gas cleanup system to remove particulates and sulfur and nitrogen compounds or first cooled to produce steam and then cleaned conventionally; (3) clean fuel gas is combusted in a gas turbine generator to produce electricity; and (4) 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.



▲ Tampa Electric Company's Polk Power Station Unit 1, a 250-MWe IGCC greenfield installation, is currently in operation. It is one of the world's cleanest and most advanced coal power plants.

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

The gas stream must be cleaned to a high degree, 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 the coal is released in the form of hydrogen sulfide rather than as  $\text{SO}_2$ , which is the case in coal combustion. In some IGCC systems, much of the sulfur-containing gas is captured by a sorbent injected into the gasifier. Others use existing commercial hydrogen sulfide removal processes, which remove up to 99 percent of the sulfur but require the fuel to be cooled, with some efficiency penalty. Therefore, hot-gas cleanup systems are being demonstrated. In these cleanup systems, the hot coal gas is passed through a bed of metal oxide particles, such as supported zinc oxides. Zinc oxide 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. Produced during the regeneration stage are salable sulfur, sulfuric acid, or sulfur-containing solid waste, which may be used to produce useful by-products, such as gypsum. The technique is capable of removing more than 99.9 percent of the sulfur in the gas stream. With hot-gas cleanup, IGCC systems have the potential for efficiencies of over 50 percent.

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.  $\text{NO}_x$  formed by the combustion air can be held to well within allowable levels by staged combustion in the turbine or by adding moisture to hold down flame temperature.

## ***Integrated Gasification Fuel Cell***

A typical fuel cell system using coal as fuel includes a coal gasifier with a gas cleanup system, a fuel cell to use the coal gas to generate electricity (direct current) and heat, an inverter to convert direct current to alternating current, and a heat-recovery system. The heat-recovery system would be used to produce additional electric power in a bottoming steam cycle.

Energy conversion in fuel cells is potentially more efficient (up to 60 percent, depending on fuel and type of fuel cell) than traditional energy conversion devices. Fuel cells directly transform the chemical energy of a fuel and an oxidant (air or oxygen) into electrical energy instead of going through an intermediate step (i.e., burner, boiler, turbines, and generators). 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***

The diesel-engine-driven electric generation system is fueled with a coal-oil or coal-water slurry. The hot exhaust from the diesel engine is routed

through a heat-recovery unit to produce steam for a steam-turbine electric generating system (combined cycle). Environmental control systems for SO<sub>2</sub>, NO<sub>x</sub>, 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 utilities (municipalities and rural cooperatives) and industrial cogeneration.

### ***Slagging Combustor***

Many new coal-burning technologies are designed to remove the coal ash as molten slag in the combustor rather than the furnace. Most of these slagging combustors are based on a 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 to reduce boiler efficiency over time.

Results to date show that by positioning air injection ports so that coal is combusted in stages, NO<sub>x</sub> emissions can be reduced by 70–80 percent.

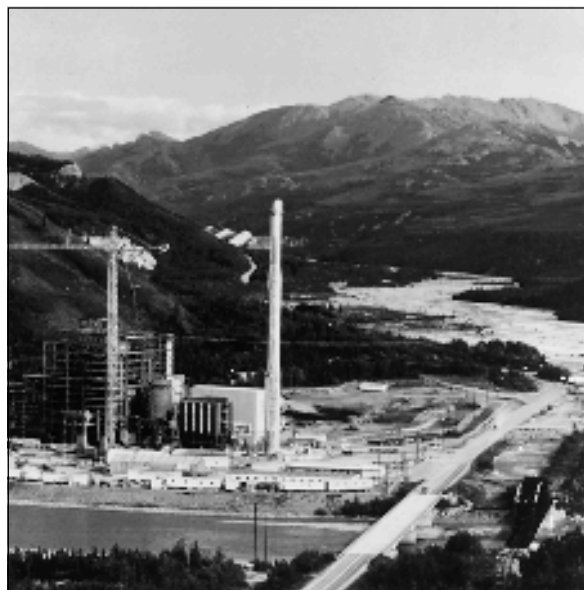
Injecting limestone into the combustion chamber has the potential to reduce sulfur emissions by 90 percent in combination with a spray-dryer absorber. Advanced slagging combustors could replace oil-fired units in both utility and industrial applications or be used to retrofit older, conventional cyclone boilers.

### ***Status of Projects***

There are 11 advanced electric power generating projects in the CCT Program of which five are fluidized-bed combustion systems, four are IGCCs, and two are advanced combustion/heat engine systems (coal diesel and advanced slagging combustor). Of the five fluidized-bed combustion projects, two have successfully completed demonstration (one PFBC and one AFBC), and the other three are in the

project definition and design phase. Of the four IGCC projects, three are in operation and one is in the project definition and design phase. Of the two remaining advanced combustion/heat engine projects, the advanced slagging combustor project is in the last stages of construction, and the coal diesel project is in the project definition and design phase.

Exhibit 5-29 summarizes the process characteristics and size of the advanced electric power generating technologies presented in more detail in the project fact sheets.



▲ Golden Valley Electric Association is adding capacity to its Healy Plant with a 50-MWe slagging combustor unit using 65% waste coal.

**Exhibit 5-29**  
**CCT Program Advanced Electric Power Generation Technology Characteristics**

Project	Process	Size	Fact Sheet
<b>Fluidized-Bed Combustion</b>			
McIntosh Unit 4A PCFB Demonstration Project	Pressurized circulating fluidized-bed combustion	157 MWe	5-86
McIntosh Unit 4B Topped PCFB Demonstration Project	McIntosh 4A with pyrolyzer and topping combustor	157 MWe + 12 MWe	5-88
Tidd PFBC Demonstration Project	Pressurized bubbling fluidized-bed combustion	70 MWe	5-90
ACFB Demonstration Project	Atmospheric circulating fluidized-bed combustion	250 MWe	5-94
Nucla CFB Demonstration Project	Atmospheric circulating fluidized-bed combustion	100 MWe	5-96
<b>Integrated Gasification Combined Cycle</b>			
Clean Energy Demonstration Project	Oxygen-blown, slagging fixed-bed gasifier with cold gas cleanup, fuel cell slipstream	477 MWe	5-100
Piñon Pine IGCC Power Project	Air-blown, fluidized-bed gasifier with hot gas cleanup	99 MWe	5-102
Tampa Electric Integrated Gasification Combined-Cycle Project	Oxygen-blown, entrained-flow gasifier with hot and cold gas cleanup	250 MWe	5-104
Wabash River Coal Gasification Repowering Project	Oxygen-blown, two-stage entrained-flow gasifier with cold gas cleanup	262 MWe	5-106
<b>Advanced Combustion/Heat Engines</b>			
Healy Clean Coal Project	Advanced slagging combustor, spray dryer with sorbent recycle	50 MWe	5-108
Clean Coal Diesel Demonstration Project	Coal-fueled diesel engine	4.2 MWe	5-110
Externally Fired Combined-Cycle Demonstration Project	Externally fired combined-cycle system	5.0 MWe (slipstream)	5-112

## McIntosh Unit 4A PCFB Demonstration Project

### Participant

City of Lakeland, Department of Electric & Water Utilities

### Additional Team Members

Foster Wheeler Energy Corp.—supplier of high-temperature combustor and heat exchanger; engineer  
Westinghouse Electric Corporation—supplier of PCFB, hot gas filter, gas turbine, and steam turbine

### Location

Lakeland, Polk County, FL (Lakeland's McIntosh Power Station, Unit 4)

### Technology

Foster Wheeler's PCFB technology integrated with Westinghouse's hot gas filter and power generation technologies

### Plant Capacity/Production

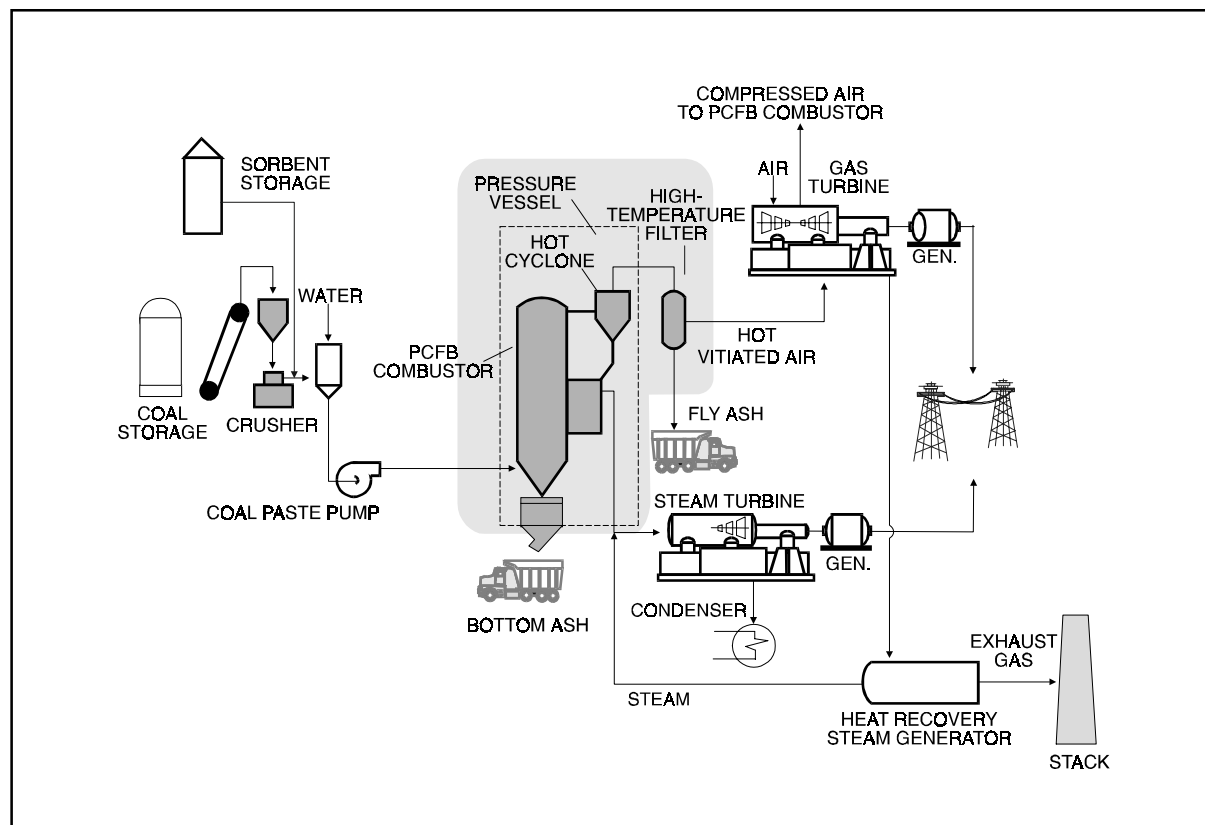
157 MWe (net)

### Project Funding

Total project cost	\$186,588,000	100%
DOE	93,252,864	50
Participant	93,335,136	50

### Project Objective

To demonstrate Foster Wheeler's PCFB technology coupled with Westinghouse's hot gas filter and power generation technologies, which represent a cost-effective, high-efficiency, low-emissions means of adding generating capacity at greenfield sites or in repowering applications.



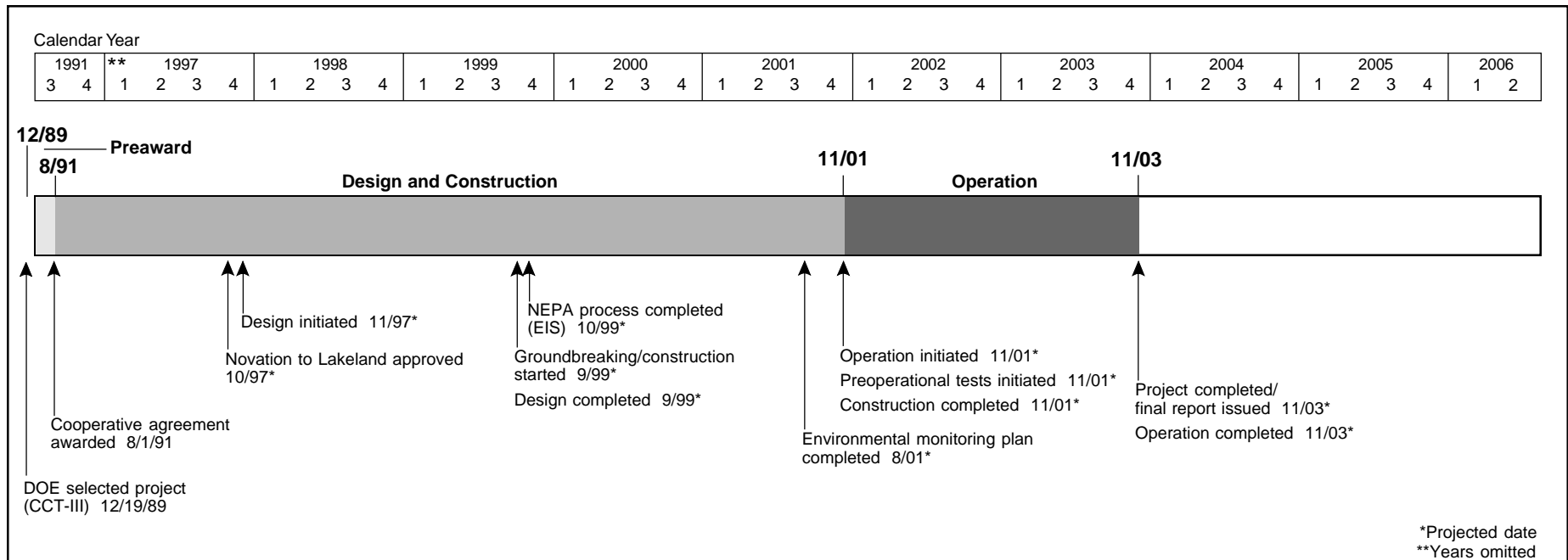
### Technology/Project Description

The project resulted from a restructuring of the DMEC-1 PCFB Demonstration Project awarded under the third solicitation. The project's pressurized fluidized-bed combustor will also serve for demonstrating the integration of a gasifier and topping combustor (topping cycle) with the PCFB technology. This integration will be demonstrated in the McIntosh Unit 4B Topped PCFB Demonstration Project.

Coal and limestone are mixed with water to form a paste, which is pumped into the combustion chamber by piston pumps commonly used in the cement industry. Combustion takes place at approximately 1,560–1,600 °F at a pressure of about 200 psig. The resulting flue gas and fly ash leaving the combustor pass through a cyclone and hot gas filter where the particulates are removed. The hot gas leaving the filter is expanded through a gas tur-

bine, which is based on a standard Westinghouse 251B12, single-shaft, cold-end-drive industrial machine. The gas inlet temperature of less than 1,650 °F allows for a simplified turbine shaft and blade-cooling system. The hot gas leaving the gas turbine passes through a heat recovery unit used to generate steam. Heat recovered from both the combustor and heat recovery unit is used to generate steam to power a reheat steam turbine. Approximately 15% of the gross power is derived from the gas turbine, with the steam turbine contributing the remaining 85%.

The unit is being designed to burn a range of coals, including the current Eastern Kentucky coal burned in Unit 3 and high-ash, high-sulfur coals that are expected to be available at a lower cost. Limestone will be purchased from nearby Florida quarries. Ash will be disposed of in landfills or sold to others.



### Project Status/Accomplishments

Approval by all participants of the transfer of the cooperative agreement to the City of Lakeland, Department of Electric & Water Utilities, is expected to be completed in late fiscal year 1997. The project schedule anticipates the start of commercial operation of the PCFB (McIntosh 4A) in the winter of 2001. In parallel with the first 2 years of operation of the PCFB will be the design, fabrication, and construction of the topped PCFB technology (McIntosh 4B), with a planned start of operation in late 2003.

### Commercial Applications

The project serves as a stepping stone to move the PCFB technology to readiness for widespread commercial deployment in the post-2000 time frame. The project will include the first commercial applications of hot-gas particulate cleanup and one of the first to use a non-ruggedized gas turbine in a pressurized fluidized-bed application.

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 PCFB

system. PCFB can be used to repower or replace conventional power plants. 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 projected net heat rate for the system is approximately 8,100 Btu/kWh (based on HHV), which equates to over 42% efficiency.

Environmental attributes include in-situ sulfur removal of 95%, NO<sub>x</sub> emissions less than 0.3 lb/10<sup>6</sup> Btu, and particulate matter discharge less than 0.03 lb/10<sup>6</sup> Btu. Solid waste will increase slightly as compared to conventional systems, but the dry material is readily disposable or potentially usable.



## McIntosh Unit 4B Topped PCFB Demonstration Project

### Participant

City of Lakeland, Department of Electric & Water Utilities

### Additional Team Members

Foster Wheeler Energy Corp.—supplier of carbonizer; engineer  
Westinghouse Electric Corporation—supplier of topping combustor and high-temperature filter

### Location

Lakeland, Polk County, FL (Lakeland's McIntosh Power Station, Unit 4)

### Technology

Fully integrated second-generation PCFB technology with the addition of a carbonizer island that includes Westinghouse's multi-annular swirl-burner (MASB) topping combustor

### Plant Capacity/Production

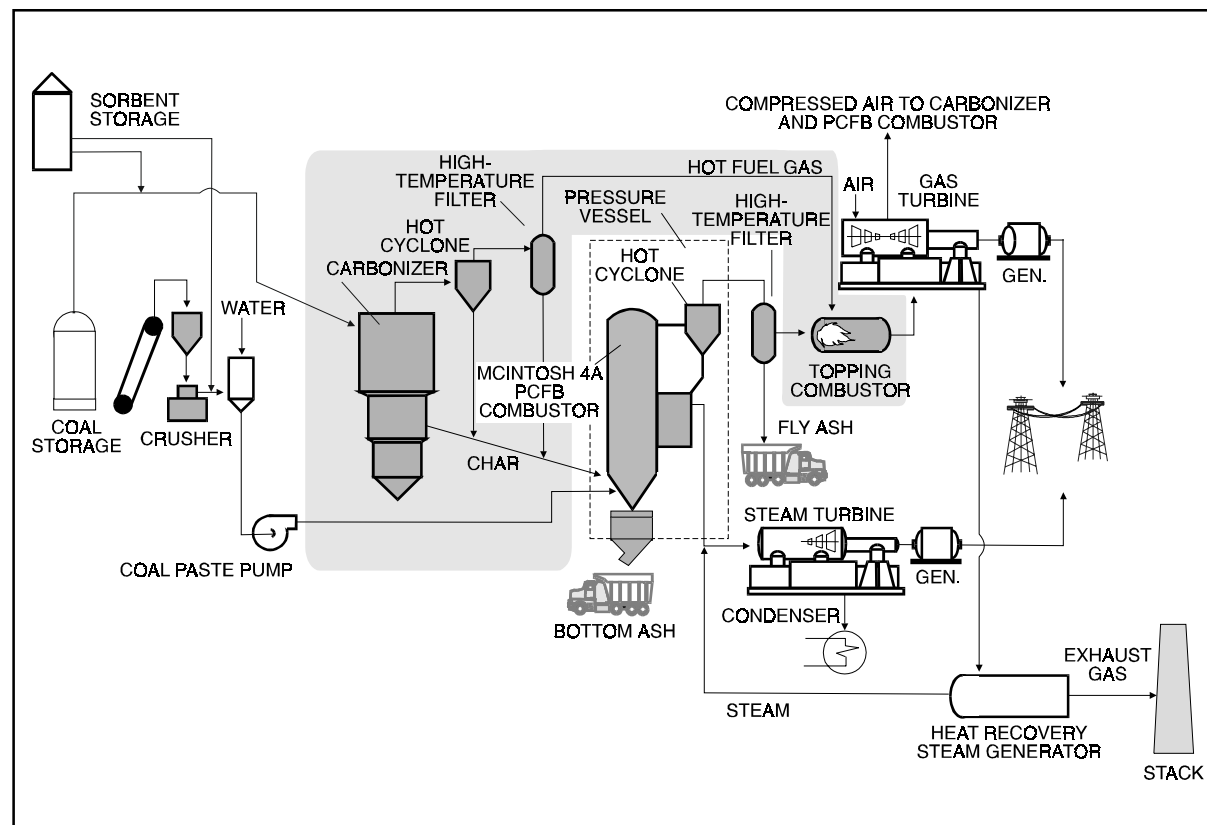
12 MWe (net) addition to the 157 MWe (net) McIntosh 4A project

### Project Funding

Total project cost	\$218,741,300	100%
DOE	109,204,000	50
Participant	109,537,300	50

### Project Objective

To demonstrate topped PCFB technology in a fully commercial power generating setting, thereby advancing the technology for future plants that will operate at higher gas turbine inlet temperatures and that are expected to achieve cycle efficiencies in excess of 45%.

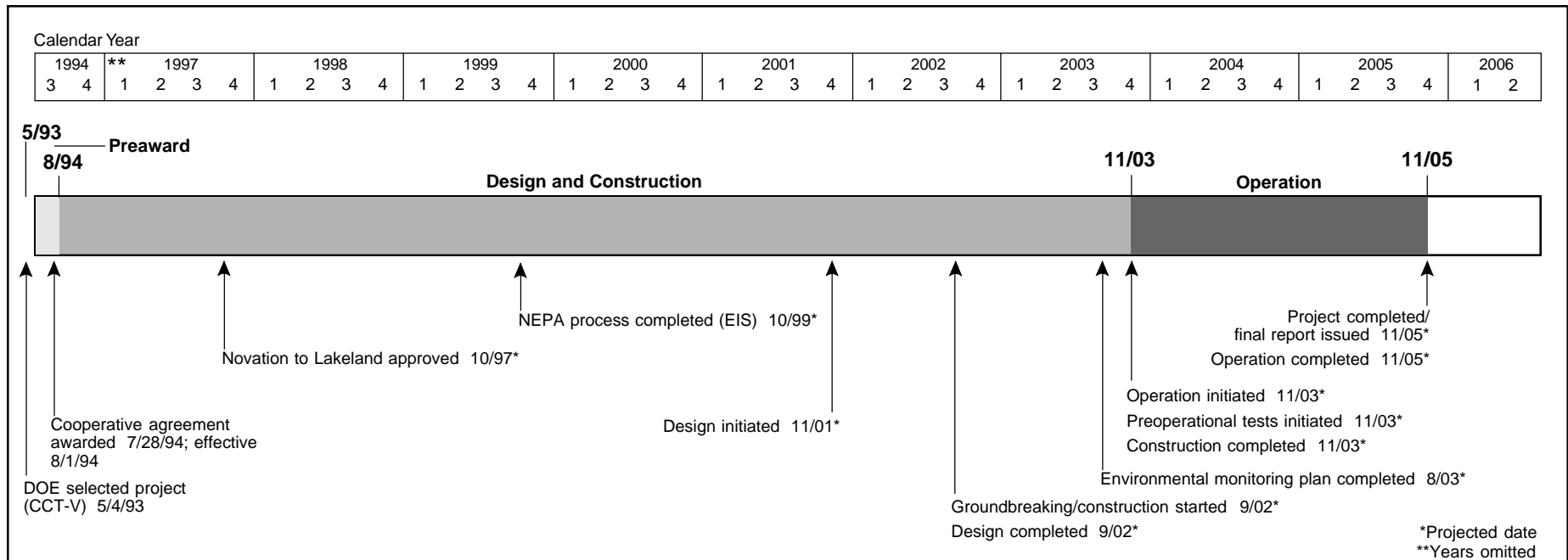


### Technology/Project Description

The project resulted from a restructuring of the Four Rivers Energy Modernization Project awarded under the fifth solicitation. The Four Rivers project was to demonstrate the integration of a gasifier and topping combustor (topping cycle) with the PCFB technology. By utilizing a segmented approach, Lakeland will be able to demonstrate both PCFB (McIntosh 4A) and topped PCFB (McIntosh 4B) technologies.

The project involves the addition of a carbonizer island to the PCFB demonstrated in the McIntosh 4A project. Dried coal and limestone are fed via a lock hopper system to the carbonizer together with part of the gas turbine discharge air. The coal is partially gasified at about 1,700 °F to produce syngas and char solids streams. The limestone is used to absorb sulfur compounds gener-

ated during the mild gasification process. After cooling the syngas to about 1,200 °F, the char and limestone entrained with the syngas are removed by a hot gas filter. The char and limestone are then transferred to the PCFB combustor for complete carbon combustion and limestone utilization. The hot, cleaned, filtered syngas is then fired in the MASB topping combustor to raise the turbine inlet temperature to approximately 2,000 °F. The gas is expanded through the turbine, cooled in a heat recovery unit, and exhausted to the stack. The net impact of the addition of the topping cycle is an increase in power output of 12 MWe and an associated improvement in plant heat rate of approximately 600 Btu/kWh. The coal and limestone used in McIntosh 4B are the same as those used in McIntosh 4A.



**Project Status/Accomplishments**

Approval by all participants of the transfer of the cooperative agreement to the City of Lakeland, Department of Electric & Water Utilities, is expected to be completed in late fiscal year 1997. The project schedule anticipates the start of commercial operation of the PCFB (McIntosh 4A) in the winter of 2001. In parallel with the first 2 years of operation of the PCFB will be the design, fabrication, and construction of the topped PCFB technology (McIntosh 4B), with a planned start of operation in late 2003.

**Commercial Applications**

The commercial version of the topped PCFB technology will have a greenfield net plant efficiency of 45% (which equates to a heat rate approaching 7,500 Btu/kWh, based on HHV). In addition to higher plant efficiencies, the 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 emission limits that are half those allowed by NSPS, (3) oper-

ate economically on a wide range of coals, and (4) be amenable to shop fabrication.

The benefits of improved efficiency include reduced cost for fuels and a reduction in CO<sub>2</sub> emissions. Other environmental attributes include in-situ sulfur retention that can meet 95% removal, NO<sub>x</sub> emission that will be lower than 0.3 lb/10<sup>6</sup> Btu, and particulate matter discharge of approximately 0.03 lb/10<sup>6</sup> Btu. Although the system will generate a slight increase in solid waste as compared to conventional systems, the material is dry, readily disposable, and potentially usable material.

## Tidd PFBC Demonstration Project

**Project completed.**

### Participant

The Ohio Power Company

### Additional Team Members

American Electric Power Service Corporation—  
designer, constructor, and manager

The Babcock & Wilcox Company—technology supplier  
Ohio Coal Development Office—cofunder

### Location

Brilliant, Jefferson County, OH (Ohio Power Company's Tidd Plant, Unit 1)

### Technology

The Babcock & Wilcox Company's pressurized fluidized-bed combustion (PFBC) system (under license from ABB Carbon)

### Plant Capacity/Production

70 MWe

### Coal

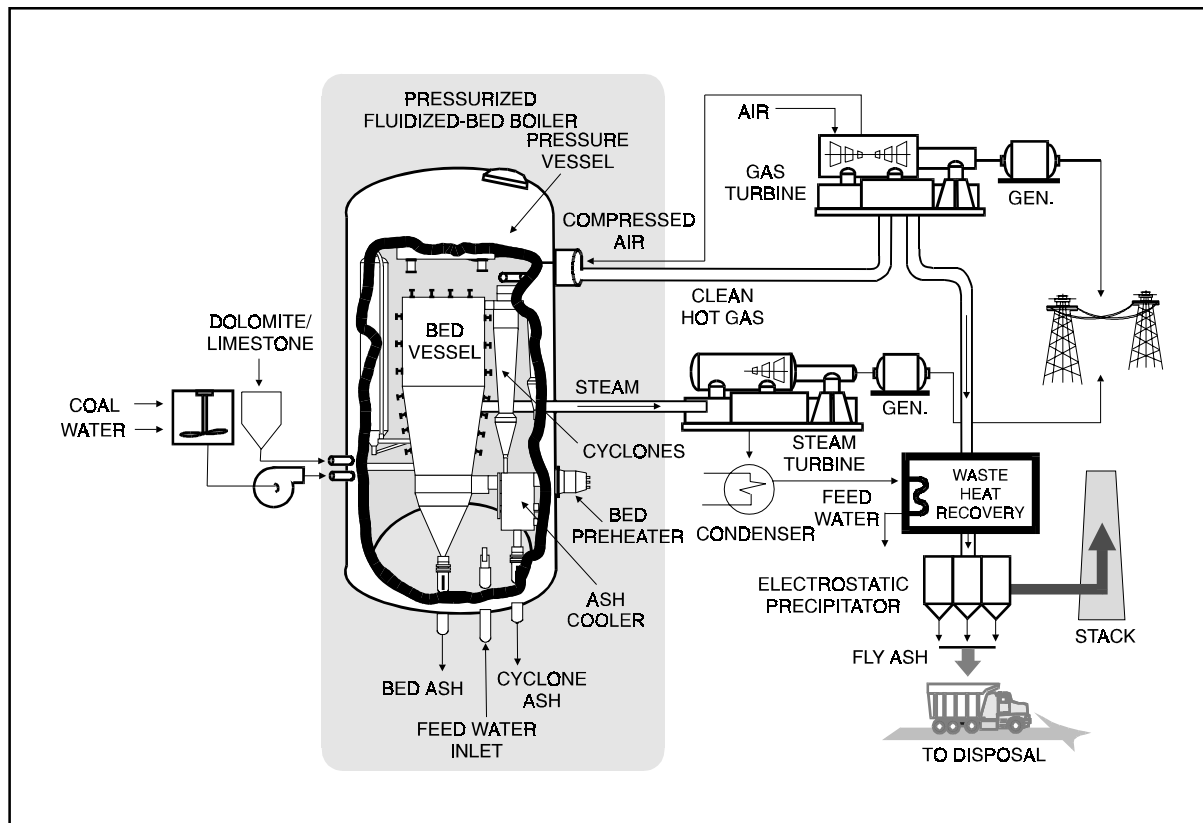
Ohio bituminous, 2–4% sulfur

### Project Funding

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

### Project Objective

To verify expectations of PFBC economic, environmental, and technical performance in a combined-cycle repowering application at utility scale; and to accomplish greater than 90% SO<sub>2</sub> removal and NO<sub>x</sub> emission level of 0.2 lb/10<sup>6</sup> Btu at full load.



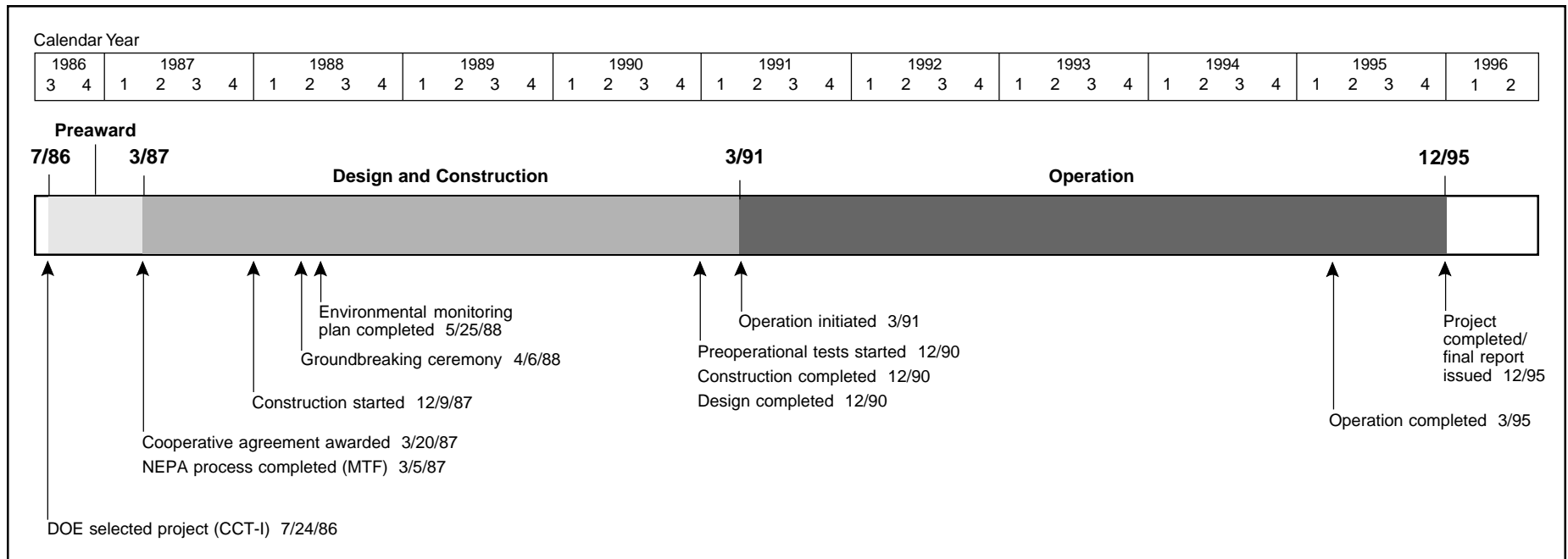
### Technology/Project Description

Tidd was the first large-scale operational demonstration of PFBC in the United States and one of only five worldwide. The boiler, cyclones, bed reinjection vessels, and associated hardware were 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 psi). 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 about 1,600 °F limits NO<sub>x</sub> 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. Heat from the gases exiting the turbine, combined with heat from a tube bundle in the fluid bed, generates steam to drive an existing 55-MWe steam turbine.



## Results Summary

### Environmental

- SO<sub>2</sub> removal efficiency of 90% was achieved at full load with a calcium-to-sulfur molar ratio (Ca/S) of 1.1 and temperature of 1,580 °F.
- SO<sub>2</sub> removal efficiency of 95% was achieved at full load with a Ca/S of 1.5 and temperature of 1,580 °F.
- NO<sub>x</sub> emissions were 0.15–0.33 lb/10<sup>6</sup> Btu.
- CO emissions were less than 0.01 lb/10<sup>6</sup> Btu.
- Particulate emissions were less than 0.02 lb/10<sup>6</sup> Btu.

### Operational

- Combustion efficiency was 99.6%.
- Heat rate was 10,280 Btu/kWh based on higher heating value of the fuel and gross electrical output, or 33.2% efficiency, because of the small-scale retrofit application.

- High-temperature particulate filtration system, a silicon carbide candle filter array, achieved 99.99% filtration efficiency on a mass basis.
- PFBC boiler demonstrated commercial readiness.
- ASEA Stal GT-35P gas turbine proved capable of operating commercially in a PFBC flue gas environment.

### Economic

Because the Tidd plant was a comparatively small-scale facility, economic performance would not be representative of a larger utility-scale plant using PFBC technology.

## Project Summary

The Tidd PFBC technology is a bubbling fluidized-bed combustion process operating at 12 atmospheres (175 psi). Fluidized combustion is inherently efficient. A pressurized environment further enhances combustion efficiency, allowing very low temperatures that mitigate thermal NO<sub>x</sub> generation, flue gas/sorbent reactions that increase sorbent utilization, and flue gas energy that is used to drive a gas turbine. The latter contributed significantly to system efficiency because of the high efficiency of gas turbines and the availability of gas turbine exhaust heat that can be applied to the steam cycle. A bed design temperature of 1,580 °F was established because it was the maximum allowable temperature at the gas turbine inlet and was well below temperatures for coal ash fusion, thermal NO<sub>x</sub> formation, and alkali vaporization.

Coal crushed to ¼ inch or less was injected into the combustor as a coal/water paste containing 25% water by weight. Crushed sorbent, either dolomite or limestone, was injected into the fluidized bed via two pneumatic feed lines, supplied from two lock hoppers. An alterna-

tive sorbent feed system was added in 1993, which provided the capability of injecting sorbent of various sizes directly into the coal-water paste feed system. The system provided the means to assess a wet-feed sorbent system while providing the opportunity to better control sorbent size.

In 1992, a 10-MWe advanced hot gas cleanup system was installed and commissioned as part of a research and development program and not part of the CCT demonstration. This system used ceramic candle filters to clean one-seventh of the exhaust gases from the PFBC system. The hot gas cleanup system unit replaced one of the seven cyclones that was normally used for final gas cleanup.

The Tidd PFBC demonstration plant accumulated 11,444 hours of coal-fired operations during its 54 months of operation. The unit completed 95 parametric tests, including continuous coal-fired runs of 28, 29, 30, 31, and 45 days. Ohio bituminous coals having sulfur contents of 2–4% were used in the demonstration.

### Environmental Performance

Testing showed that 90% SO<sub>2</sub> capture was achievable with a Ca/S molar ratio of 1.1 and that 95% SO<sub>2</sub> capture was possible with a Ca/S molar ratio of 1.5, provided the size gradation of the sorbent being utilized was optimized. This sulfur retention was achieved at a bed temperature of 1,580 °F and full bed height. Limestone proved ineffective as a sorbent, and as a result, testing focused on dolomite. The testing showed that sulfur capture as well as sintering was sensitive to the fineness of the dolomite sorbent (Plum Run Greenfield dolomite). Sintering of fluidized-bed materials, a fusing of the materials rather than effective reaction, had become a serious problem that required operation at bed temperatures below the optimum for effective boiler operation. Tests were conducted with sorbent size reduced from minus 6 mesh to a minus 12 mesh. The result with the finer material was a major, positive impact on process performance without the expected excessive elutriation of sorbent. The finer material increased the fluidization activity as

evidenced by a 10% improvement in heat transfer rate and an approximately 30% increase in sorbent utilization. In addition, the process was much more stable as indicated by reductions in temperature variations in both the bed and the evaporator tubes. Further, post-bed combustion and sintering were effectively eliminated.

The process demonstrated NO<sub>x</sub> emissions in the range of 0.15–0.33 lb/10<sup>6</sup> Btu. These emissions were inherent to the process, which was operating at approximately 1,580 °F. No NO<sub>x</sub> control enhancements, such as ammonia injection, were required. Emissions of carbon monoxide and particulates were less than 0.01 and 0.02 lb/10<sup>6</sup> Btu, respectively.

### Operational Performance

Except for localized erosion of the in-bed tube bundle and the more general erosion of the water walls, the Tidd boiler performed extremely well and was considered a commercially viable design. The in-bed tube bundle experienced no widespread erosion that would require significant maintenance. While the tube bundle was in good condition, a significant amount of erosion on each of the four water walls was observed. While no operational failure occurred during the demonstration, remedial action, such as the use of refractory coatings utilized successfully on two commercial PFBC units, was deemed to be warranted.

The gas turbine experienced both structural and erosion problems and was the leading cause of unit unavailability during the first 3 years of operation. However, design changes instituted over the course of the demonstration proved effective in addressing the problems. The Tidd demonstration showed that a gas turbine



▲ The PFBC demonstration at the repowered 70-MWe unit at Ohio Power's Tidd Plant led to significant refinements and understanding of the technology.

could operate in a PFBC flue gas environment, and it was concluded that erosion was manageable with a scheduled maintenance program.

The efficiency of the PFBC combustion process was calculated during the testing from the amount of unburned carbon in the cyclone ash and bed ash together with the measurements of the amount of carbon monoxide in the flue gas. Tests showed combustion efficiencies of 99.6%, surpassing the design or expected efficiency of 99.0%.

Using data for typical full-load operation, a heat rate of 10,280 Btu/kWh (HHV basis) was calculated. This corresponds to a cycle thermodynamic efficiency of 33.2% at a point where the cycle produced 70 MWe of

gross electrical power while burning Pittsburgh No. 8 coal. Because the Tidd plant was a repowering application at a comparatively small scale, the measured efficiency does not represent what would be expected for a larger utility-scale plant using Tidd technology. Studies conducted under the PFBC Utility Demonstration Project showed that efficiencies of over 40% are likely for a larger utility-scale PFBC plant.

In summary, the Tidd PFBC Demonstration Project showed that the PFBC system could be applied to electric power generation. Further, the demonstration project led to significant refinements and understanding of the technology in the areas of turbine erosion, sorbent utilization, sintering, post-bed combustion, and boiler materials.

Testing of advanced ceramic candle filtration elements on a slipstream of one-seventh of the exhaust gases for over 5,800 hours of coal-fired operation showed that the design of the particulate filter was structurally adequate. However, results also showed that clay-bonded silicon carbide lost 50% of its strength after 1,000–2,000 hours of exposure and that a buildup of ash in the filter vessel caused breakage of the candles. The filter operated at a pressure drop on the order of 100 inches of water column and a filtration efficiency (mass basis) of 99.99%.

### Economic Performance

Because the Tidd plant was a comparatively small-scale facility, economic performance would not be representative of a larger utility-scale plant using PFBC technology.

### Commercial Applications

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.

The environmental attributes of a mature system include in-situ sulfur removal of 95% and NO<sub>x</sub> emission levels less than 0.1 lb/10<sup>6</sup> Btu. Although the system generates slightly more solid waste compared to conventional systems, the dry material is either readily disposable or potentially usable.

### Contacts

Mario Marrocco, (614) 223-2460

American Electric Power Service Corporation  
1 Riverside Plaza  
Columbus, OH 43215

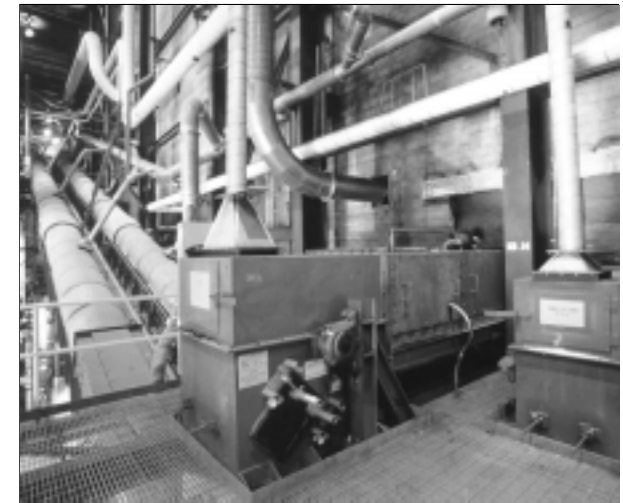
George Lynch, DOE/HQ, (301) 903-9434

Donald W. Geiling, FETC, (304) 285-4784

### References

- *Tidd PFBC Hot Gas Clean Up Program Final Report*. Report No. DOE/MC/26042-5130. The Ohio Power Company. October 1995. (Available from NTIS as DE96000650.)
- *Tidd PFBC Demonstration Project Final Report, Including Fourth Year of Operation*. The Ohio Power Company. August 1995. (Available from DOE Library/Morgantown, 1-800-432-8330, ext. 4184 as DE96000623.)
- *Tidd PFBC Demonstration Project Final Report, March 1, 1994–March 30, 1995*. Report No. DOE/MC/24132-T8. The Ohio Power Company. August 1995. (Available from NTIS as DE96004973.)
- *Tidd PFBC Demonstration Project—First Three Years of Operation*. Report No. DOE/MC/24132-5037-vol. 1 and 2. The Ohio Power Company. April 1995. (Available from NTIS as DE96000559 for vol. 1 and DE96003781 for vol. 2.)

- *A Study of Hazardous Air Pollutants at the Tidd PFBC Demonstration Plant*. Report No. DOE/MC/26042-4083. American Electric Power Service Corporation. October 1994. (Available from NTIS as DE95009729.)
- *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 DE94004120.)
- *Tidd PFBC Demonstration Project: Public Final Design Report*. Report No. DOE/MC/24132-3195. The Ohio Power Company. October 1992. (Available from NTIS as DE93000234.)
- *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. (Available from NTIS as DE87005803.)



▲ Coal and sorbent conveyors can be seen just after entering the Tidd Plant.

## ACFB Demonstration Project

### Participant

York County Energy Partners, L.P.

### Additional Team Member

Foster Wheeler Energy Corp.—technology supplier

### Location

To be determined

### Technology

Foster Wheeler's atmospheric circulating fluidized-bed (ACFB) combustor

### Plant Capacity/Production

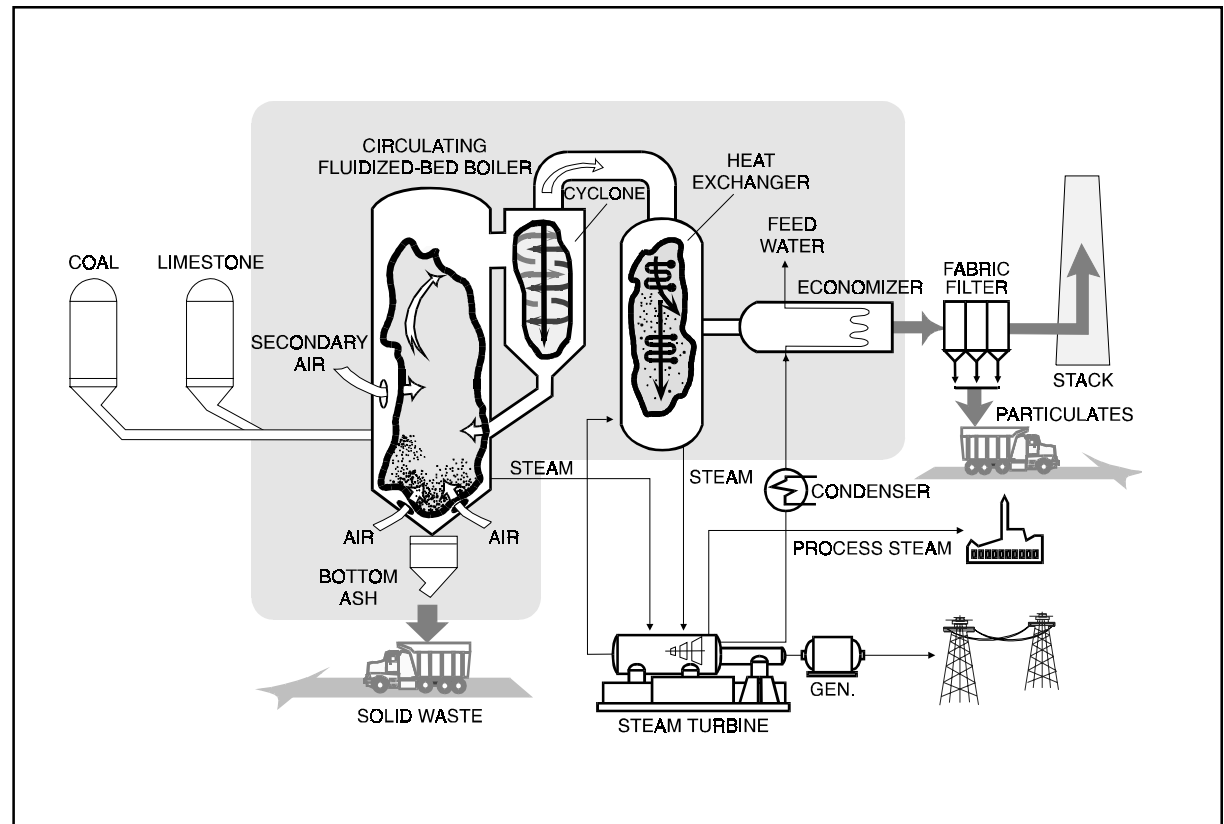
235 MWe (net)

### Project Funding

Total project cost	\$379,645,000	100%
DOE	74,733,833	20
Participant	304,911,167	80

### Project Objective

To demonstrate ACFB at 235 MWe, representing a scale-up from previously constructed facilities; to verify expectations of the technology's economic, environmental, and technical performance to provide utility and nonutility power producers with the data necessary for evaluating a large-scale ACFB as a commercial alternative to accomplish greater than 90% SO<sub>2</sub> removal and to reduce NO<sub>x</sub> emissions by 60% when compared with conventional technology.



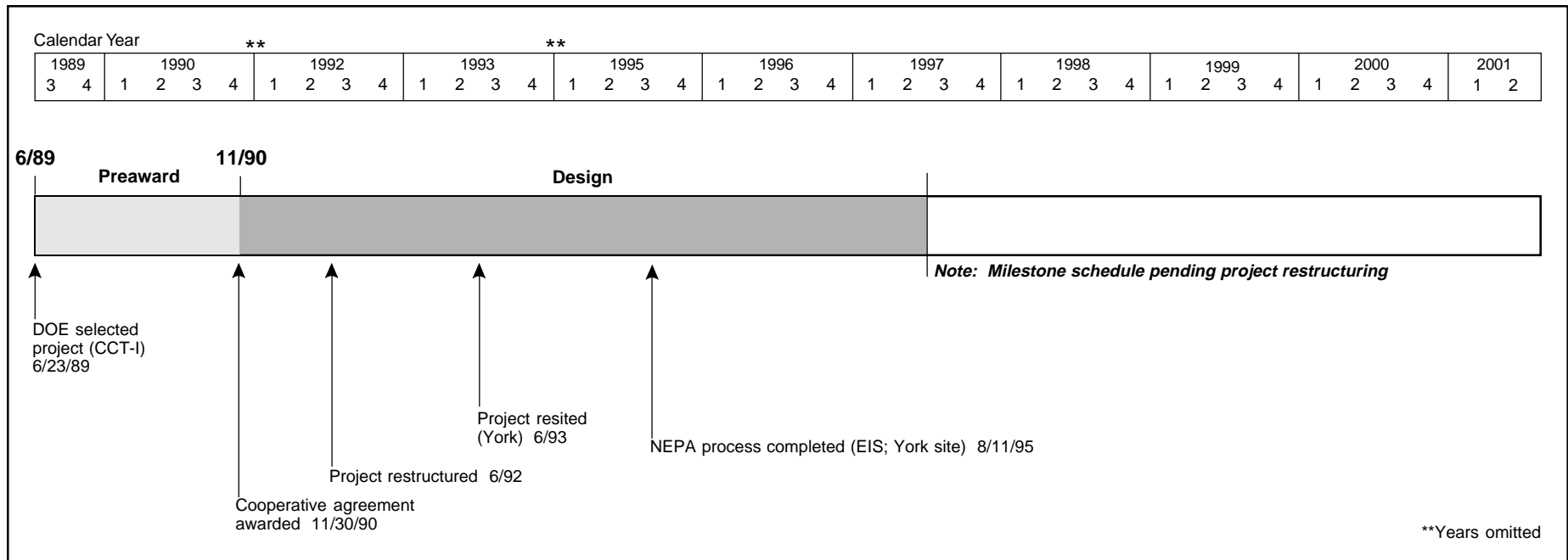
### Technology/Project Description

In this project, the circulating fluidized-bed combustor operates at atmospheric pressure. Coal and coal-refuse fuels, 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 downstream of the cyclone particulate separator to protect against erosion. The steam is then used to produce power in a conventional steam cycle.

The heat rate for this cogeneration plant is expected to be 9,200 Btu/kWh (37% efficiency). SO<sub>2</sub> emissions are expected to be below 0.24 lb/10<sup>6</sup> Btu. This technology operates at lower temperatures than conventional boilers, thus reducing NO<sub>x</sub> formation.



**Project Status/Accomplishments**

All activities have been put on hold while resiting of the project is considered. On September 26, 1995, York County Energy Partners and Metropolitan Edison Company announced their joint decision to restructure the power-purchase agreement, thus removing York County as a site for this project.

In its commercial configuration, ACFB technology offers several potential benefits when compared to conventional pulverized coal-fired systems: lower capital costs; reduced SO<sub>2</sub> and NO<sub>x</sub> emissions at lower costs; higher combustion efficiency; and dry, granular solid material that is easily disposed of or potentially salable.

**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 or ash 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.



## Nucla CFB Demonstration Project

**Project completed.**

### Participant

Tri-State Generation and Transmission Association, Inc.  
(formerly Colorado-Ute Electric Association, Inc.)

### Additional Team Members

Foster Wheeler Energy Corp.—technology supplier  
Technical Advisory Group (potential users)—cofounder  
Electric Power Research Institute—technical consultant

### Location

Nucla, Montrose County, CO (Nucla Station)

### Technology

Foster Wheeler's atmospheric circulating fluidized-bed (ACFB) combustion system

### Plant Capacity/Production

100 MWe (net)

### Coals

Western bituminous—

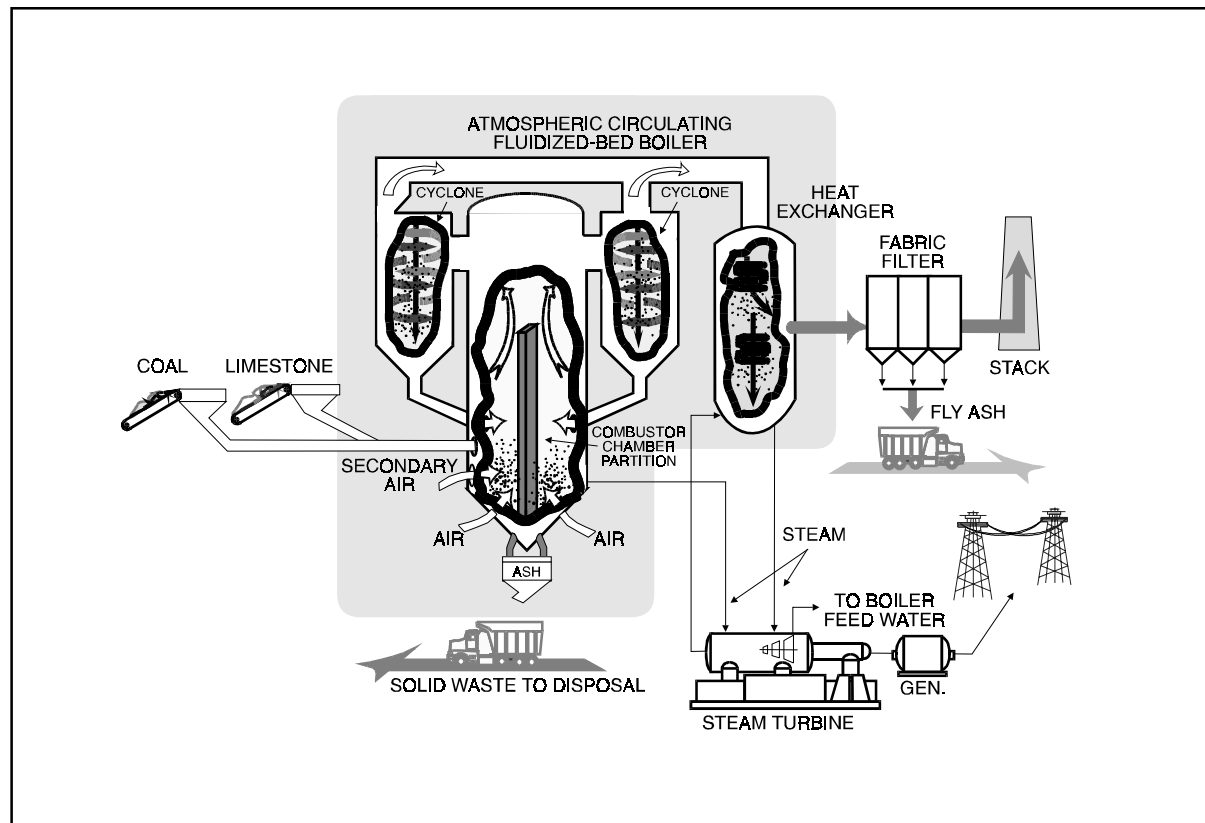
- Salt Creek, 0.5% sulfur, 17% ash
- Peabody, 0.7% sulfur, 18% ash
- Dorchester, 1.5% sulfur, 23% ash

### Project Funding

Total project cost	\$46,512,678	100%
DOE	17,130,411	37
Participant	29,382,267	63

### Project Objective

To demonstrate the feasibility of ACFB technology at utility scale and to evaluate the economic environmental, and operational performance at that scale.



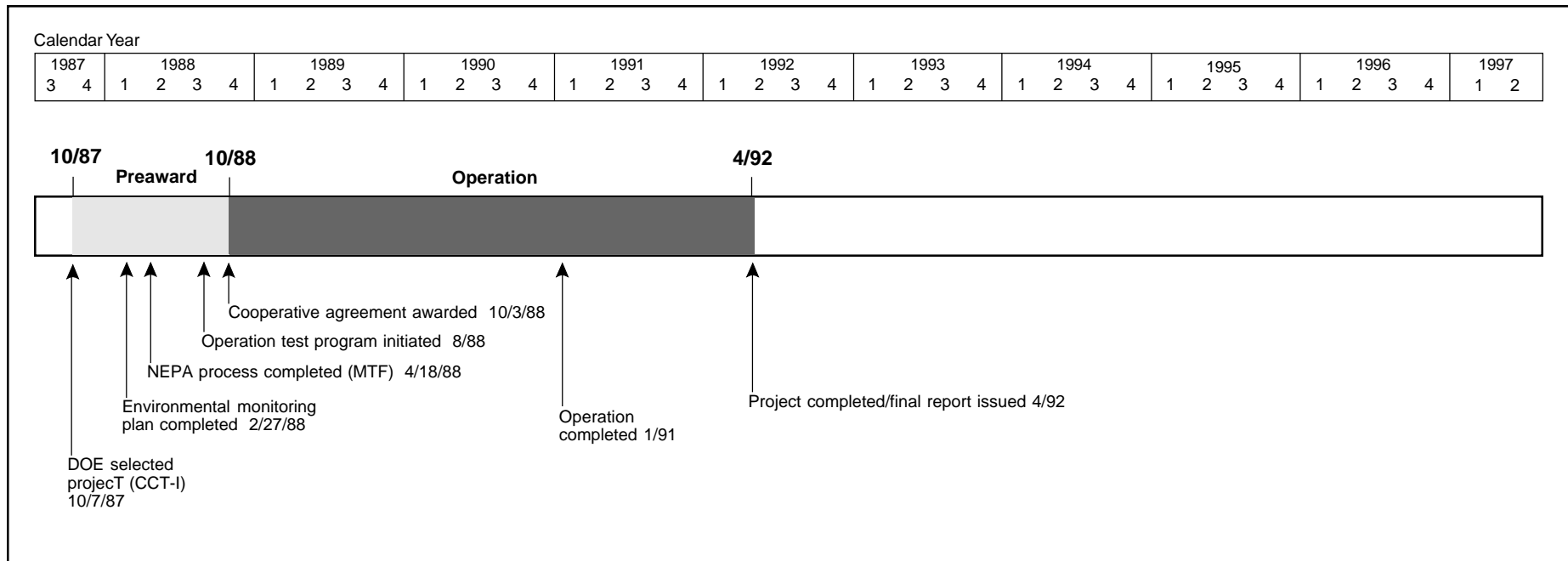
### Technology/Project Description

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  $\text{NO}_x$  formation. Calcium in the sorbent combines with  $\text{SO}_2$  gases to form calcium sulfite and sulfate solids, 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-lb/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).

In 1992, Colorado-Ute Electric Association, Inc., the owner of Nucla Station, was purchased by Tri-State Generation and Transmission Association, Inc.



## Results Summary

### Environmental

- Bed temperature had the greatest effect on pollutant emissions and boiler efficiency.
- At bed temperatures below 1,620 °F, sulfur capture efficiencies of 70 and 95% were achieved at calcium-to-sulfur (Ca/S) molar ratios of 1.5 and 4.0, respectively.
- During all tests, NO<sub>x</sub> emissions averaged 0.18 lb/10<sup>6</sup> Btu and did not exceed 0.34 lb/10<sup>6</sup> Btu.
- CO emissions varied between 70 and 140 ppmv.
- Particulate emissions ranged from 0.0072 to 0.0125 lb/10<sup>6</sup> Btu, corresponding to a removal efficiency of 99.9%.
- Solid waste was essentially benign and showed potential as an agricultural soil amendment, soil/road bed stabilizer, or landfill cap.

### Operational

- Boiler efficiency ranged from 85.6–88.6% and combustion efficiency ranged from 96.9–98.9%.
- A 3:1 boiler turndown capability was demonstrated.
- Heat rate at full load was 11,600 Btu/kWh and was 12,400 Btu/kWh at half load.

### Economic

- Capital cost for the Nucla retrofit was \$1,123/kW and a normalized power production cost was 64 mills/kWh.

## Project Summary

Fluidized-bed combustion evolved from efforts to find a combustion process conducive to controlling pollutant emissions without external controls. Fluidized-bed combustion enables efficient combustion at temperatures of 1,400–1,700 °F, well below the thermal NO<sub>x</sub> generation temperature (2,500 °F), and high SO<sub>2</sub>-capture efficiency through effective sorbent/flue gas contact. ACFB differs from the more traditional fluid-bed combustion. Rather than submerging a heat exchanger in the fluid bed, which dictates a low-fluidization velocity, ACFB uses a relatively high fluidization velocity, creating a more turbulent bed. Hot cyclones capture and return the solids emerging from the turbulent bed to control temperature and extend the gas/solid contact time and to protect a downstream heat exchanger.

Interest and participation of the Department of Energy, Electric Power Research Institute, and Technical Advisory Group (potential users) in the project involved evaluating ACFB potential for broad utility application through a comprehensive test program. Over a 2½-year

period, 72 steady-state performance tests were conducted and 15,700 hours logged. The result was a database that remains the most comprehensive, available resource on ACFB technology.

### Operational Performance

Between July 1988 and January 1991, the plant operated with an average availability of 58% and an average capacity factor of 40%. However, toward the end of the demonstration, most of the technical problems had been overcome. During the last 3 months of the demonstration, average availability was 97% and the capacity factor, 66.5%.

Over the range of operating temperature at which testing was performed, bed temperature was found to be the most influential operating parameter. With the exception of coal-fired configuration and excess air at elevated temperatures, bed temperature was the only parameter that had a measurable impact on emissions and efficiency.

Combustion efficiency, a measure of the quantity of carbon that is fully oxidized to CO<sub>2</sub>, ranged from 96.9–98.9%. 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 85.6–88.6%. 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.

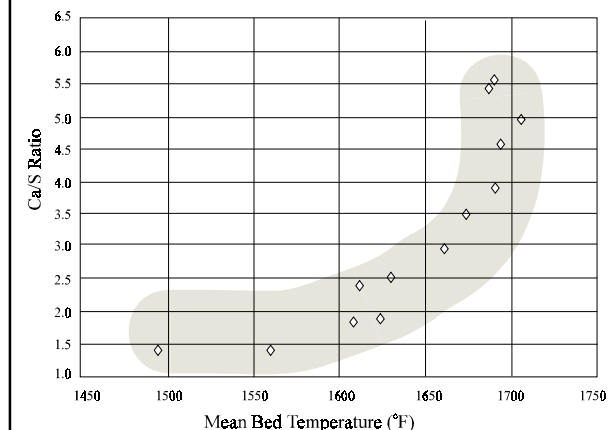
### Environmental Performance

As indicated above, bed temperature had the greatest impact on ACFB performance, including pollutant emissions. Exhibit 5-30 shows the effect of bed temperatures on the Ca/S requirement for 70% sulfur retention. Ca/S ratios were calculated based on the calcium content of the sorbent only and do not account for the calcium content of the coal. While a Ca/S of about 1.5 was sufficient to achieve 70% sulfur retention in the 1,500 °F to 1,620 °F range, the Ca/S requirement jumped to 5.0 or more at 1,700 °F or greater.

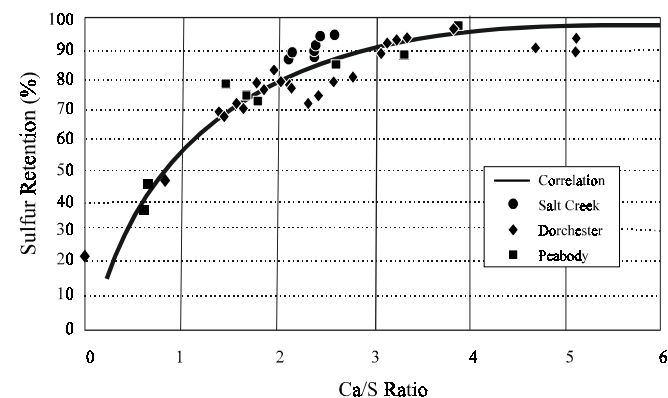
Exhibit 5-31 shows the effect of Ca/S molar ratio on sulfur retention at average bed temperatures below 1,620 °F. Salt Creek and Peabody coals contain 0.5% and 0.7% sulfur, respectively. To achieve 70% SO<sub>2</sub> reduction, or the 0.4 lb/10<sup>6</sup> Btu emission rate required by the licensing agreement, a Ca/S molar ratio of approximately 1.5 is required. To achieve an SO<sub>2</sub> reduction of 95%, a Ca/S molar ratio of approximately 4.0 is necessary. Dorchester coal, averaging 1.5% sulfur content, required a somewhat lower Ca/S for a given retention.

NO<sub>x</sub> emissions measured throughout the demonstration were less than 0.34 lb/10<sup>6</sup> Btu, which is well below the regulated value of 0.5 lb/10<sup>6</sup> Btu. The average level of NO<sub>x</sub> emissions for all tests was 0.18 lb/10<sup>6</sup> Btu. NO<sub>x</sub> emissions indicate a relatively strong correlation with temperature, increasing from 40 ppmv (0.06 lb/10<sup>6</sup> Btu) at 1,425 °F to 240 ppmv (0.34 lb/10<sup>6</sup> Btu) at 1,700 °F. Limestone feed rate was also identified as a variable affecting NO<sub>x</sub> emissions, i.e., somewhat higher NO<sub>x</sub> emissions resulted from increasing calcium-to-nitrogen (Ca/N) ratios. The mechanism was believed to be oxidation

**Exhibit 5-30**  
**Effect of Bed Temperature on Ca/S Requirement**



**Exhibit 5-31**  
**Calcium Requirements and Sulfur Retentions for Various Fuels**



of volatile nitrogen in the form of ammonia ( $\text{NH}_3$ ) catalyzed by calcium oxide.

CO emissions decrease as temperature increases, from 140 ppmv at 1,425 °F to 70 ppmv at 1,700 °F.

At full load, the hot cyclones removed 99.8% of the particulates. With the addition of baghouses, removal efficiencies achieved on Peabody and Salt Creek Coals were 99.905% and 99.959%, respectively. This equated to emission levels of 0.0125 lb/10<sup>6</sup> Btu for Peabody coal and 0.0072 lb/10<sup>6</sup> Btu for Salt Creek coal, well below the required 0.03 lb/10<sup>6</sup> Btu.

### Economic Performance

The final capital costs associated with the engineering, construction, and start-up of the Nucla ACFB system were \$112.3 million. This represents a cost of \$1,123/net kW. Total power costs associated with plant operations between September 1988 and January 1991 were approximately \$54.7 million, resulting in a normalized cost of power production of 64 mills/kWh. The average monthly operating cost over this period was about \$1,888,000. Fixed costs represent about 62% of the total and include interest (47%), taxes (4.8%), depreciation (6.9%), and insurance (2.7%). Variable costs represent more than 38% of the power production costs and include fuel expenses (26.2%), non-fuel expenses (6.8%), and maintenance expenses (5.5%).

### Commercial Applications

ACFB could play a role in near-term electric power generation markets, in which the Energy Information Administration estimates that 4 GWe of new coal-based capacity will be needed between 1996 and 2000 to replace retiring utility units. In the post-2000 time frame, ACFB will be



▲ The 110-MWe Nucla ACFB demonstration enabled Pyropower Corporation (now owned by Foster Wheeler) to save almost 3 years in establishing a commercial line of ACFB units.

well positioned to compete for the estimated 32 GWe of additional coal-based power generation and cogeneration needed between 2000 and 2015. The international power generation market is expected to substantially overshadow the domestic market, particularly in the near-term, and the attributes of ACFB make it particularly suitable for worldwide deployment.

### Contacts

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

George Lynch, DOE/HQ, (301) 903-9434  
Nelson F. Rekos, FETC, (304) 285-4066

### References

- “Field Study of Wastes from Fluidized Bed Combustion Technologies.” Andrew Weinberg, Larry Holcomb, and Ray Butler. *1991 11th International Conference on Fluidized Bed Combustion—Volume 2*, page 865. Available from American Society of Mechanical Engineers.
- *Colorado-Ute Nucla Station Circulating Fluidized-Bed (CFB) Demonstration—Volume 2: Test Program Results*. EPRI Report No. GS-7483. October 1991.
- *Demonstration Program Performance Test: Summary Reports*. Report No. DOE/MC/25137-3104. Colorado-Ute Electric Association, Inc. March 1992. (Available from NTIS as DE92001299.)
- *Economic Evaluation Report: Topical Report*. Report No. DOE/MC/25137-3127. Colorado-Ute Electric Association, Inc., March 1992. (Available from NTIS as DE93000212.)
- *Nucla CFB Demonstration Project: Detailed Public Design Report*. Report No. DOE/MC/25137-2999. Colorado-Ute Electric Association, Inc., December 1990. (Available from NTIS as DE91002081.)
- *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 DE93000251.)
- *Comprehensive Report to Congress on the Clean Coal Technology Program: Nucla CFB Demonstration Project*. (Colorado-Ute Electric Association, Inc.). Report No. DOE/FE-0106. U.S. Department of Energy. July 1988.

## 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

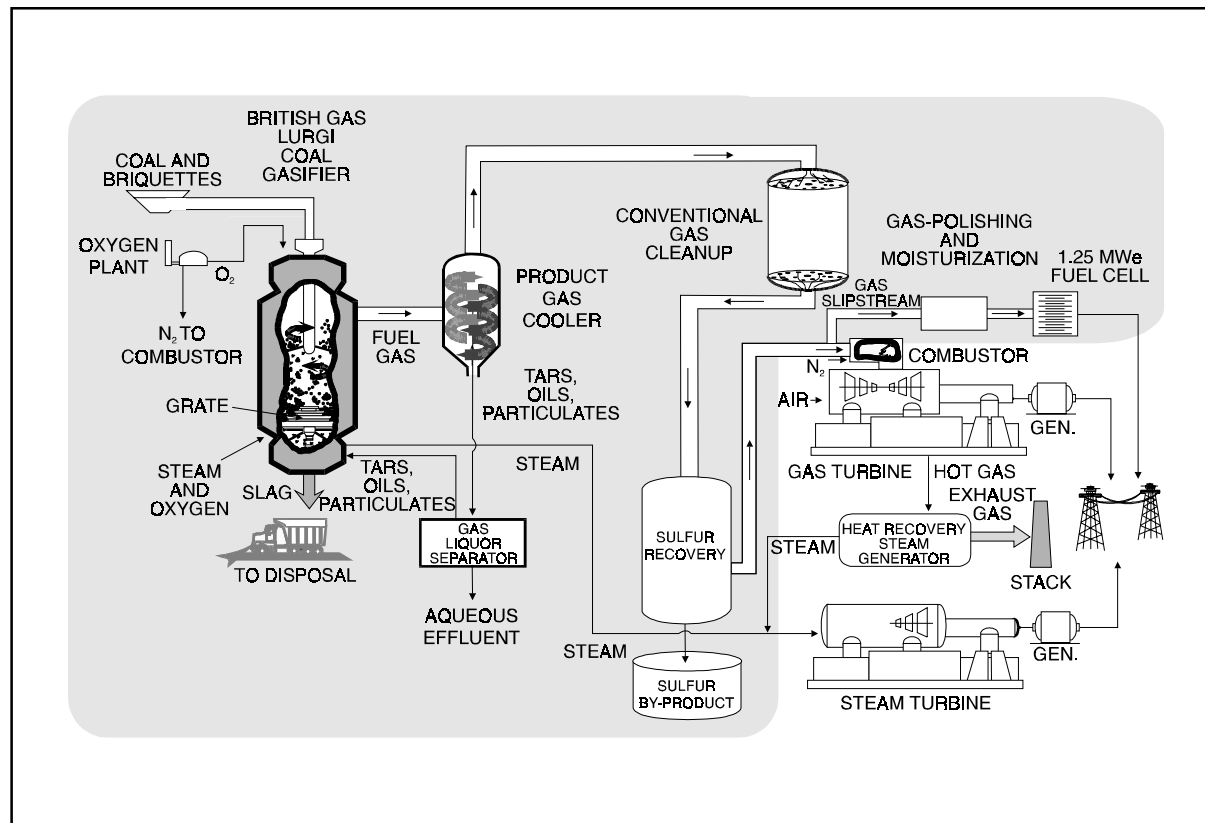
An east coast site

### 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)

### 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
Participant	657,796,189	78

### Project Objective

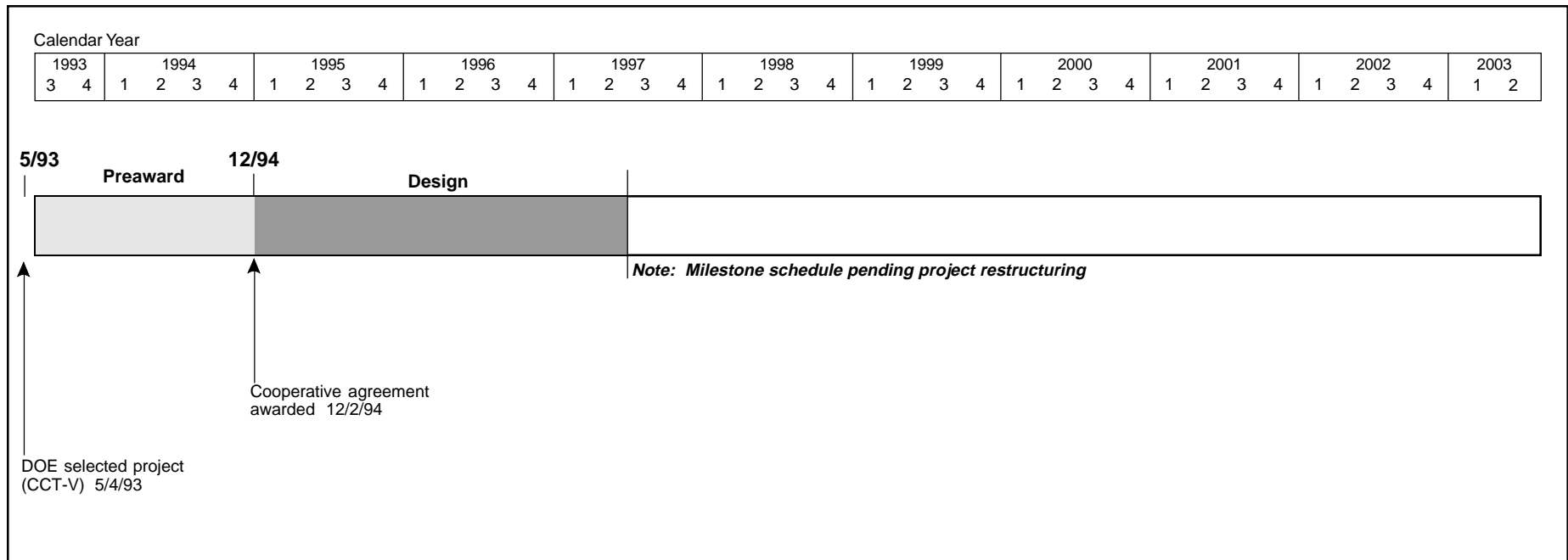
To demonstrate and assess the reliability, availability, and maintainability of a utility-scale IGCC system using high-sulfur bituminous coal in an oxygen-blown, fixed-bed, slagging gasifier and the operability of a molten carbonate fuel cell fueled by coal gas, by an independent power producer under 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 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 MMCFC module.

### Project Status/Accomplishments

The cooperative agreement was awarded December 2, 1994. The participant is looking for an east coast site.

### 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<sub>2</sub> when compared to a conventional pulverized coal plant equipped with a scrubber. SO<sub>2</sub> emissions from the IGCC system are expected to be less than 0.1 lb/10<sup>6</sup> Btu (99% reduction); NO<sub>x</sub> emissions, less than 0.15 lb/10<sup>6</sup> 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

### Plant Capacity/Production

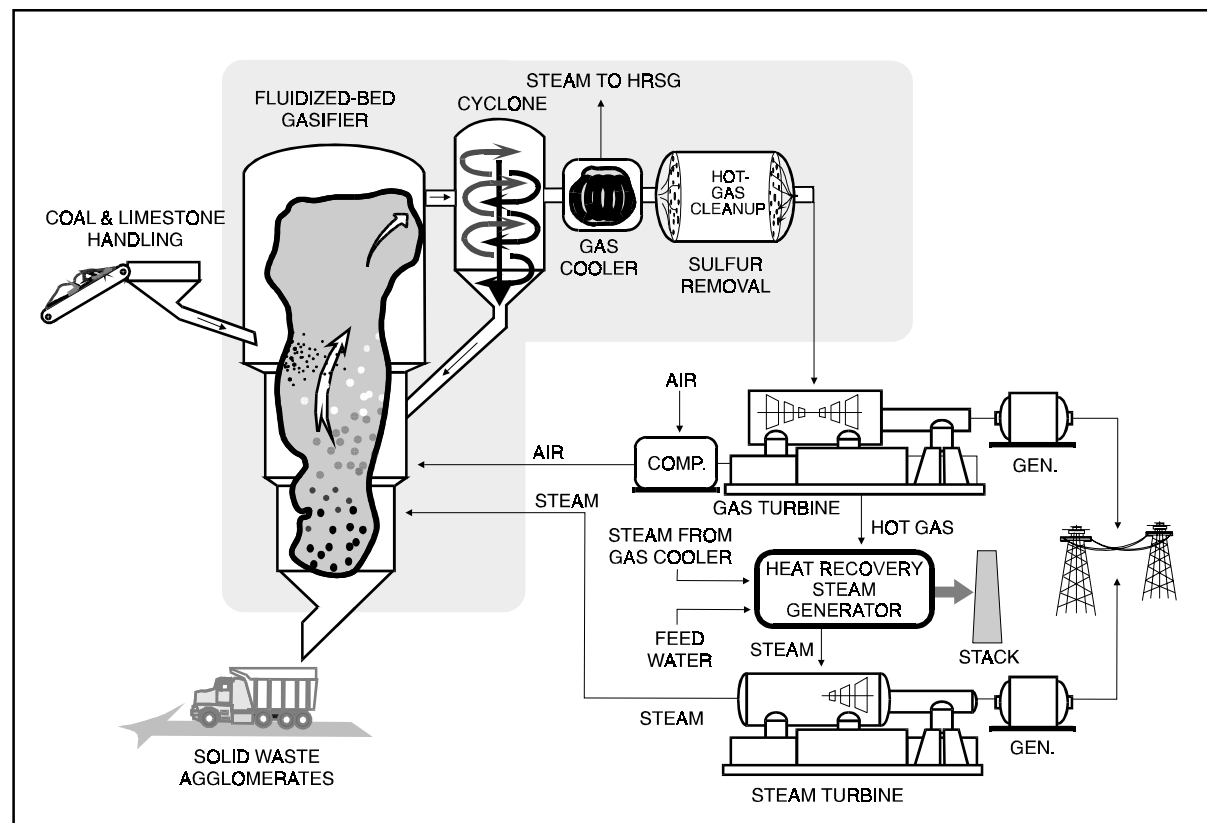
99 MWe (net)

### Project Funding

Total project cost	\$335,913,000	100%
DOE	167,956,500	50
Participant	167,956,500	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

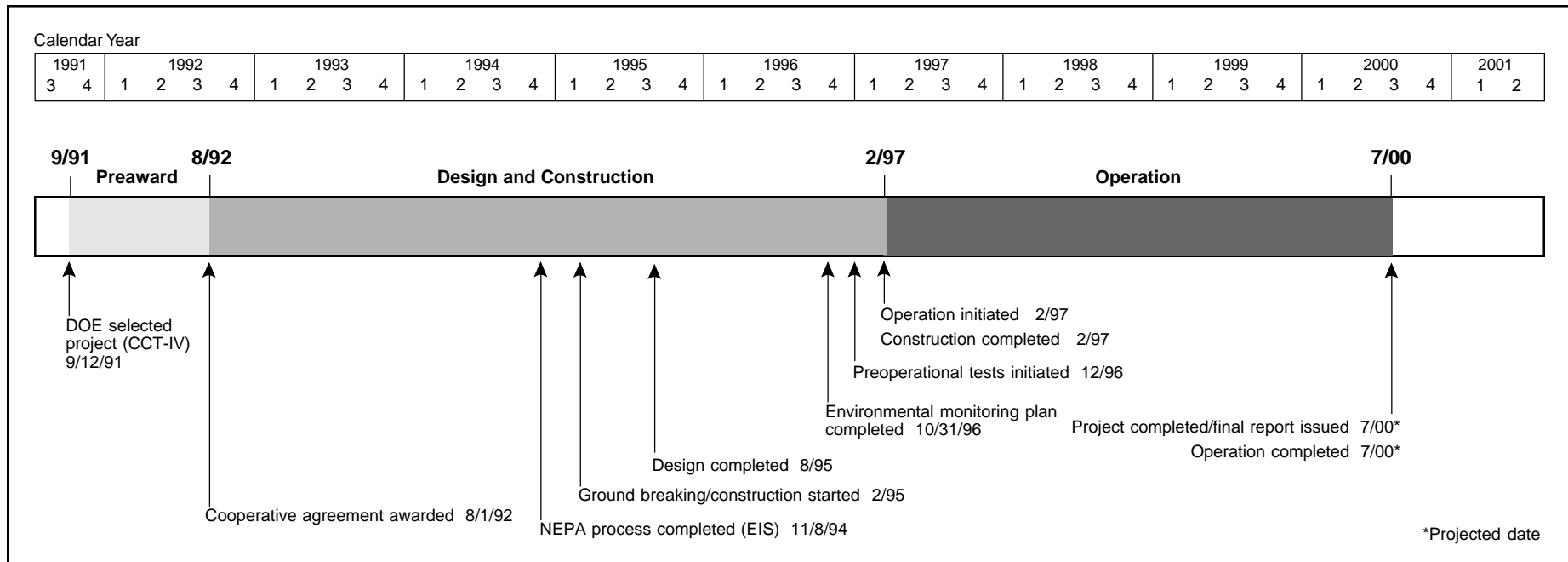
Dried and crushed coal and limestone are introduced into a pressurized, air-blown, fluidized-bed gasifier. Crushed limestone is used to capture a portion of the sulfur and to inhibit conversion of fuel nitrogen to ammonia. The sulfur reacts with the limestone to form calcium sulfide which, after oxidation, exits as calcium sulfate 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 in a transport reactor.

The hot, cleaned gas then enters the GE Model MS6001FA 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<sub>x</sub> emissions are 0.069 lb/10<sup>6</sup> Btu (94% reduction). Due to the combination of in-bed sulfur capture and hot gas cleanup, SO<sub>2</sub> emissions are 0.069 lb/10<sup>6</sup> Btu (90% reduction).



In the demonstration project, 880 tons/day of coal are converted into 107 MWe (gross), or 99 MWe (net), for export to the grid. Southern Utah bituminous coal (0.5–0.9% sulfur) is the design coal; tests using midwestern or eastern high-sulfur bituminous coal (2–3% sulfur) also are planned. The integrated gasification system is located at Sierra Pacific Power Company’s Tracy Station, near Reno, NV.

### Project Status/Accomplishments

Construction activities, which began in early 1995, were completed in February 1997. Start-up efforts began during the second half of 1996 and continued through June 1997. The GE Frame 6FA (Model MS6001FA) combustion turbine at the unit is the first of its kind in the world and was successfully fired for the first time on August 15, 1996, using natural gas. The combined-cycle part of the plant began commercial operation on natural gas in November 1996.

### 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<sub>2</sub> emissions. The compactness of a IGCC system 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.



## 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

G.E. Environmental Systems—hot-gas cleanup technology supplier

TECO Power Services, Inc.—project manager and marketer

Bechtel Power Corporation—architect and engineer

### Location

Mulberry, Polk County, FL (Tampa Electric Company's Polk Power Station, Unit 1)

### Technology

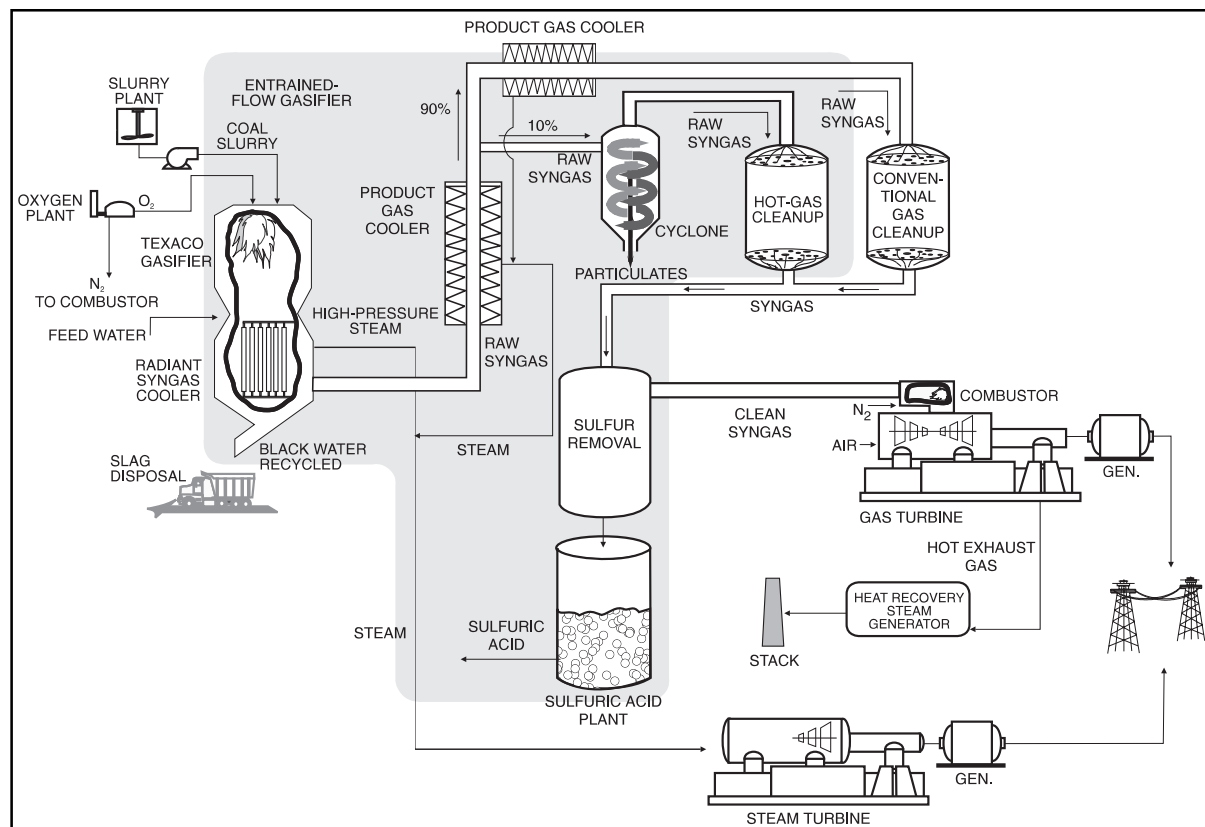
Integrated gasification combined-cycle (IGCC) system using Texaco's pressurized, oxygen-blown, entrained-flow gasifier technology and incorporating both conventional, low-temperature acid-gas removal and hot-gas moving-bed desulfurization

### Plant Capacity/Production

250 MWe (net)

### Project Funding

Total project cost	\$303,288,446	100%
DOE	150,894,223	49
Participant	152,394,223	51



### Project Objective

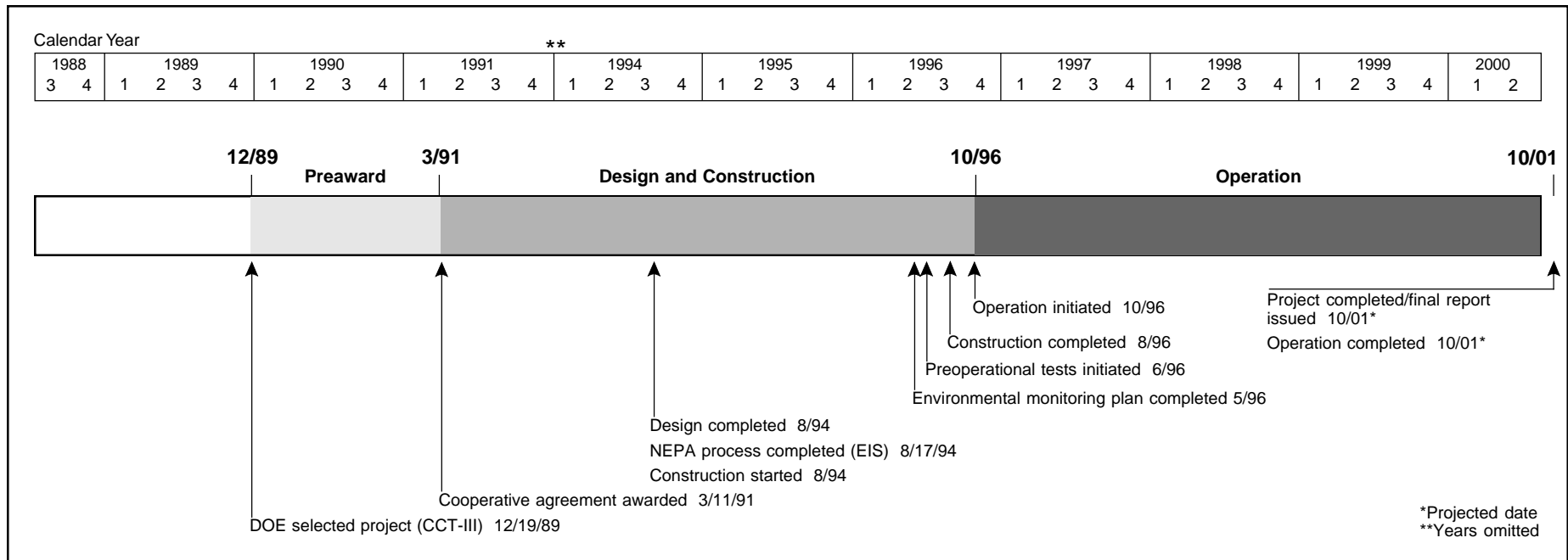
To demonstrate IGCC technology in a greenfield, commercial, electric utility application at the 250-MWe size with a Texaco gasifier. To demonstrate the integrated performance of a metal oxide hot-gas cleanup system, conventional cold-gas cleanup, and an advanced gas turbine with nitrogen injection (from the air separation plant) for power augmentation and  $\text{NO}_x$  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 reacted 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. Combined, these cleanup systems are expected to maintain sulfur levels below  $0.21 \text{ lb}/10^6 \text{ Btu}$  (96% capture). The cleaned gases are then routed to a combined-cycle system for power generation. A GE MS 7001F gas turbine generates about 192 MWe (gross). Thermally generated  $\text{NO}_x$  is controlled to below  $0.27 \text{ lb}/10^6 \text{ Btu}$  by injecting



nitrogen as a diluent in the turbine's combustion section. A heat-recovery steam-generator uses heat from the gas-turbine exhaust to produce high-pressure steam. This steam, along with the steam generated in the gasification process, is routed to the steam turbine to generate an additional 121 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) of the planned 1,150-MWe Polk Power Station. 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 can be used as a raw material to make agricultural fertilizer and the nonleachable slag used in roofing shingles and asphalt roads and as a structural fill in construction projects.

### Project Status/Accomplishments

The first syngas was produced on July 19, 1996. The first gasifier run lasted 21.5 hours, which set the longevity record for first fire on a solid-fuel Texaco gasifier. Ten gasifier runs totalling 174 hours were completed by the end of September. All plant systems had been successfully commissioned, so Unit 1 was placed in commercial operation on September 30, 1996.

Another 10 gasifier runs totaling 701 hours were made in October and November 1996, prior to a planned outage, which began December 5 for routine maintenance, inspection, and some minor improvements. In the 30 days preceding the outage, the gasifier was on-line 67% of the time and the gas turbine was on 100% syngas fuel 59% of the time, exceeding target expectations for this period. Efforts in late 1996 were geared toward keeping the unit on line as much as possible to obtain operating experience. During December 1996 and January 1997, the combined-cycle system operated for 40 out of 45 days, while achieving a maximum load of 310 MWe (gross) on clean syngas. Efforts in 1997 are

focusing on improving the unit's reliability, reducing operating costs, improving heat rate, commissioning the hot gas cleanup system, and beginning alternate coal testing. The unit was dedicated on January 10, 1997. The project was presented the 1997 Powerplant Award by *Power* magazine.

### 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<sub>2</sub> capture with a NO<sub>x</sub> emissions reduction of 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 a 100-MWe pilot unit (Cool Water plant) tested without full system integration.

## 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  
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

### Plant Capacity/Production

262 MWe (net)

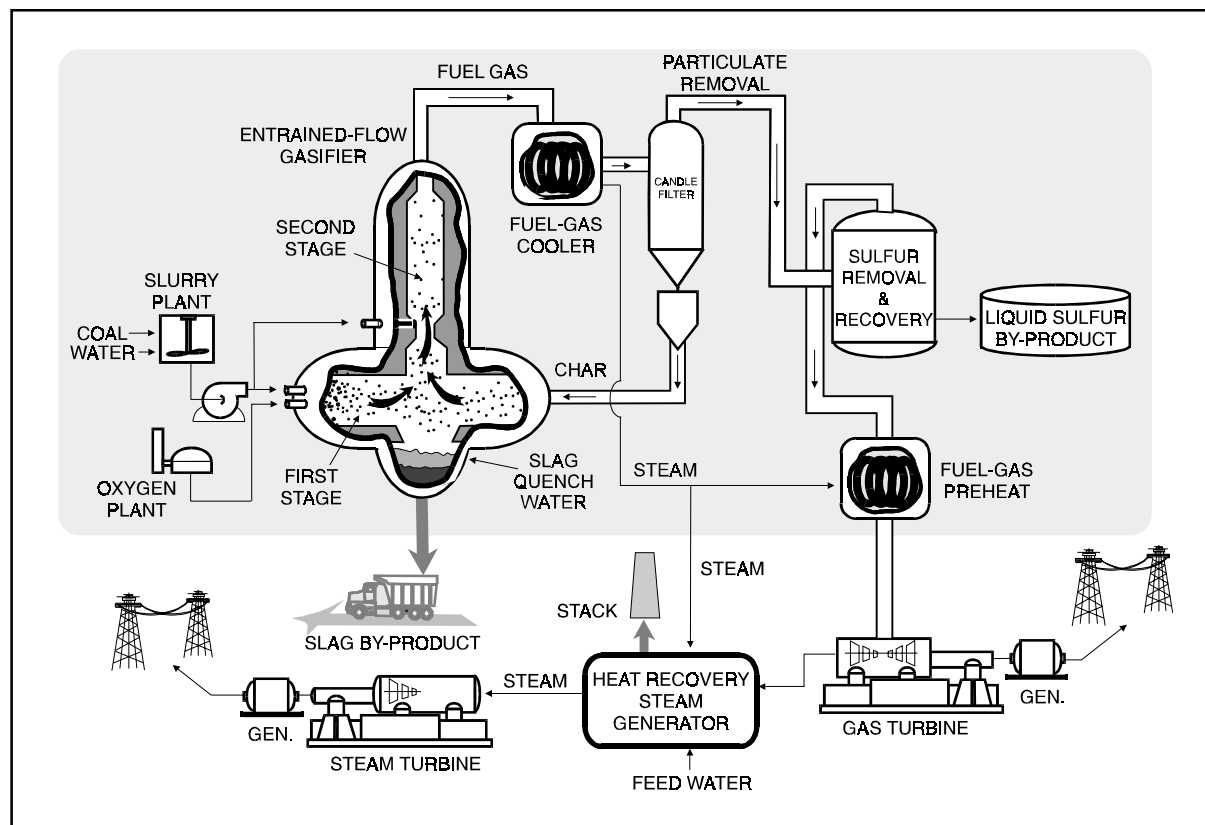
### Project Funding

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 bitumi-  
nous coal; and to assess long-term reliability, availability,  
and maintainability of the system at a fully commercial  
scale.

\*Destec Energy, Inc., merger with NGC is expected to be completed in  
August 1997.

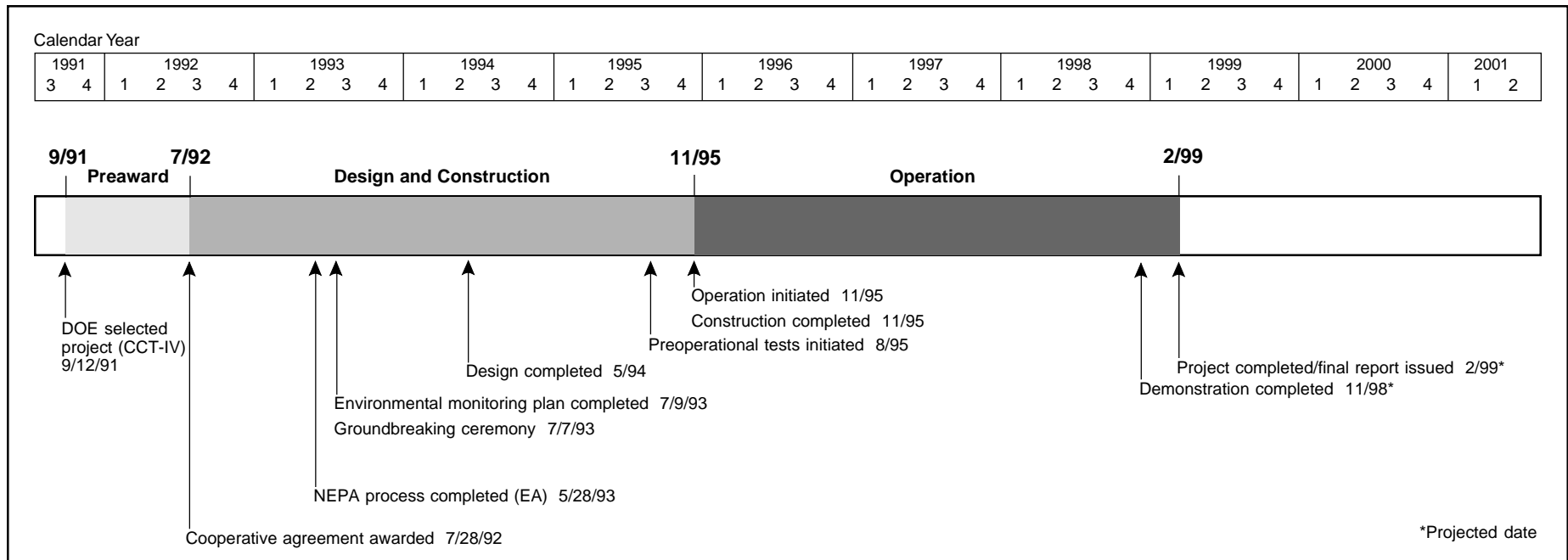


### Technology/Project Description

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 ex-  
changers 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) GE 7FA  
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, refurbished  
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  
that 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 Wabash River Generating Station  
was repowered. The demonstration unit generates  
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 approxi-  
mately 9,000 Btu/kWh (38% efficiency). Using high-  
sulfur bituminous coal, SO<sub>2</sub> emissions are expected to be  
less than 0.1 lb/10<sup>6</sup> Btu (98% reduction). NO<sub>x</sub> emissions  
are expected to be less than 0.1 lb/10<sup>6</sup> Btu (90% reduction).



The project represents the world's largest single-train IGCC plant currently in operation.

### Project Status/Accomplishments

The plant is in its second year of operation, which began in November 1995. Through June 30, 1997, the plant has operated for about 3,500 hours on syngas in combined-cycle mode and has produced about 700,000 MWh of electricity using syngas. The combustion turbine has demonstrated 192 MWe (100% of nameplate) and the gasifier has demonstrated 1,825 million Btu/hr, HHV (103% of nameplate). The gasifier has operated about 4,000 hours on coal and produced over 6 trillion Btu (dry) of syngas by processing over 350,000 tons of coal. Gasifier operation has attained over 74% cold gas efficiency.

The project has completed the first 1½ years of a three-year demonstration period. Early operation has demonstrated the ability to run at full-load capability while meeting the environmental requirements for sulfur and NO<sub>x</sub> emissions. CInergy, PSI's post-merger parent company, dispatches the project second behind its hydro

facilities on the basis of environmental emissions and efficiency, with a demonstrated heat rate of better than 9,000 Btu/kWh (HHV). CInergy Corp./PSI Energy, Inc., received the 1996 Powerplant Award from *Power* magazine.

### 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 over 30 years old. Many of these aging plants are without air pollution controls and are candidates for repowering with IGCC technology. Repowering these plants with IGCC systems will improve plant efficiencies and reduce SO<sub>2</sub>, NO<sub>x</sub>, and CO<sub>2</sub> 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 will provide utilities with more choice in selecting

fuel supplies to meet increasingly stringent air quality regulations.

Given 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 CO<sub>2</sub> emissions.

## Healy Clean Coal Project

### Participant

Alaska Industrial Development and Export Authority

### Additional Team Members

Golden Valley Electric Association—host

Stone and Webster Engineering Corp.—engineer

TRW Inc., Space & Technology Division—combustor  
technology supplier

The Babcock & Wilcox Company (which has acquired  
assets of Joy Environmental Technologies, Inc.)—  
spray-dryer absorber technology supplier

Usibelli Coal Mine, Inc.—coal supplier

### Location

Healy, Denali Borough, AK (adjacent to Healy Unit #1)

### Technology

TRW's advanced entrained (slagging) combustor

Babcock & Wilcox's spray-dryer absorber with sorbent  
recycle

### Plant Capacity/Production

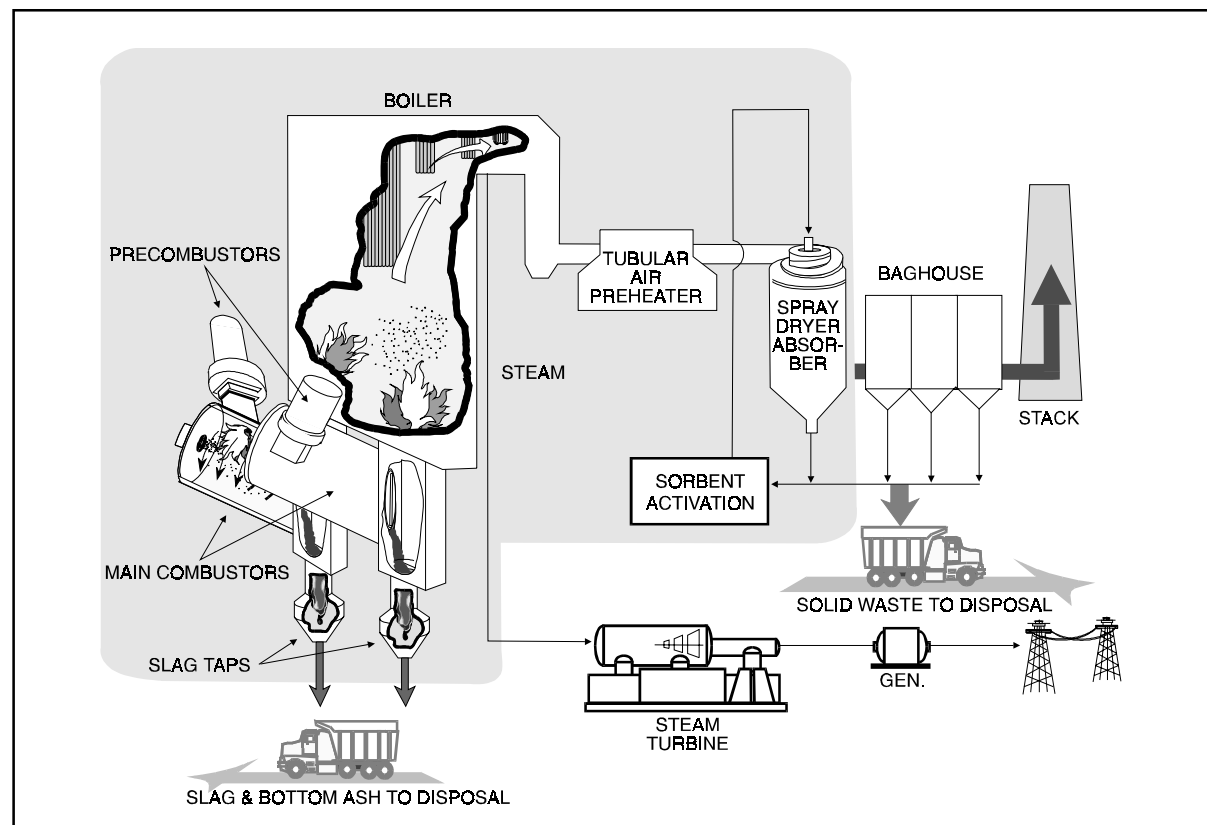
50 MWe (nominal electric output)

### 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.

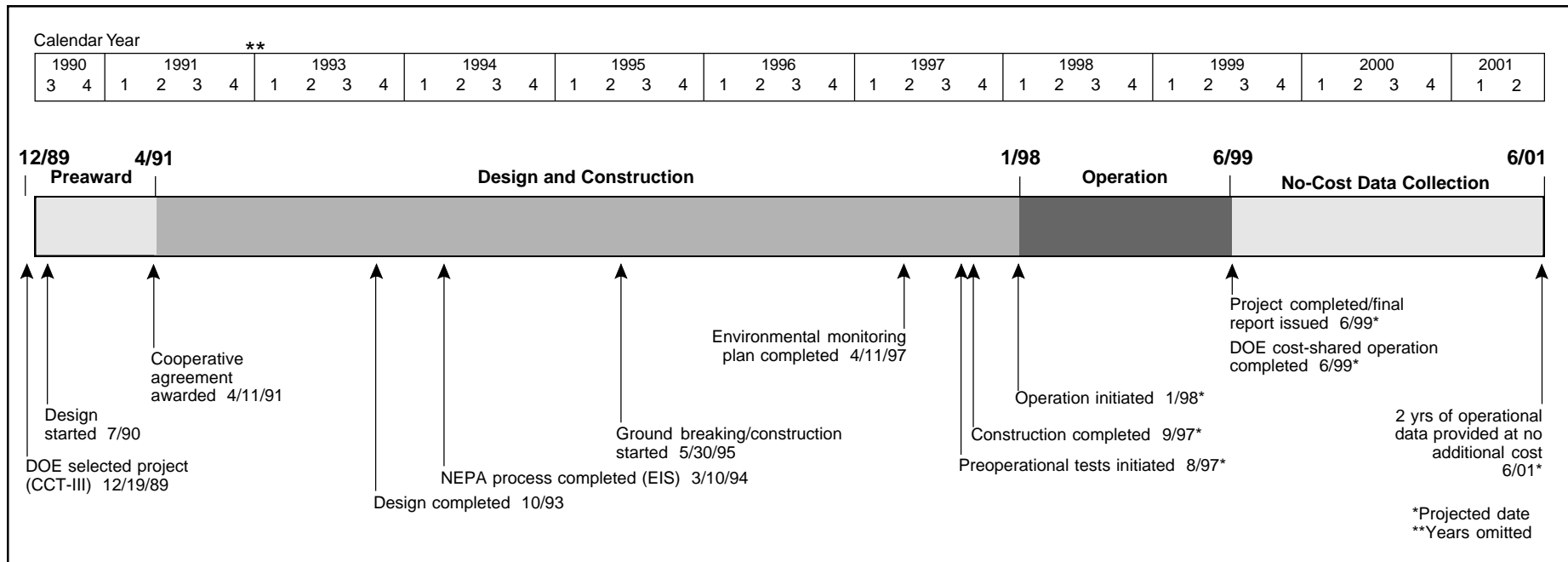


### Technology/Project Description

The project is to be a nominal 50-MWe facility consisting of two pulverized-coal-fired combustor systems. Emissions of  $\text{SO}_2$  and  $\text{NO}_x$  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. Additional  $\text{SO}_2$  will be removed using Babcock & Wilcox's activated recycle spray-dryer absorber system. Performance goals are  $\text{NO}_x$  emissions of less than  $0.2 \text{ lb}/10^6 \text{ Btu}$ , particulate emissions of  $0.015 \text{ lb}/10^6 \text{ Btu}$ , and  $\text{SO}_2$  removal greater than 90%. The performance testing of coal consists of 35% run-of-mine and 65% 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 that 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  $\text{NO}_x$  control. The ash forms molten slag, which accumulates on the water-cooled walls and is 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  $\text{NO}_x$  ports and to final overfire air ports.



Pulverized limestone ( $\text{CaCO}_3$ ) for  $\text{SO}_2$  control is fed into the combustor where most is flash calcined. The mixture of this lime ( $\text{CaO}$ ) 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 Babcock & Wilcox's dry scrubbing technology.  $\text{SO}_2$  in the flue gas reacts with the slurry droplets as water is simultaneously evaporated.  $\text{SO}_2$  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, and to the Usibelli coal mine. 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. The project will collect performance data for 3½ years, 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 so that the combined emissions from the two units will be only slightly greater than those currently emitted from Unit #1 alone. Total site emissions will be further reduced to current levels if necessary to protect the park.

#### Project Status/Accomplishments

By June 30, 1997, engineering efforts were complete and construction was 91% complete. The erection of structural steel and on-site fabrication and installation of all major equipment was complete, and startup and commissioning of individual plant systems was under way. The retrofit of Unit No. 1 (low- $\text{NO}_x$  burners with overfire air

and its performance testing was completed. Construction is on schedule for completion in September 1997.

#### 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  $\text{SO}_2$ ,  $\text{NO}_x$ , 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.

TRW is offering licensing of its technology worldwide and already has a licensing agreement in place in China.

## Clean Coal Diesel Demonstration Project

### Participant

Arthur D. Little, Inc.

### Additional Team Members

University of Alaska at Fairbanks—host and cofunder  
R.W. Beck—architect/engineer, designer, and constructor  
Usibelli Coal Mine, Inc.—coal supplier

### Proposed Team Members

Alaskan Science & Technology Foundation—cofunder  
Coltec—diesel engine technology vendor  
EERC—fuel preparation technology vendor

### Location

Fairbanks, AK (University of Alaska facility)

### Technology

Coal-fueled diesel engine

### Plant Capacity/Production

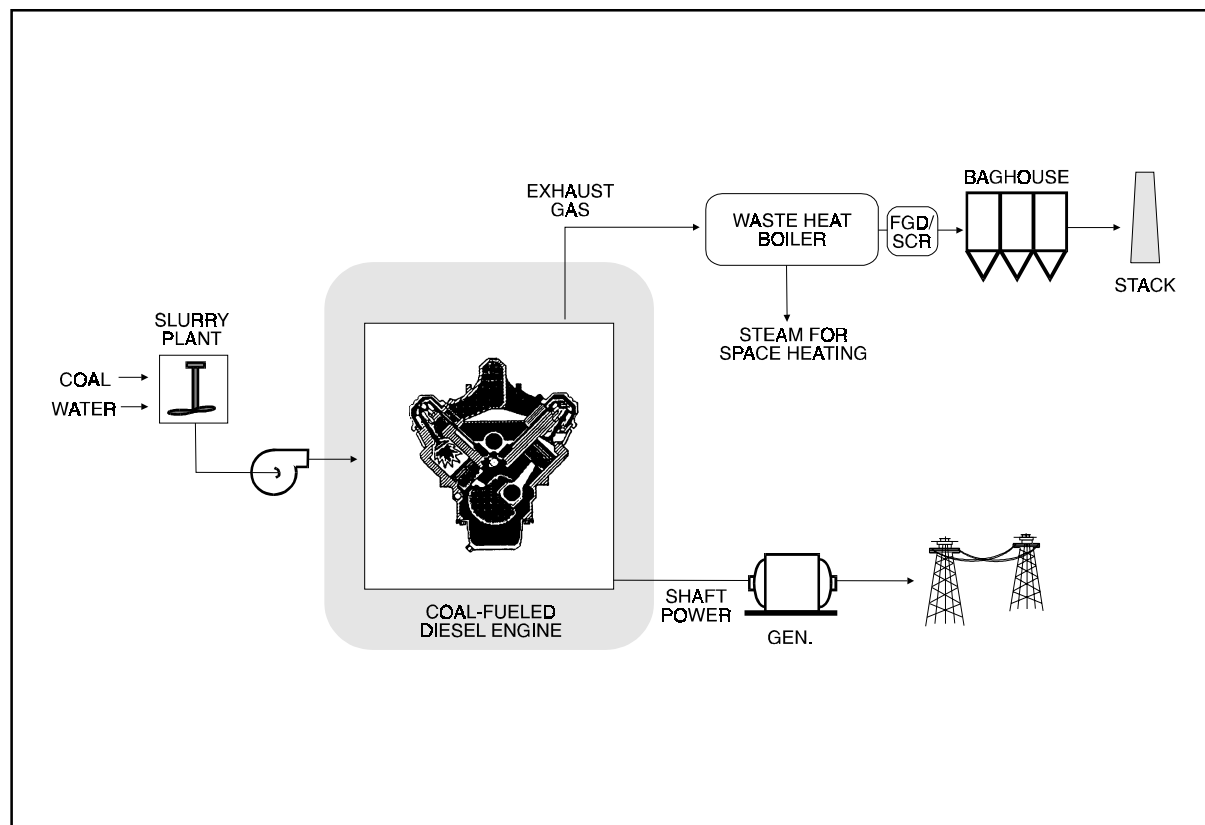
4.2 MWe (net)

### Project Funding

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

### Project Objective

To prove the design, operability, and durability of the coal diesel engine during 6,000 hours of operation and verify the design and operation of an advanced drying/slurrying process for subbituminous Alaskan coals and for testing the coal slurry in the diesel and a retrofitted oil-fired boiler.

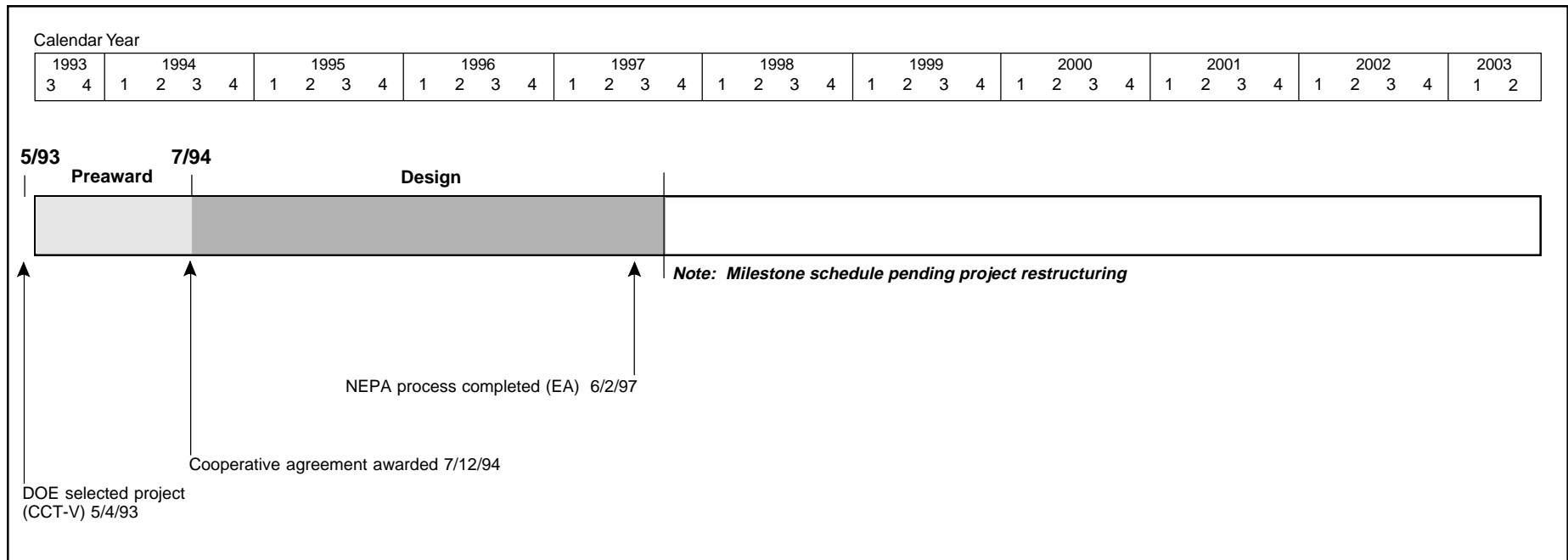


### Technology/Project Description

The project is based on the demonstration of a 12-cylinder, heavy duty engine (4.2 MWe) modified to operate on Alaskan subbituminous. The clean coal diesel technology, which uses a coal slurry (specifically, low-rank coal-water fuel), is expected to have very low  $\text{NO}_x$  and  $\text{SO}_x$  emission levels (50–70% below current New Source Performance Standards). In addition, the demonstration plant is expected to achieve 41% efficiency, while future plant designs are expected to reach 48% efficiency. This will result in a 25% reduction in  $\text{CO}_2$  compared to conventional coal-fired plants.

The low-rank coal-water fuel is prepared using an advanced coal drying process that allows dried coal to be slurried in water. The University of Alaska will assemble and operate a 5-ton/hr coal-water-fuel processing plant

that will utilize local coal brought by truck from Usibelli's mine in Healy, Alaska. In addition to its use in the coal-fueled diesel engine, the low-rank coal-water fuel is expected to be an alternative to fuel oil in conventional oil-fired industrial boilers.



### Project Status/Accomplishments

Easton Utilities, the original host, withdrew from the project after reevaluating its long-term need for power. DOE has approved the participant's plans to resite the project at the University of Alaska in Fairbanks, where the engine will operate on subbituminous Alaskan coals. An extension until September 30, 1997, has been granted to complete restructuring activities, obtain firm financial commitments, and establish the schedule and milestones for the project.

Project definition and design activities are ongoing. NEPA requirements have been satisfied by an environmental assessment, which was completed June 2, 1997.

### Commercial Applications

The coal-fueled diesel engine is particularly suited for nonutility new capacity, small utility repowering, and exports to developing countries. The net effective heat rate for the mature diesel system is expected to be 6,830 Btu/kWh (48%), which makes it very competitive with similarly sized coal- and fuel-oil-fired installations. Envi-

ronmental emissions from commercial diesel systems should be reduced to levels between 50% and 70% below NSPS. The estimated installation cost of a mature commercial unit is approximately \$1,300/kW.



## Externally Fired Combined-Cycle Demonstration Project

**Project concluded.**

### Participant

Pennsylvania Electric Company

### Additional Team Members

Hague International—technology developer and supplier  
Black & Veatch—engineer and construction manager

### Location

Site under negotiation

### Technology

Hague International's externally fired combined-cycle (EFCC) system using a novel, high-temperature, ceramic gas-to-air heat exchanger

### Plant Capacity/Production

5 MWe slipstream

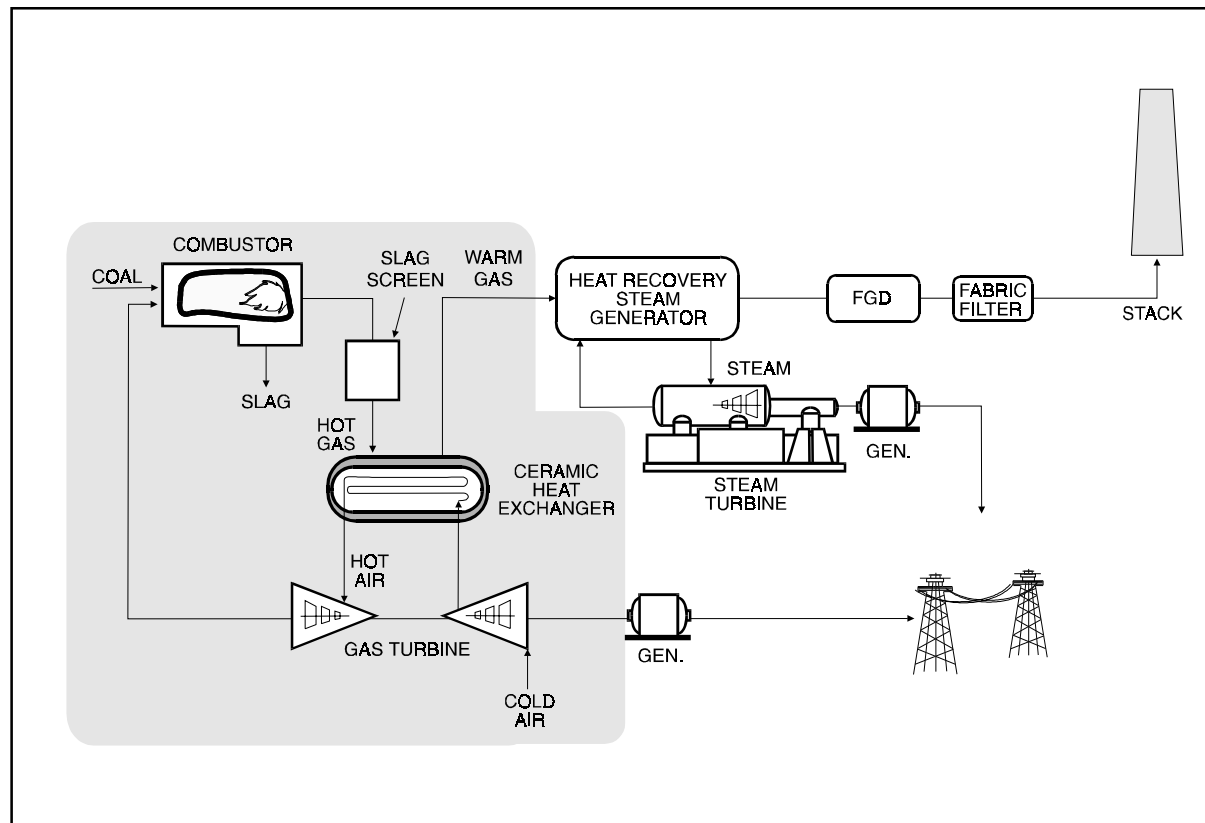
### Project Funding

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.

CerHx is a registered trademark of Hague International.



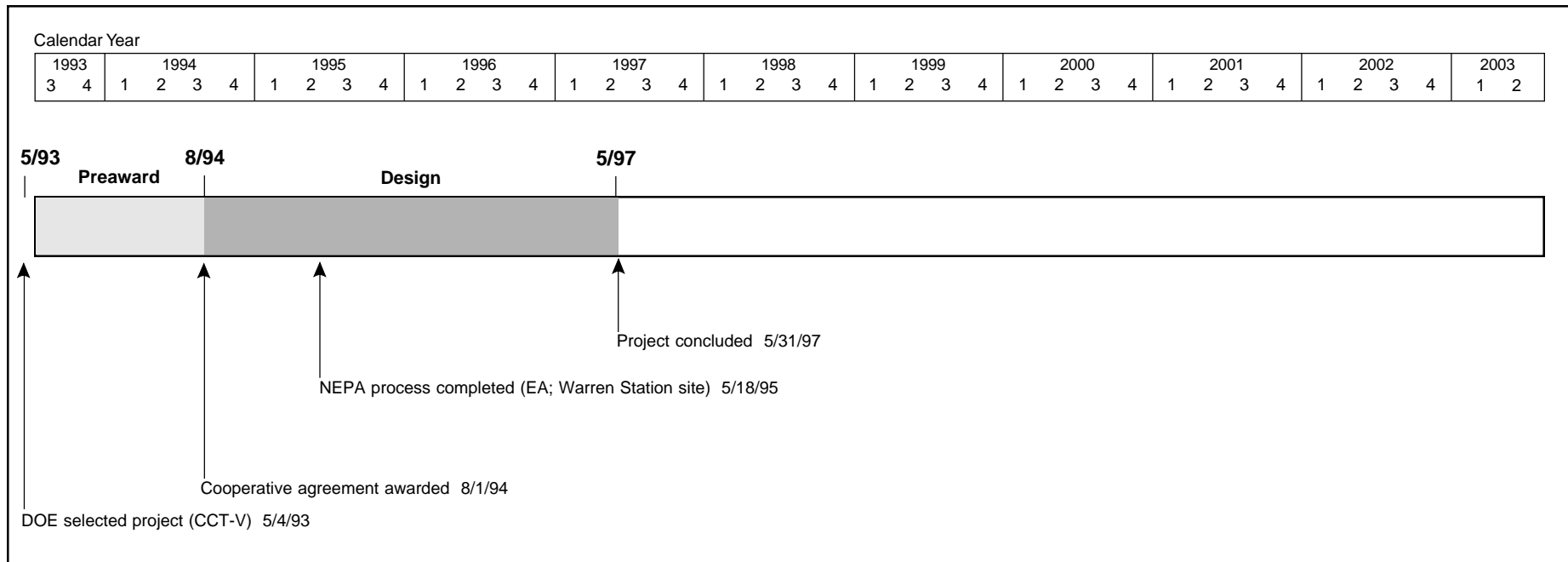
### Technology/Project Description

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<sup>®</sup>) 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<sub>x</sub> 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<sup>®</sup>. The product gas is then passed through a heat recovery steam generator, where more heat is extracted to drive a steam turbine generator and pro-

duce 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<sup>®</sup> is passed through a gas turbine to produce additional electricity before being fed to 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<sup>®</sup> raises the temperature of the air to the turbine inlet conditions using tube elements that are manufactured from corrosion-resistant, toughened, ceramic materials.



Potential SO<sub>x</sub> release is reduced by more than 90% through capture in the flue gas desulfurization system. NO<sub>x</sub> emissions are expected to be less than 0.13 lb/10<sup>6</sup> Btu.

### Project Status/Accomplishments

In May 1995, Pennsylvania Electric stopped all project activity due to lack of progress in resolving technical issues relating to the ceramic heat exchanger. In June 1996, the utility announced it would not pursue the full-scale EFCC at Warren Station. The utility did propose a demonstration of a scaled down EFCC in a 5-MWe slipstream at Seward Station. However, Hague International did not complete developmental testing of the ceramic heat exchanger at the Kennebunk facility. Because a successful 50-hour coal-fired test at the pilot-plant was not completed, the project was concluded on May 31, 1997.

### Commercial Applications

The EFCC system concept is suitable for new electric power generation, repowering needs, and cogeneration applications. The potential commercial market for EFCC 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<sub>2</sub> emissions are expected to be less than 0.081 lb/10<sup>6</sup> Btu, which is a reduction of more than 90% for most coals. NO<sub>x</sub> emissions are expected to be less than 0.15 lb/10<sup>6</sup> Btu, and particulate emissions are expected to be less than 0.015 lb/10<sup>6</sup> Btu.

## Coal Processing for Clean Fuels Technology

This category includes a range of technologies designed to produce high-energy-density, low-sulfur solid and clean liquid fuels, as well as systems to assist users in evaluating impacts of coal quality on boiler performance.

In the case of the Customs Coals International project, advanced physical-cleaning techniques are applied to bituminous coal with an already high Btu content to remove the ash, which contains sulfur in the form of pyrite, an inorganic iron compound. A dense-medium cyclone using finely sized magnetite effectively separates 90 percent of the pyritic sulfur. But, because physical methods cannot remove the organically bound sulfur, dense-medium-cyclone processed coals can only be considered compliance coals (meeting CAAA SO<sub>2</sub> requirements) if the organic sulfur content is very low. This processed compliance coal is called Carefree Coal™. For coals with significant organic sulfur content, sorbents and other additives must be added to capture the sulfur released upon combustion and bring the coal into compliance. This second product is called Self-Scrubbing Coal™.

The Rosebud SynCoal Partnership's advanced coal conversion project applies mostly physical-cleaning methods to low-Btu, low-sulfur subbituminous coals, primarily to remove moisture and secondarily to remove ash. The objective is to enhance the energy density of the already low-sulfur coal. Some conversion of the surface properties of the coal is required, however, to provide stability (prevent

spontaneous combustion) in transport and handling. In the process, coal with 5,500–9,000 Btu per pound, 25–40 percent moisture content, and 0.5–1.5 percent sulfur is converted to a 12,000-Btu-per-pound product with 1.0 percent moisture and as low as 0.3 percent sulfur. Test burning of processed coal at utilities is continuing.

The ENCOAL® project uses mild gasification to convert low-Btu, low-sulfur-content subbituminous coal to a high-energy-density, low-sulfur solid product and a clean liquid fuel comparable to No. 6 fuel oil. Mild gasification is a pyrolysis process (heating in the absence of oxygen) performed at moderate temperatures and pressures. It produces condensable volatile hydrocarbons in addition to solids and gas. The condensable fraction is drawn off as a liquid product. Most of the gas is used to provide on-site energy requirements. The process solid is significantly beneficiated to produce a 12,000-Btu-per-pound low-sulfur solid fuel. The demonstration plant is processing 500 tons per day of subbituminous coal and producing 250 tons per day of solid process-derived fuel (PDF™) and 250 barrels per day of coal-derived liquids (CDL™). Both the solid and liquid fuels are undergoing test burns at utility and industrial sites.

The liquid-phase methanol (LPMEOH™) process being demonstrated is an indirect liquefaction process using synthesis gas from a coal gasifier. The unique aspect of the process is the use of an inert liquid to suspend the conversion catalyst. This removes the heat of reaction and precludes the need for an intermediate water-gas shift conversion. Also addressed in the project are the load-following capability of the process by simulating application in

an IGCC system and fuel characteristics of the unrefined product. Construction on the project was completed in January 1997. Operation began in April 1997. The LPMEOH™ demonstration unit logged over 500 hours of stable operation in the first month on stream—an availability of over 90 percent.

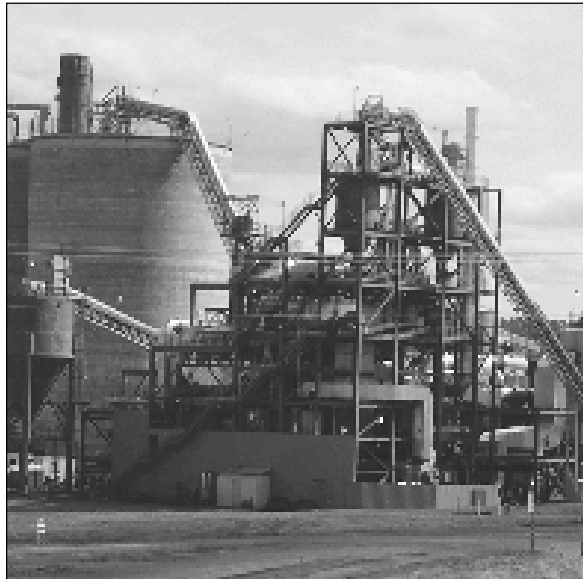
CQ Inc. has developed a personal computer software package that will serve as a predictive tool to assist utilities in selecting optimal quality coal for a specific boiler based on operational efficiency, cost, and environmental considerations. Algorithms were developed and verified through comparative testing at bench, pilot, and utility scale. Six large-scale field tests were conducted at five separate utilities. The software has been released for use.

Exhibit 5-32 summarizes the process characteristics and size of the coal processing for clean fuels technologies presented in more detail in the project fact sheets.

## Exhibit 5-32 CCT Program Coal Processing for Clean Fuels Technology Characteristics

Project	Process	Size	Fact Sheet
Development of the Coal Quality Expert™	Coal Quality Expert™ computer software	Tested at 250–880 MWe	5-116
Self-Scrubbing Coal™: An Integrated Approach to Clean Air	Dense-medium cyclones with finely sized magnetite and sorbent addition for bituminous coals	500 tons/hr	5-120
Advanced Coal Conversion Process Demonstration	Advanced coal conversion process for upgrading low-rank coals	45 tons/hr	5-122
ENCOAL® Mild Gasification Project	Liquids-from-coal (LFC™) mild gasification to produce solid and liquid fuels	1,000 tons/day	5-124
Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process	Liquid-phase methanol (LPMEOH™) process for methanol production from coal syngas	80,000 gal/day	5-126

▼ Rosebud SynCoal Partnership's advanced coal conversion process plant in Colstrip, MT has produced over a million tons of SynCoal® products.



▼ The ENCOAL® mild gasification plant near Gillette, WY, has operated more than 13,000 hours and processed more than 210,000 tons of raw coal.



▼ Custom Coals International's advanced coal-cleaning plant in Central City, PA, can process 500 tons/hr of raw coal.



## Development of the Coal Quality Expert™

*Project completed.*

### Participants

ABB Combustion Engineering, Inc.  
CQ Inc.

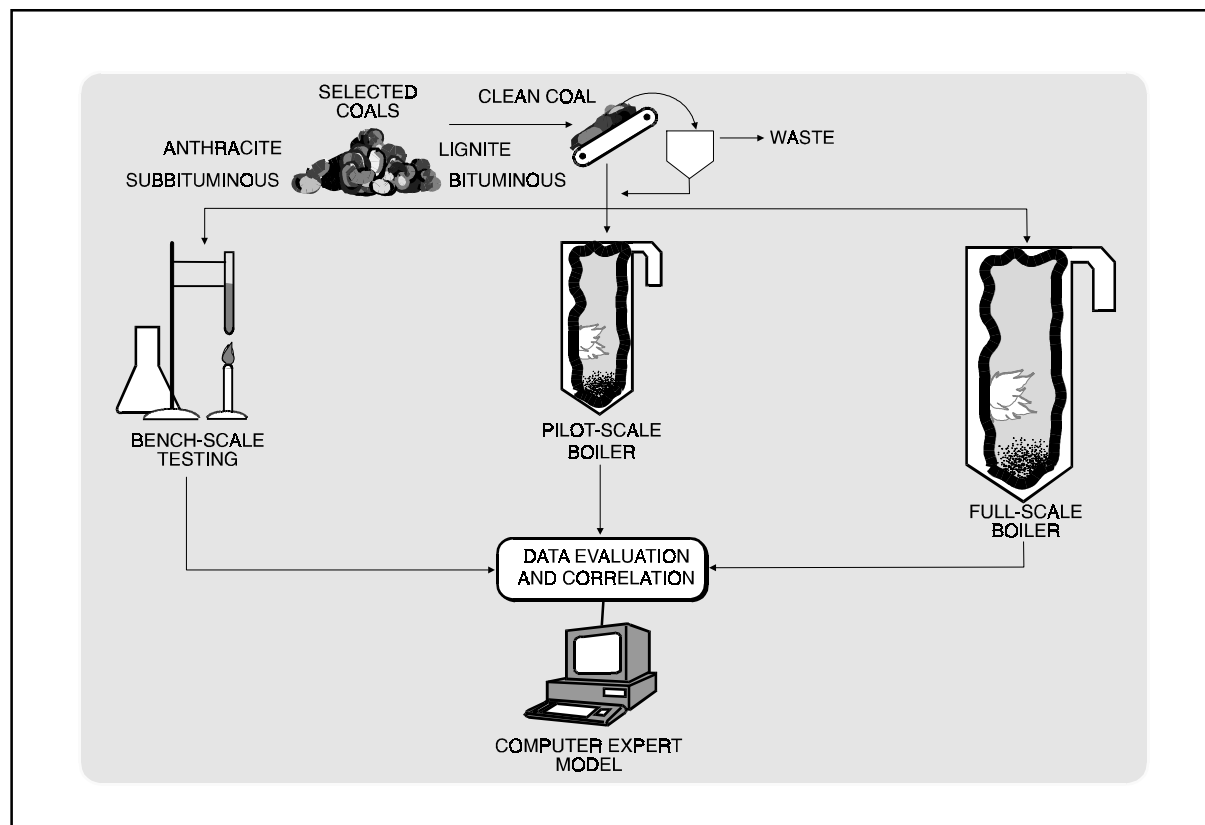
### Additional Team Members

Black & Veatch—cofounder and software developer  
Electric Power Research Institute—cofounder  
The Babcock & Wilcox Company—cofounder and pilot-scale tester  
Electric Power Technologies, Inc.—field tester  
University of North Dakota, Energy and Environmental Research Center—bench-scale tester  
Alabama Power Company—host  
Mississippi Power Company—host  
New England Power Company—host  
Northern States Power Company—host  
Public Service Company of Oklahoma—host

### Locations

Grand Forks, Grand Forks County, ND (bench tests)  
Windsor, Hartford County, CT (bench- and pilot-scale tests)  
Alliance, Columbiana County, OH (pilot-scale 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)

Coal Quality Expert, CQE, CQIS, and CQIM are trademarks of the Electric Power Research Institute.



### Technology

CQ Inc.'s EPRI Coal Quality Expert™ (CQE™) computer software

### 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

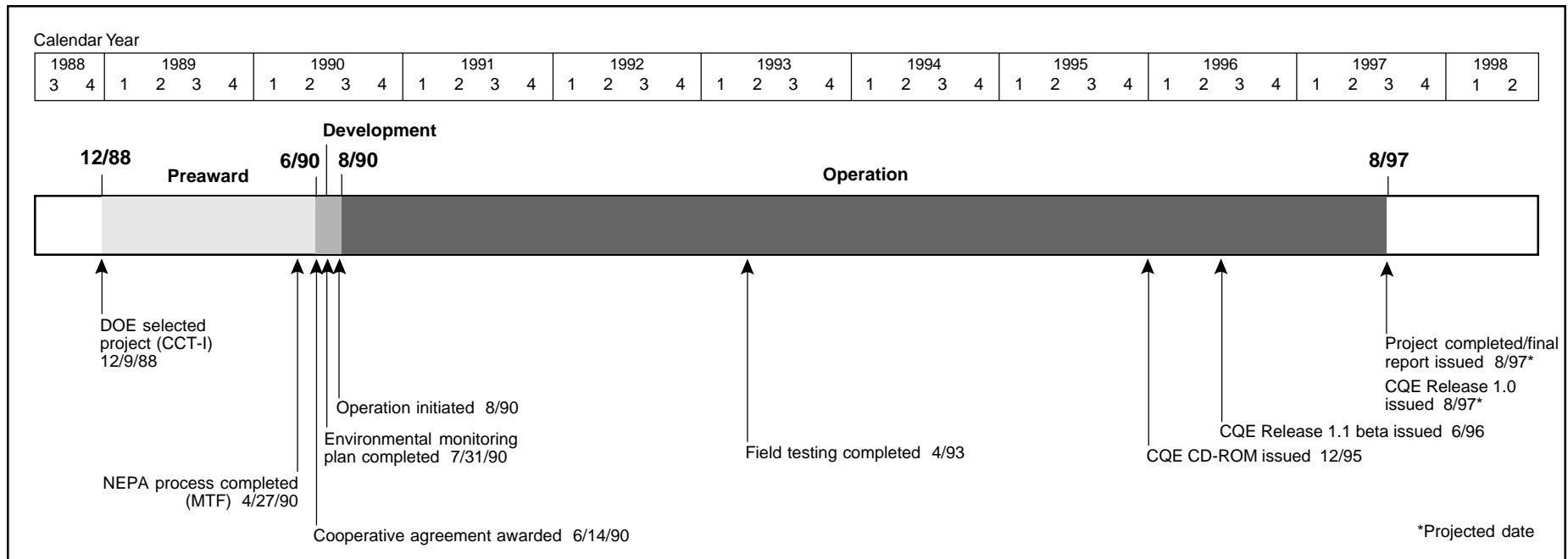
### Project Objective

The objective of the project was to provide the utility industry with a PC software program to confidently and inexpensively evaluate the potential for coal-cleaning, blending, and switching options to reduce emissions

while producing the lowest cost electricity. Specifically the project was to (1) enhance the existing Coal Quality Information System (CQIS™) database and Coal Quality Impact Model (CQIM™) to allow assessment of the effects of coal-cleaning on specific boiler costs and performance and (2) develop and validate CQE™, a methodology that allows accurate and detailed prediction of coal quality impacts on total power plant operating cost and performance.

### Technology/Project Description

The CQE™ is a software tool that brings a new level of sophistication to fuel decisions by integrating the system-wide effects of fuel purchase decisions on power plant performance, emissions, and power generation costs. CQE™ can be used on a stand-alone computer or as a network application for utilities, coal producers, and



equipment manufacturers to perform detailed analyses of the impacts of coal quality, capital improvements, operational changes, and/or environmental compliance alternatives on power plant emissions, performance, and production costs. CQE™ can be used as an organized methodology for systematically evaluating all such impacts or it may be used in modules with some default data to perform more strategic or comparative studies.

## Project Summary

### Background

CQE™ began with EPRI's Coal Quality Impact Model (CQIM™), developed for EPRI by Black & Veatch and introduced in 1989. CQIM™ was endowed with a variety of capabilities, including evaluating Clean Air Act compliance strategies, evaluating bids on coal contracts, conducting test-burn planning and analysis, and providing techno-economic analyses of plant operating strategies. CQE™, which combines CQIM™ with other existing software and databases, extends the art of model-based fuel evaluation established by CQIM™ in three dimen-

sions: new flexibility and application, advanced technical models and performance correlations, and advanced user interface and network awareness.

### Algorithm Development

Data derived from bench-, pilot-, and full-scale testing were used to develop the CQE™ algorithms. 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 Alabama Power's Gatson, Unit 5 (880 MWe), Wilsonville, AL; Mississippi Power's Watson, Unit 4 (250 MWe), Gulfport, MS; New England Power's Brayton Point, Unit 2 (285 MWe) and Unit 3 (615 MWe), Somerset, MA; Northern States Power's King Station (560 MWe), Bayport, MN; and Public Service Company of Oklahoma's Northeastern, Unit 4 (445 MWe), Oologah, OK.

The six large-scale field tests consisted of burning a baseline coal and an alternate coal over a 2-month period. The baseline coal 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 used to develop the model.

### CQE™ Capability

The PC-based program evaluates coal quality, transportation system options, performance issues, and alternative emissions control strategies for utility power plants. CQE™ is composed of technical tools to evaluate perfor-

mance issues, environmental models to evaluate emissions and regulatory issues, and economic models to determine production cost components, including consumables (e.g., fuel, scrubber additives), waste disposal, operation and maintenance, replacement energy costs, and operational and maintenance costs for coal-cleaning processes, power production equipment, and emissions control systems. CQE™ has four main features:

- Fuel Evaluator—Performs system-, plant-, and/or unit-level fuel quality, economic, and technical assessments.
- Plant Engineer—Provides in-depth performance evaluations with a more focused scope than provided in the Fuel Evaluator.
- Environmental Planner—Provides access to evaluation and presentation capabilities of the Acid Rain Advisor.
- Coal-Cleaning Expert—Establishes the feasibility of cleaning a coal, determines cleaning processes, and predicts associated costs.

### Software Description

CQE™ includes more than 100 algorithms based on the data generated in the six full-scale field test.

CQE™'s design philosophy underscores the importance of flexibility by modeling all important power plant equipment and systems and their performance in real-world situations. This level of sophistication allows new applications to be added by assembling a model of how objects interact. Updated information records can be readily shared among all affected users because CQE™ is network-aware, enabling users throughout an organization to share data and results. The CQE™ object-oriented design, coupled with an object database management system, allows different views into the same data. As a result, staff efficiency is enhanced when decisions are made.

CQE™ also can be expanded without major revisions to the system. Object-oriented programming allows

new objects to be added and old objects to be deleted or enhanced easily. For example, if modeling advancements are made with respect to predicting boiler ash deposition (i.e., slagging and fouling), the internal calculations of the object that provides these predictions can be replaced or augmented. Other objects affected by ash deposition (e.g., ash collection and disposal systems, soot blower systems) do not need to be altered; thus the integrity of the underlying system is maintained.

### System Requirements

CQE™ currently uses the OS/2 operating system, but the developers are planning to migrate to a Windows-based platform. CQE™ can operate in stand-alone mode on a single computer or on a network. The system requirements for stand-alone operation are listed in Exhibit 5-33. Technical support is available from Black & Veatch by sending an e-mail message to [cqe@bv.com](mailto:cqe@bv.com) or phoning (913) 458-9772, Monday through Friday, 8:00 a.m. to 5:00 p.m. (central time).

### Commercial Applications

The CQE™ system is applicable to all electric power generation plants and large industrial/institutional boilers that burn pulverized coal. Potential users include fuel suppliers, environmental organizations, government and regulatory institutions, and engineering firms. International markets for CQE™ are being explored by both CQ Inc. and Black & Veatch.

EPRI owns the software and distributes CQE™ to EPRI members for their use. CQE™ is available to others in the form of three types of licenses: user, consultant, and commercializer. CQ Inc. is EPRI's licensing agent. CQ Inc. and Black & Veatch have each signed commercialization agreements, which give both companies non-exclusive worldwide rights to sell user's licenses and to offer consulting services that include the use of CQE™ software. Two U.S. utilities have been licensed to use copies of CQE™'s stand-alone Acid Rain Advisor. Over 40 U.S. utilities and one U.K. utility have CQE™ through their EPRI membership. Proposals are pending with several non-EPRI-member U.S. and foreign utilities to license their software.

The CQE™ team has a Home Page on the World Wide Web (<http://www.fuels.bv.com:80/cqe/cqe.htm>) to promote CQE™, facilitate communications between CQE™ developers and users, and eventually allow software updates to be distributed over the Internet. It also was developed to provide an on-line updatable user's

**Exhibit 5-33  
CQE™ Stand-Alone System Requirements**

Item	Minimum	Preferred
Hardware speed	486 PC, 33 Mhz	Pentium PC, market stock
RAM	16 MB	32 MB
Disk space	200 MB	1 GB
Monitor	SVGA color	SVGA color
Graphics card	Capable of 1024x768 mode	Capable of 1024x768 mode
External drives	1.44 MB 3.5-inch; CD-ROM	1.44 MB 3.5-inch; CD-ROM
Mouse	Required	Required
Keyboard	Required	Required
Printer	Access to high-speed printer	Access to laser printer
Operating system	OS/2 Version 2.0	WARP (3.0)

manual. The Home Page also helps attract the interest of international utilities and consulting firms that are unable to be reached by Black & Veatch and CQ Inc.

CQE™ was recognized by then Energy Secretary Hazel O'Leary and EPRI President Richard Balzhiser in 1996 as the best of nine DOE/EPRI cost-shared utility research and development projects under the "Sustainable Electric Partnership" program.

### Contacts

Clark D. Harrison, President, (412) 479-6016

CQ Inc.

One Quality Center

P.O. Box 280

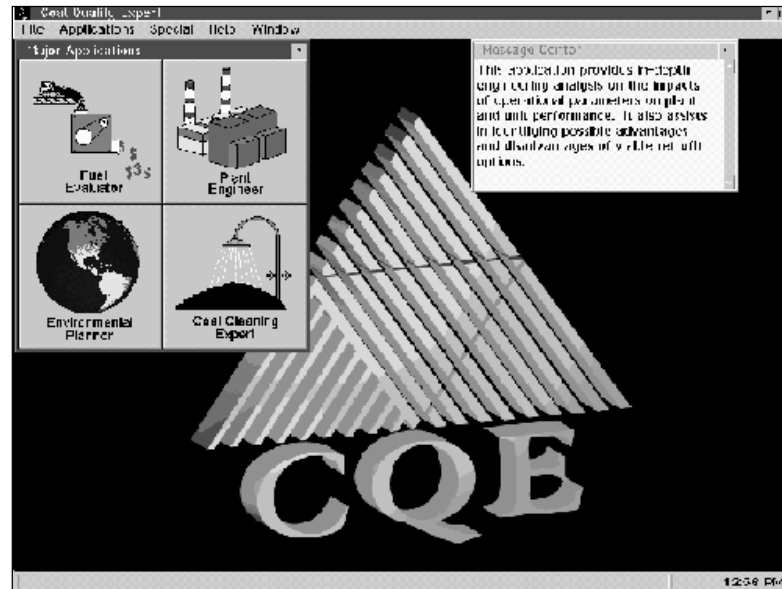
Homer City, PA 15748-0280

Douglas Archer, DOE/HQ, (301) 903-9443

Scott M. Smouse, FETC, (412) 892-5725

### References

- Harrison, Clark D., et al. "Recent Experience with the CQE™." *Fifth Annual Clean Coal Technology Conference: Technical Papers*. January 1997.
- *CQE™ Users Manual*, CQE™ Home Page at <http://www.fuels.bv.com:80/cqe/cqe.htm>.
- *Comprehensive Report to Congress on the Clean Coal Technology Program: Development of the Coal Quality Expert*. ABB Combustion Engineering, Inc., and CQ Inc. Report No. DOE/FE-0174P. U.S. Department of Energy. May 1990. (Available from NTIS as DE90010381.)



▲ CQE™, a PC-based software tool, can be used to determine the complete costs of various fuel options by seamlessly integrating the effects of fuel purchase decisions on power plant performance, emissions, and power generation costs. Portions of the CQE™ User's Manual are available on the Internet.



## 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

Pennsylvania Power & Light Company—host  
Richmond Power & Light—host  
Centerior Service Company—host

### Locations

Central City, Somerset County, PA (advanced coal-cleaning plant)

Lower Mt. Bethel Township, Northampton County, PA (combustion tests at Pennsylvania Power & Light's Martin's Creek Power Station, Unit 2)

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

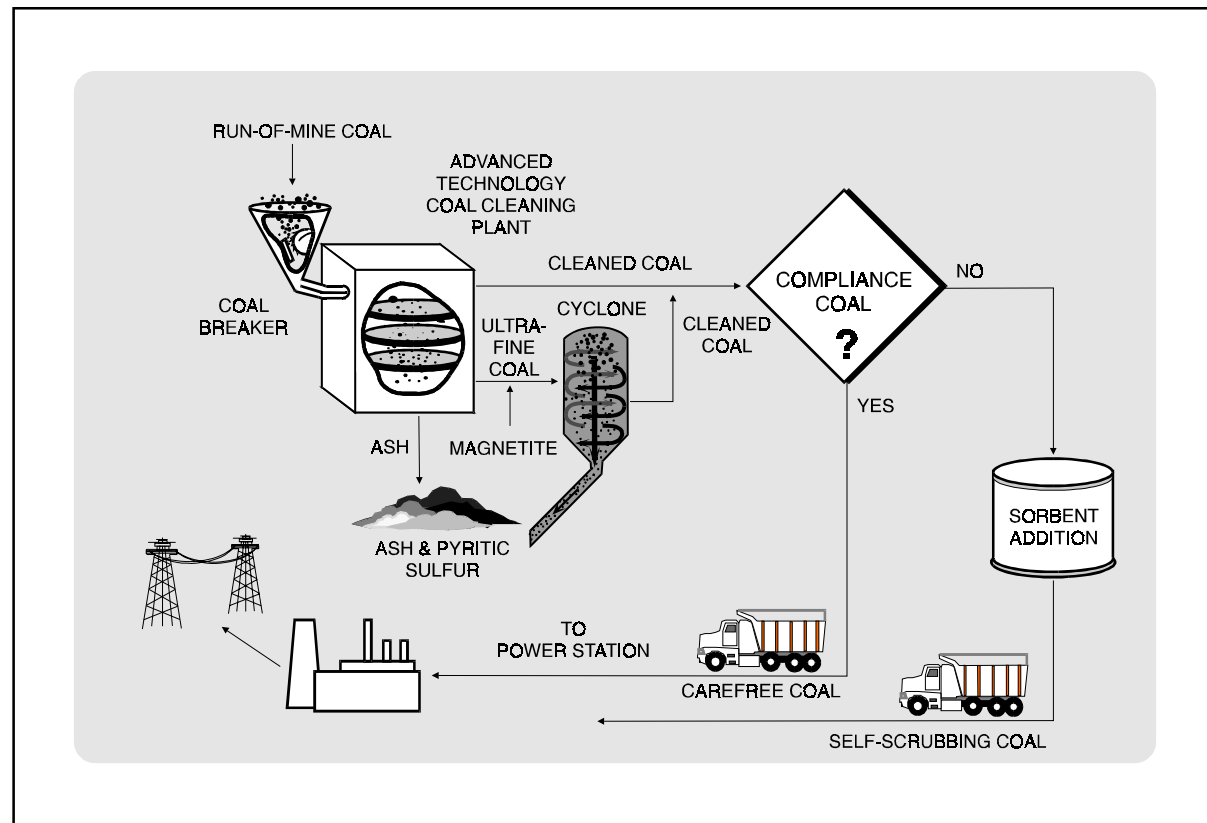
### Plant Capacity/Production

500 tons/hr

### Project Funding

Total project cost	\$87,386,102	100%
DOE	37,994,437	43
Participant	49,391,665	57

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 provisions of the CAAA.

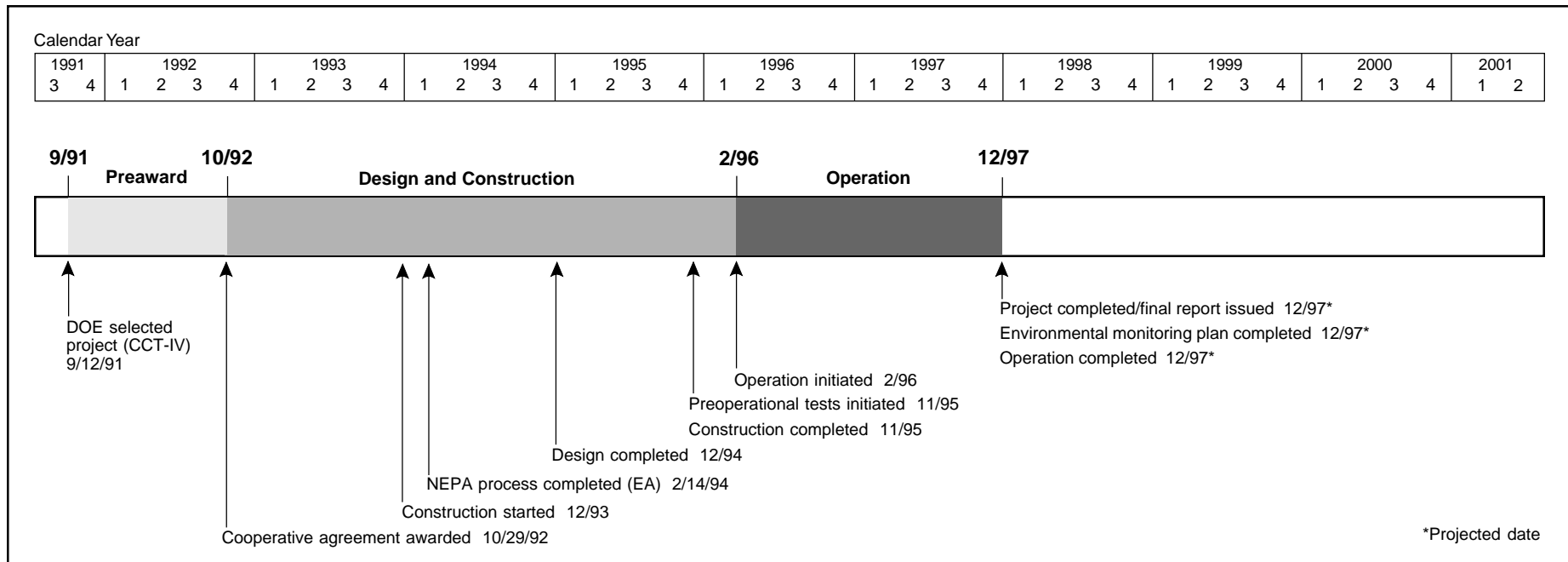
### Technology/Project Description

An advanced coal-cleaning plant has been 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-medium 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<sub>2</sub> 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<sub>2</sub> emissions. The reduced ash content of the Self-Scrubbing Coal™ permits addition of relatively



large amounts of sorbent without exceeding ash specifications of boilers or overloading electrostatic precipitators.

Two medium- to high-sulfur coals—Illinois No. 5 (2.7% sulfur) and Lower Freeport (3.9% sulfur)—are being used to produce Self-Scrubbing Coal™. Carefree Coal™ is being made using Lower Kittanning (1.8% sulfur). Lower Kittanning coal is being tested at Martin’s Creek Power Station; Illinois No. 5 coal is being tested at Whitewater Valley Generating Station; and Lower Freeport Seam coal is being tested at Ashtabula C.

**Project Status/Accomplishments**

Start-up began in late December 1995, and the first coal was processed in February 1996. In May 1996, the facility reached its design capacity. Equipment and circuit optimization testing began immediately thereafter and continued throughout 1996.

The Carefree Coal™ test burn (cleaned Lower Kittanning coal) at Martin’s Creek Power Station was conducted in mid-November 1996. Although plant optimization was not completed, the overall product made for

the test was consistent with the current quality of the plant feed coal. The unit experienced some opacity problems due to the low sulfur in the coal and a marginal electrostatic precipitator. Data analysis is under way.

High organic sulfur in the raw coal created problems with the ability to produce compliance quality clean coal. Further, difficulties with the plant resulted in an excessive amount of material going to the refuse pond, and plant operation was suspended in February 1997. Activities needed for the plant to resume operation have been delayed due to financial problems.

In June 1997, Custom Coals International accepted an offer from a coal supplier to purchase the facility and continue the demonstration project. DOE is evaluating the offer to continue the demonstration.

**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 repre-

sents more than 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 by 80–90%.

A U.S.-led consortium with Custom Coals as the principal partner has signed a cooperative agreement worth \$450 million with China to build a coal-cleaning plant, a 500-mile underground slurry pipeline, and port facility. The pipeline will bring coal from the northwest Shanxi province to the coastal province of Shandong. A letter of intent for three additional pipelines in China was signed in August 1996.

Custom Coals is aggressively marketing the technology in Eastern Europe and has received letters of intent from Polish utilities interested in producing 5 million tons/yr of cleaned coal. Custom Coals also has a proposed agreement with domestic coal-marketing companies for 1 million tons of compliance coal annually.

## 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

### Plant Capacity/Production

45 tons/hr of SynCoal® product (300,000 tons/yr)

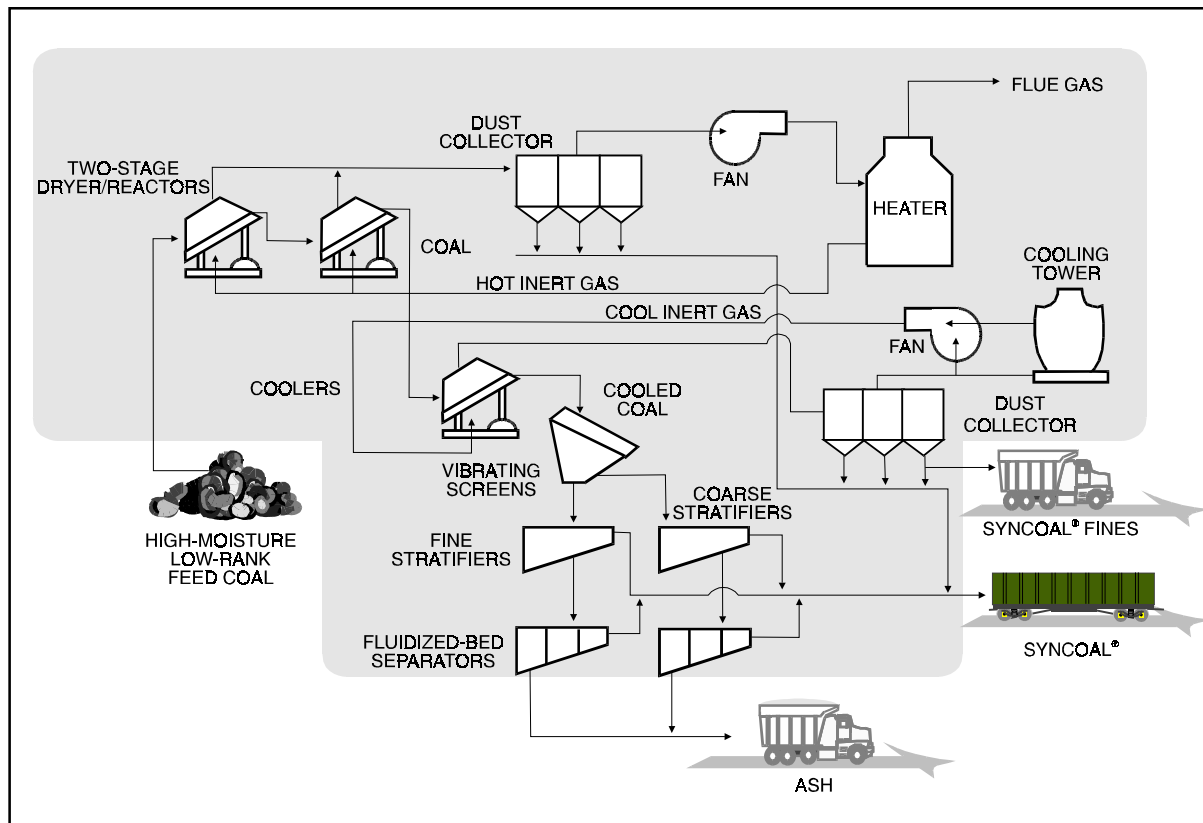
### Project Funding

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 SynCoal®, 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.

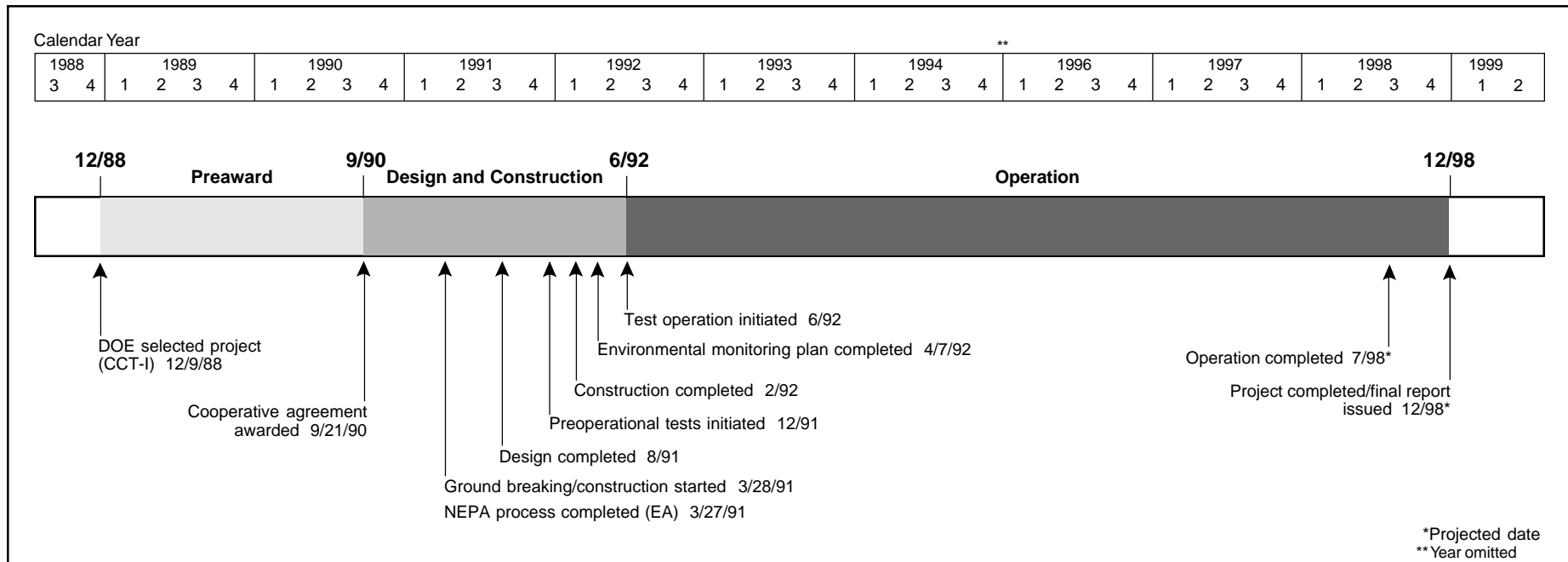


### Technology/Project Description

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 dryer/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

The demonstration facility continues reliable operation. It has processed more than 1.5 million tons of coal, and on April 19, 1997, the plant produced its one millionth ton of SynCoal®. Total sales of SynCoal® product have exceeded 900,000 tons.

SynCoal® products totaling nearly 130,000 tons have been delivered over an extended period of time to several industrial customers, including Ash Grove Cement, Bentonite Corporation, Wyoming Lime, Continental Lime, and Empire Sand and Gravel. In May 1997, tests were performed on several coke/SynCoal® blends.

A SynCoal® test burn was completed at Montana Power's J.E. Corette in April 1996. The test involved both handling and combustion of SynCoal® in a variety of blends ranging from 15% to 85% SynCoal®. Overall results indicated that a 50% SynCoal®/raw coal blend provides improved results. SO<sub>2</sub> emissions were reduced by 21% overall, generation increased at normal operating loads, and there was no noticeable impact on NO<sub>x</sub> emis-

sions. Also, SynCoal® is being sent to Montana Power's Colstrip Project Units 1 and 2, where tests will provide information on boiler efficiency, output, and air emissions. In November 1996, 25 tons of specific-sized uncleaned SynCoal® was sent to Morgantown for use in DOE's coal gasification test program.

The main product issue continues to be the spontaneous combustion tendency of the SynCoal®. Efforts also are continuing to reduce operational costs per ton.

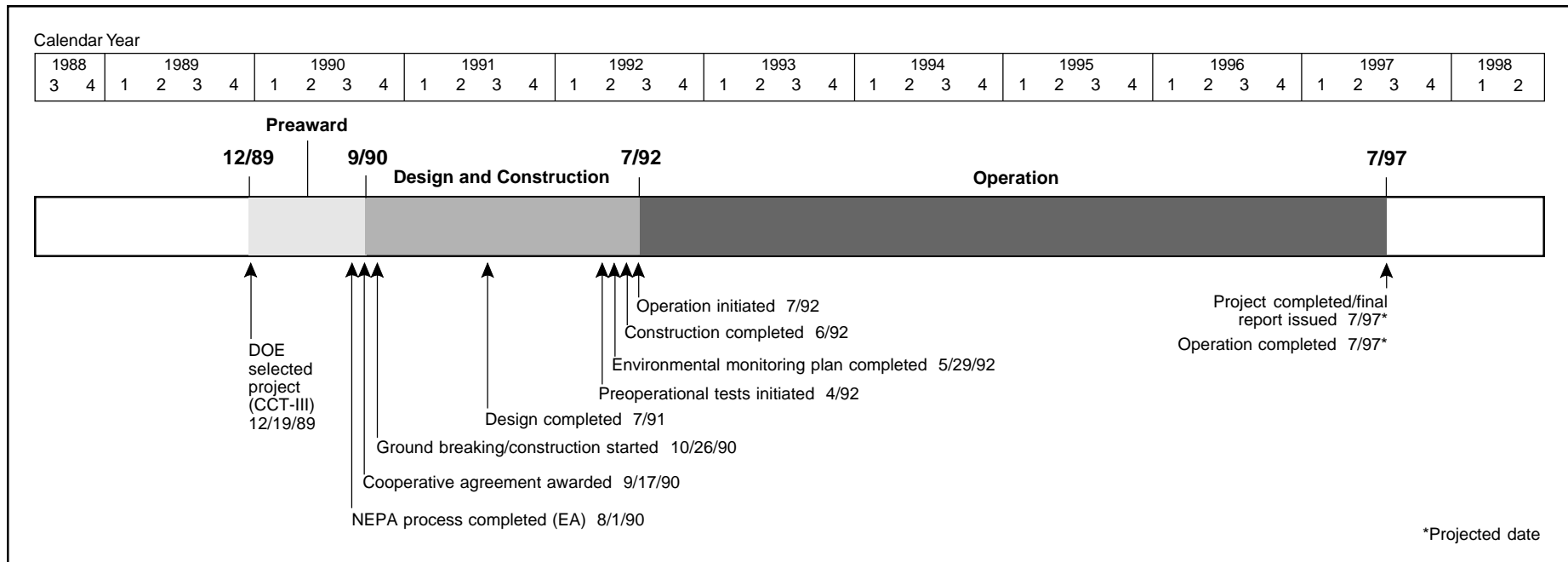
### Commercial Applications

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. Currently, 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® that has a consistently low moisture content, low sulfur content, high heating value, and high volatile content. Because of these characteristics, SynCoal® could have significant impact on SO<sub>2</sub> reduction and provide a clean, economical 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.

SynCoal® technology is being marketed actively worldwide. The partnership has been working on a potential semi-commercial project located in Wyoming. The partnership has been working closely with a Japanese equipment and technology company to expand into Asian markets. Prospects also are being pursued in Europe.





to remove SO<sub>2</sub>, 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<sup>®</sup> 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 with 0.4–0.9% sulfur content is being used.

### Project Status/Accomplishments

The plant is processing 500 tons/day of coal and producing 250 tons/day of PDF<sup>™</sup> and 250 barrels/day of CDL<sup>™</sup>. The plant has been in operation for 4½ years and has delivered 15 unit trains of PDF<sup>™</sup> to five major utilities. More than 3 million gallons of CDL<sup>™</sup> has also been delivered to seven industrial fuel users and one steel mill blast furnace. By the end of June 1997, the plant had operated nearly 13,000 hours and processed more than 210,000 tons of raw coal.

In 1996, ENCOAL<sup>®</sup> began shipping unit trains containing 100% PDF<sup>™</sup> for the first time. Several 100%

PDF<sup>™</sup> unit trains have been delivered to two separate utilities for test burns. At Indiana-Kentucky Electric Cooperative's Clifty Creek Station, blends of 70–90% PDF<sup>™</sup> with Ohio high-sulfur coal indicated that unit capacity was increased significantly relative to the base blend, and there was at least a 20% NO<sub>x</sub> reduction because of a more stable flame. Several unit trains were sent to Union Electric.

### 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 is being limited to high-moisture, low-heating-value coals.

The potential benefits of this mild gasification technology in its commercial configuration are attributable to the increased heating value (about 12,000 Btu/lb) and lower sulfur content (per unit of fuel value) of the new solid-fuel product compared to the low-rank coal feed-

stock, 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<sub>2</sub> emissions at industrial and utility facilities currently burning high-sulfur bituminous coals or fuel oils.

ENCOAL<sup>®</sup> Corporation's newly formed company, NuCoal, L.L.C., has signed a contract with Mitsubishi International Corporation to construct a \$460-million, 15,000-metric-ton/day plant in Wyoming. Feasibility studies also have been completed for two Indonesian projects and one Russian project.

## 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; operator; synthesis gas and services provider  
Acurex Environmental Corporation—fuel methanol tester and cofunder  
Electric Power Research Institute—fuel methanol test advisor

### Location

Kingsport, Sullivan County, TN (Eastman Chemical Company's Integrated Coal Gasification Facility)

### Technology

Air Products and Chemicals' liquid-phase methanol (LPMEOH™) process

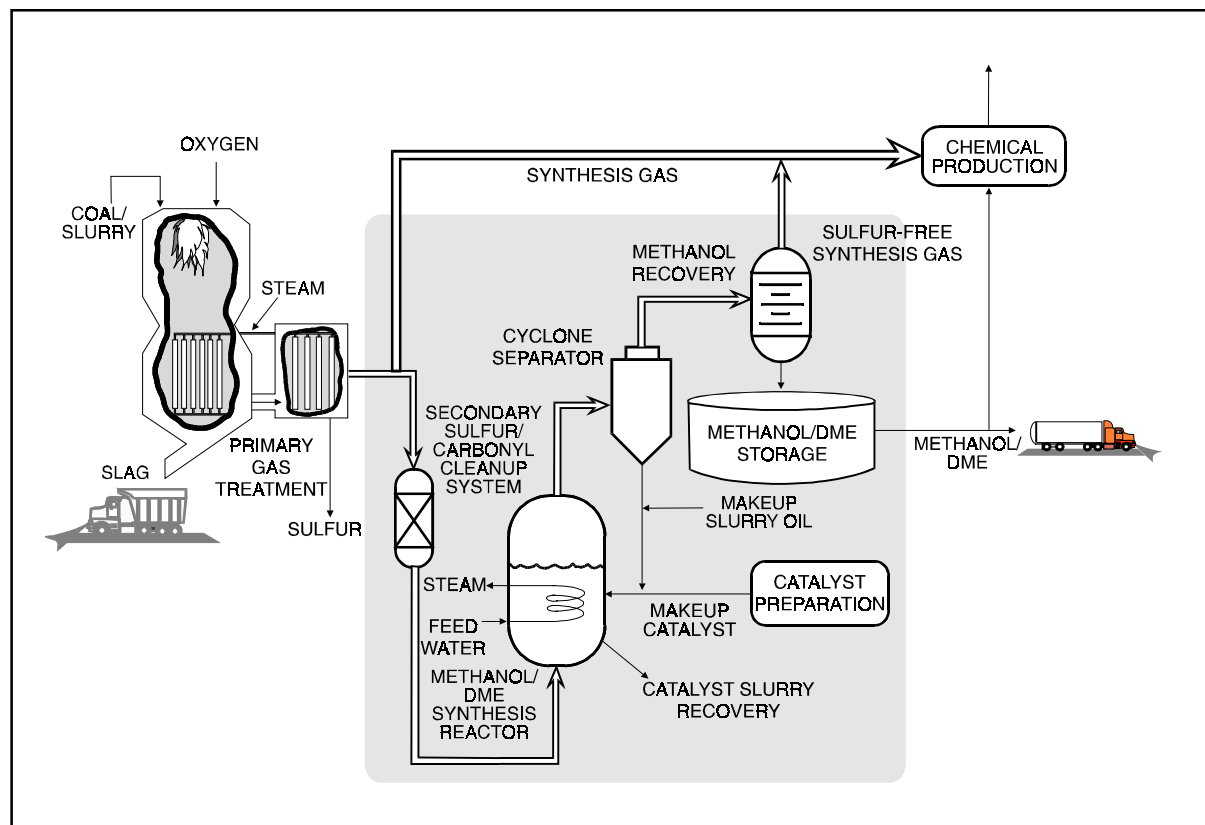
### Plant Capacity/Production

80,000 gallons/day of methanol (nominal)

### Project Funding

Total project cost	\$213,700,000	100%
DOE	92,708,370	43
Participant	120,991,630	57

LPMEOH is a trademark of Air Products and Chemicals, Inc.



### Project Objective

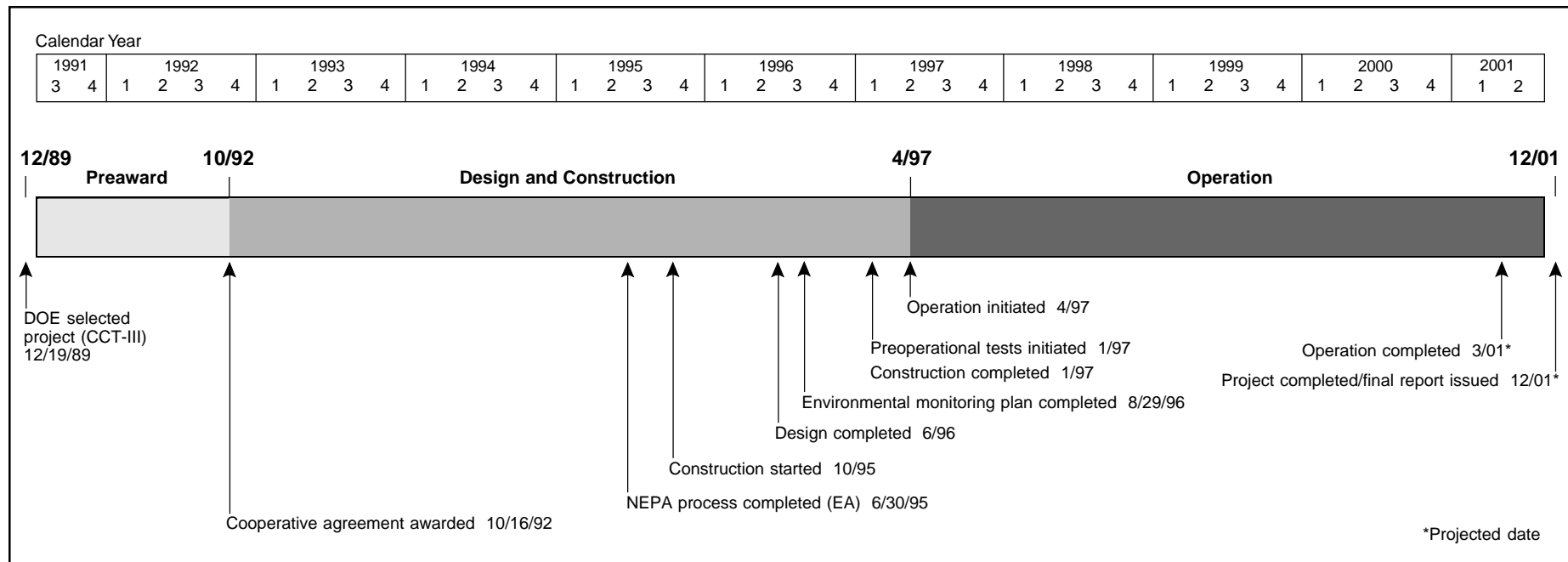
To demonstrate on a commercial scale the production of methanol from coal-derived synthesis gas using the LPMEOH™ process; and to determine the suitability of methanol produced during this demonstration for use as a chemical feedstock or as a low-SO<sub>x</sub>, low-NO<sub>x</sub> alternative fuel in 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 phase-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 fuel cells, buses, and distributed electric power generation. Design verification testing for the production of DME as a mixed coproduct with methanol for use as a stor-



able fuel is planned, and a decision on whether or not 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

Construction was completed and commissioning and start-up began in January 1997. All utility and control systems were commissioned, and a functional checkout of the liquid-phase reactor system using coal-derived synthesis gas at operating temperatures and pressures was performed. Functional checkout of the methanol distillation system and catalyst preparation areas was also performed at normal operating temperatures and pressures. Activation of the methanol catalyst was completed and methanol production in the LPMEOH™ process demonstration unit began on April 2, 1997. The first stable operation of the LPMEOH™ process demonstration unit at nameplate capacity of 80,000 gal/day occurred on April 6, 1997. The initial operating period continued until May 9, 1997; over 700 hours of stable

operation was logged. A continuous operating period of over 351 hours was also achieved. Eastman has accepted all of the 1.67 million gallons of product methanol from the initial run for use in its onsite chemicals production.

A recent economic study of the LPMEOH™ process as an add-on to an IGCC power plant indicates that cost-savings are realized when utilities manufacture and sell two products: electricity and methanol. Based on these economics, a commercial-scale IGCC coproduction facility generating 426 MWe of electric power could also manufacture 152,000 gal/day of methanol at a cost of about 46.5 cents/gal. This compares favorably to new world-scale (700,000–900,000 gal/day) chemical-grade methanol plants having a U.S. Gulf Coast delivered cost of 55–60 cents/gal.

### 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 utility peaking units, contains no sulfur, and has exceptionally low-NO<sub>x</sub> 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. 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 50,000 to 300,000 gal/day of methanol produced when associated with commercial IGCC power generation trains of 200–500 MWe. Air Products and Chemicals expects to market the LPMEOH™ technology through licensing, owning/operating, and tolling arrangements.



## Industrial Applications Technology

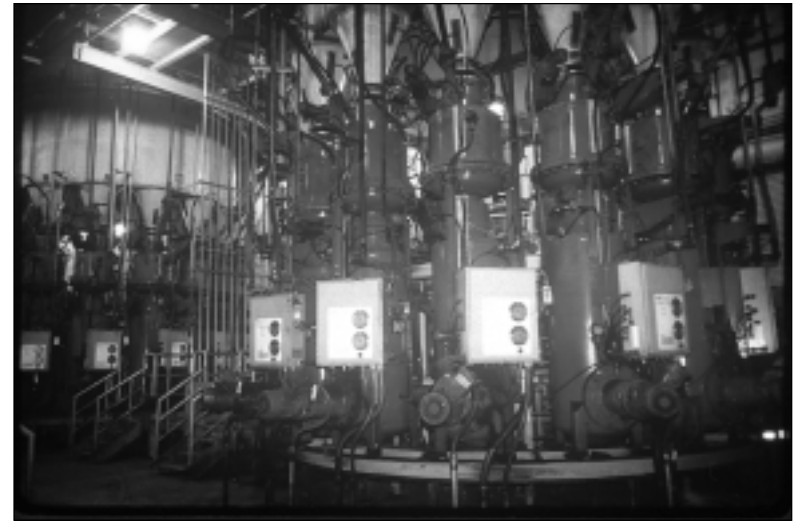
Technologies applicable to the industrial sector address significant environmental issues and barriers associated with coal use in industrial processes. These technologies are directed at both continued coal use and introduction of coal use in various industrial sectors.

One of the critical environmental concerns has to do with pollutant emissions resulting from producing coke from coal in steelmaking. Two approaches to mitigate or eliminate this problem are being demonstrated. In one, about 40 percent of the coke is displaced through direct injection of granular coal into a blast furnace system. The coal is essentially burned in the blast furnace where the pollutant emissions are readily controlled (as opposed to first coking the coal). The other approach precludes the need for coke making by using a direct iron-making process, COREX®. In this process, raw coal is introduced into a melter-gasifier to produce reducing gas and heat for a unique reduction furnace; no coke is required. Excess reducing gas is cleaned and used to fuel a gas turbine for electric power generation.

Because production costs are largely driven by fuel cost, coal is often the fuel of choice in cement production. Faced with the need to control SO<sub>2</sub> emissions and also to address growing solid waste management problems, industry sponsored the demonstration of an innovative SO<sub>2</sub> scrubber. The successfully demonstrated Passamaquoddy Technology Recovery Scrubber™ uses cement kiln dust, otherwise discarded as waste, to control SO<sub>2</sub> emis-

sions, convert the sulfur and chloride acid gases to fertilizer, return the solid by-product as cement kiln feedstock, and produce distilled water. No new wastes are generated and cement kiln dust waste is converted to feedstock. This technology also has application for controlling pollutant emissions in paper production and waste-to-energy applications.

In many industrial boiler applications, the relatively low, stable price of coal makes it an attractive substitute for oil and gas feedstock. However, drawbacks to conversion of oil/gas-fired units to coal include addition of SO<sub>2</sub> and NO<sub>x</sub> controls, tube fouling, and the need for a coolant water circuit for the combustor. Oil/gas-fired units are not high SO<sub>2</sub> or NO<sub>x</sub> emitters, use relatively tight tube spacing in the absence of the potential for ash fouling, and the flow of oil or gas cools the combustor, precluding the need for water cooling. For these reasons, the CCT Program demonstrated an advanced air-cooled, slagging combustor that could avoid these potential problems. The cyclone combustor stages introduction of air to control NO<sub>x</sub>, injects sorbent to control SO<sub>2</sub>, slags the ash in the combustor to prevent tube



▲ Shown here is the granular-coal injection system.



▲ Shown here is the completed Bethlehem Steel Corporation facility to demonstrate the injection of granulated coal directly into two blast furnaces at Burns Harbor, IN.

**Exhibit 5-34**  
**CCT Program Industrial Applications Technology Characteristics**

<b>Project</b>	<b>Process</b>	<b>Size</b>	<b>Fact Sheet</b>
Blast Furnace Granular-Coal Injection System Demonstration Project	Blast furnace granular-coal injection for reduction of coke use	7,000 net tons/day of hot metal/furnace	5-130
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	Advanced slagging combustor with staged combustion and sorbent injection	23 million Btu/hr	5-132
Clean Power from Integrated Coal/Ore Reduction (CPICOR™)	COREX® direct reduction iron-making process to eliminate coke; combined-cycle power generation	195 MWe 3,300 tons/day of hot metal	5-136
Cement Kiln Flue Gas Recovery Scrubber	Cement kiln dust used to capture SO <sub>2</sub> ; dust converted to feedstock; and fertilizer and distilled water produced	1,450 tons/day of cement	5-138
Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal	Advanced combustion using pulse combustor/gasifier	170 million Btu/hr of medium-Btu fuel 10 tons/hr of low-sulfur char 4,500 lb/hr of hydrocarbon liquids	5-142

fouling, and uses air cooling to preclude the need for water circuitry.

The cement kiln and slagging combustor projects are completed. The project demonstrating granular-coal injection into a blast furnace is in operation. Demonstration of the COREX® direct iron-making process is in the project definition and design phase.

A fifth project to demonstrate a pulse combustor in an application for steam gasification of coal was concluded in March 1997, when the project was unable to be restructured.

Exhibit 5-34 summarizes process characteristics and size for the industrial applications technologies presented in more detail in the project fact sheets.

## Blast Furnace Granular-Coal Injection System Demonstration Project

### Participant

Bethlehem Steel Corporation

### Additional Team Members

British Steel Consultants Overseas Services, Inc.

(marketing arm of British Steel Corporation)—  
BFGCI technology owner

CPC-Macawber, Ltd. (formerly named Simon-Macawber, Ltd.)—equipment supplier (world rights to sublicense BFGCI)

Fluor Daniel, Inc.—architect and engineer

ATSI, Inc.—injection equipment engineer  
(North America BFGCI licensee)

### Location

Burns Harbor, Porter County, IN (Bethlehem Steel's Burns Harbor Plant, Blast Furnace Units C and D)

### Technology

British Steel and CPC-Macawber blast furnace granular-coal injection (BFGCI) process

### Plant Capacity/Production

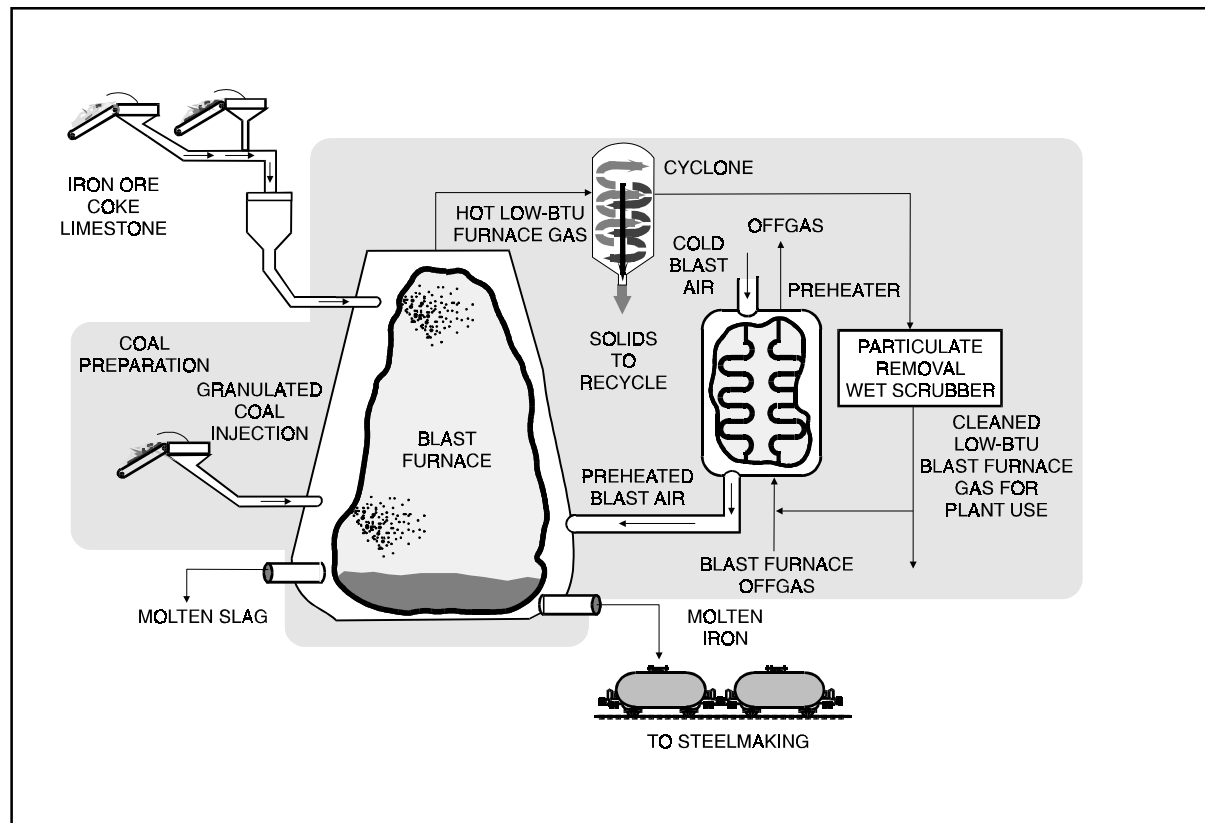
7,000 net tons/day of hot metal (each blast furnace)

### Project Funding

Total project cost	\$194,301,790	100%
DOE	31,824,118	16
Participant	162,477,672	84

### Project Objective

To demonstrate that existing iron-making blast furnaces can be retrofitted with blast furnace granular-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.

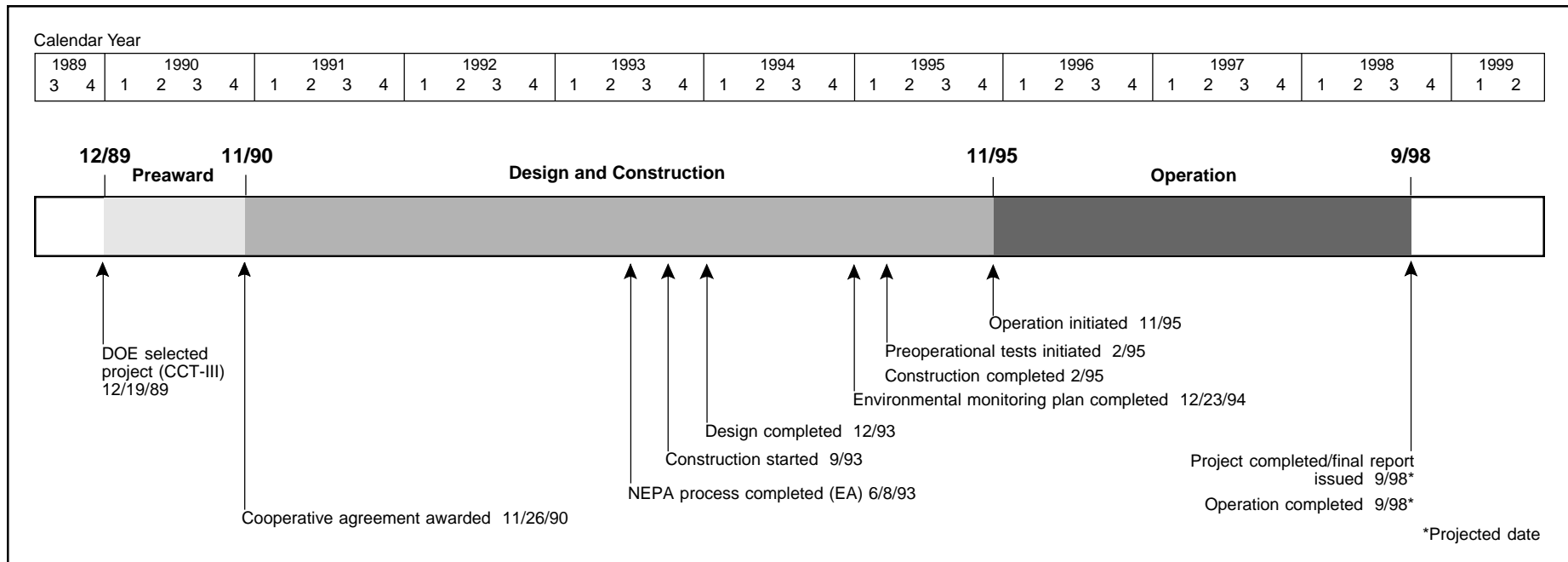


### Technology/Project Description

In the BFGCI process, either granular or 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  $\text{NO}_x$ ,  $\text{SO}_2$ , and air toxics and coal could replace up to 40% of the coke requirement, BFGCI technology has significant potential to reduce pollutant 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  $\text{SO}_2$  or  $\text{NO}_x$ . 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 pollutant 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's Burns Harbor Plant, were retrofitted with BFGCI technology. Each unit has a production capacity of 7,000 net tons/day of hot metal. The two units use about 2,800 tons/day of coal during full operation. Bituminous coals with sulfur content of 0.8–2.8% from West Virginia, Pennsylvania, Illinois, and Kentucky are being used. A western subbituminous coal having 0.4–0.9% sulfur is being tested also.

### Project Status/Accomplishments

The plant is now fully operational in a commercial mode. Furnace C has been operated with an average coal injection rate of 264 lb/net ton of hot metal, using low-volatile bituminous coals. Coal injection rates reached 270 lb/ton by mid-1996 and 300 lb/ton for short periods. Furnace C continued to operate with a coke rate of approximately 660 lb/net ton of hot metal, down from 770 lb/net ton. Permeability was stabilized at 1.19 with the addition of moisture to produce more hydrogen in the bosh gas. Furnace D commonly has achieved coal

injection rates 10% above the design rate of 180 lb/net ton and has operated at an average coke rate of 715 lb/ton of hot metal.

A comparison of high- and low-volatile coals as injectants showed that low-volatile coal replaces more coke and results in better blast furnace operation than high-volatile coal. The replacement ratio with low-volatile coal is 0.96 lb coke/lb coal. A major conclusion of the work to date was that granular-coal injection performs very well on large blast furnaces.

Further testing of different coals will include a high-ash coal and a direct comparison of granular versus pulverized coal injection. Bethlehem Steel plans to increase substantially the coal feed rate through all 52 tuyeres for comparison with the baseline standard of 275 lb/net ton of hot metal on Furnace C.

### 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.

The BFGCI technology was developed jointly by British Steel and CPC-Macawber (then named Simon-Macawber). British Steel has granted exclusive rights to market BFGCI technology worldwide to CPC-Macawber. CPC-Macawber also has the right to sublicense BFGCI rights to other organizations throughout the world. British Steel and CPC-Macawber have recently installed a similar facility at a United States Steel blast furnace.

## 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

### Location

Williamsport, Lycoming County, PA (Tampella Power Corporation's boiler manufacturing plant)

### Technology

Coal Tech's advanced, air-cooled, slagging combustor

### Plant Capacity/Production

23 million Btu/hr

### Coal

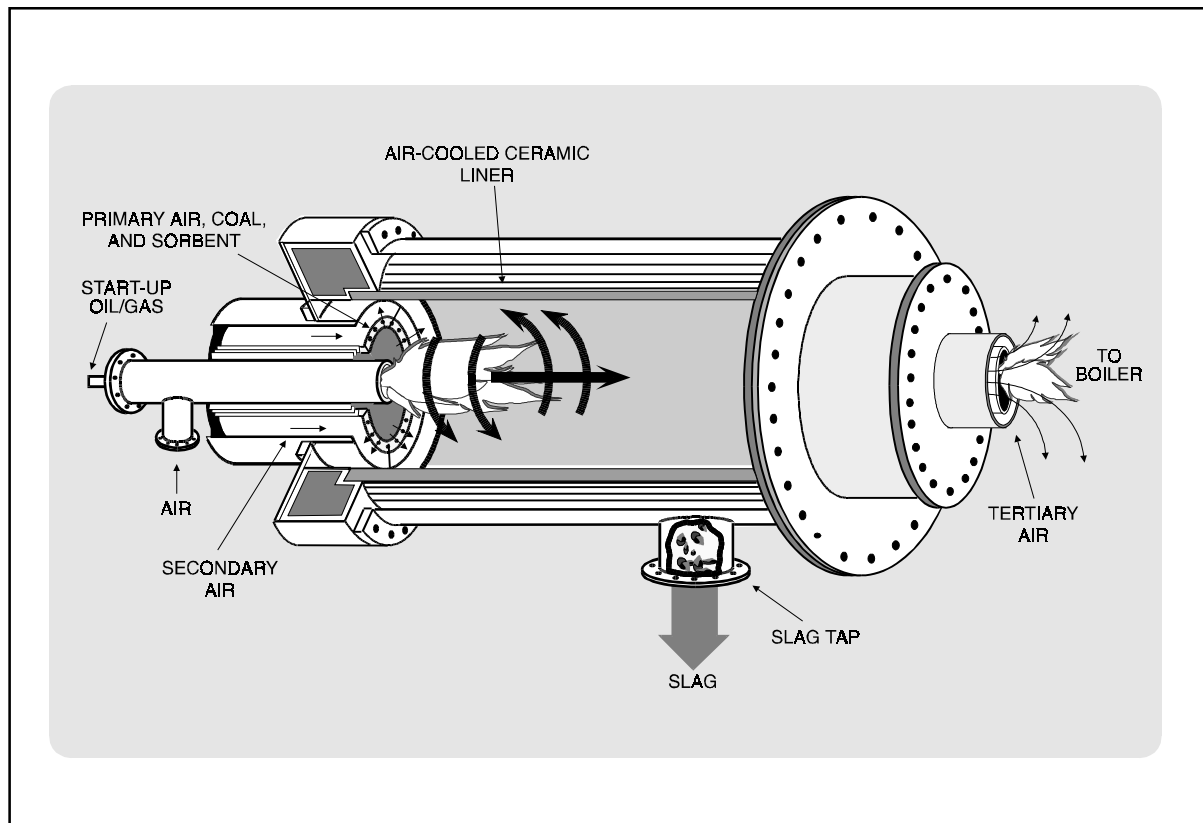
Pennsylvania bituminous, 1.0–3.3% sulfur

### Project Funding

Total project cost	\$984,394	100%
DOE	490,149	50
Participant	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<sub>2</sub> and 90–95% of the ash within the combustor and reduce NO<sub>x</sub> to 100 ppm.

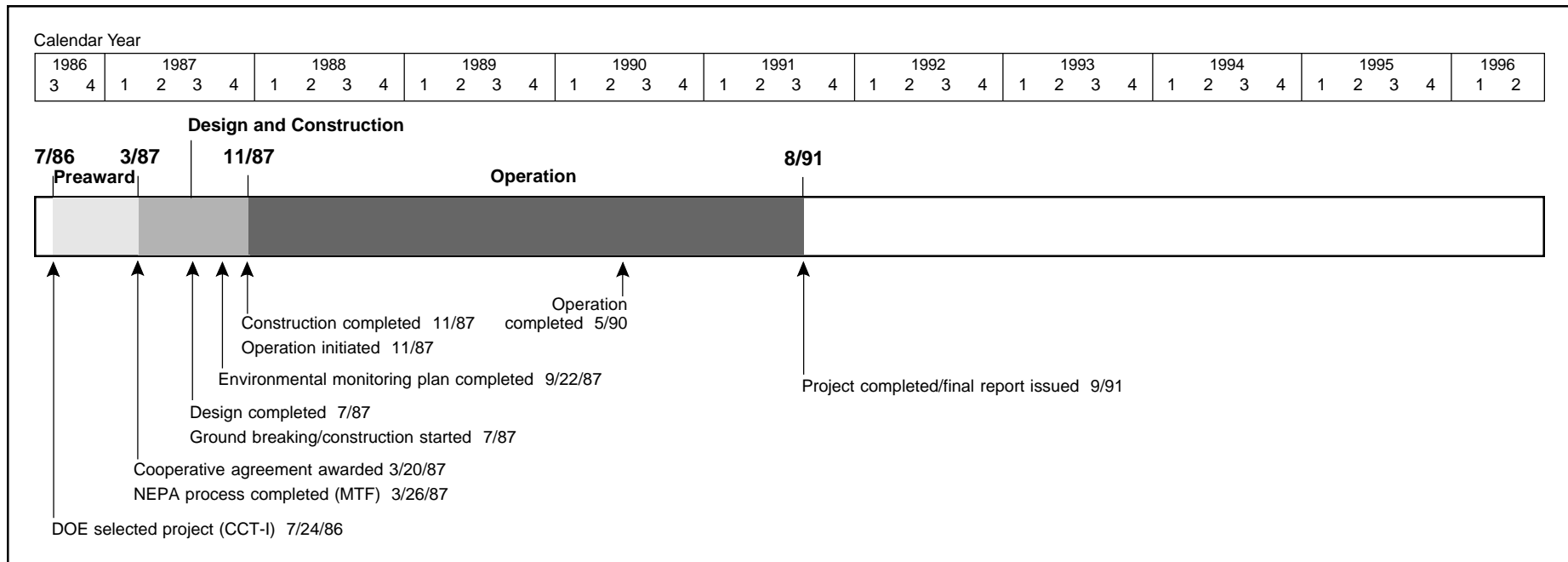


### Technology/Project Description

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. Tertiary air is injected at the combustor/boiler interface. The ceramic liner is cooled by the secondary air and maintained at a temperature high enough to keep the slag in a liquid, free-flowing state. The secondary air is preheated by the combustor walls to attain efficient combustion of the coal particles in the fuel-rich combustor. Fine coal pulverization allows combustion of most of the coal particles near the cyclone wall. The combus-

tor was designed to retain as slag a high percentage of the ash and sorbent fed to the combustor. For NO<sub>x</sub> control, the combustor is operated fuel rich, with final combustion taking place in the boiler furnace to which the combustor is attached. SO<sub>2</sub> 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.

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.

## Results Summary

### Environmental

- SO<sub>2</sub> removal efficiencies of over 80% were achieved with sorbent injection in the furnace at various calcium-to-sulfur molar ratios (Ca/S).
- SO<sub>2</sub> removal efficiencies up to 58% were achieved with sorbent injection in the combustor at a Ca/S of 2.0.
- A maximum of 1/3 of the coal's sulfur was retained in the dry ash removed from the combustor (as slag) and furnace hearth.
- At most, 11% of the coal's sulfur was retained in the slag rejected through the combustor's slag tap.
- NO<sub>x</sub> emissions were reduced to 184 ppm by the combustor and furnace and to 160 ppm with the addition of a wet particulate scrubber.

- Combustor slag was essentially inert.
- Ash/sorbent retention in the combustor as slag averaged 72% and ranged from 55% to 90%. Under more fuel lean conditions, retention averaged 80%.
- Meeting local particulate emissions standards required the addition of a wet venturi scrubber.

### Operational

- Combustion efficiencies of over 99% were achieved.
- A 3-to-1 combustor turndown capability was demonstrated. Protection of combustor refractory with slag was shown to be possible.
- A computer-controlled system for automatic combustor operation was developed and demonstrated.

### Economic

- Because the technology failed to meet commercialization criteria, economics were not developed during the demonstration. However, subsequent efforts indicate that incremental capital costs for installing

the coal combustor in lieu of oil or gas systems are \$100–\$200/kW.

## Project Summary

The novel features of Coal Tech's patented ceramic-lined, slagging cyclone combustor included its air-cooled walls and environmental control of NO<sub>x</sub>, SO<sub>2</sub>, and solid waste emissions. Air cooling took place in a very compact combustor, which could be retrofitted to a wide range of industrial and utility boiler designs without disturbing the boiler's water-steam circuit. In this technology, NO<sub>x</sub> reduction was achieved by staged combustion, and SO<sub>2</sub> was captured by injection of limestone into the combustor and/or boiler. Critical to combustor performance was removal of ash, as slag, which would otherwise erode boiler tubes. This was particularly important in oil furnace retrofits where tube spacing is tight (made possible by the low-ash content of oil-based fuels).

The test effort consisted of 800 hours of operation, including five individual tests, each of 4 days duration. An additional 100 hours of testing was performed as part

of a separate ash vitrification test. Test results obtained during operation of the combustor indicated that Coal Tech attained most of the objectives contained in the cooperative agreement. About eight different Pennsylvania bituminous coals with sulfur contents ranging from 1.0% to 3.3% and volatile matter contents ranging from 19% to 37% were tested.

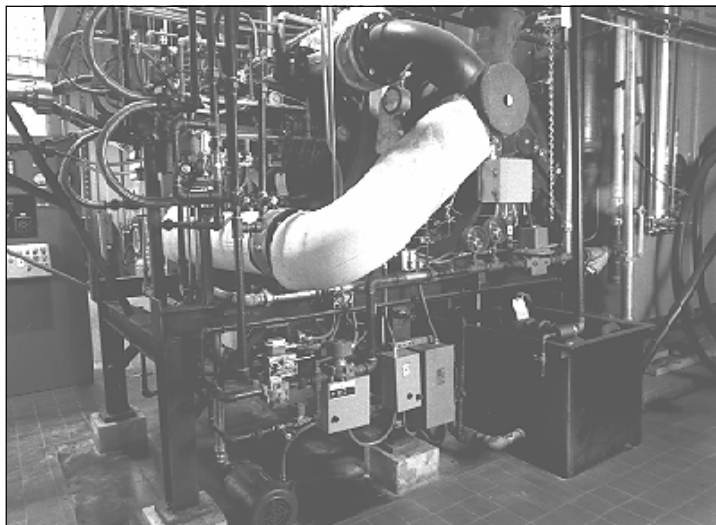
### Environmental Performance

A maximum of over 80% SO<sub>2</sub> reduction measured at the boiler outlet stack was achieved using sorbent injection in the furnace at various Ca/S molar ratios. A maximum SO<sub>2</sub> reduction of 58% 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 as much as 11% of the coal's sulfur was retained in the slag rejected through the slag tap. Additional sulfur retention in the slag is possible by increasing the slag flow rate and further improving fuel-rich combustion and sorbent-gas mixing.

With fuel-rich operation of the combustor, a three-fourths reduction in measured boiler outlet stack NO<sub>x</sub> was obtained, corresponding to 184 ppm. An additional 5–10% reduction was obtained by the action of the wet particulate scrubber, resulting in atmospheric NO<sub>x</sub> emissions as low as 160 ppm.

All the slag removed from the combustor produced trace metal leachates well below EPA's Drinking Water Standard.

Total ash/sorbent retention as slag 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



▲ The slagging combustor, associated piping, and control panel for Coal Tech's advanced ceramic-lined slagging combustor are shown.

combustor, modifications to the solids injection system and increases in the slag flow rate produced substantial increases in the slag retention rate. To meet local stack particulate emission standards, a wet venturi particulate scrubber was installed at the boiler outlet.

### Operational Performance

Combustion efficiencies exceeded 99% after proper operating procedures were achieved. Combustor turn-down to 6 million Btu/hr from a peak of 19 million Btu/hr (or a 3-to-1 turndown) was achieved. 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. This situation resulted from facility limits on water availability for the boiler and for cooling the combustor. In fact, due to the lack of sufficient water cooling, even 20 million Btu/hr was borderline, so that most of the testing was conducted at lower rates.

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. As an example, by implementing certain procedures, such as changing the combustor wall temperature, it was possible to replenish the combustor refractory wall thickness with slag produced during combustion rather than by adding ceramic to the combustor walls.

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.

Developing proper combustor operating procedures was also an 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.

### Commercial Applications

In conclusion, the goal of this project was to validate the performance of the air-cooled combustor at a commercial scale. While the combustor was not yet fully ready for sale with commercial guarantees, it was believed to have commercial potential. Subsequent work was undertaken, which has brought the technology close to commercial introduction.

### Contacts

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

Merion, PA 19066  
William E. Fernald, DOE/HQ, (301) 903-9448  
Arthur L. Baldwin, FETC, (412) 892-6011

#### References

- *The Coal Tech Advanced Cyclone Combustor Demonstration Project—A DOE Assessment*. Report No. DOE/PC/79799-T1. U.S. Department of Energy. May 1993.
- *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; Vol. 1: Final Technical Report; Vol. 2: Appendixes I–V; Vol. 3: Appendix VI*. Coal Tech Corporation. August 1991. (Available from NTIS as DE92002587 and DE92002588.)
- *Comprehensive Report to Congress on the Clean Coal Technology Program: Advanced Cyclone Combustor with Integral Sulfur, Nitrogen, and Ash Control*. Coal Tech Corporation. Report No. DOE/FE-0077. U.S. Department of Energy. February 1987. (Available from NTIS as DE87005804.)



▲ Coal Tech's slugging combustor demonstrated the capability to retain, as slag, a high percentage of the non-fuel components injected into the combustor. The slag, shown on the conveyor, is essentially an inert glassy by-product with value in the construction industry as aggregate or in the manufacture of abrasives.



## Clean Power from Integrated Coal/Ore Reduction (CPICOR™)

### Participant

CPICOR™ Management Company, L.L.C. (a limited liability company composed of subsidiaries of Centor Energy Corporation, Air Products and Chemicals, Inc., and the Geneva Steel Company)

### Additional Team Members

Geneva Steel Company—cofounder and host; constructor and operator of COREX® unit

Centor Energy Corporation—cofounder

Air Products and Chemicals, Inc.—cofounder; 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

### Location

Vineyard, Utah County, UT (Geneva Steel Company's mill)

### Technology

Integration of Deutsche Voest-Alpine

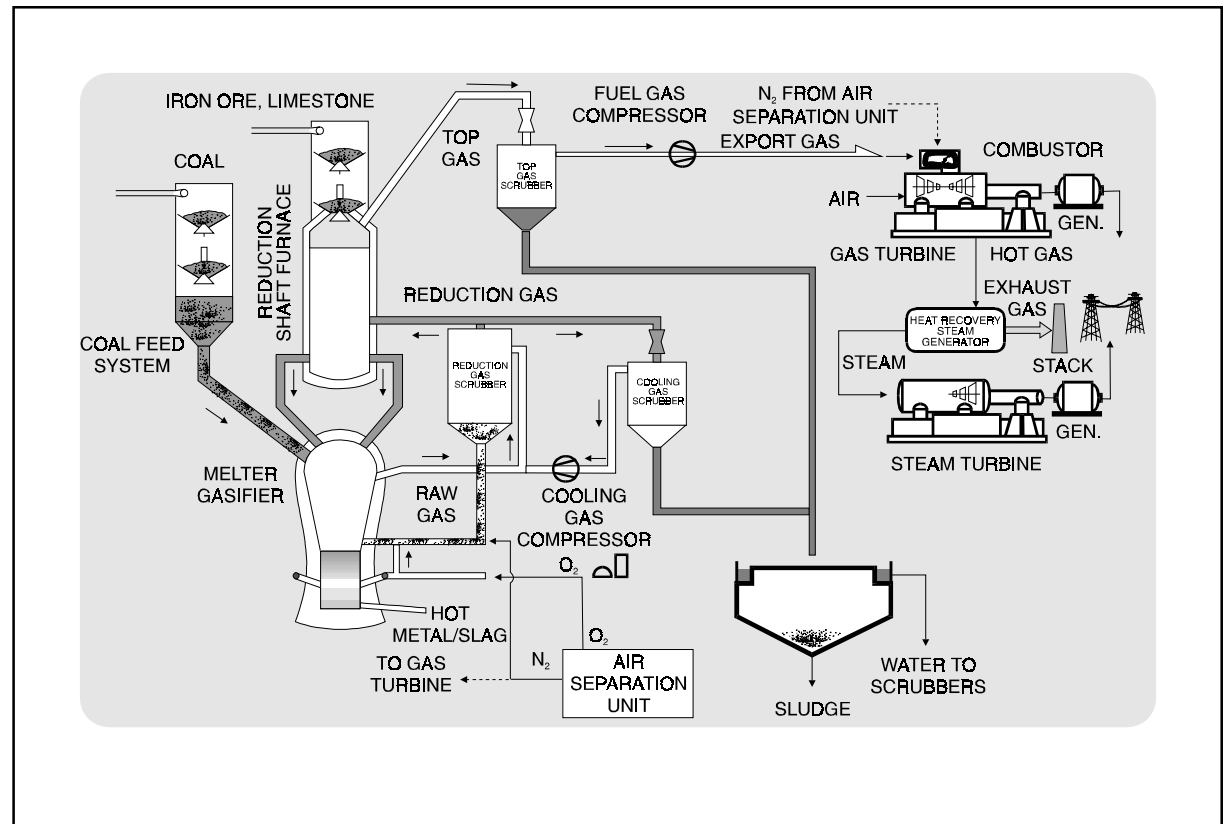
Industrieanlagenbau's COREX® iron-making process with a combined-cycle power generation system

### Plant Capacity/Production

195 MWe (net) or 250 MWe (gross) and 3,300 tons/day of hot metal (liquid iron)

COREX is a registered trademark of Deutsche Voest-Alpine Industrieanlagenbau GmbH.

CPICOR is a trademark of the CPICOR Management Company, L.L.C.



### Project Funding

Total project cost	\$1,065,805,000	100%
DOE	149,469,242	14
Participant	916,335,758	86

### Project Objective

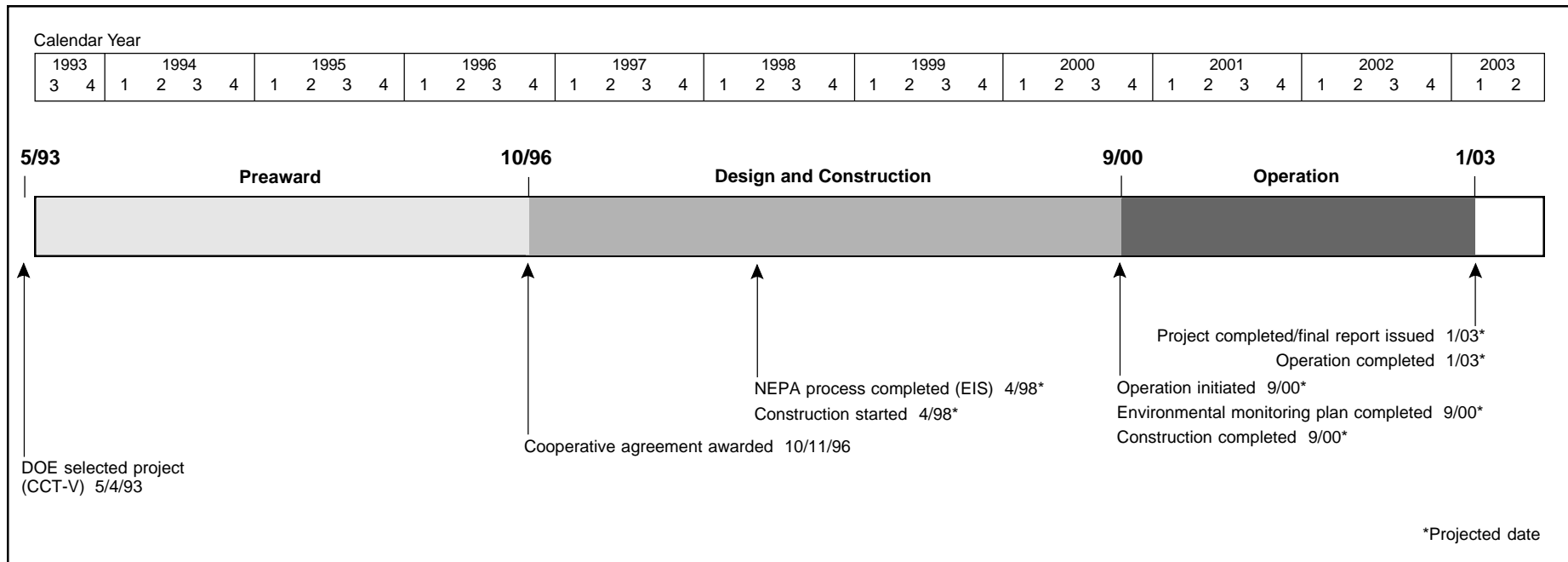
To demonstrate the integration of a direct iron-making process (COREX®) with the co-production of electricity using various U.S. coals in an efficient and environmentally responsible manner.

### 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 that 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, the facility will utilize approximately 3,400 tons/day of a western bituminous coal blend containing about 0.5% sulfur. The project will produce 3,300 tons/day of hot metal and 195 MWe.

**Project Status/Accomplishments**

The cooperative agreement was awarded on October 11, 1996. Permitting and project definition are under way.

**Commercial Applications**

The CPICOR™ technology is a direct replacement for existing blast furnace and coke-making facilities with the additional benefit of combined-cycle power generation. A full-scale commercial plant based on the CPICOR™ demonstration project will produce 195 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.

All criteria pollutants, particularly SO<sub>2</sub> and NO<sub>x</sub>, are reduced by more than 85%. This reduction is due largely to the desulfurizing capability of the COREX® process,

efficient control systems within the combined-cycle power generation facility, and use of oxygen in place of air. The COREX® process releases no air toxics from the high-temperature gasifier into the environment, and most trace elements are captured in the slag. The predominant solid by-product of the COREX® process is a usable slag, which is similar to blast furnace slag and can be sold as construction balast.

The energy efficiency of the CPICOR™ technology is over 30% greater than the competing commercial technology when considering only the effective production of hot metal and electric power. CPICOR™ technology's higher efficiency is due to the more effective use of sensible heat and volatile matter than the coke-making/blast furnace process. In addition, combined-cycle power generation achieves energy efficiencies of nearly 50%.

Of the existing 79 U.S. coke oven batteries, half are 30 years of age or older and are due for replacement or major rebuilds. There are about 60 U.S. blast fur-

naces, all of which have been operating for more than 10 years, with some originally installed up to 90 years ago. Worldwide, more than 300 blast furnaces with capacities of 0.3–1.2 million net tons/yr could be replaced by COREX®.

The CPICOR™ project exceeds the individual production rates of 75% of domestic blast furnaces. Further, a utility facility scale-up by only 150% would exceed production rates of 90% of existing U.S. blast furnaces.

## Cement Kiln Flue Gas Recovery Scrubber

**Project completed.**

### Participant

Passamaquoddy Tribe

### Additional Team Members

Dragon Products Company—project manager and host  
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™

### Plant Capacity/Production

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

### Coal

Pennsylvania bituminous, 2.5–3.0% sulfur

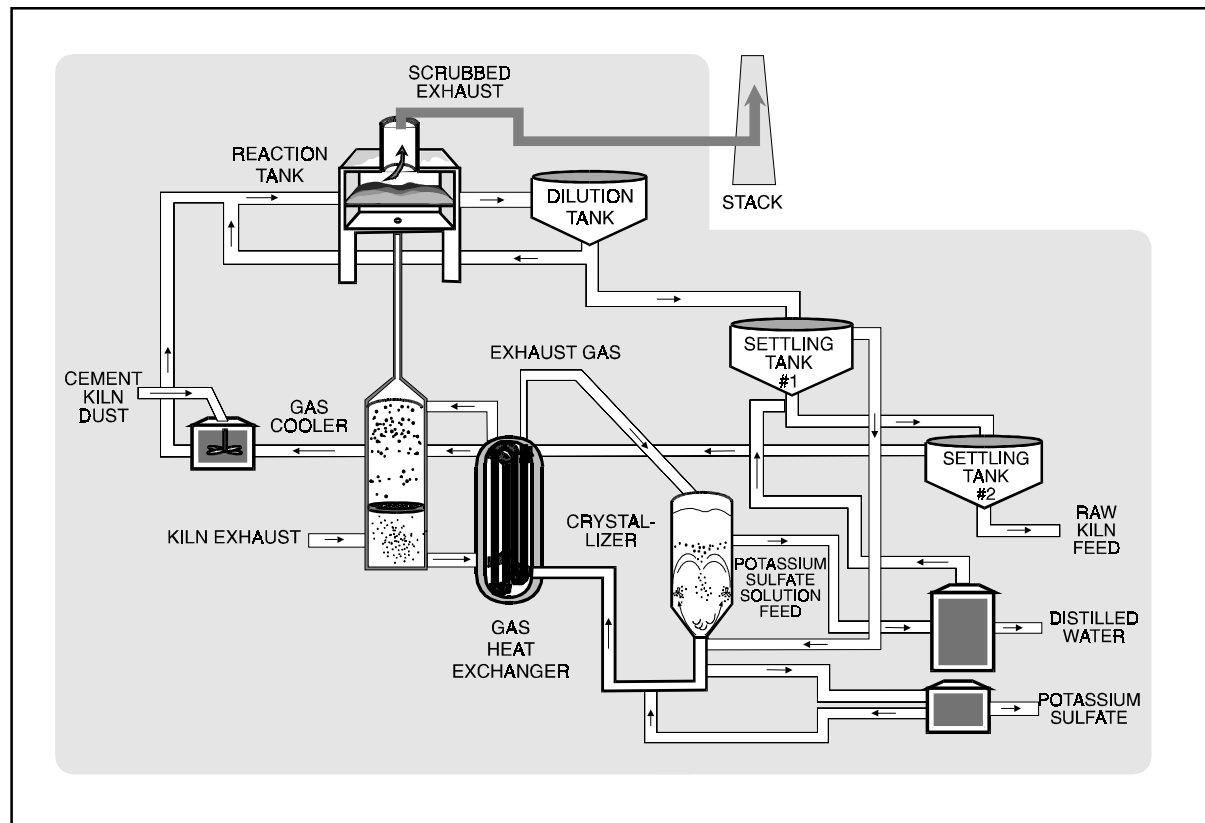
### Project Funding

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<sub>2</sub> reduction using high-sulfur eastern coals; and to produce a commercial by-product, potassium-based fertilizer.

Passamaquoddy Technology Recovery Scrubber is a trademark of the Passamaquoddy Tribe.

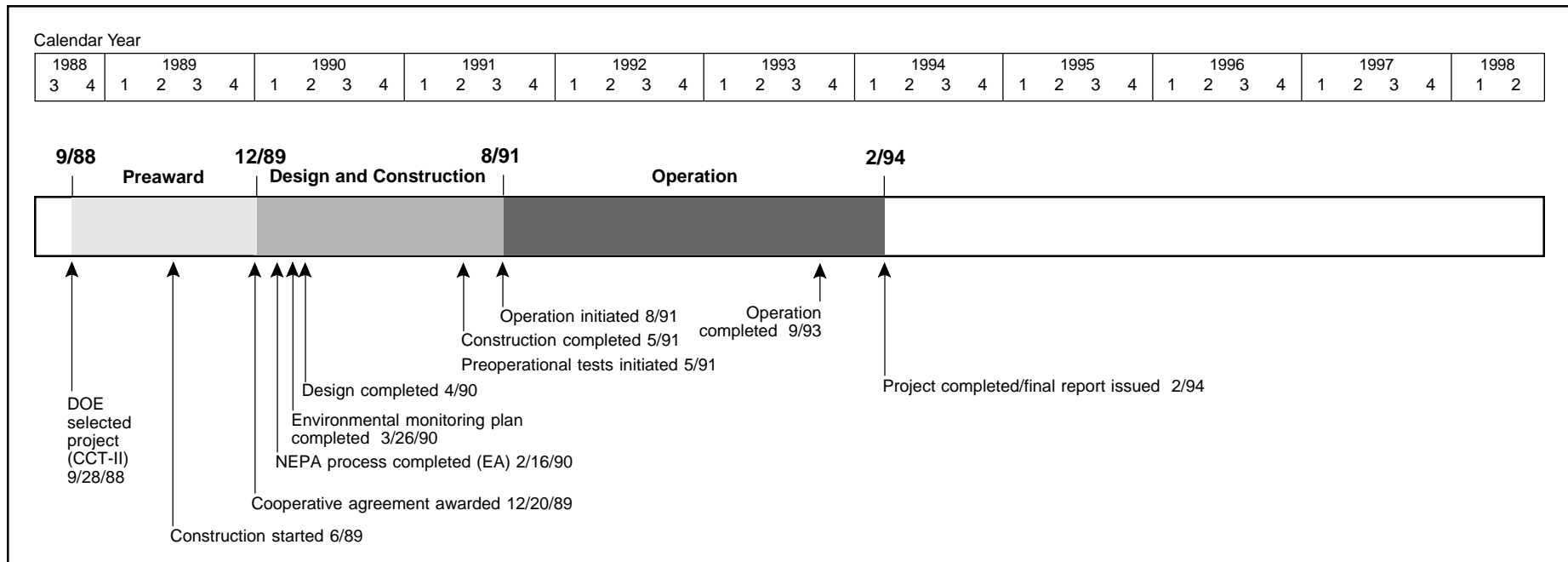


### Technology/Project Description

The Passamaquoddy Technology Recovery Scrubber™ uses cement kiln dust (CKD), an alkaline-rich (potassium) waste, to react with the acidic flue gas. This CKD, representing about 10% of the cement feedstock otherwise lost as waste, is formed into a water-based slurry and mixed with the flue gas as the slurry passes over a perforated tray that enables the flue gas to percolate through the slurry. The SO<sub>2</sub> in the flue gas reacts with the potassium to form potassium sulfate, which stays in solution and remains in the liquid as the slurry undergoes separation into liquid and solid fractions. The solid fraction, in thickened slurry form and freed of the potassium and other alkali constituents, is returned to the kiln as feedstock (it is the alkali content that makes the CKD unusable as feedstock). No dewatering is necessary for

the wet process used at the Dragon Products Plant. The liquid fraction is passed to a crystallizer that uses waste heat in the flue gas to evaporate the water and recover dissolved alkali metal salts. A recuperator lowers the incoming flue gas temperature to prevent slurry evaporation, enables the use of low-cost fiberglass construction material, and provides much of the process water through condensation of exhaust gas moisture.

The Passamaquoddy Technology Recovery Scrubber™ was constructed at the Dragon Products Company's cement plant in Thomaston, ME, a plant that can process approximately 450,000 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.



## Results Summary

### Environmental

- The SO<sub>2</sub> removal efficiency averaged 94.6% during the last several months of operation and 89.2% for the entire operating period.
- The NO<sub>x</sub> removal efficiency averaged nearly 25% during the last several months of operation and 18.8% for the entire operating period.
- All of the 250-ton/day CKD waste produced by the plant was renovated and reused as feedstock. This resulted in reducing the raw feedstock requirement by 10% and eliminating solid waste disposal costs.
- Particulate emission rates of 0.005–0.007 gr/std ft<sup>3</sup>, about 1/10 that allowed for cement kilns, were achieved with dust loadings of approximately 0.04 gr/std ft<sup>3</sup>.
- Pilot testing conducted at U.S. Environmental Protection Agency laboratories under Passamaquoddy Technology, L.P., sponsorship showed 98% HCl removal.

- On three different runs, VOC (as represented by alpha-pinene) removal efficiencies of 72.3%, 83.1%, and 74.5% were achieved.
- A reduction of approximately 2% in CO<sub>2</sub> emissions was realized through recycling of the CKD.

### Operational

- During the last operating interval, April to September 1993, recovery scrubber availability (discounting host site downtime) steadily increased from 65% in April 1993 to 99.5% in July 1993.

### Economic

- Capital costs are approximately \$10,090,000 (1990\$) for a recovery scrubber to control emissions from a 450,000-ton/yr wet process plant, with a simple pay-back estimated in 3.1 years. Operating and maintenance costs, estimated at \$500,000/yr, plus capital and interest costs, are generally offset by avoided costs associated with fuel, feedstock, and waste disposal and with revenues from the sale of fertilizer.

## Project Summary

The Passamaquoddy Technology Recovery Scrubber™ is a unique process that achieves efficient acid gas and particulate control through effective contact between flue gas and a potassium-rich slurry composed of waste kiln dust. Flue gas passes through the slurry as it moves over a special sieve tray. This results in high SO<sub>2</sub> and particulate capture, some NO<sub>x</sub> reduction, and sufficient uptake of the potassium (an unwanted constituent in cement) to allow the slurry to be recycled as feedstocks. Waste cement kiln dust, exhaust gases (including waste heat), and wastewater are the only inputs to the process. Renovated cement kiln dust, potassium-based fertilizer, scrubbed exhaust gas, and distilled water are the only proven outputs. There is no waste.

The scrubber was evaluated over 3 basic operating intervals dictated by winter shutdowns for maintenance and inventory and 14 separate operating periods (within these basic intervals) largely determined by unforeseen host-plant maintenance and repairs and a depressed

cement market. Over the period August 1991 to September 1993, more than 5,300 hours was logged, 1,400 hours in the first operating interval, 1,300 hours in the second interval, and 2,600 hours in the third interval. Sulfur loadings varied significantly over the operating periods due to variations in feedstock and operating conditions.

### Operational Performance

Several design problems were discovered and corrected during start-up. No further problems were experienced in these areas during actual operation.

Two problems persisted into the demonstration period. The mesh-type mist eliminator, which was installed to prevent slurry entrainment in the flue gas, experienced plugging. Attempts to design a more efficient water spray for cleaning failed. However, replacement with a chevron-type mist eliminator prior to the third operating interval was effective. Potassium sulfate pelletization proved to be a more difficult problem. The cause was eventually isolated and found to be excessive water entrainment due to carry-over of gypsum and syngenite. Hydroclones were installed in the crystallizer circuit to separate the very fine gypsum and syngenite crystals from the much coarser potassium sulfate crystals. Although the correction was made, it was not in time to realize pellet production during the demonstration period. After all modifications were completed, the recovery scrubber entered into the third and final operating interval—April to September 1993. During this interval, recovery scrubber availability (discounting host site downtime) steadily increased from 65% in April to 99.5% in July.

### Environmental Performance

An average 250 tons/day of CKD waste generated by the Dragon Products plant was used as the sole reagent in the recovery scrubber to treat approximately 250,000 std ft<sup>3</sup>/min of flue gas. All the CKD, or approximately 10 tons/hr, were renovated and returned to the plant as

feedstock and mixed with about 90 tons/hr of fresh feed to make up the required 100 tons/hr. The alkali in the CKD was converted to potassium-based fertilizer, eliminating all solid waste. Exhibit 5-35 lists the number of hours per operating period, SO<sub>2</sub> and NO<sub>x</sub> inlet and outlet readings in pounds per hour, and removal efficiency as a percentage for each operating period.

Average removal efficiencies during the demonstration period were 89.2% for SO<sub>2</sub> and 18.8% for NO<sub>x</sub> emissions. No definitive explanation for the NO<sub>x</sub> control mechanics was available at the conclusion of the demonstration.

Aside from the operating period emissions data, an assessment was made of inlet SO<sub>2</sub> load impact on re-

moval efficiency. For SO<sub>2</sub> inlet loads in the range of 100 lb/hr or less, recovery scrubber removal efficiency averaged 82.0%. For SO<sub>2</sub> inlet loads in the range of 100–200 lb/hr, removal efficiency increased to 94.1% and up to 98.5% for loads greater than 200 lb/hr.

In compliance testing for the state of Maine's Department of Environmental Quality, the recovery scrubber was subjected to dust loadings of approximately 0.04 gr/std ft<sup>3</sup> and demonstrated particulate emission rates of 0.005–0.007 gr/std ft<sup>3</sup>—less than 1/10 the current allowable limit.

**Exhibit 5-35  
Summary of Emissions and Removal Efficiencies**

Operating Period	Operating Time (hr)	Inlet (lb/hr)		Outlet (lb/hr)		% Removal Efficiency	
		SO <sub>2</sub>	NO <sub>x</sub>	SO <sub>2</sub>	NO <sub>x</sub>	SO <sub>2</sub>	NO <sub>x</sub>
1	211	73	320	10	279	87.0	12.8
2	476	71	284	11	260	84.6	08.6
3	464	87	292	13	251	85.4	14.0
4	259	131	252	16	165	87.6	34.5
5	304	245	293	28	243	88.7	17.1
6	379	222	265	28	208	87.4	21.3
7	328	281	345	28	244	90.1	29.3
8	301	124	278	10	188	91.8	32.4
9	314	47	240	7	194	85.7	19.0
10	402	41	244	6	218	86.1	10.5
11	460	36	315	6	267	83.4	15.0
12	549	57	333	2	291	95.9	12.4
13	464	86	288	4	223	95.0	22.6
14	405	124	274	9	199	92.4	27.4
Total	5,316						
<b>Weighted Avg</b>		<b>109</b>	<b>289</b>	<b>12</b>	<b>234</b>	<b>89.2</b>	<b>18.8</b>



▲ The Passamaquoddy Technology Recovery Scrubber™ was successfully demonstrated at Dragon Products Company's cement plant in Thomaston, ME.

### Economic Performance

The estimated "as built" capital cost to reconstruct the Dragon Products prototype, absent the modifications, is \$10,090,000 in 1990 dollars.

Annual operating and maintenance costs are estimated at \$500,000. Long-term annual maintenance costs are estimated at \$150,000. Power costs, estimated at \$350,000/yr, are the only significant operating costs. There are no costs for reagents or disposal, and no dedicated staffing or maintenance equipment are required.

Considering various revenues and avoided costs that may be realized by installing a recovery scrubber similar in size to the one used at Dragon Products, simple pay-back on the investment is projected in as little as 3.1 years. In making this projection, \$6,000,000 was added to the "as built" capital costs to allow for contingency, design/permitting, construction interest, and licensing fees.

### Commercial Applications

Of the approximately 2,000 Portland cement kilns in the world, about 250 are in the United States and Canada. These 250 kilns emit an estimated 230,000 tons/yr of SO<sub>2</sub> (only three plants have SO<sub>2</sub> controls, one of which is the Passamaquoddy Technology Recovery Scrubber™). The applicable market for SO<sub>2</sub> control is estimated at 75% of the 250 installations. If full penetration of this estimated market were realized, approximately 150,000 tons/yr of SO<sub>2</sub> reduction could be achieved.

### Contacts

Thomas N. Tureen, Project Manager, (207) 773-7166  
 Passamaquoddy Technology, L.P.  
 1 Monument Way  
 Portland, ME 04101

William E. Fernald, DOE/HQ, (301) 903-9448

John C. McDowell, FETC, (412) 892-6237

### References

- *Passamaquoddy Technology Recovery Scrubber™: Final Report*. Volumes 1 and 2 (Appendices A–M). Passamaquoddy Tribe. February 1994. (Vol. 1 available from NTIS as DE94011175, Vol. 2 as DE94011176.)
- *Passamaquoddy Technology Recovery Scrubber™: Public Design Report*. Report No. DOE/PC/89657-T2. Passamaquoddy Tribe. October 1993. (Available from NTIS as DE94008316.)
- *Passamaquoddy Technology Recovery Scrubber™: Topical Report*. Report No. DOE/PC/89657-T1. Passamaquoddy Tribe. March 1992. (Available from NTIS as DE92019868.)

- *Comprehensive Report to Congress on the Clean Coal Technology Program: Cement Kiln Flue Gas Recovery Scrubber*. (Passamaquoddy Tribe). Report No. DOE/FE-0152. U.S. Department of Energy. November 1989. (Available from NTIS as DE90004462.)



▲ The Passamaquoddy Technology Recovery Scrubber™ became a permanent part of the Dragon Products facility at the project's end.

## Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal

**Project concluded.**

### Participant

ThermoChem, Inc.

### Additional Team Member

Manufacturing and Technology Conversion International, Inc.—technology supplier

### Location

Silver Bay, Lake County, MN (Northshore Mining Company facility)

### Technology

Advanced combustion using Manufacturing and Technology Conversion International's (MTCI) pulse combustor/gasifier

### Plant Capacity/Production

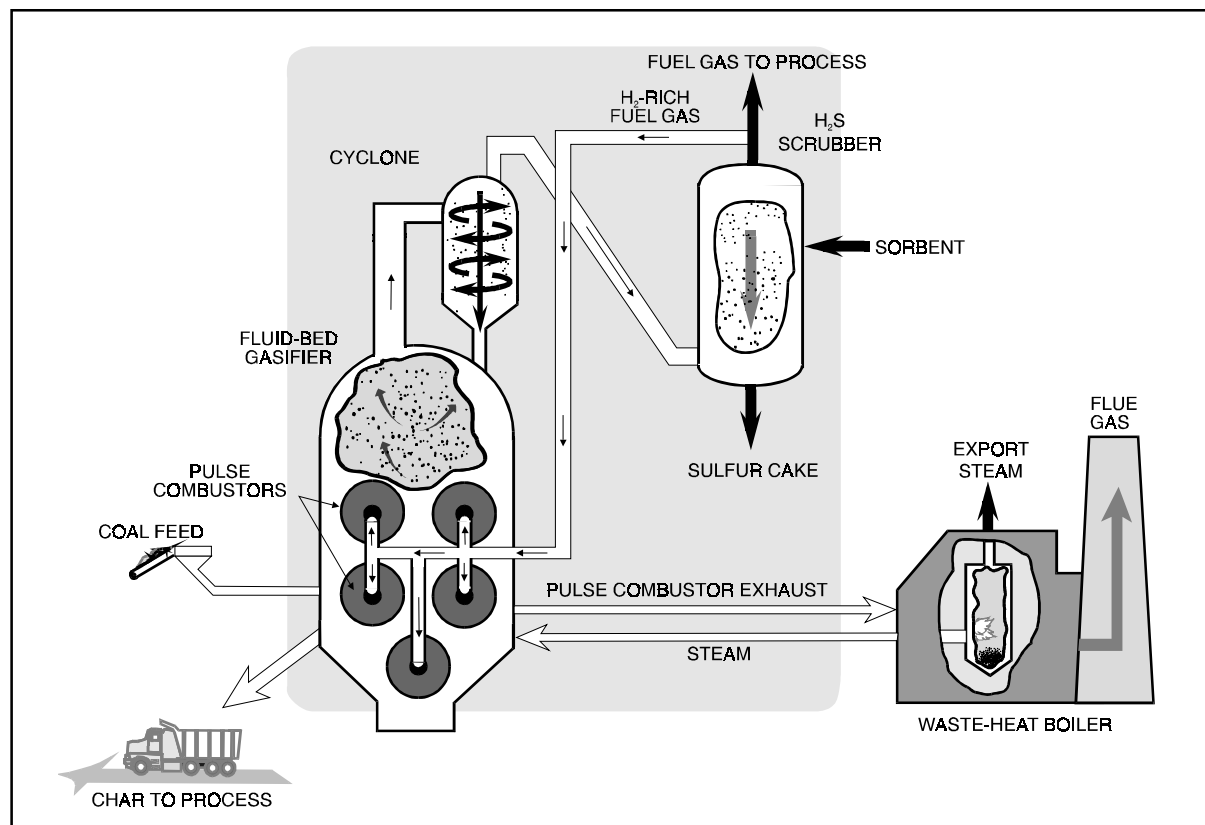
170 million Btu/hr of 280 Btu/std ft<sup>3</sup> medium-Btu fuel gas plus 10 tons/hr of low-sulfur char and 4,500 lb/hr of hydrocarbon liquids

### 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 and char from subbituminous coal.

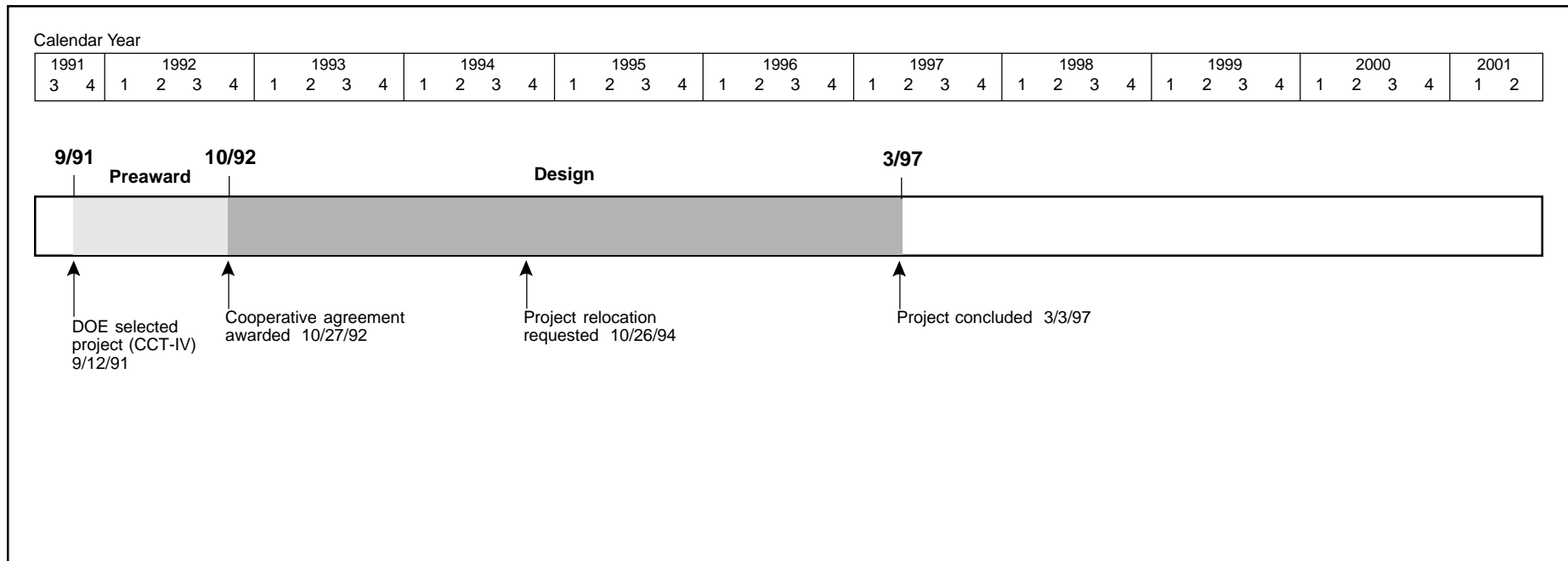


### Technology/Project Description

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<sub>2</sub> 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.



**Project Status/Accomplishments**

The cooperative agreement was awarded on October 27, 1992. Fabrication of the design-verification-scale 253-tube pulse combustor has been completed. On October 26, 1994, ThermoChem, Inc., requested that DOE consider relocating the project to Silver Bay, MN. ThermoChem was unable to restructure the project at the new site, and on March 3, 1997, the project was concluded.

**Commercial Applications**

The MTCI fluidized-bed gasifier is expected to provide the exceptional environmental performance exhibited by coal gasification in general. SO<sub>2</sub> 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<sub>x</sub> combus-

tion process, thereby assuring that NO<sub>x</sub> emissions are substantially below acceptable limits.

Because of its potential for reducing emissions while producing a clean-burning, hydrogen-rich fuel gas, the MTCI fluidized-bed gasifier is expected to have considerable commercial potential. Some of the early industrial applications of this technology are expected to be waste-to-energy or waste and coal cofired facilities for power and steam generation. One of the more promising non-coal applications is processing of kraft black liquor.

The processing of pulp results in the production of about 88 million tons of by-product black liquor. The current practice of using black liquor recovery boilers to produce steam and electricity is inefficient. Replacing these boilers with MTCI gasifiers would significantly improve the conversion efficiency. The estimated market for MTCI gasifiers in this application alone is 28 units annually.

Another potential application for the technology is

in industrial coal gasification because of its modularity and ability to produce a medium-Btu gas without requiring an oxygen plant.



---

# **Appendix A: Historical Perspective and Relevant Legislation**

In The Process of Being Updated.

# Appendix B: Program History

## Solicitation History

The objective of the CCT-I solicitation, issued February 17, 1986, was to seek cost-shared projects to demonstrate the feasibility of clean coal technologies for commercial applications. The Program Opportunity Notice (PON) elicited 51 proposals. Nine projects were selected and 14 projects were placed on a list of alternatives in the event negotiations on the original 9 projects were unsuccessful; 8 alternate projects were eventually selected as replacement projects. Projects were selected from the list of alternates on three separate occasions.

The CCT-II PON, issued February 22, 1988, 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<sub>2</sub> and/or NO<sub>x</sub> emissions from existing coal-burning facilities, particularly those that contribute to transboundary and interstate air 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).

The objective of the CCT-III PON, issued May 1, 1989, 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<sub>2</sub> and/or NO<sub>x</sub> from existing facilities to minimize environmental impacts, such as transboundary and interstate air 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.

The CCT-IV PON, issued January 17, 1991, 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<sub>2</sub> and/or NO<sub>x</sub> 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, 3 have been withdrawn.

The objective of the CCT-V PON, issued July 6, 1992, was to solicit proposals to conduct cost-shared demonstration projects that significantly advance the efficiency and environmental performance of coal-using technologies and are applicable to either new or existing facilities. In response to the solicitation, DOE received proposals for 24 projects and selected 5 projects.

## Selection and Negotiation History

### July 1986

Nine 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.

Four 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**

Sixteen 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. (Advanced Slagging Coal Combustor Utility Demonstration Project).

### **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, was selected from the alternate list.

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**

Thirteen 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 (SO<sub>x</sub>-NO<sub>x</sub>-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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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 Granular-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<sub>2</sub>/NO<sub>x</sub> Removal Flue Gas Cleanup System); Public Service Company of Colorado (Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> 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**

Nine 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<sub>x</sub> 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**

Five 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 L.L.C. (Clean Power from Integrated Coal/Ore Reduction [CPICOR™]); Arthur D. Little, Inc. (Clean Coal Combined-Cycle Project; previously Demonstration of Coal Diesel Technology at Easton Utilities); and Pennsylvania Electric Company (Warren Station Externally Fired Combined-Cycle Demonstration Project).

### **July 1993**

Union Carbide Chemicals and Plastics Company, Inc., withdrew its CCT-IV proposal, Demonstration of the Union Carbide CANSOLV™ System at the Alcoa Generating Corporation Warrick Power Plant.

### **December 1993**

The Babcock & Wilcox Company's CCT-II project, SO<sub>x</sub>-NO<sub>x</sub>-Rox Box™ Flue Gas Cleanup Demonstration Project, was completed; final reports have been issued.

The Babcock & Wilcox Company's CCT-II project, Demonstration of Coal Reburning for Cyclone Boiler NO<sub>x</sub> 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 have been issued.

### **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<sub>x</sub> 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<sub>2</sub>/NO<sub>x</sub> 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<sub>x</sub> 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 have been issued.

AirPol's CCT-III project, 10-MWe Demonstration of Gas Suspension Absorption, was completed; final reports have been issued.

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.

Southern Company Services' CCT-II project, Demonstration of Innovative Applications of Technology for the CT-121 FGD Process, completed operational testing; final reports are in preparation.

### **January 1995**

Energy and Environmental Research Corporation's CCT-III project, Evaluation of Gas Reburning and Low-NO<sub>x</sub> Burners on a Wall-Fired Boiler, completed operational testing; final reports are in preparation.

### **March 1995**

The Ohio Power Company's CCT-I project, Tidd PFBC Demonstration Project, completed operational testing; final reports have been issued.

TAMCO Power Partner's CCT-IV project, Toms Creek IGCC Demonstration Project, was not granted a further extension and the project was ended.

### **April 1995**

Bethlehem Steel Corporation's CCT-II project,

Innovative Coke Oven Gas Cleaning System for Retrofit Applications, was terminated by mutual agreement with DOE because coke production was suspended at the demonstration facility.

#### **June 1995**

Pure Air on the Lake's CCT-II project, Advanced Flue Gas Desulfurization Project, completed operational testing; final reports have been issued.

#### **July 1995**

Southern Company Services' CCT-II project, Demonstration of Selective Catalytic Reduction Technology for the Control of NO<sub>x</sub> Emissions from High-Sulfur Coal-Fired Boilers, completed operational testing; final reports have been issued.

#### **December 1995**

The Tennessee Valley Authority and New York State Electric & Gas Corporation finalized an agreement to allow the project, Micronized Coal Reburning Demonstration for NO<sub>x</sub> Control, to be conducted at both Milliken Station in Lansing, NY, and Eastman Kodak Company in Rochester, NY.

#### **May 1996**

The ABB Combustion Engineering, Inc., CCT-II project, Combustion Engineering IGCC Repowering Project, was ended.

#### **August 1996**

The Arthur D. Little, Inc., CCT-V project was restructured and retitled as the Clean Coal Diesel Demonstration Project.

#### **September 1996**

The Appalachia Power Company CCT-II project, PFBC Utility Demonstration Project, was ended.

#### **October 1996**

DOE signed a cooperative agreement with CCT-V participant, CPICOR™ Management Company, L.L.C. (Clean Power from Integrated Coal/Ore Reduction [CPICOR™]).

The DMEC-1 Limited Partnership project (CCT-III) was restructured and transferred to the City of Lakeland, Department of Electric & Water Utilities (McIntosh Unit 4A PCFB Demonstration Project).

The Four Rivers Energy Partners, L.P., project (CCT-V) was restructured and transferred to the City of Lakeland, Department of Electric & Water Utilities (McIntosh Unit 4B Topped PCFB Demonstration Project).

#### **December 1996**

The ABB Combustion Engineering, Inc., and CQ Inc. CCT-I project, Development of the Coal Quality Expert™, was completed; final reports are in preparation.

The Public Service Company of Colorado's CCT-III project, Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> Emissions Control System, completed operational testing; final reports are in preparation.

#### **March 1997**

The ThermoChem, Inc., CCT-IV project, Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal, was concluded.

#### **May 1997**

The Pennsylvania Electric Company CCT-V project, Externally Fired Combined-Cycle Demonstration Project, was concluded.

# Appendix C: Environmental Aspects

## Introduction

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 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). DOE's NEPA regulations also provide for categorical exclusions (CX) for certain classes of actions.

Exhibit C-1 shows the progress made through June 30, 1997, to complete NEPA reviews of projects in the CCT Program. By June 30, 1997, NEPA reviews were completed for 33 of the 39 CCT projects remaining in the program (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 June 30, 1997, NEPA requirements were satisfied with a CX

for 1 project, MTFs for 17 projects, EAs for 18 projects and EISs for 4 proposed projects (actions exceed 33 because of project terminations, withdrawals, and restructuring).

For each project cofunded by DOE under the CCT Program, the industrial 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.

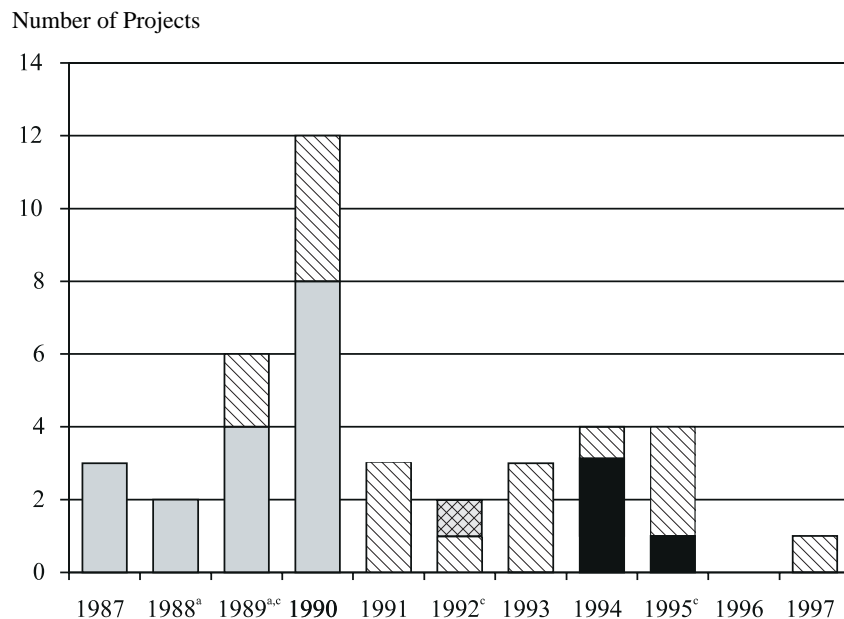
## Compliance with NEPA

In November 1989, a PEIS was completed 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



### Exhibit C-1 NEPA Reviews Completed through June 30, 1997



<sup>a</sup> Includes an MTF (1988) and an EA (1989) required for one project  
<sup>b</sup> Includes an EA for a project that was withdrawn  
<sup>c</sup> Includes an EA for a project that was terminated

Memoranda-to-file  
 Environmental assessments  
 Environmental impact statements  
 Categorical exclusions

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 select-

ing 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 and DOE 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, Micronized Coal Reburning Demonstration for NO<sub>x</sub> Control, was 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 C-2 lists the 17 projects for which an MTF was prepared.

## Environmental Assessments

An EA has the following three functions:

1. To provide sufficient evidence and analysis for determining whether a proposed action requires preparation of an EIS or a finding of no significant impact (FONSI)
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 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 therefore will not be prepared. The FONSI includes the EA, or a summary of it, and notes any other related environmental documents. CEQ and DOE regulations also provide for notification of the public that a FONSI has been issued. Also, DOE provides copies of the EA and FONSI to the public on request.

Exhibit C-3 lists the 18 projects for which an EA has been prepared. The exhibit includes EAs for one

## Exhibit C-2 Memoranda-to-File Completed

Project and Participant	Completed
<b>CCT-I</b>	
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 site) (Energy and Environmental Research Corporation)	5/9/88
Tidd PFBC Demonstration Project (The Ohio Power Company)	3/5/87
<b>CCT-II</b>	
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	1/31/90
SO <sub>x</sub> -NO <sub>x</sub> -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 <sub>x</sub> 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 <sub>x</sub> Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	7/21/89
<b>CCT-III</b>	
10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.)	9/21/90
Full-Scale Demonstration of Low-NO <sub>x</sub> 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 <sub>x</sub> 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 <sub>x</sub> /SO <sub>2</sub> Emissions Control System (Public Service Company of Colorado)	9/27/90

**Exhibit C-3**  
**Environmental Assessments Completed**

<b>Project and Participant</b>	<b>Completed</b>
<b>CCT-I</b>	
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Lakeside site) (Energy and Environmental Research Corporation)	6/25/89
Advanced Coal Conversion Process Demonstration (Rosebud SynCoal Partnership)	3/27/91
<b>CCT-II</b>	
Combustion Engineering IGCC Repowering Project (ABB Combustion Engineering, Inc.) (project terminated)	3/27/92
Demonstration of Coal Reburning for Cyclone Boiler NO <sub>x</sub> Control (The Babcock & Wilcox Company)	2/12/91
Innovative Coke Oven Gas Cleaning System for Retrofit Applications (Bethlehem Steel Corporation) (project terminated)	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 <sub>x</sub> /SO <sub>2</sub> Burner Retrofit for Utility Cyclone Boilers (TransAlta Resources Investment Corporation) (project withdrawn)	3/21/91
<b>CCT-III</b>	
Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process (Air Products Liquid Phase Conversion Company, L.P.)	6/30/95
Blast Furnace Granulated-Coal Injection System Demonstration Project (Bethlehem Steel Corporation)	6/8/93
ENCOAL® Mild Coal Gasification Project (ENCOAL® Corporation)	8/1/90
Commercial Demonstration of the NOXSO SO <sub>2</sub> /NO <sub>x</sub> Removal Flue Gas Cleanup System (NOXSO Corporation) (Warrick Power Plant site)	6/26/95
<b>CCT-IV</b>	
Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International)	2/14/94
Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Company)	8/18/93
Warren Station Externally Fired Combined-Cycle Demonstration Project (Pennsylvania Electric Company) (Warren Station site) (project terminated)	5/18/95
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	5/28/93
<b>CCT-V</b>	
Clean Coal Diesel Demonstration Project (Arthur D. Little, Inc.)	6/2/97

project that was subsequently withdrawn from the program—TransAlta Resources Investment Corporation’s Low-NO<sub>x</sub>/SO<sub>2</sub> Burner Retrofit for Utility Cyclone Boilers project—and three that were terminated—ABB Combustion Engineering’s Combustion Engineering IGCC Repowering Project, Bethlehem Steel Corporation’s Innovative Coke Oven Gas Cleaning System for Retrofit Applications, and Pennsylvania Electric’s Warren Station Externally Fired Combined-Cycle Demonstration Project.

The list of completed EAs includes one for the original site of NOXSO Corporation’s project. However, relocation of the project will require a new NEPA compliance document (see Exhibit C-4).

### ***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 full and fair discussion of all significant 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 environmental impacts of a proposed DOE action, rather than justifying decisions already made, prior to making a decision to proceed

<b>Exhibit C-4 Environmental Impact Statements Completed</b>	
<b>Project and Participant</b>	<b>Completed*</b>
<b>CCT-I</b> York County Energy Partners Cogeneration Project (York County site) (York County Energy Partners, L.P.)	8/11/95
<b>CCT-III</b> Healy Clean Coal Project (Alaska Industrial Development and Export Authority) Tampa Electric Company Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	3/10/94 8/17/94
<b>CCT-IV</b> Piñon Pine IGCC Power Project (Sierra Pacific Power Company)	11/8/94
* Completion is the date DOE issued a record of decision.	

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. EISs for three projects were completed in 1994. In 1995, DOE issued a record of decision on the EIS prepared for the York County Energy Partners project located in York county, Pennsylvania. However, because this project is being restructured, a new NEPA compliance document will be required for the new site. (See Exhibit C-4).

### ***NEPA Actions in Progress***

Exhibit C-5 lists the status of projects for which the NEPA process has not yet been completed.

## **Environmental Monitoring**

CCT project participants are required to develop and implement an environmental monitoring plan (EMP) which addresses both compliance and supplemental monitoring. Exhibit C-6 lists the status of EMPs for all 39 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 are used to characterize and quantify the environmental performance of the technology in order to evaluate its commercialization and deployment potential. In addition to regulatory

## Exhibit C-5 NEPA Reviews in Progress

Project and Participant	Status
<b>CCT-I</b>	
ACFB Demonstration Project (York County Energy Partners, L.P.) (new site)	To be determined
<b>CCT-III</b>	
McIntosh Unit 4A PCFB Demonstration Project (City of Lakeland, Department of Electric & Water Utilities)	EIS planned (10/99)
Commercial Demonstration of the NOXSO SO <sub>2</sub> /NO <sub>x</sub> Removal Flue Gas Cleanup System (NOXSO Corporation) (new site)	To be determined
<b>CCT-V</b>	
McIntosh Unit 4B Topped PCFB Demonstration Project (City of Lakeland, Department of Electric & Water Utilities)	EIS planned (10/99)
Clean Power from Integrated Coal/Ore Reduction (CPICOR™) (CPICOR™ Management Company, L.L.C.)	EIS planned (4/98)
Clean Energy Demonstration Project (Clean Energy Partners Limited Partnership)	To be determined

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

- 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 that 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 Environmental Protection Agency (EPA) to establish categories of sources that emit these pollutants. 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 which HAPs will be regulated, 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 24 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 CCT-V PON also stipulates that information on air toxics be presented in the environmental information required by DOE. Exhibit C-7 lists the 23 projects that provide for HAPs monitoring. Ten of these projects have completed the HAPs monitoring requirements. The objective of the HAPs monitoring program is 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 activities focused on HAPs monitoring and analysis. Further, under the DOE Coal R&D Program, two reports summarizing the source, distribution, and fate of HAPs from coal-fired power plants were published in 1996. A report released in July 1996, *Summary of Air Toxics Emissions Testing at Sixteen Utility Plants*, provided assessment of HAPs measured in the coal, across the major pollution control devices, and the HAPs emitted from the stack. A second report, *A Comprehensive Assessment of Toxics Emissions from Coal-Fired Power Plants: Phase I Results from the U.S. Department of Energy Study*, was released in September 1996 and provided the raw data from the emissions testing. Emissions data were collected from 16 power plants, representing nine process configurations, operated by eight different utilities; several power plants were sites for CCT projects. The power plants represented a range of different coal types,

process configurations, furnace types, and pollution control methods.

The second phase of the DOE/EPRI effort currently in progress will conduct sampling at other sites, including the CCT Program's Wabash River integrated gasification combined-cycle (IGCC) project. Further, the results from the first phase will be used to determine what configuration and coal types require further assessment.

In October 1996, EPA submitted to Congress an interim version of its technical assessment of toxic air pollutant emissions from power plants, *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units, Interim Final Report*. EPA plans to continue evaluating the potential exposures and potential public health concerns from mercury emissions from utilities. In addition, the agency will evaluate information on various potential control technologies for mercury. If EPA decides that HAPs pose a risk, then the agency must propose air toxic emissions controls by November 15, 1998, and make them final 2 years later.

However, the results of the HAPs program have significantly mitigated concerns about HAPs emission from coal-fired generation and focused attention on but a few flue gas constituents. The results have the potential to make the forthcoming EPA regulations less strict, which could avoid unnecessary control costs and thus save consumers money on electricity bills.

**Exhibit C-6**  
**Status of Environmental Monitoring Plans for CCT Projects**

Project and Participant	Status
<b>CCT-I</b>	
Development of the Coal Quality Expert (ABB Combustion Engineering, Inc., and CQ Inc.)	Completed 7/31/90
LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)	Completed 10/19/88
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)	Completed 9/22/87
Nucla CFB Demonstration Project (Colorado-Ute Electric Association, Inc.; now 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
ACFB Demonstration Project (York County Energy Partners, L.P.)	To be determined
<b>CCT-II</b>	
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	Completed 10/31/91
Demonstration of Coal Reburning for Cyclone Boiler NO <sub>x</sub> Control (The Babcock & Wilcox Company)	Completed 11/18/91
SO <sub>x</sub> -NO <sub>x</sub> -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) (project terminated)	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 <sub>x</sub> 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 <sub>x</sub> Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	Completed 12/27/90

**Exhibit C-6 (continued)**  
**Status of Environmental Monitoring Plans for CCT Projects**

<b>Project and Participant</b>	<b>Status</b>
<b>CCT-III</b>	
Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process (Air Products Liquid Phase Conversion Company, L.P.)	Completed 8/29/96
10-MW Demonstration of Gas Suspension Absorption (AirPol, Inc.)	Completed 10/2/92
Healy Clean Coal Project (Alaska Industrial Development and Export Authority)	Completed 4/11/97
Full-Scale Demonstration of Low-NO <sub>x</sub> 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
McIntosh Unit 4A PCFB Demonstration Project (City of Lakeland, Department of Electric & Water Utilities)	Projected 8/01
ENCOAL Mild Coal Gasification Project (ENCOAL Corporation)	Completed 5/29/92
Evaluation of Gas Reburning and Low-NO <sub>x</sub> 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 <sub>2</sub> /NO <sub>x</sub> Removal Flue Gas Cleanup System (NOXSO Corporation)	To be determined
Integrated Dry NO <sub>x</sub> /SO <sub>2</sub> Emissions Control System (Public Service Company of Colorado)	Completed 8/5/93
Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	Completed 5/96
<b>CCT-IV</b>	
Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International)	Projected 12/97
Micronized Coal Reburning Demonstration for NO <sub>x</sub> Control (New York State Electric & Gas Corporation)	Projected 8/97
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)	Completed 10/31/96
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	Completed 7/9/93
<b>CCT-V</b>	
Clean Coal Diesel Demonstration Project (Arthur D. Little, Inc.)	To be determined
Clean Power from Integrated Coal/Ore Reduction (CPICOR™) (CPICOR™ Management Company, L.L.C.)	Projected 9/00
Clean Energy Demonstration Project (Clean Energy Partners Limited Partnership)	To be determined
McIntosh Unit 4B Topped PCFB Demonstration Project (City of Lakeland, Department of Electric & Water Utilities)	Projected 8/03



**Exhibit C-7**  
**CCT Projects Monitoring Hazardous Air Pollutants**

<b>Application Category</b>	<b>Participant</b>	<b>Project</b>	<b>Status</b>
<b>Advanced Electric Power Generation</b>	Alaska Industrial Development and Export Authority	Healy Clean Coal Project	Planned
	Arthur D. Little, Inc.	Clean Coal Diesel Demonstration Project	Planned
	Clean Energy Partners Limited Partnership	Clean Energy Demonstration Project	Planned
	City of Lakeland, Department of Electric & Water Utilities	McIntosh Unit 4B Topped PFBC Demonstration Project	Planned
	The Ohio Power Company	Tidd PFBC Demonstration Project	Completed
	Sierra Pacific Power Company	Piñon Pine IGCC Power Project	Planned
	Tampa Electric Company	Tampa Electric Integrated Gasification Combined-Cycle Project	Planned
	Wabash River Coal Gasification Repowering Project Joint Venture	Wabash River Coal Gasification Repowering Project	In progress
	York County Energy Partners, L.P.	ACFB Demonstration Project	Planned
<b>Environmental Control Devices</b>	ABB Environmental Systems	SNOX™ Flue Gas Cleaning Demonstration Project	Completed
	AirPol, Inc.	10-MWe Demonstration of Gas Suspension Absorption	Completed
	The Babcock & Wilcox Company	Demonstration of Coal Reburning for Cyclone Boiler NO <sub>x</sub> Control	Completed
	The Babcock & Wilcox Company	SO <sub>x</sub> -NO <sub>x</sub> -Rox Box™ Flue Gas Cleanup Demonstration Project	Completed
	New York State Electric & Gas Corporation	Milliken Clean Coal Technology Demonstration Project	In progress
	Public Service Company of Colorado	Integrated Dry NO <sub>x</sub> /SO <sub>2</sub> Emissions Control System	Completed
	Pure Air on the Lake, L.P.	Advanced Flue Gas Desulfurization Demonstration Project	Completed
	Southern Company Services, Inc.	Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	Completed
	Southern Company Services, Inc.	Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	Completed
	Southern Company Services, Inc.	180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO <sub>x</sub> Emissions from Coal-Fired Boilers	Completed
<b>Coal Processing for Clean Fuels</b>	Custom Coals International	Self-Scrubbing Coal™: An Integrated Approach to Clean Air	In progress
	ENCOAL® Corporation	ENCOAL® Mild Coal Gasification Project	In progress
<b>Industrial Applications</b>	CPICOR™ Management Company, L.L.C.	Clean Power from Integrated Coal/Ore Reduction (CPICOR™)	Planned

# Appendix D: CCT Project Contacts

Listed below are contacts for obtaining further information about specific CCT Program demonstration projects. Listed are the name, title, phone number, fax number, mailing address, and e-mail address for the participant's 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. In addition, the names, phone numbers, and e-mail addresses for contact persons at DOE Headquarters and the Federal Energy Technology Center are provided.

## **Environmental Control Devices—SO<sub>2</sub> Control Technologies**

### **10-MWe Demonstration of Gas Suspension Absorption**

*Participant:*  
AirPol, Inc.

*Contacts:*  
Frank E. Hsu, Vice President, Operations  
(201) 490-6400  
(201) 538-8066 (fax)

AirPol, Inc.  
3 Century Drive  
Parsippany, NJ 07054-4610

Lawrence Saroff, DOE/HQ, (301) 903-9483  
lawrence.saroff@hq.doe.gov  
Sharon K. Marchant, FETC, (412) 892-6008  
marchant@fetc.doe.gov

### **Confined Zone Dispersion Flue Gas Desulfurization Demonstration**

*Participant:*  
Bechtel Corporation

*Contacts:*  
Joseph T. Newman, Project Manager  
(415) 768-1189  
(415) 768-3580 (fax)

Bechtel Corporation  
P.O. Box 193965  
San Francisco, CA 94119-3965

Lawrence Saroff, DOE/HQ, (301) 903-9483  
lawrence.saroff@hq.doe.gov  
James U. Watts, FETC, (412) 892-5991  
watts@fetc.doe.gov

### **LIFAC Sorbent Injection Desulfurization Demonstration Project**

*Participant:*  
LIFAC—North America

*Contacts:*  
Jim Hervol, Project Manager  
(412) 497-2235  
(412) 497-2298 (fax)

ICF Kaiser Engineers, Inc.  
Gateway View Plaza  
1600 West Carson Street  
Pittsburgh, PA 15219-1031

Lawrence Saroff, DOE/HQ, (301) 903-9483  
lawrence.saroff@hq.doe.gov  
James U. Watts, FETC, (412) 892-5991  
watts@fetc.doe.gov

### **Advanced Flue Gas Desulfurization Demonstration Project**

*Participant:*  
Pure Air on the Lake, L.P.

*Contacts:*  
Don C. Vymazal, Manager, Contract Administration  
(610) 481-3687

Pure Air on the Lake, L.P.  
7201 Hamilton Boulevard  
Allentown, PA 18195-1501

Lawrence Saroff, DOE/HQ, (301) 903-9483  
lawrence.saroff@hq.doe.gov  
James U. Watts, FETC, (412) 892-5991  
watts@fetc.doe.gov

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

*Participant:*  
Southern Company Services, Inc.

*Contacts:*  
David P. Burford, Project Manager  
(205) 992-6329

Southern Company Services, Inc.  
P.O. Box 2625  
Birmingham, AL 35202-2625

Lawrence Saroff, DOE/HQ, (301) 903-9483  
lawrence.saroff@hq.doe.gov  
James U. Watts, FETC, (412) 892-5991  
watts@fetc.doe.gov

## **Environmental Control Devices—NO<sub>x</sub> Control Technologies**

### **Demonstration of Coal Reburning for Cyclone Boiler NO<sub>x</sub> Control**

*Participant:*

The Babcock & Wilcox Company

*Contacts:*

Tony Yagiela

(330) 829-7403

The Babcock & Wilcox Company  
1562 Beeson Street  
Alliance, OH 44601

Lawrence Saroff, DOE/HQ, (301) 903-9483

lawrence.saroff@hq.doe.gov

John C. McDowell, FETC, (412) 892-6237

mcdowell.fetc.doe.gov

### **Full-Scale Demonstration of Low-NO<sub>x</sub> Cell Burner Retrofit**

*Participant:*

The Babcock & Wilcox Company

*Contacts:*

Tony Yagiela

(330) 829-7403

The Babcock & Wilcox Company  
1562 Beeson Street  
Alliance, OH 44601

Lawrence Saroff, DOE/HQ, (301) 903-9483

lawrence.saroff@hq.doe.gov

John C. McDowell, FETC, (412) 892-6237

mcdowell@fetc.doe.gov

### **Evaluation of Gas Reburning and Low-NO<sub>x</sub> Burners on a Wall-Fired Boiler**

*Participant:*

Energy and Environmental Research Corporation

*Contacts:*

Blair A. Folsom, Senior Vice President

(714) 859-8851

(714) 859-3194 (fax)

Energy and Environmental Research  
Corporation  
18 Mason  
Irvine, CA 92718

Lawrence Saroff, DOE/HQ, (301) 903-9483

lawrence.saroff@hq.doe.gov

Jerry L. Hebb, FETC, (412) 892-6079

hebb@fetc.doe.gov

### **Micronized Coal Reburning Demonstration of NO<sub>x</sub> Control**

*Participant:*

New York State Electric & Gas Corporation

*Contacts:*

Dennis O'Dea, Project Manager

(607) 729-2551

New York State Electric & Gas Corporation  
120 Chenango Street  
Binghamton, NY 13902

Lawrence Saroff, DOE/HQ, (301) 903-9483

lawrence.saroff@hq.doe.gov

James U. Watts, FETC, (412) 892-5991

watts@fetc.doe.gov

### **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

john.sorge@scsnet.com

Southern Company Services, Inc.  
P.O. Box 2625  
Birmingham, AL 35202-2625

Lawrence Saroff, DOE/HQ, (301) 903-9483

lawrence.saroff@hq.doe.gov

Scott M. Smouse, FETC, (412) 892-5725

smouse@fetc.doe.gov

### **Demonstration of Selective Catalytic Reduction Technology for the Control of NO<sub>x</sub> Emissions from High-Sulfur-Coal-Fired Boilers**

*Participant:*

Southern Company Services, Inc.

*Contacts:*

Robert R. Hardman, Project Manager

(205) 257-7772

rob.hardman@scsnet.com

Southern Company Services, Inc.  
P.O. Box 2625  
Birmingham, AL 35202-2625

Lawrence Saroff, DOE/HQ, (301) 903-9483

lawrence.saroff@hq.doe.gov

Arthur L. Baldwin, FETC, (412) 892-6011

baldwin@fetc.doe.gov

**180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO<sub>x</sub> Emissions from Coal-Fired Boilers**

*Participant:*

Southern Company Services, Inc.

*Contacts:*

Robert R. Hardman, Project Manager  
(205) 257-7772  
rob.hardman@scsnet.com  
  
Southern Company Services, Inc.  
P.O. Box 2625  
Birmingham, AL 35202-2625

Lawrence Saroff, DOE/HQ, (301) 903-9483  
lawrence.saroff@hq.doe.gov  
Scott M. Smouse, FETC, (412) 892-5725  
smouse@fetc.doe.gov

---

**Environmental Control Devices—Combined SO<sub>2</sub>/NO<sub>x</sub> Control Technologies**

**SNOX™ Flue Gas Cleaning Demonstration Project**

*Participant:*

ABB Environmental Systems

*Contacts:*

Paul Yosick, Project Manager  
(423) 653-7550  
  
ABB Environmental Systems  
1400 Center Port Boulevard  
Knoxville, TN 37932

Lawrence Saroff, DOE/HQ, (301) 903-9483  
lawrence.saroff@hq.doe.gov  
James U. Watts, FETC, (412) 892-5991  
watts@fetc.doe.gov

**LIMB Demonstration Project Extension and Coolside Demonstration**

*Participant:*

The Babcock & Wilcox Company

*Contacts:*

Paul Nolan  
(216) 860-1074  
(216) 860-2045 (fax)  
  
The Babcock & Wilcox Company  
20 South Van Buren Avenue  
P.O. Box 351  
Barberton, OH 44203-0351

Lawrence Saroff, DOE/HQ, (301) 903-9483  
lawrence.saroff@hq.doe.gov  
James U. Watts, FETC, (412) 892-5991  
watts@fetc.doe.gov

**SO<sub>x</sub>-NO<sub>x</sub>-Rox Box™ Flue Gas Cleanup Demonstration Project**

*Participant:*

The Babcock & Wilcox Company

*Contacts:*

Kevin Redinger  
(330) 829-7719  
  
The Babcock & Wilcox Company  
1562 Beeson Street  
Alliance, OH 44601

Lawrence Saroff, DOE/HQ, (301) 903-9483  
lawrence.saroff@hq.doe.gov  
John C. McDowell, FETC, (412) 892-6237  
mcdowell@fetc.do.gov

**Enhancing the Use of Coals by Gas Reburning and Sorbent Injection**

*Participant:*

Energy and Environmental Research Corporation

*Contacts:*

Blair A. Folsom, Senior Vice President  
(714) 859-8851  
(714) 859-3194 (fax)  
  
Energy and Environmental Research Corporation  
18 Mason  
Irvine, CA 92718

Lawrence Saroff, DOE/HQ, (301) 903-9483  
lawrence.saroff@hq.doe.gov  
Jerry L. Hebb, FETC, (412) 892-6079  
hebb@fetc.doe.gov

**Milliken Clean Coal Technology Demonstration Project**

*Participant:*

New York State Electric & Gas Corporation

*Contacts:*

Dennis O'Dea, Project Manager  
(607) 729-2551  
  
New York State Electric & Gas Corporation  
120 Chenango Street  
Binghamton, NY 13902

Lawrence Saroff, DOE/HQ, (301) 903-9483  
lawrence.saroff@hq.doe.gov  
James U. Watts, FETC, (412) 892-5991  
watts@fetc.doe.gov

**Commercial Demonstration of the NOXSO  
SO<sub>2</sub>/NO<sub>x</sub> Removal Flue Gas Cleanup System**

*Participant:*

NOXSO Corporation

*Contacts:*

James B. Black

(412) 854-12007

(412) 854-5729 (fax)

noxso@city-net.com

NOXSO Corporation

2414 Lytle Road

Bethel Park, PA 15102-2704

Lawrence Saroff, DOE/HQ, (301) 903-9483

lawrence.saroff@hq.doe.gov

Jerry L. Hebb, FETC, (412) 892-6079

hebb@fetc.doe.gov

**Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> Emissions Control System**

*Participant:*

Public Service Company of Colorado

*Contacts:*

Terry Hunt, Project Manager

(303) 571-7113

(303) 571-7868 (fax)

thunt@msp.psc.com

Public Service Company of Colorado

550 15th Street, Suite 880

Denver, CO 80202

Lawrence Saroff, DOE/HQ, (301) 903-9483

lawrence.saroff@hq.doe.gov

Jerry L. Hebb, FETC, (412) 892-6079

hebb@fetc.doe.gov

**Advanced Electric Power Generation—  
Fluidized-Bed Combustion**

**McIntosh Unit 4A PCFB Demonstration Project**

*Participant:*

City of Lakeland, Department of Electric & Water  
Utilities

*Contacts:*

Alfred M. Dodd, Project Manager

(941) 499-6461

(941) 499-6344 (fax)

Lakeland Electric & Water Utilities

501 E. Lemon Street

Lakeland, FL 33801-5079

George Lynch, DOE/HQ, (301) 903-9434

george.lynch@hq.doe.gov

Donald W. Geiling, FETC, (304) 285-4784

dgeili@fetc.doe.gov

**McIntosh Unit 4B Topped PCFB Demonstration  
Project**

*Participant:*

City of Lakeland, Department of Electric & Water  
Utilities

*Contacts:*

Alfred M. Dodd, Project Manager

(941) 499-6461

(941) 499-6344 (fax)

Lakeland Electric & Water Utilities

501 E. Lemon Street

Lakeland, FL 33801-5079

George Lynch, DOE/HQ, (301) 903-9434

george.lynch@hq.doe.gov

Donald W. Geiling, FETC, (304) 285-4784

dgeili@fetc.doe.gov

**Tidd PFBC Demonstration Project**

*Participant:*

American Electric Power Service Corporation as  
agent for The Ohio Power Company

*Contacts:*

Mario Marrocco

(614) 223-2460

(614) 223-3204 (fax)

American Electric Power Service Corporation

1 Riverside Plaza

Columbus, OH 43215

George Lynch, DOE/HQ, (301) 903-9434

george.lynch@hq.doe.gov

Donald W. Geiling, FETC, (304) 285-4784

dgeili@fetc.doe.gov

**ACFB Demonstration 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

George Lynch, DOE/HQ, (301) 903-9434

george.lynch@hq.doe.gov

Jerry L. Hebb, FETC, (412) 892-6079

hebb@fetc.doe.gov

### **Nucla CFB Demonstration Project**

*Participant:*

Tri-State Generation and Transmission Association, Inc.

*Contacts:*

Marshall L. Pendergrass, Assistant General Manager  
(303) 249-4501

Tri-State Generation and Transmission Association, Inc.  
P.O. Box 1149  
Montrose, CO 81402

George Lynch, DOE/HQ, (301) 903-9434  
george.lynch@hq.doe.gov

Nelson F. Rekos, FETC, (304) 285-4066  
nrekos@fetc.doe.gov

---

### **Advanced Electric Power Generation— Integrated Gasification Combined Cycle**

#### **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

George Lynch, DOE/HQ, (301) 903-9434  
george.lynch@hq.doe.gov

Gary A. Nelkin, FETC, (304) 285-4216  
gnelki@fetc.doe.gov

### **Piñon Pine IGCC Power Project**

*Participant:*

Sierra Pacific Power Company

*Contacts:*

Sherry Dawes, Project Manager  
(702) 343-0816  
(702) 343-0407 (fax)  
sherry@sppco.sppco.com

Sierra Pacific Power Company  
6100 Neil Road  
Reno, NV 89520-0400

George Lynch, DOE/HQ, (301) 903-9434  
george.lynch@hq.doe.gov

Douglas M. Jewell, FETC, (304) 285-4720  
djewel@fetc.doe.gov

*Web Site:*

<http://www.sierrapacific.com/utiserv/electric/pinon>

### **Tampa Electric Integrated Gasification Combined- Cycle Project**

*Participant:*

Tampa Electric Company

*Contacts:*

Donald E. Pless, Director, Advanced Technology  
(813) 228-1332  
(813) 228-4802 (fax)

TECO Power Services, Inc.  
P.O. Box 111  
Tampa, FL 33601-0111

George Lynch, DOE/HQ, (301) 903-9434  
george.lynch@hq.doe.gov

Nelson F. Rekos, FETC, (304) 285-4066  
nrekos@fetc.doe.gov

*Web Site:*

<http://www.teco.net/teco/TEPlkPwrStn.html>

### **Wabash River Coal Gasification Repowering Project**

*Participant:*

Wabash River Coal Gasification Repowering Project Joint Venture

*Contacts:*

Phil Amick  
(713) 735-4178  
(713) 735-4837 (fax)  
amick@destec.attmail.com

Destec Energy, Inc.  
2500 CityWest Boulevard, Suite 150  
Houston, TX 77042

George Lynch, DOE/HQ, (301) 903-9434  
george.lynch@hq.doe.gov

Gary A. Nelkin, FETC, (304) 285-4216  
gnelki@fetc.doe.gov

---

## **Advanced Electric Power Generation— Advanced Combustion/Heat Engines**

### **Healy Clean Coal Project**

*Participant:*

Alaska Industrial Development and Export Authority

*Contacts:*

John B. Olson, Deputy Director (Development)  
(907) 269-3000  
(907) 269-3044 (fax)  
jolson@aidea.alaska.net

Alaska Industrial Development and Export  
Authority  
480 West Tudor Road  
Anchorage, AK 99503-6690

George Lynch, DOE/HQ, (301) 903-9434  
george.lynch@hq.doe.gov

Robert M. Kornosky, FETC, (412) 892-4521  
kornosky@fetc.doe.gov

### **Clean Coal Diesel Demonstration 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

George Lynch, DOE/HQ, (301) 903-9434  
george.lynch@hq.doe.gov

Nelson F. Rekos, FETC, (304) 285-4066  
nrekos@fetc.doe.gov

## **Externally Fired Combined-Cycle Demonstration Project**

*Participant:*

Pennsylvania Electric Company

*Contacts:*

Kenneth Gray, Project Manager  
(814) 533-8044  
(814) 533-8108 (fax)

Pennsylvania Electric Company  
1001 Broad Street  
Johnstown, PA 15907

George Lynch, DOE/HQ, (301) 903-9434  
george.lynch@hq.doe.gov

Donald W. Geiling, FETC, (304) 285-4784  
dgeili@fetc.doe.gov

---

## **Coal Processing for Clean Fuels— Coal Preparation Technologies**

### **Development of the Coal Quality Expert™**

*Participants:*

ABB Combustion Engineering, Inc., and CQ Inc.

*Contacts:*

Clark D. Harrison, President  
(412) 479-6016

CQ Inc.  
One Quality Center  
P.O. Box 280  
Homer City, PA 15748-0280

Douglas Archer, DOE/HQ, (301) 903-9443  
douglas.archer@hq.doe.gov

Scott M. Smouse, FETC, (412) 892-5725  
smouse@fetc.doe.gov

*Web Site:*

<http://www.fuels.bv.com:80/cqe/cqe.htm>

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

*Participant:*

Custom Coals International

*Contacts:*

Robin Godfrey, President and CEO  
(412) 642-2625

Custom Coals International  
100 First Avenue, Suite 500  
Pittsburgh, PA 15222

Douglas Archer, DOE/HQ, (301) 903-9443  
douglas.archer@hq.doe.gov

Joseph B. Renk, FETC, (412) 892-6249  
renk@fetc.doe.gov

## **Advanced Coal Conversion Process Demonstration**

*Participant:*

Rosebud SynCoal Partnership

*Contacts:*

Ray W. Sheldon, P.E., Director of Development  
(406) 748-2366 or (406) 252-2277

Rosebud SynCoal Partnership  
P.O. Box 7137  
Billings, MT 59103-7137

Douglas Archer, DOE/HQ, (301) 903-9443  
douglas.archer@hq.doe.gov

Joseph B. Renk, FETC, (412) 892-6249  
renk@fetc.doe.gov

**Coal Processing for Clean Fuels—  
Mild Gasification**

**ENCOAL® Mild Coal Gasification Project**

*Participant:*

ENCOAL® Corporation

*Contacts:*

Brent A. Knottnerus, Project Manager

(307) 686-5486

(307) 682-7938 (fax)

bknottnerus@vcn.com

ENCOAL® Corporation

P.O. Box 3038

Gillette, WY 82717

Douglas Archer, DOE/HQ, (301) 903-9443

douglas.archer@hq.doe.gov

Douglas M. Jewell, FETC, (304) 285-4720

djewel@fetc.doe.gov

---

**Coal Processing for Clean Fuels—Indirect  
Liquefaction**

**Commercial-Scale Demonstration of the Liquid-  
Phase Methanol (LPMEOH™) Process**

*Participant:*

Air Products Liquid Phase Conversion Company, L.P.

*Contacts:*

Edward C. Heydorn, Project Manager

(610) 481-7099

(610) 706-7299 (fax)

heydorec@apci.com

Air Products and Cemicals, Inc.

7201 Hamilton Boulevard

Allentown, PA 18195-1501

Edward Schmetz, DOE/HQ, (301) 903-3931

edward.schmetz@hq.doe.gov

Robert M. Kornosky, FETC, (412) 892-4521

kornosky@fetc.doe.gov

---

**Industrial Applications**

**Blast Furnace Granular-Coal Injection System  
Demonstration Project**

*Participant:*

Bethlehem Steel Corporation

*Contacts:*

Robert W. Bouman, Project Director

(610) 694-6792

(610) 694-2981 (fax)

Bethlehem Steel Corporation

Homer Research Laboratory

Building C, Room 211

Bethlehem, PA 18016

Douglas Archer, DOE/HQ, (301) 903-9443

douglas.archer@hq.doe.gov

Douglas M. Jewell, FETC, (304) 285-4720

djewel@fetc.doe.gov

**Advanced Cyclone Combustor with Internal  
Sulfur, Nitrogen, and Ash Control**

*Participant:*

Coal Tech Corporation

*Contacts:*

Bert Zauderer, President

(215) 667-0442

Coal Tech Corporation

P.O. Box 154

Merion, PA 19066

William E. Fernald, DOE/HQ, (301) 903-9448

william.fernald@hq.doe.gov

Arthur L. Baldwin, FETC, (412) 892-6011

baldwin@fetc.doe.gov



**Clean Power from Integrated Coal/Ore Reduction  
(CPICOR™)**

*Participant:*

CPICOR™ Management Company, L.L.C.

*Contacts:*

Brian O'Neil

(610) 481-5683

(610) 481-2576 (fax)

Air Products and Chemicals, Inc.

7201 Hamilton Boulevard

Allentown, PA 18195-1501

William Fernald, DOE/HQ, (301) 903-9448

william.fernald@hq.doe.gov

Douglas M. Jewell, FETC, (304) 285-4720

djewel@fetc.doe.gov

**Cement Kiln Flue Gas Recovery Scrubber**

*Participant:*

Passamaquoddy Tribe

*Contacts:*

Thomas N. Tureen, Project Manager

(207) 773-7166

(207) 773-8832 (fax)

ttureen@gwi.com

Passamaquoddy Technology, L.P.

1 Monument Way

Portland, ME 04101

William E. Fernald, DOE/HQ, (301) 903-9448

william.fernald@hq.doe.gov

John C. McDowell, FETC, (412) 892-6237

mcdowell@fetc.doe.gov

**Demonstration of Pulse Combustion in an  
Application for Steam Gasification of Coal**

*Participant:*

ThermoChem, Inc.

*Contacts:*

William Steedman, Project Manager

(410) 997-9671

ThermoChem, Inc.

5570 Sterrett Place, Suite 210

Columbia, MD 21044

William Fernald, DOE/HQ, (301) 903-9448

william.fernald@hq.doe.gov

Douglas F. Gyorke, FETC, (412) 892-6173

gyorke@fetc.doe.gov

# Appendix E: Acronyms and Abbreviations

Acronyms					
ABB CE	ABB Combustion Engineering, Inc.	CX	categorical exclusion	GHG	greenhouse gases
ABB ES	ABB Environmental Systems	CZD	confined zone dispersion	GNOCIS	Generic NO <sub>x</sub> Control Intelligence System
ACFB	atmospheric circulating fluidized bed	DER	discrete emissions reduction	GPM	gallons per minute
AFBC	atmospheric fluidized-bed combustion	DME	dimethyl ether	GR	gas reburning
AFGD	advanced flue gas desulfurization	DOE	U.S. Department of Energy	GR-LNB	gas reburning and low-NO <sub>x</sub> burner
AIDEA	Alaska Industrial Development and Export Authority	DOE/HQ	U.S. Department of Energy Headquarters	GR-SI	gas reburning and sorbent injection
AOFA	advanced overfire air	EA	environmental assessment	GSA	gas suspension absorption
AR&TD	advanced research and technology development	EER	Energy and Environmental Research Corporation	HAP(s)	hazardous air pollutant(s)
BFGCI	blast furnace granular-coal injection	EFCC	externally fired combined cycle	HHV	high heating value
BG	British Gas	EIA	Energy Information Administration	HRSG	heat recovery steam generator
BG/L	British Gas/Lurgi	EIS	environmental impact statement	IEA	International Energy Agency
B&W	The Babcock & Wilcox Company	EMP	environmental monitoring plan	IGCC	integrated gasification combined cycle
CAAA	Clean Air Act Amendments of 1990	EPA	U.S. Environmental Protection Agency	JBR	Jet Bubbling Reactor®
CAPI	Clean Air Power Initiative	EPAct	Energy Policy Act of 1992	LHV	low heating value
CCOFA	close-coupled overfire air	EPRI	Electric Power Research Institute	LIMB	limestone injection multistage burner
CCT	clean coal technology	ESP	electrostatic precipitator	LNB	low-NO <sub>x</sub> burner
CCT Program	Clean Coal Technology Demonstration Program	EWG	exempt wholesale generator	LNCFS	Low-NO <sub>x</sub> Concentric-Firing System
CDL	coal-derived liquid	FBC	fluidized-bed combustion	LOI	loss on ignition
CEQ	Council on Environmental Quality	FCCC	Framework Convention on Climate Change	LSFO	limestone forced oxidation
CFB	circulating fluidized bed	FERC	Federal Energy Regulatory Commission	MASB	multi-annular swirl burner
CKD	cement kiln dust	FETC	Federal Energy Technology Center	MCFC	molten carbonate fuel cell
COP	Conference of Parties	FGD	flue gas desulfurization	MTCI	Manufacturing and Technology Conversion International
CT-121	Chiyoda Thoroughbred-121	FONSI	finding of no significant impact	MTF	memorandum (memoranda)-to-file
CQE	Coal Quality Expert	FRP	fiberglass-reinforced plastic	NAAQS	National Ambient Air Quality Standards
		FY	fiscal year	NEPA	National Environmental Policy Act
		GE	General Electric	NOPR	Notice of Proposed Rulemaking
				NSPS	New Source Performance Standards

NTIS	National Technical Information Service	REA	Rural Electrification Administration
NYSEG	New York State Electric & Gas Corporation	SBIR	Small Business Innovation Research
O&M	operating and maintenance	SCR	selective catalytic reduction
OTAG	Ozone Transport Assessment Group	SCS	Southern Company Services, Inc.
OTC	Ozone Transport Commission	SFC	Synthetic Fuels Corporation
PC	personal computer	SI	sorbent injection
PCFB	pressurized circulating fluidized bed	SIP	state implementation plan
PDF	process-derived fuel	SNCR	selective noncatalytic reduction
PEIA	programmatic environmental impact assessment	SOFA	separated overfire air
PEIS	programmatic environmental impact statement	STTR	Small Business Technology Transfer Program
PEOA	Plant Emission Optimization Advisor	SVGA	super video graphics adapter
PEP	progress evaluation plan	TCLP	toxicity-characteristics leaching procedure
PFBC	pressurized fluidized-bed combustion	TVA	Tennessee Valley Authority
PJBH	pulse jet baghouse	UARG	Utility Air Regulatory Group
PM	particulate matter	UBCL	unburned carbon boiler efficiency losses
PON	program opportunity notice	U.K.	United Kingdom
PRB	Powder River Basin	U.S.	United States
PSCC	Public Service Company of Colorado	VOC	volatile organic compound
PSD	Prevention of Significant Deterioration	WES	wastewater evaporation system
PUHCA	Public Utility Holding Company Act of 1935	WLFO	wet limestone, forced oxidation
PURPA	Public Utility Regulatory Policies Act of 1978		
QF	qualified facilities		
RAM	random access memory		
R&D	research and development		
RD&D	research, development, and		

## Abbreviations

States are abbreviated using two-letter postal codes.

atm	atmosphere(s)
avg	average
Btu	British thermal unit(s)
C/H	molar ratio of carbon to hydrogen
CaCO <sub>3</sub>	calcium carbonate (calcitic limestone)
CaO	calcium oxide (lime)
Ca(OH) <sub>2</sub>	calcium hydroxide (calcitic hydrated lime)
Ca(OH) <sub>2</sub> •MgO	dolomitic hydrated lime
Ca/N	molar ratio of calcium to nitrogen
Ca/S	molar ratio of calcium to sulfur
CaSO <sub>3</sub>	calcium sulfite
CaSO <sub>4</sub>	calcium sulfate
CO	carbon monoxide
CO <sub>2</sub>	carbon dioxide
°F	degrees Fahrenheit
ft, ft <sup>2</sup> , ft <sup>3</sup>	foot (feet), square feet, cubic feet
gal	gallon(s)
GB	gigabyte(s)
GW	gigawatt(s)
GWe	gigawatt(s)-electric
H <sub>2</sub> S	hydrogen sulfide
H <sub>2</sub> SO <sub>4</sub>	sulfuric acid
HCl	hydrogen chloride
HF	hydrogen fluoride
hr	hour(s)
in, in <sup>2</sup> , in <sup>3</sup>	inch(es), square inches, cubic inches
KCl	potassium chloride

$K_2SO_4$	potassium sulfate
kW	kilowatt(s)
kWh	kilowatt-hour(s)
lb	pound(s)
MB	megabyte(s)
$MgCO_3$	magnesium carbonate
MgO	magnesium oxide
Mhz	megahertz
min	minute(s)
mo	month(s)
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
psi	pound(s) per square inch
rpm	revolutions per minute
S	sulfur
$SO_2$	sulfur dioxide
$SO_3$	sulfur trioxide
std ft <sup>3</sup>	standard cubic feet
yr	year(s)

# Index of CCT Projects

ABB Combustion Engineering, Inc.'s Combustion Engineering IGCC Repowering Project B-3, B-6, C-4, C-5

ABB Combustion Engineering, Inc.'s and CQ Inc.'s Development of the Coal Quality Expert™ ES-7, ES-9, ES-11, 2-6, 3-7, 3-8, 4-7, 4-8, 5-4, 5-5, 5-7, 5-114, 5-115, 5-116–5-119, B-2, B-3, B-6, C-3, C-8, D-6

ABB Environmental Systems' SNOX™ Flue Gas Cleaning Demonstration Project ES-5, ES-8, 2-6, 3-6, 4-4, 4-5, 5-3, 5-5, 5-7, 5-57, 5-58–5-61, B-2, B-5, C-3, C-8, C-10, D-3

Air Products Liquid Phase Conversion Company, L.P.'s Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process ES-12, 2-6, 2-12, 3-7, 5-4, 5-5, 5-114, 5-115, 5-126–5-127, B-5, C-4, C-9, D-7

AirPol, Inc.'s 10-MWe Demonstration of Gas Suspension Absorption ES-3, ES-4, 2-6, 3-6, 3-8, 4-2, 4-3, 5-3, 5-5, 5-7, 5-9, 5-10–5-13, B-3, B-5, C-3, C-9, C-10, D-1

Alaska Industrial Development and Export Authority's Healy Clean Coal Project ES-12, 2-3, 2-6, 3-7, 4-7, 5-4, 5-5, 5-84, 5-85, 5-108–5-109, B-3, C-5, C-9, C-10, D-6

The Appalachian Power Company's PFBC Utility Demonstration Project B-3, B-6

Arthur D. Little, Inc.'s Clean Coal Diesel Demonstration Project 2-7, 3-7, 5-4, 5-5, 5-85, 5-110–5-111, B-6, C-4, C-9, C-10, D-6

The Babcock & Wilcox Company's Demonstration of Coal Reburning for Cyclone Boiler NO<sub>x</sub> Control ES-5, 2-6, 3-6, 4-4, 5-3, 5-5, 5-7, 5-31, 5-32–5-35, B-3, B-5, C-4, C-8, C-10, D-2

The Babcock & Wilcox Company's Full-Scale Demonstration of Low-NO<sub>x</sub> Cell Burner Retrofit ES-5, ES-8, ES-11, 2-6, 3-6, 3-8, 4-4, 5-3, 5-5, 5-7, 5-31, 5-36–5-39, B-3, B-5, C-3, C-9, D-2

The Babcock & Wilcox Company's LIMB Demonstration Project Extension and Coolside Demonstration ES-5, 2-6, 3-6, 4-4, 4-5, 5-3, 5-5, 5-7, 5-57, 5-62–5-65, B-1, B-4, C-3, C-8, D-3

The Babcock & Wilcox Company's SO<sub>x</sub>-NO<sub>x</sub>-Rox Box™ Flue Gas Cleanup Demonstration Project ES-5, 2-6, 3-6, 4-4, 5-3, 5-5, 5-7, 5-57, 5-66–5-69, B-2, B-5, C-3, C-8, C-10, D-3

Bechtel Corporation's Confined Zone Dispersion Flue Gas Desulfurization Demonstration ES-4, 2-7, 3-6, 5-3, 5-5, 5-7, 5-9, 5-14–5-17, B-3, B-5, C-3, C-9, D-1

Bethlehem Steel Corporation's Blast Furnace Granular-Coal Injection System Demonstration Project ES-9, 2-7, 3-7, 4-8, 4-9, 5-4, 5-5, 5-128, 5-129, 5-130–5-131, B-3, C-4, C-9, D-7

City of Lakeland, Department of Electric & Water Utilities' McIntosh Unit 4A PCFB Demonstration Project 2-7, 3-7, 4-6, 5-3, 5-5, 5-85, 5-86–5-87, B-6, C-6, C-9, D-4

City of Lakeland, Department of Electric & Water Utilities' McIntosh Unit 4B Topped PCFB Demonstration Project 2-7, 3-7, 4-6, 5-3, 5-5, 5-85, 5-88–5-89, B-6, C-6, C-9, C-10, D-4

Clean Energy Partners Limited Partnership's Clean Energy Demonstration Project 2-7, 3-7, 5-4, 5-5, 5-85, 5-100–5-101, B-5, C-6, C-9, C-10, D-5

Coal Tech Corporation's Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control ES-7, 2-6, 3-7, 4-8, 5-4, 5-5, 5-7, 5-129, 5-132–5-135, B-1, B-4, C-3, C-8, D-7

Colorado-Ute Electric Association, Inc. (*see Tri-State Generation and Transmission Association, Inc.*)

CPICOR™ Management Company, L.L.C.'s Clean Power from Integrated Coal/Ore Reduction (CPICOR™) 2-7, 3-7, 5-4, 5-5, 5-129, 5-136–5-137, B-4, B-6, C-6, C-9, C-10, D-8

Custom Coals International's Self-Scrubbing Coal™: An Integrated Approach to Clean Air ES-9, ES-10, 1-12, 2-7, 2-12, 3-7, 4-8, 5-4, 5-5, 5-114, 5-115, 5-120–5-121, B-4, C-4, C-9, C-10, D-6

ENCOAL® Corporation's ENCOAL® Mild Coal Gasification Project ES-9, ES-10, 2-7, 2-12, 3-7, 4-6, 4-7, 4-8, 5-4, 5-5, 5-114, 5-115, 5-124–5-125, B-3, C-4, C-9, C-10, D-7

Energy and Environmental Research Corporation's Enhancing the Use of Coals by Gas Reburning and Sorbent Injection ES-6, 2-6, 3-6, 4-4, 4-5, 5-3, 5-5, 5-7, 5-57, 5-70–5-73, B-1, B-5, C-3, C-4, C-8, D-3

Energy and Environmental Research Corporation's Evaluation of Gas Reburning and Low-NO<sub>x</sub> Burners on a Wall-Fired Boiler ES-5, ES-11, 2-7, 3-6, 4-4, 5-3, 5-5, 5-7, 5-31, 5-40–5-43, B-3, B-5, C-3, C-9, D-2

LIFAC–North America's LIFAC Sorbent Injection Desulfurization Demonstration Project ES-4, ES-8, 2-7, 3-6, 4-2, 4-3, 5-5, 5-7, 5-9, 5-18–5-21, B-3, B-5, C-3, C-9, D-1

New York State Electric & Gas Corporation's Micronized Coal Reburning Demonstration for NO<sub>x</sub> Control ES-10, 2-7, 2-12, 3-6, 5-3, 5-5, 5-31, 5-44–5-45, B-6, C-2, C-9, D-2

New York State Electric & Gas Corporation's Milliken Clean Coal Technology Demonstration Project ES-8, 1-4, 2-7, 3-6, 4-5, 5-3, 5-6, 5-56, 5-57, 5-74–5-75, B-4, C-4, C-9, C-10, D-3

NOXSO Corporation's Commercial Demonstration of the NOXSO SO<sub>2</sub>/NO<sub>x</sub> Removal Flue Gas Cleanup System 2-7, 3-6, 5-3, 5-6, 5-57, 5-76–5-77, B-5, C-4, C-6, C-9, D-4

The Ohio Power Company's Tidd PFBC Demonstration Project ES-1, ES-6, ES-8, ES-11, 2-6, 3-7, 4-6, 4-7, 5-3, 5-6, 5-7, 5-85, 5-90–5-93, B-1, B-5, C-3, C-8, C-10, D-4

Passamaquoddy Tribe's Cement Kiln Flue Gas Recovery Scrubber ES-7, 2-6, 3-7, 4-8, 4-9, 5-4, 5-6, 5-7, 5-128, 5-129, 5-138–5-141, B-2, B-5, C-4, C-8, D-8

Pennsylvania Electric Company's Externally Fired Combined-Cycle Demonstration Project 2-7, 3-7, 5-4, 5-6, 5-85, 5-112–5-113, B-7, C-4, D-6

Public Service Company of Colorado's Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> Emissions Control System ES-6, ES-8, 2-7, 3-6, 4-4, 4-5, 5-3, 5-6, 5-7, 5-57, 5-78–81, B-3, B-6, C-3, C-9, C10, D-4

Pure Air on the Lake, L.P.'s Advanced Flue Gas Desulfurization Demonstration Project ES-3, ES-4, ES-11, 1-4, 2-6, 3-6, 3-8, 4-2, 4-3, 5-3, 5-6, 5-7, 5-9, 5-22–5-25, B-2, B-6, C-4, C-8, C-10, D-1

Rosebud SynCoal Partnership's Advanced Coal Conversion Process Demonstration ES-9, 2-6, 3-7, 4-6, 4-7, 4-8, 5-4, 5-6, 5-114, 5-115, 5-122–5-123, B-3, C-4, C-8, D-6

Sierra Pacific Power Company's Piñon Pine IGCC Power Project ES-9, ES-10, 1-9, 2-7, 2-12, 3-7, 4-6, 4-7, 4-13, 5-4, 5-6, 5-85, 5-102–5-103, B-4, C-5, C-9, C-10, D-5

Southern Company Services, Inc.'s Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler ES-10, 2-6, 2-12, 3-6, 4-4, 5-3, 5-6, 5-31, 5-46–5-47, B-2, C-3, C-8, C-10, D-2

Southern Company Services, Inc.'s Demonstration of Innovative Applications of Technology for the CT-121 FGD Process ES-2, ES-4, ES-8, ES-11, 1-4, 1-5, 2-6, 3-6, 4-3, 5-3, 5-6, 5-7, 5-9, 5-26–5-29, B-3, B-5, C-4, C-8, C-10, D-1

Southern Company Services, Inc.'s Demonstration of Selective Catalytic Reduction Technology for the Control of NO<sub>x</sub> Emissions from High-Sulfur-Coal-Fired Boilers ES-5, 2-6, 3-6, 5-3, 5-6, 5-7, 5-31, 5-48–5-51, B-3, B-6, C-3, C-8, D-2

Southern Company Services, Inc.'s 180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO<sub>x</sub> Emissions from Coal-Fired Boilers ES-5, 2-6, 3-6, 4-4, 5-3, 5-6, 5-7, 5-31, 5-52–5-55, B-3, B-5, C-3, C-8, C-10, D-3

Tampa Electric Company's Tampa Electric  
Integrated Gasification Combined-Cycle Project  
ES-1, ES-9, ES-11, 1-9, 2-7, 3-7, 4-6, 4-7, 4-13,  
4-14, 4-15, 5-4, 5-6, 5-83, 5-85, 5-104-5-105, B-3,  
C-5, C-9, C-10, D-5

ThermoChem, Inc.'s Demonstration of Pulse  
Combustion in an Application for Steam Gasification  
of Coal 2-7, 3-7, 5-4, 5-6, 5-129, 5-142-5-143,  
B-4, B-6, D-8

Tri-State Generation and Transmission Association,  
Inc.'s Nucla CFB Demonstration Project ES-7,  
ES-9, 2-6, 3-7, 3-8, 4-5, 4-7, 5-3, 5-6, 5-7, 5-82,  
5-85, 5-96-5-99, B-2, B-4, C-3, C-8, D-5

Wabash River Coal Gasification Repowering Project  
Joint Venture's Wabash River Coal Gasification  
Repowering Project ES-8, ES-9, ES-11, 1-4,  
1-7, 1-8, 1-9, 2-7, 3-7, 4-6, 4-7, 4-13, 5-4, 5-6, 5-85,  
5-106-5-107, B-4, C-4, C-9, C-10, D-5

York County Energy Partners, L.P.'s ACFB  
Demonstration Project 2-6, 3-7, 5-3, 5-6, 5-85,  
5-94-5-95, B-4, C-6, C-8, C-10, D-4