CLEAN
COAL
TECHNOLOGY

DOE/FE-0369

Clean Coal Technology Demonstration Program

Project Fact Sheets 1997

February 1998

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

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The Clean Coal Technology Demonstration Program

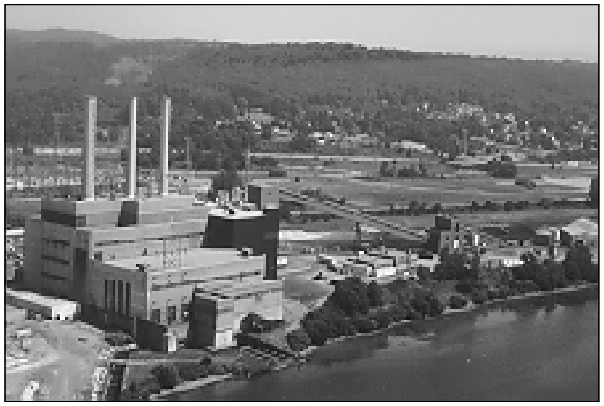
Introduction

The Clean Coal Technology Demonstration Program (known as the CCT Program) reached a significant milestone in 1997 with the completion of 21 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 contribute to meeting the accords on transboundary air pollution recommended by the Special Envoys on Acid Rain in 1986 and the requirements of the Clean Air Act Amendments of 1990 (CAAA). 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 emerging 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 10-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_2) emissions capped under the 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:

- Environmental control devices
- Advanced electric power generation
- 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 demonstration 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 $700 million. These projects include 7 nitrogen oxide (NO_x) emissions control systems installed on over 1,700 MWe of utility generating capacity, 5 SO_2 emissions control systems installed on about 770 MWe, and 7 combined SO_2/NO_x emissions control systems installed on about 700 MWe of capacity. Most of these environmental control devices had their operating experience documented by the end of 1997.

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

The five projects in the coal processing for clean fuels category, valued at nearly $520 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 project is demonstrating a new methanol production process; and 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 December 31, 1997, a total 21 CCT demonstration projects have completed operation, 10 are in operation, 1 project is in construction, 5 are in design, and 2 are being restructured. Exhibit 1 shows the number of completed projects by application category. Exhibit 2 provides a schedule for the 39 projects as of December 31, 1997.

Technology Successes

The CCT Program is establishing marketplace credibility as the demonstrated technologies are entering commercial use. Today, technologies used to reduce NO_x 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_x technology demonstrations to guide its efforts in establishing NO_x 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_2 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.

Exhibit 1
Completed Projects by Application Category

Application Category	Projects Completed
Environmental Control Devices	
NO_x control technology	5
SO_2 control technology	5
Combined SO_2/NO_x control technology	5
Advanced Electric Power Generation	
Atmospheric fluidized-bed combustion	1
Pressurized fluidized-bed combustion	1
Coal Processing for Clean Fuels	
Coal preparation technologies	1
Mild gasification	1
Industrial Applications	
Industrial cyclone combustor	1
Cement kiln flue gas recovery scrubber	1

Project Fact Sheets

The remainder of this report contains fact sheets for all 39 projects. Exhibit 3 provides an index to the fact sheets. The information provided in each fact sheet includes the project participant, team members, location, process flow diagram, significant project features, project objectives, process description and performance attributes, progress and accomplishments, commercial applications, major milestones, and references. For completed projects, the results of operational testing are summarized. To prevent the release of project-specific information of a proprietary nature, process flow diagrams contained in 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.

Project contacts are listed in Appendix A. A key to acronyms and abbreviations is provided in Appendix B.

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

Exhibit 2
Project Schedules and Funding by Application Category

Exhibit 2 (continued)
Project Schedules and Funding by Application Category

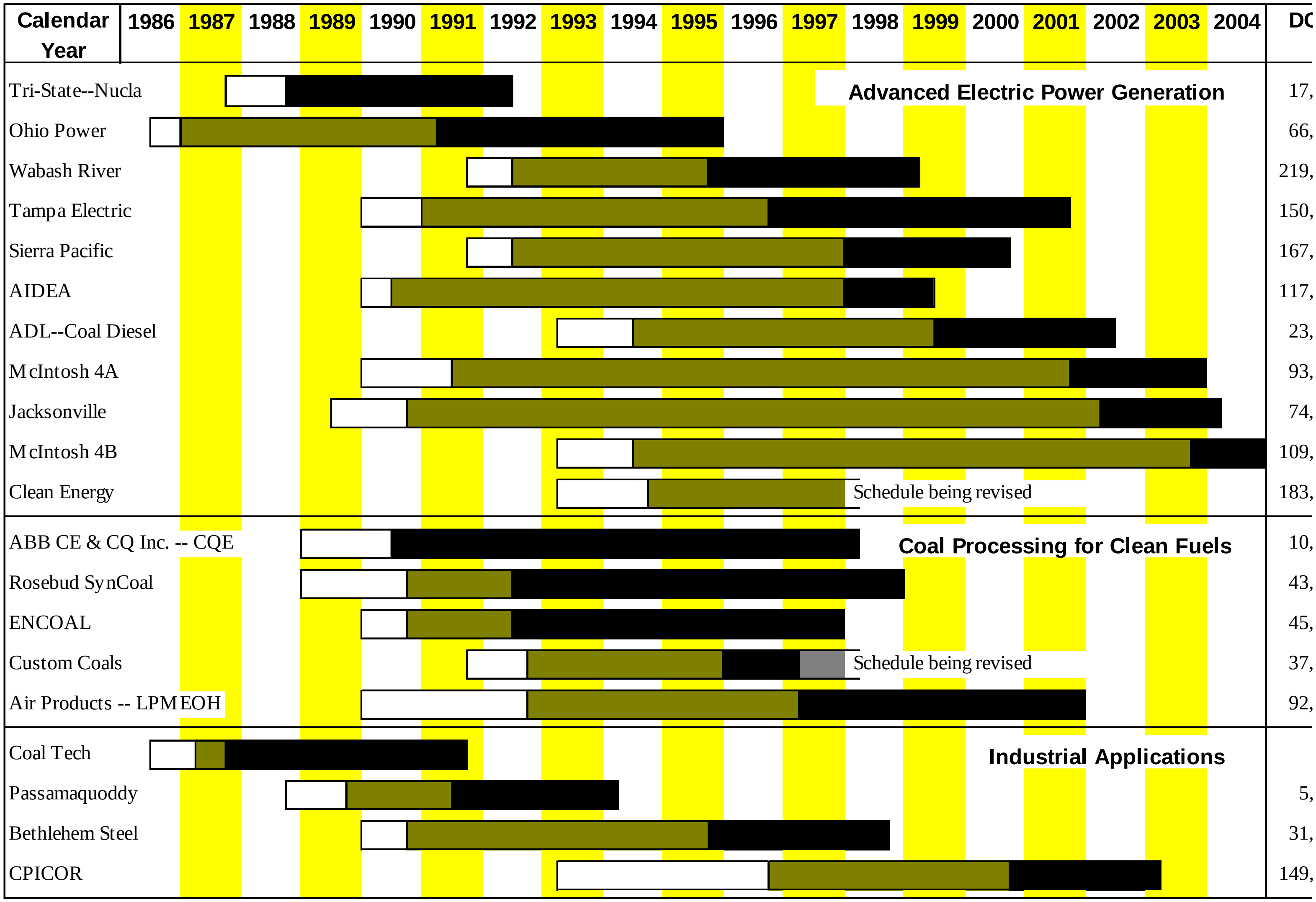


Exhibit 3

Project Fact Sheets: Clean Coal Technology Demonstration Program

Project	Participant	Page
Environmental Control Devices		
SO_2 Control Technologies		
10-MWe Demonstration of Gas Suspension Absorption	AirPol, Inc.	10
Confined Zone Dispersion Flue Gas Desulfurization Demonstration	Bechtel Corporation	14
LIFAC Sorbent Injection Desulfurization Demonstration Project	LIFAC–North America	18
Advanced Flue Gas Desulfurization Demonstration Project	Pure Air on the Lake, L.P.	22
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	Southern Company Services, Inc.	26
NO_x Control Technologies		
Demonstration of Coal Reburning for Cyclone Boiler NO_x Control	The Babcock & Wilcox Company	32
Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit	The Babcock & Wilcox Company	36
Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler	Energy and Environmental Research Corporation	40
Micronized Coal Reburning Demonstration for NO_x Control	New York State Electric & Gas Corporation	44
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	Southern Company Services, Inc.	46
Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers	Southern Company Services, Inc.	48
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers	Southern Company Services, Inc.	52
Combined SO_2/NO_x Control Technologies		
SNOX™ Flue Gas Cleaning Demonstration Project	ABB Environmental Systems	58
LIMB Demonstration Project Extension and Coolside Demonstration	The Babcock & Wilcox Company	62
SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project	The Babcock & Wilcox Company	66
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	Energy and Environmental Research Corporation	70
Milliken Clean Coal Technology Demonstration Project	New York State Electric & Gas Corporation	74
Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System	NOXSO Corporation	76
Integrated Dry NO_x/SO_2 Emissions Control System	Public Service Company of Colorado	78

Exhibit 3 (continued)
Project Fact Sheets: Clean Coal Technology Demonstration Program

Project	Participant	Page
Advanced Electric Power Generation		
Fluidized-Bed Combustion		
McIntosh Unit 4A PCFB Demonstration Project	City of Lakeland, Department of Electric & Water Utilities	86
McIntosh Unit 4B Topped PCFB Demonstration Project	City of Lakeland, Department of Electric & Water Utilities	88
Tidd PFBC Demonstration Project	The Ohio Power Company	90
Jacksonville Electric Authority Large-Scale CFB Combustion Demonstration Project	Jacksonville Electric Authority	94
Nucla CFB Demonstration Project	Tri-State Generation and Transmission Association, Inc.	96
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Clean Energy Demonstration Project	Clean Energy Partners Limited Partnership	100
Piñon Pine IGCC Power Project	Sierra Pacific Power Company	102
Tampa Electric Integrated Gasification Combined-Cycle Project	Tampa Electric Company	104
Wabash River Coal Gasification Repowering Project	Wabash River Coal Gasification Repowering Project Joint Venture	106
Advanced Combustion/Heat Engines		
Healy Clean Coal Project	Alaska Industrial Development and Export Authority	108
Clean Coal Diesel Demonstration Project	Arthur D. Little, Inc.	110
Coal Processing for Clean Fuels		
Coal Preparation Technologies		
Development of the Coal Quality Expert™	ABB Combustion Engineering, Inc., and CQ Inc.	114
Self-Scrubbing Coal™: An Integrated Approach to Clean Air	Custom Coals International	118
Advanced Coal Conversion Process Demonstration	Rosebud SynCoal Partnership	120
Mild Gasification		
ENCOAL® Mild Coal Gasification Project	ENCOAL® Corporation	122
Indirect Liquefaction		
Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process	Air Products Liquid Phase Conversion Company, L.P.	124
Industrial Applications		
Blast Furnace Granulated-Coal Injection System Demonstration Project	Bethlehem Steel Corporation	128
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	Coal Tech Corporation	130
Clean Power from Integrated Coal/Ore Reduction (CPICOR™)	CPICOR™ Management Company, L.L.C.	134
Cement Kiln Flue Gas Recovery Scrubber	Passamaquoddy Tribe	136

Environmental Control Devices

Environmental control devices are those technologies applied (retrofitted) to existing or new facilities for the purpose of controlling SO_2 and NO_x emissions. Although boilers may be modified and combustion affected, the basic boiler configuration and function remains unchanged in retrofitting these technologies.

SO_2 Control Technology

Sulfur dioxide (SO_2) is an acid gas formed during coal combustion, which oxidizes the inorganic, pyritic sulfur (Fe_2S), and organically bound sulfur in the coal. Identified as a precursor to formation of acid rain, SO_2 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_2 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_2 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_2 control technologies.

SO_2 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_2. 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_2 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_2 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_2 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_2 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).

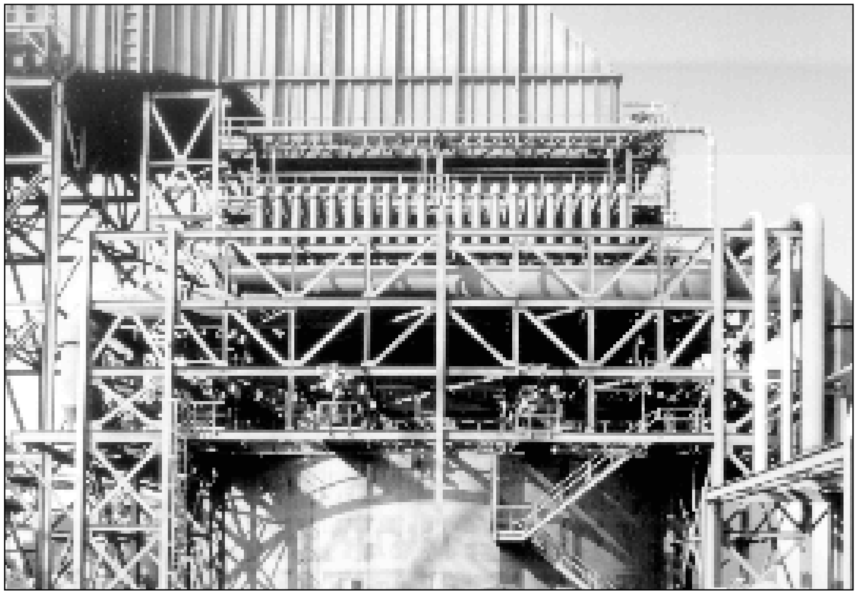
At the other end of the spectrum are the larger (300-MWe and more) boilers with some latitude in space availability, as well as new capacity additions. For these, advanced flue gas desulfurization (AFGD) wet scrubbers, with higher capital cost, but higher sulfur capture efficiency than other approaches, 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_2 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 4 briefly summarizes the characteristics and performance of the technologies that are described in more detail in the project fact sheets.

Exhibit 4
CCT Program SO_2 Control Technology Characteristics

Project	Process	Coal Sulfur Content	SO_2 Reduction	Fact Sheet
Confined Zone Dispersion Flue Gas Desulfurization Demonstration	Sorbent injection—in-duct lime sorbent injection and humidification	1.5–2.5%	50%	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%	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%	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%	22
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	AFGD—forced flue gas injection into reaction tank (Jet Bubbling Reactor®) for combined SO_2 and particulate capture (gypsum by-product)	1.2–3%	90+%	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

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

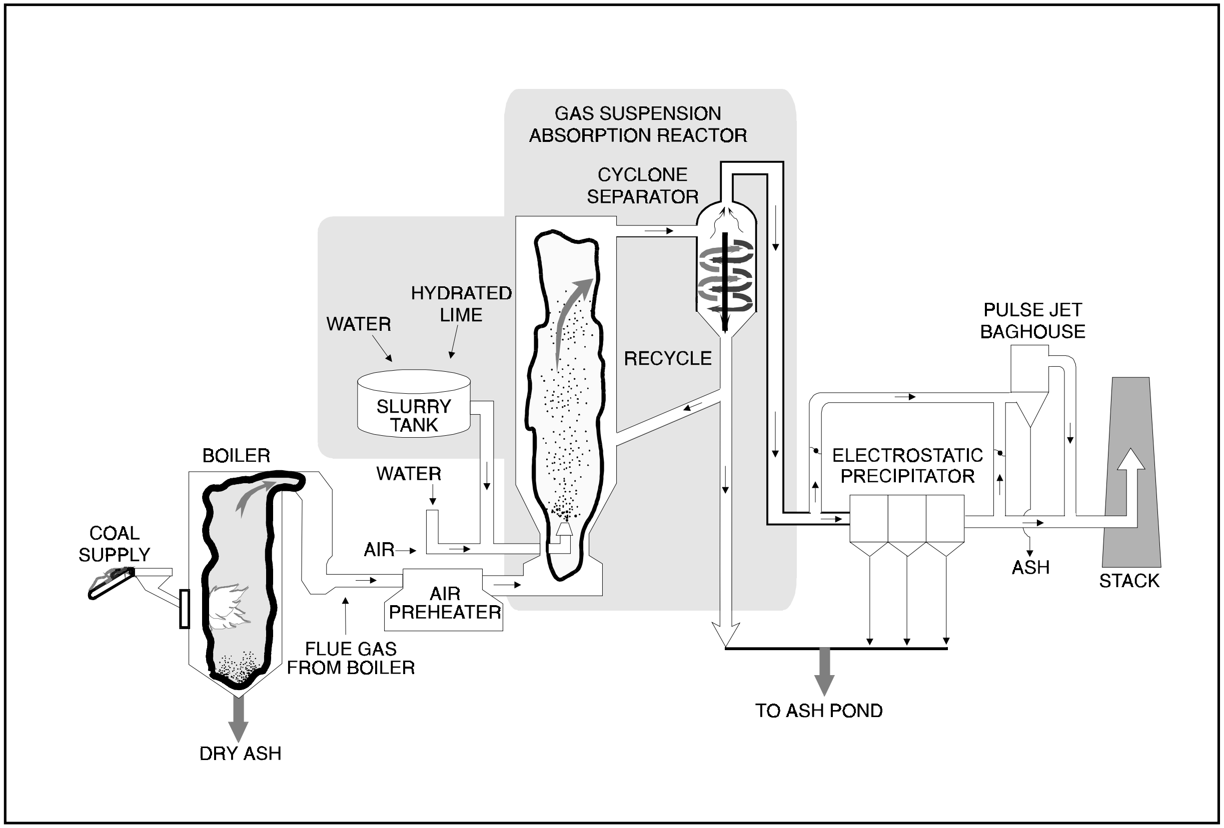
Warrior Basin, 3.5% sulfur (used intermittently)

Project Funding

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

Project Objective

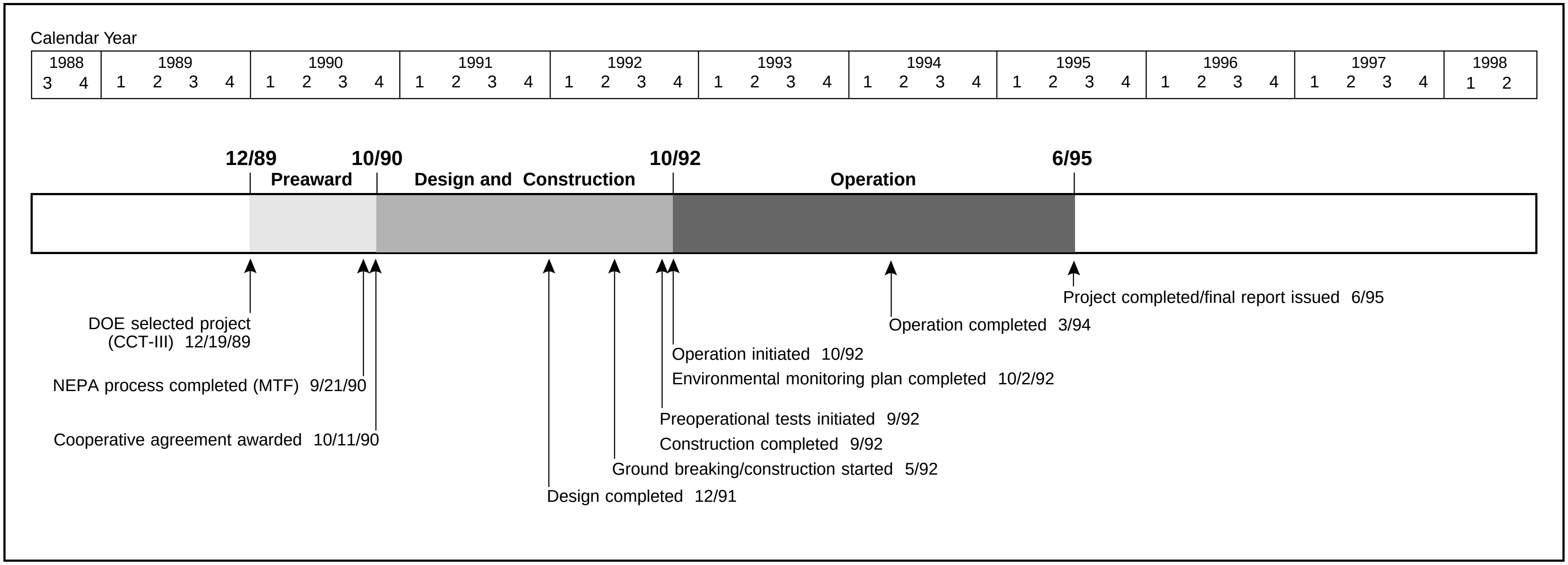
To demonstrate the applicability of Gas Suspension Absorption as an economic option for achieving Phase II CAAA SO_2 compliance on pulverized-coal-fired boilers using high-sulfur coal.



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_2 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_2, air toxic control tests were conducted, and the effectiveness of a GSA/ESP and GSA/PJBH to control both SO_2 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_2 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 ºF approach-to-saturation and 0.04% chloride,
  - 90% sulfur capture at a Ca/S of 1.4 with 18 ºF 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 ºF approach-to-saturation and 0.12% chloride,
  - 3–5% increase in SO_2 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, artimony, 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 $^1/_4$–$^1/_3$ 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_2 control comparable to that of wet scrubbers and high lime utilization. The high concentration of solids provides the sorbent/SO_2 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 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 ºF. Factorial testing showed that lime stoichiometry had the greatest effect on SO_2 removal. Approach-to-saturation temperature was the next most important factor, followed closely by chloride levels. Although an approach-to-saturation temperature of 8 ºF 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 ºF approach-to-saturation temperature was chosen for the higher 0.12% coal chloride level. Exhibit 6 summarizes key results from factorial testing.

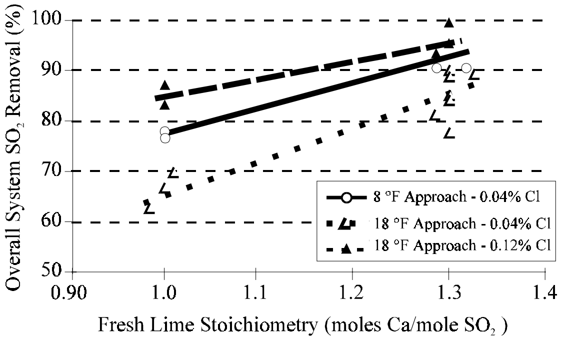
A 28-day continuous run to evaluate the GSA/ESP configuration was made with bituminous coals averaging 2.7% sulfur, 0.12% chloride levels, and 18 ºF approach-to-saturation temperature. A subsequent 14-day continuous run to evaluate the GSA/PJBH configuration was performed under the same conditions as those of the 28-day run, except for adjustments in flyash injection rate from 1.5 to 1.0 gr/ft^3 (actual).

Exhibit 5
Variables and Levels Used in GSA Factorial Testing

Variable	Level
Approach-to-saturation temperature (°F)	8[*], 18, 28
Ca/S (moles $Ca(OH)_2$/mole inlet SO_2)	1.00 and 1.30
Flyash loading (gr/ft^3, actual)	0.50 and 2.0
Coal chloride level (%)	0.04 and 0.12
Flue gas flow rate (10^3 std ft^3/min)	14 and 20
Recycle screw speed (rpm)	30 and 45

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

Exhibit 5
GSA Factorial Testing Results



Note: All tests were conducted at a 320 °F inlet flue gas temperature.

The 28-day run on the GSA/ESP system showed that the overall SO_2 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 $Ca(OH)_2$/mole inlet SO_2. The system was able to adjust rapidly to the surge in inlet SO_2 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/10^6 Btu. The 14-day run on the GSA/PJBH system showed that the SO_2 removal efficiency averaged more than 96% at an average Ca/S ratio of 1.34–1.43 moles $Ca(OH)_2$/mole inlet SO_2. Lime utilization averaged 70.5%. The particulate removal efficiency averaged 99.99+% and emission rates ranged from 0.001 to 0.003 lb/10^6 Btu.

All air toxic tests were conducted with 2.7% sulfur, low-chloride coal with a 12 ºF approach-to-saturation temperature and a high flyash loading of 2.0 gr/ft^3 (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. Removal efficiencies were greater than 98% for HCl and 96% for HF.

Operational Performance

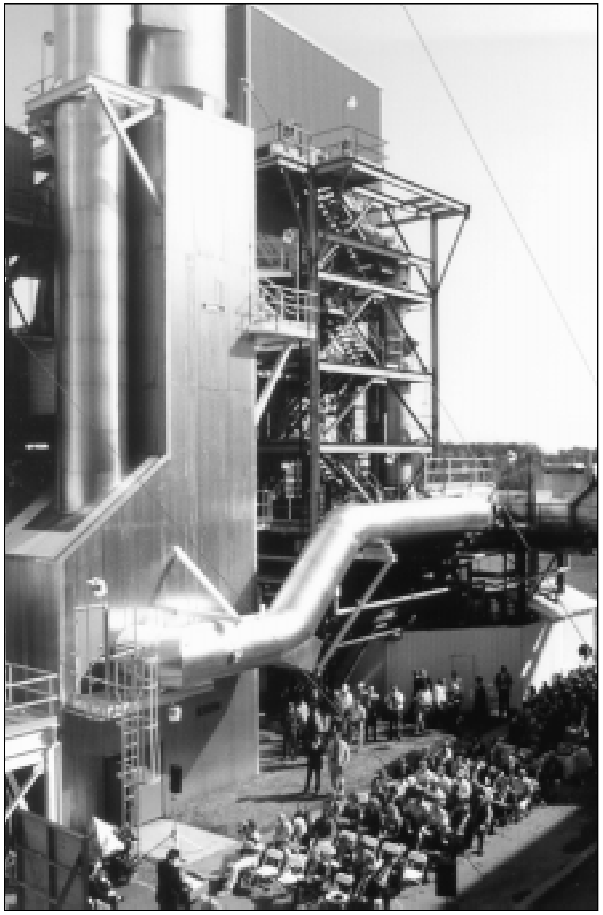
Because the GSA system has suspended recycle solids to provide a contact area for SO_2 capture, multiple high-pressure atomizer nozzles or high-speed rotary nozzles to achieve uniform, fine droplet size are not required. Also, recycle of solids is direct and avoids recycling material in the feed slurry, 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—¼ to ⅓ 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—2–5 gr/ft^3 for GSA versus 6–10 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 SO_2 removal efficiency was 90% at a lime feed rate equivalent to 1.30 moles of Ca/mole inlet 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 lime utilization than a spray dryer, the GSA will have a lower operating cost.



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

Commercial Applications

The low capital cost, moderate operating cost, and high 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, worth $10 million, to the city of Hamilton, OH, subsidized by the Ohio Coal Development Office. A sale worth $1.3 million has been made to the U.S. Army for hazardous waste disposal. A GSA system has been sold to a Swedish iron ore sinter plant. Sales to Taiwan and India have a combined value of $5.5 million.

Contacts

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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

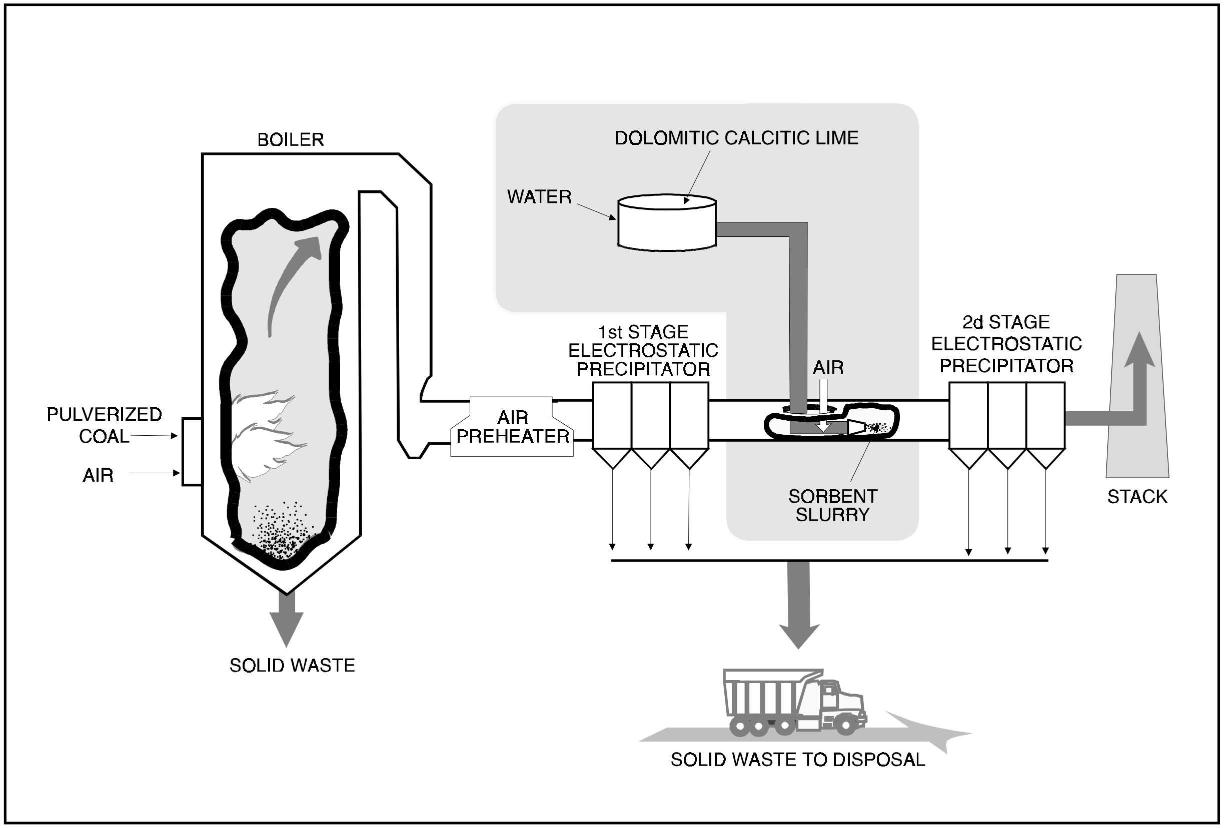
Pennsylvania bituminous, 1.2–2.5% sulfur

Project Funding

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

Project Objective

To demonstrate SO_2 removal capabilities of in-duct CZD/FGD technology; specifically, to define the optimum process operating parameters and to determine CZD/FGD's operability, reliability, and cost-effectiveness during long-term testing and its impact on downstream operations and emissions.



Technology/Project Description

In Bechtel's CZD/FGD process, a finely atomized slurry of reactive lime is sprayed into the flue gas stream between the boiler air heater and the electrostatic precipitator (ESP). The lime slurry is injected into the center of the duct by spray nozzles designed to produce a cone of fine spray. As the spray moves downstream and expands, the gas within the cone cools and the SO_2 is 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_2 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.

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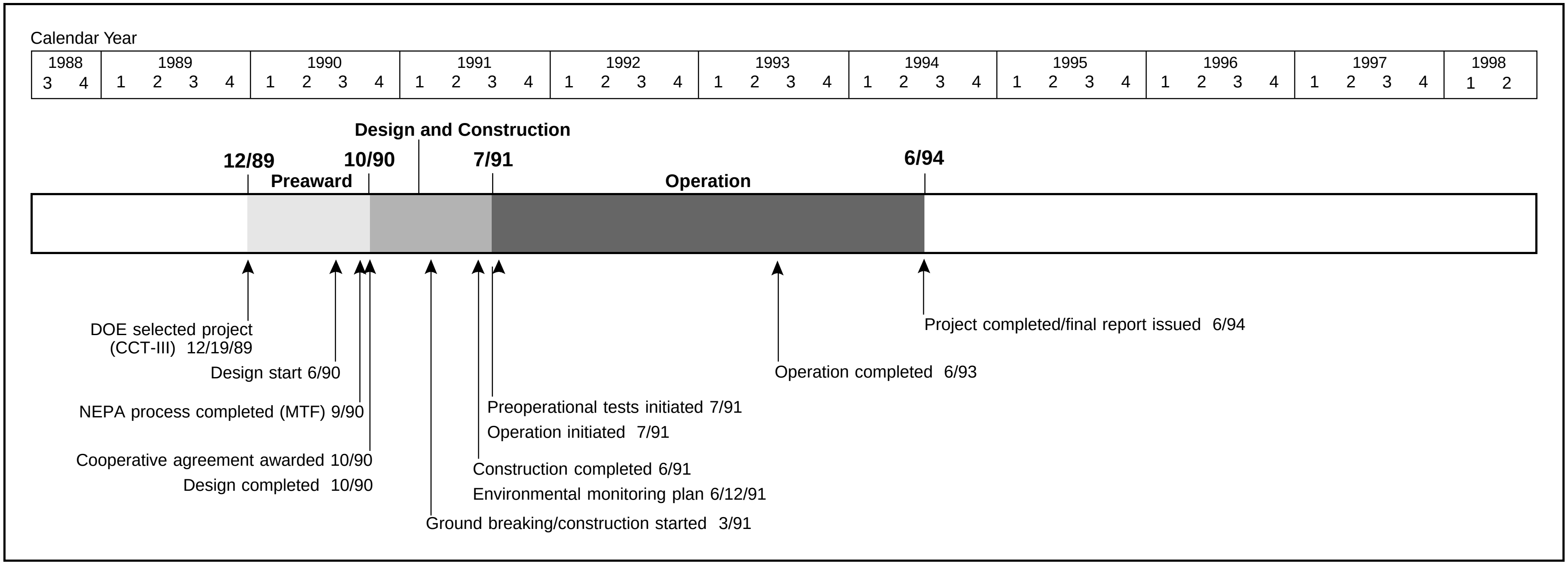
*Additional project overrun costs were funded 100% by the participant for a final total project cost of $12,173,000.



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_2 capture. Flue gas temperature was the limiting factor on injection rate. For SO_2 capture efficiency of 50% or more, a flue gas temperature of 300 ºF or more was needed.
- Slurry concentration for a given sorbent did not increase SO_2 removal efficiency beyond a certain threshold concentration.
- Testing indicated that SO_2 removal efficiencies of 50% or more were achievable with flue gas temperatures of 300–310 ºF (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_2 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_2 removed.
- Assuming 92% lime purity, 1.9–2.4 tons of lime was required for every ton of SO_2 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_2 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_2 reduction was estimated at less than \$30/kW and operating cost at \$300/ton of SO_2 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_2 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_2 removal parametric test program, which began in October 1991, was completed in August 1992.

Specific objectives were as follows:

- Achieve projected SO_2 removal of 50%
- Realize SO_2 removal costs of less than \$300/ton
- Eliminate negative effects on normal boiler operations without increasing particulate emissions and opacity

▲ Bechtel's demonstration showed that 50% SO_2 removal efficiency was possible using CZD/FGD technology. The extended duct into which lime slurry was injected is in the foreground.

The parametric tests included duct injection of atomized lime slurry made of dry hydrated calcitic lime, freshly slaked calcitic lime, and pressure-hydrated dolomitic lime. All three reagents remove SO_2 from the flue gas but require different feed concentrations of lime slurry for the same percentage of SO_2 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_2 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 ºF to 260–280 ºF. At 300–310 ºF, injection rates of 52–57 gal/min were possible and SO_2 reductions greater than 50% were achieved. At 260–280 ºF, injection rates had to be dropped to 30–40 gal/min, resulting in a 15–30% drop in SO_2 removal efficiency. Slurry concentration for a given sorbent did not increase SO_2 removal efficiency beyond a certain threshold concentration. For example, with pressure-hydrated dolomitic lime, slurry concentrations above 9% did not increase SO_2 capture efficiency.

Parametric tests indicated that SO_2 removals above 50% are possible under the following conditions: flue gas temperature of 300–310 ºF; 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_2 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_2 removed
- Lime slurry feed concentration

For operating conditions at Seward Station, data indicated that for 40–50% SO_2 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_2 removed; or assuming 92% lime purity, 1.9–2.4 tons of lime were required for every ton of SO_2 removed. In summary, the demonstration showed the following results:

- A 50% SO_2 removal efficiency with CZD/FGD was possible.
- Drying and SO_2 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_2 removal and avoid deposition of solids within the gas duct during upsets.
- Availability of the system was very good.

- At Seward Station, stack opacity was not detrimentally affected by the CZD/FGD system.

Economic Performance

The CZD/FGD process can achieve costs of $300/ton of SO_2 removed when operating a 500-MWe unit burning 4% sulfur coal. Based on a 500-MWe plant retrofitted with CZD/FGD for 50% SO_2 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_2 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_2 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_2 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.

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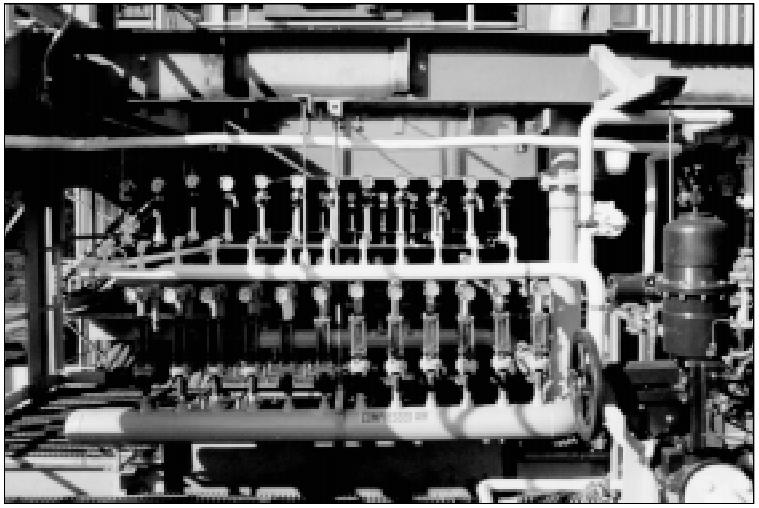


▲ This photo shows the CZD/FGD lime slurry injector control system.

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

Location

Richmond, Wayne County, IN (Richmond Power & Light's Whitewater Valley Station, Unit No. 2)

Technology

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

Plant Capacity/Production

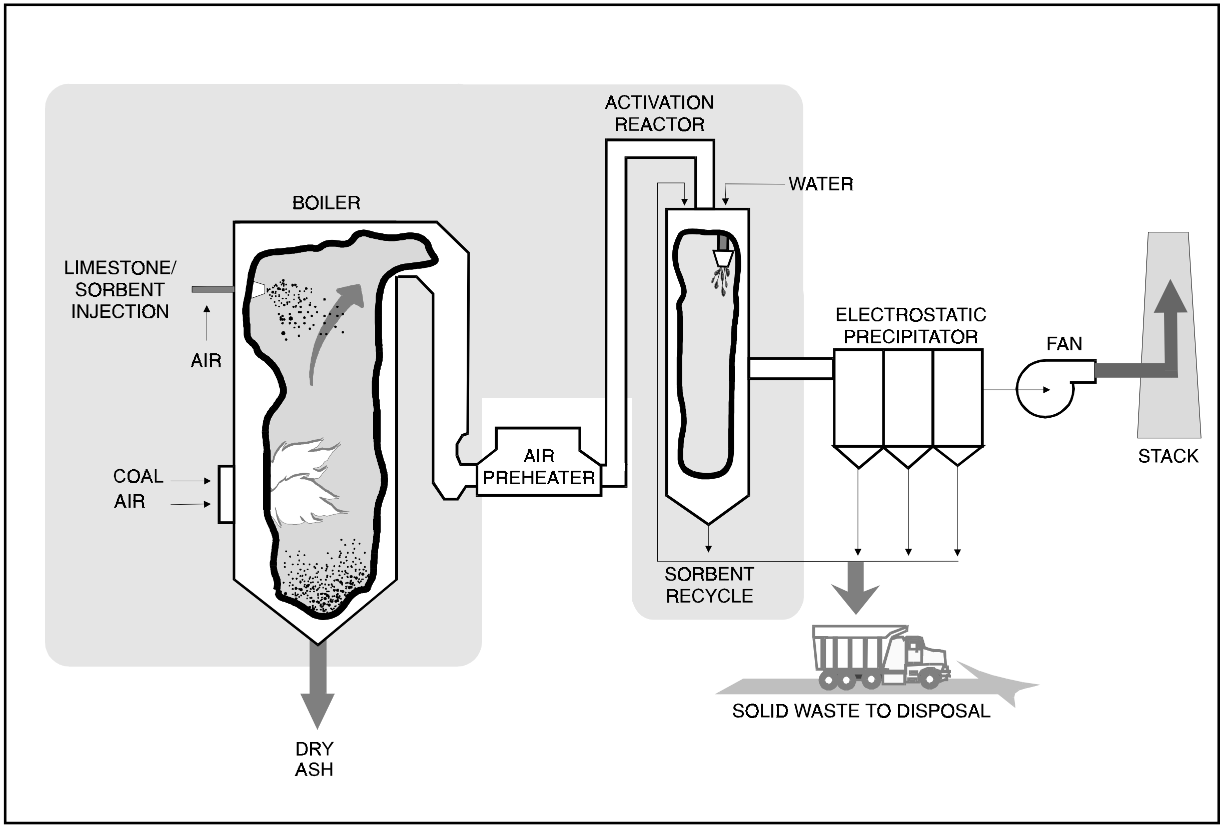
60 MWe

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



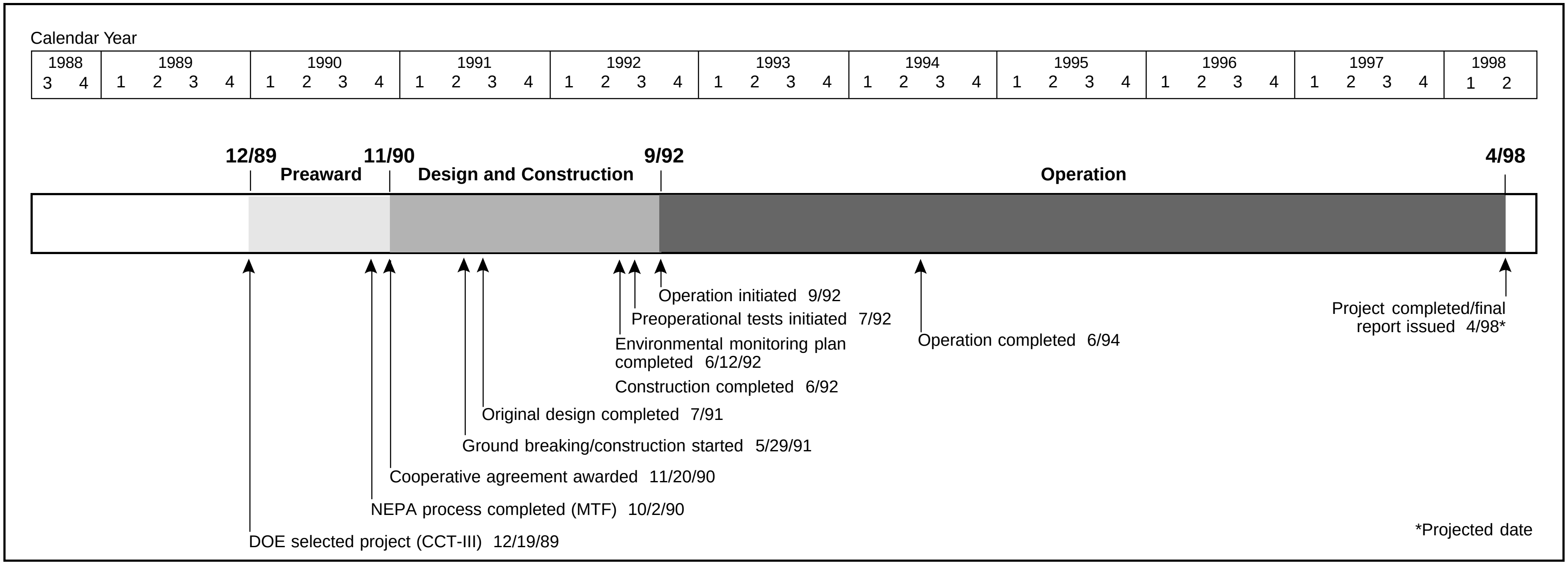
Project Objective

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_2 from flue gas and produce a dry solid waste product for disposal in a landfill.

Technology/Project Description

Pulverized limestone is pneumatically blown into the upper part of the boiler near the superheater where it absorbs some of the SO_2 in the boiler flue gas. The limestone is calcined into calcium oxide and is available for capture of additional SO_2 downstream in the activation, or humidification, reactor. In the vertical chamber, water sprays initiate a series of chemical reactions leading to SO_2 capture. After leaving the chamber, the sorbent is easily separated from the flue gas along with the fly ash in the electrostatic precipitator (ESP). The sorbent material from the reactor and electrostatic precipitator 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_2 from flue gas and produces a dry solid waste product suitable for disposal in a landfill.



Results Summary

Environmental

- SO_2 removal efficiency was 70% at a calcium-to-sulfur (Ca/S) molar ratio of 2.0, approach-to-saturation temperature of 7–12 ºF, and limestone fineness of 80% minus 325 mesh.
- SO_2 removal efficiency with limestone fineness of 80% minus 200 mesh was 15% lower at a Ca/S of 2.0 and 7–12 ºF 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 ºF approach-to-saturation temperature was projected to increase SO_2 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_2.

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_2 removal, assuming 75% SO_2 capture, Ca/S of 2.0, limestone composed of 95% $CaCO_3$, and $15/ton.

Project Summary

The LIFAC technology was designed to enhance the effectiveness of dry sorbent injection systems for SO_2 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_2 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

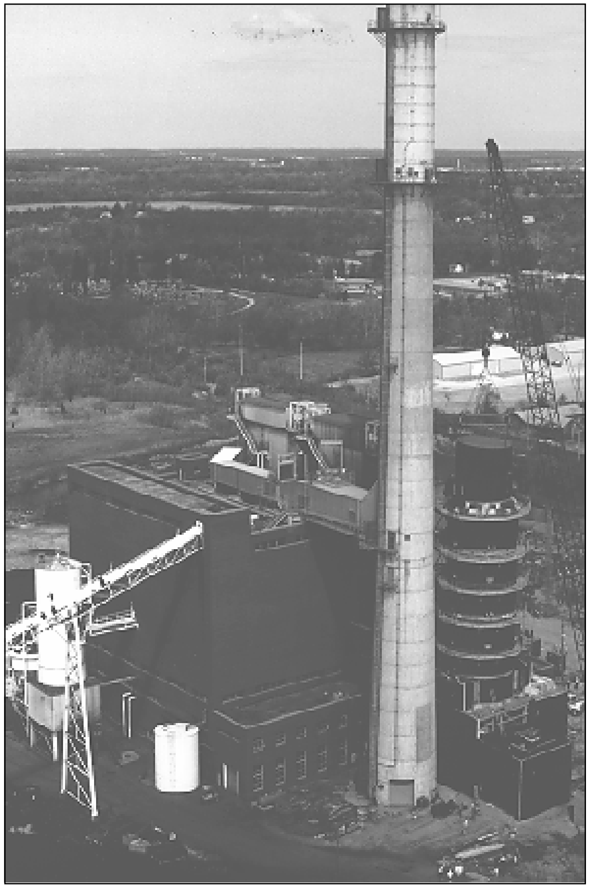
During the parametric testing phase, the numerous LIFAC process values and their effects on sulfur removal efficiency were evaluated. The four major parameters having the greatest influence on sulfur removal efficiency were limestone quality, Ca/S molar ratio, reactor bottom temperature (approach-to-saturation), and ESP ash recycling rate. Total SO_2 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_2 reduction was achievable with a Ca/S molar ratio of 2.0. ESP ash containing unspent sorbent and fly ash was recycled from the ESP hoppers back into the reactor inlet duct work. Ash recycling is essential for efficient SO_2 capture. The large quantity of ash removed from the LIFAC reactor bottom and the small size of the ESP hoppers limited the ESP ash recycling rate. As a result, the amount of material recycled from the ESP was approximately 70% less than had been anticipated. However, this low recycling rate was found to affect SO_2 capture. During a brief test, it was found that increasing the recycle rate by 50% resulted in a 5% increase in SO_2 removal efficiency. It was estimated that if the reactor bottom ash is recycled along with ESP ash, while sustaining a reactor temperature of 5 ºF above saturation temperature, an SO_2 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_2 reductions above 70%. Reactor bottom temperature was about 5 ºF higher than optimum to avoid ash buildup on the steam reheaters. Atomized water droplet size was smaller than optimum for the same reason. Other key process parameters held constant during the long-term tests included the degree of humidification, grind size of the high-calcium-content limestone, and recycle of spent sorbent from the ESP.



▲ 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.

Long-term testing showed that SO_2 reductions of 70% or more can be maintained under normal boiler operating ranges. Stack opacity was low (about 10%) and ESP efficiency was high (99.2%). The amount of boiler bottom ash increased slightly during testing, but there was

▲ The top of the LIFAC reactor is shown being lifted into place. During 2,800 hours of operation, long-term testing showed that SO_2 reductions of 70% or more could be sustained under normal boiler operation.

no negative impact on the power plant's bottom and 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_2, assuming 75% SO_2 capture, a Ca/S ratio of 2.0, and limestone containing 95% $CaCO_3$. Assuming limestone costs of $15/ton, LIFAC's operating cost would be $65/ton of SO_2 removed.

Commercial Applications

There are 10 full-scale LIFAC units in operation 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%).

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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

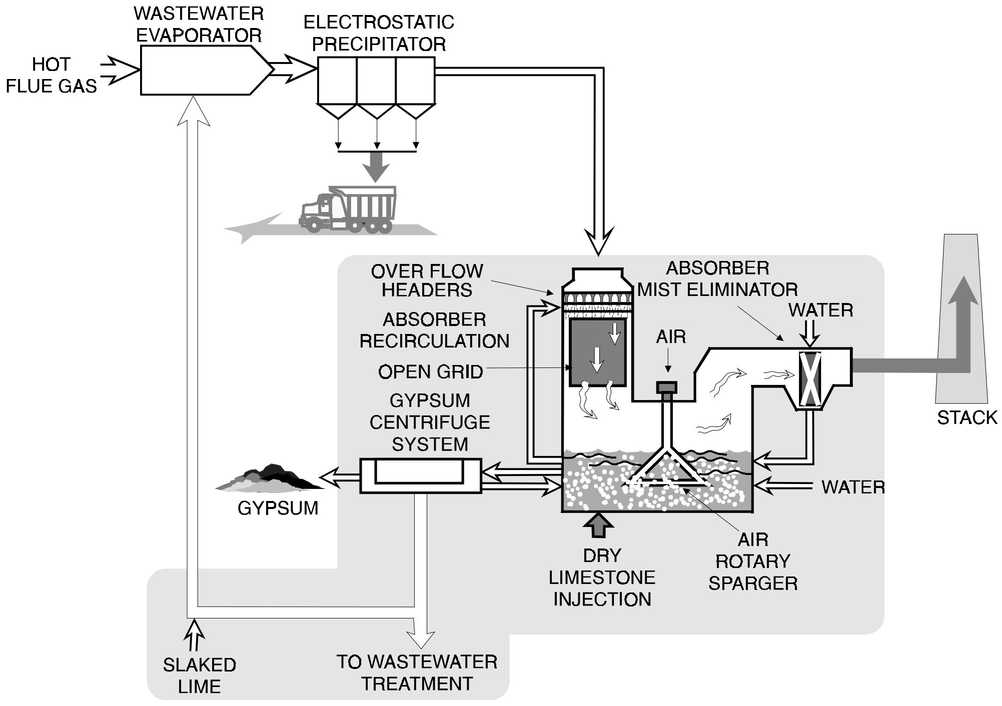
528 MWe

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_2 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.

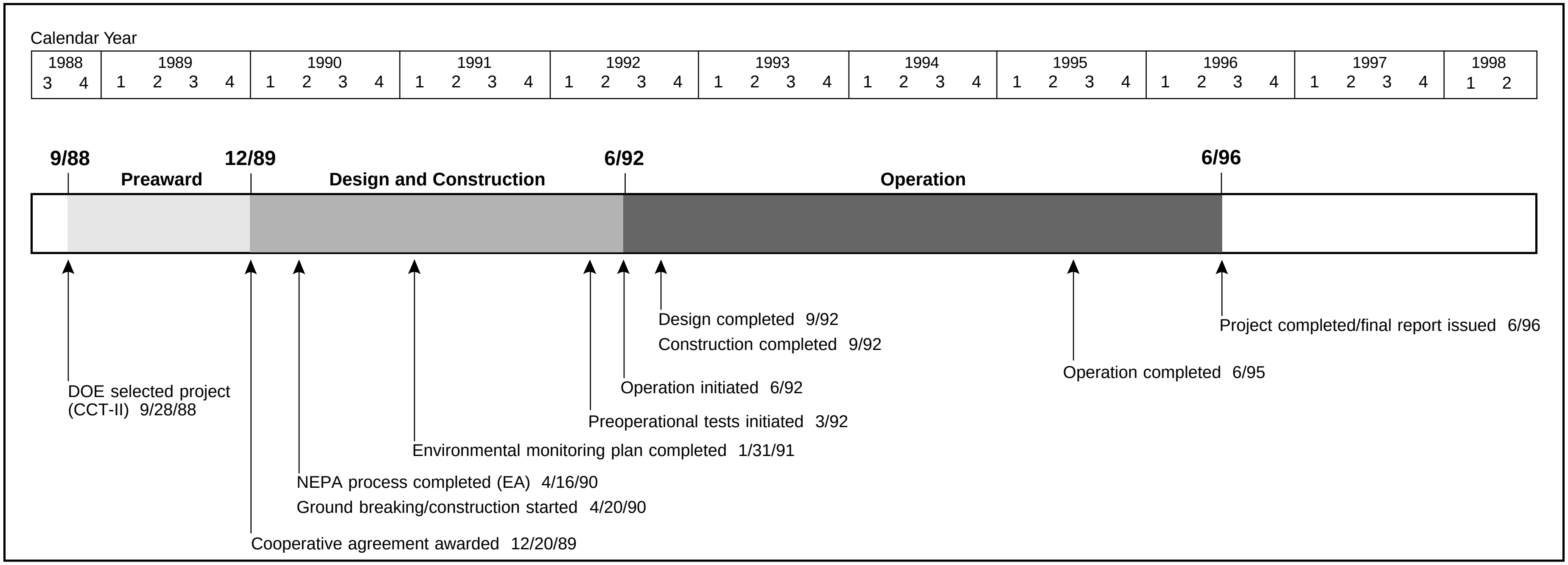
Technology/Project Description

Pure Air built a single SO_2 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_2 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_2 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_2 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_2 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/10^3 ft^3. 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_2 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 7 summarizes the results of parametric testing at full load.

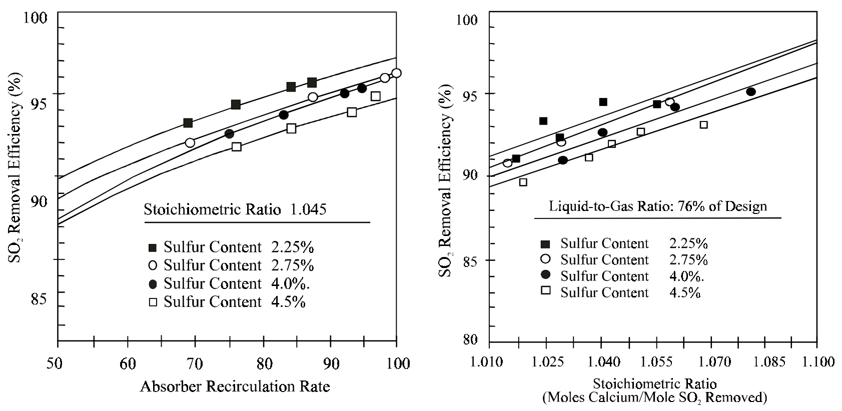
In the AFGD process, chlorides that would have been released to the air are captured and potentially become a wastewater problem. This was mitigated by the addition of the WES which takes a portion of the wastewater stream with high chloride and sulfate levels and injects it into the ductwork upstream 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 byproduct. For these reasons, PowerChip® 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.

Exhibit 7

SO_2 Removal Performance

(100% Boiler Load)



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_2 removal efficiency 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_2 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

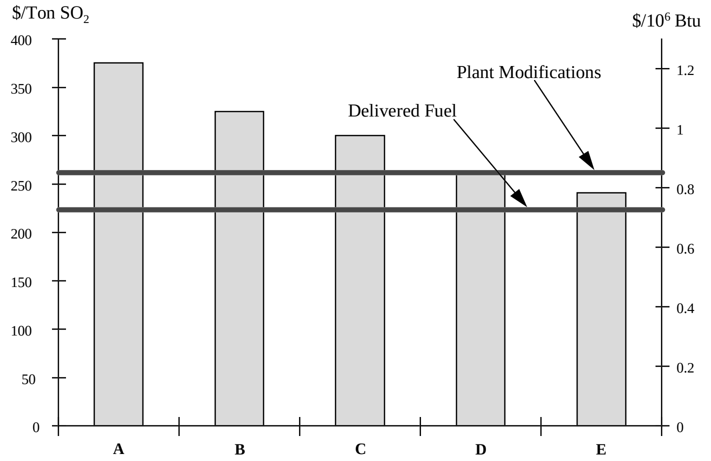
Exhibit 8 summarizes capital and levelized current dollar cost estimates for nine cases with varying plant capacity and coal sulfur content. A capacity factor of 65% and a sulfur removal efficiency of 90% were assumed. The calculation of levelized cost followed guidelines established in the Electric 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 9 depicts the relative costs of a hypothetical 500-MWe generating unit in the

Exhibit 8
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_2)									
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 9
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_2 removal
E—Increases SO_2 removal to 95%

Midwest burning 4.3% sulfur coal with a base case conventional FGD system and four incremental cases. The horizontal lines in Exhibit 9 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_2-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 and PowerChip®. The Manatee project has a value of $200 million.

The project received *Power* magazine's 1993 Powerplant Award and the National Society of Professional Engineer's 1992 Outstanding Engineering Achievement Award.

Contacts

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- *Advanced Flue Gas Desulfurization (AFGD) Demonstration Project. Final Technical Report, Vol. II: Project Performance and Economics.* Pure Air on the Lake, L.P. April 1996. (Available from NTIS as DE96050313.)
- *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

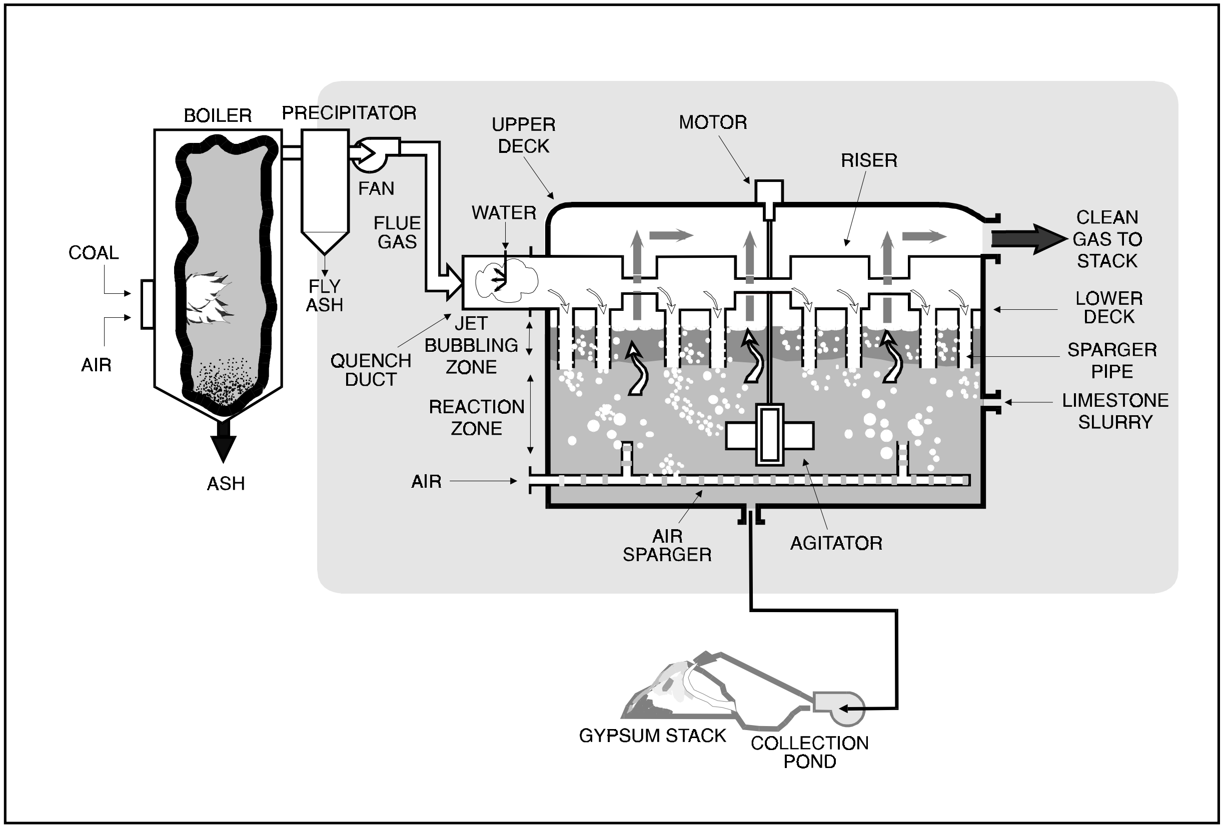
Chiyoda Corporation's Chiyoda Thoroughbred-121 (CT-121) advanced flue gas desulfurization (FGD) process

Plant Capacity/Production

100 MWe

Coals

Illinois No. 5 & No. 6 blend, 2.4% sulfur
Compliance, 1.2% sulfur



Project Funding

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

Project Objective

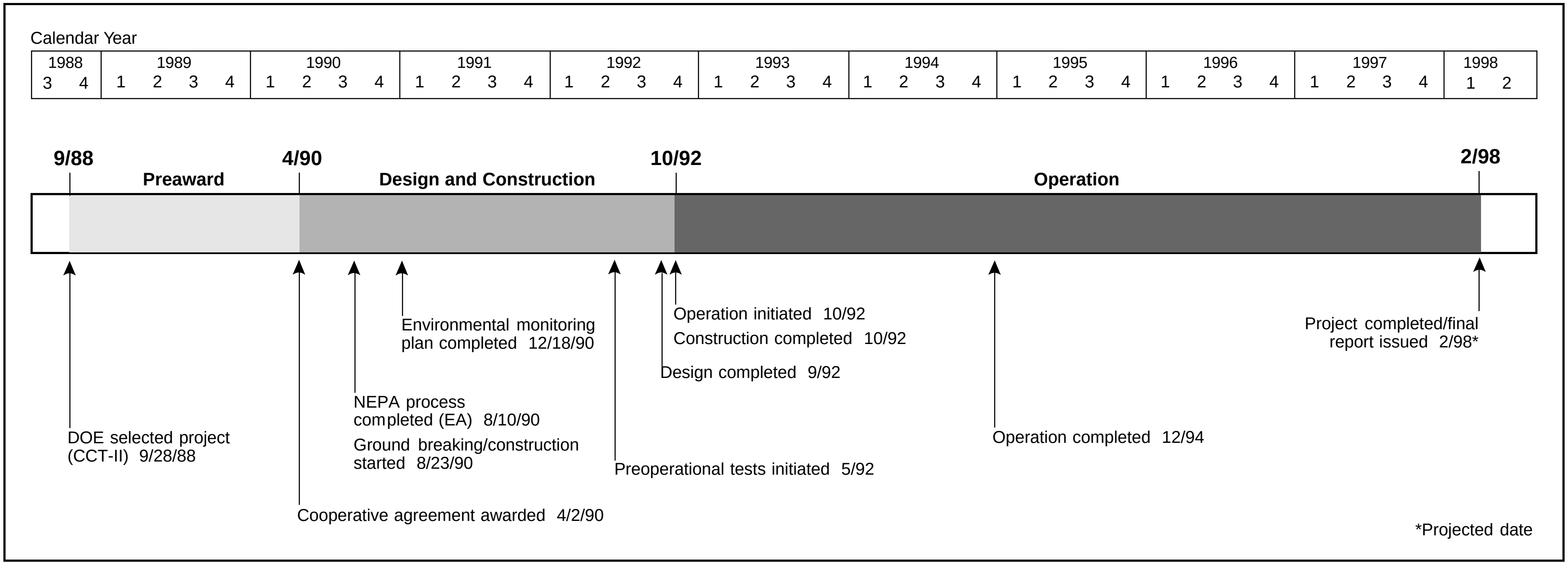
To demonstrate 90% SO_2 control at high reliability with and without simultaneous particulate control; to evaluate use of fiberglass-reinforced-plastic (FRP) vessels to eliminate flue gas reheat and spare absorber modules; and to evaluate use of gypsum to reduce waste management costs.

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 limestone FGD reaction, forced oxidation, and gypsum crystallization in one process vessel. The process is mechanically and chemically simpler than conventional FGD processes and can be expected to exhibit lower cost characteristics.

The flue gas enters underneath the scrubbing solution in the Jet Bubbling Reactor®. The SO_2 in the flue gas is absorbed and forms calcium sulfite ($CaSO_3$). Air is bubbled into the bottom of the solution to oxidize the calcium sulfite to form gypsum. The slurry is dewatered in a gypsum stack, which involves filling a dyked area with gypsum slurry. Gypsum solids settle in the dyked area by gravity, and clear water flows to a retention pond. The clear water from the pond is returned to the process.

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



Results Summary

Environmental

- Over 90% SO_2 removal efficiency was achieved at SO_2 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/10^6 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 wallboard/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_2 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 10 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_2 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 prescrubber 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 11 shows SO_2 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_2 concentration increased, removal efficiency decreased, but adjustments in JBR fluid level could maintain the efficiency above 90% and, at lower SO_2 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 12.

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 11

SO_2 Removal Efficiency

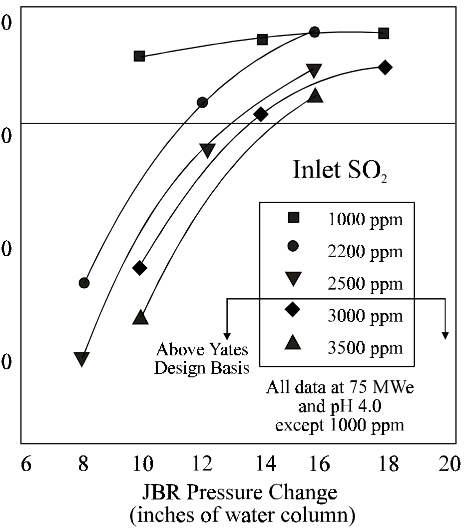


Exhibit 10

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[a]	0.98	0.95	0.96
Availability[b]	0.97	0.95	0.97
Utilization[c]	0.73	0.72	0.75

[a] Reliability = hours scrubber operated divided by the hours called upon to operate

[b] Availability = hours scrubber available divided by the total hours in the period

[c] Utilization = hours scrubber operated divided by the total hours in the period

Exhibit 12

Particulate Capture Performance

(ESP Marginally Operating)

JBR Pressure Change (inches of water column)	Boiler Load (MWe)	Inlet Mass Loading (lb/10^6 Btu)	Outlet Mass Loading* (lb/10^6 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/10^6 Btu for units constructed after September 18, 1978. Plant Yates permit limit is 0.24 lb/10^6 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 13.

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.

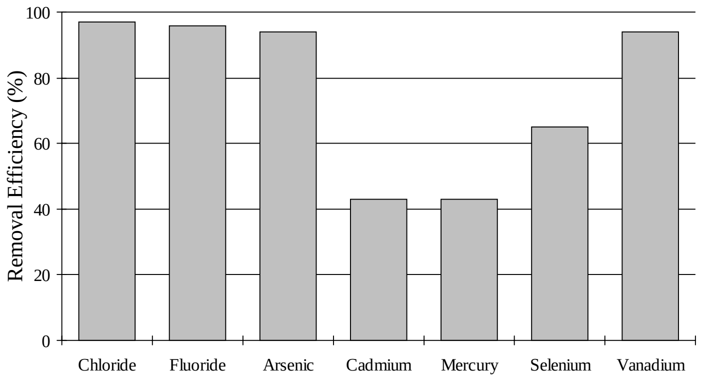
Commercial Applications

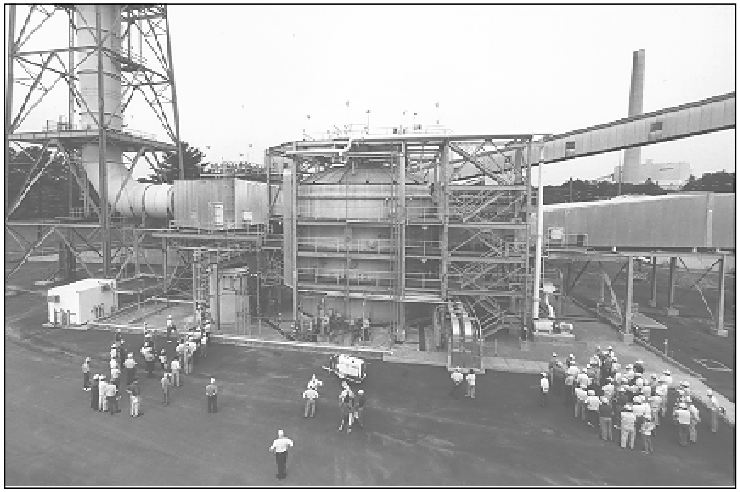
Involvement of Southern Company (which owns Southern Company Services, Inc.), with more than 20,000 MWe of coal-fired generating capacity, is expected to enhance confidence in the CT-121 process among other large high-sulfur-coal boiler users. This process will be applicable to 370,000 MWe of new and existing generating capacity by the year 2010. A 90% reduction in SO_2 emissions from only the retrofit portion of this capacity represents more than 10,500,000 tons/yr of potential SO_2 control.

Exhibit 13

CT-121 Air Toxics Removal

(JBR Components Only)





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

Plant Yates continues to operate with the CT-121 scrubber as an integral part of the site's CAAA compliance strategy. A 350-MWE unit has been sold to a Canadian tar sands refinery; the sale is worth $100 million. A total of 1,200 MWe of FGD capacity has been sold to the Czech Republic and Korea.

The project received *Power* magazine's 1994 Powerplant Award. Other awards include the Society of Plastics Industries' 1995 Design Award for the mist eliminator, the Georgia Chapter of the Air and Waste Management Association's 1994 Outstanding Achievement Award, and the Georgia Chamber of Commerce's 1993 Environmental Award.

Contacts

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- *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.)

NO_x Control Technology

Nitrogen oxides (NO_x) 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_x). Rapid formation of NO_x at the flame front can occur; but usually, this reaction of hydrocarbon fragments with atmospheric nitrogen represents a small fraction of total NO_x emissions. To control fuel-NO_x formation, it is important to limit oxygen at the early stages of combustion. To control thermal NO_x, it is important to limit peak temperatures.

Exhibit 14

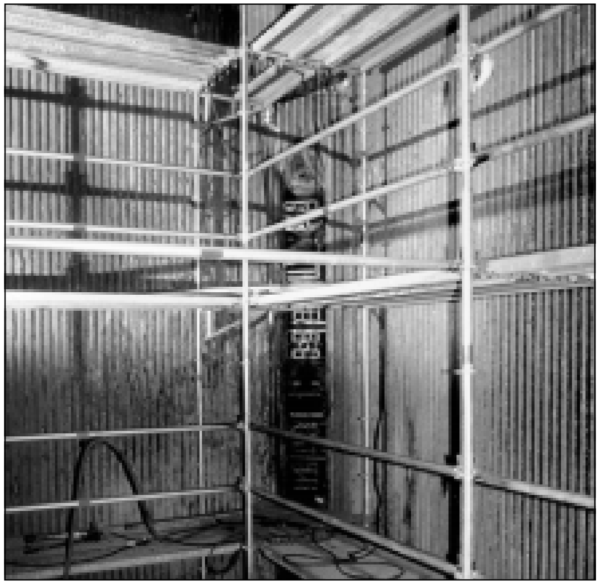
Group I and 2 Boiler Statistics and Phase II NO_x Emission Limits

Boiler Types	No. of Boilers	Phase II NO_x Emission Limits (lb/10^6 Btu)
Group 1		
Tangentially fired	299	0.40
Dry-bottom, wall-fired	308	0.46
Group 2		
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/noxfs3.html).

NO_x 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 14). The proposed new NSPS for NO_x 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_x in 13 eastern states will be required to monitor and report their NO_x 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_x limits, the CCT Program has sought to provide a number of NO_x control options to cover the range of boiler types and emission reduction requirements.

Control of NO_x 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_x burners (LNBs), advanced overfire air (AOFA), and reburning processes using either gas or coal. Processes used to act upon flue gas include selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR).



▲ A portion of ABB Combustion Engineering's Low-NO_x Concentric Firing System (LNCFS™) is shown being installed on a tangentially fired boiler.

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_x and thermal-NO_x formation. LNBs alone typically can achieve 40–50 percent NO_x 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 miti-

Exhibit 15

CCT Program NO_x Control Technology Characteristics

Project	Process	Boiler Size/ Type	NO_x Reduction	Fact Sheet
Demonstration of Coal Reburning for Cyclone Boiler NO_x Control	Coal reburning—30% heat input	100 MWe/cyclone	52–62%	32
Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler	LNB/gas reburning/AOFA—13–18% gas heat input	172 MWe/wall	37–65%	40
Micronized Coal Reburning Demonstration for NO_x Control	Coal reburning—30% heat input	148 MWe/tangential 50 MWe/cyclone	50–60% (goal)	44
Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit	LNB—separation of coal and air ports on plug-in unit	605 MWe/cell burner	48–58%	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)	46
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers	LNB/AOFA—advanced LNB with close-coupled and separated overfire air	180 MWe/tangential	37–45%	52
Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers	SCR—eight catalysts with different shapes and chemical compositions	8.7 MWe/various	80%	48

gates fuel-NO_x formation. AOFA injected at high velocity creates turbulent mixing to complete the combustion in a gradual fashion at lower temperatures to mitigate thermal-NO_x formation. Usually, AOFA is used in combination with LNBs, but alone, AOFA can achieve 10–25 percent NO_x emission reductions. LNB/AOFA systems generally can achieve NO_x 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_x 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_x 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_x to form elemental nitrogen and water. SNCR can only be used at high temperatures (1,600–2,200 ºF) where a catalyst is not needed. SCR is typically applied at temperatures between 600–800 ºF. Generally, SNCR and SCR systems alone can achieve NO_x emission reductions of 30–50 percent and 80–90+ percent, respectively.

Under the CCT Program, seven NO_x 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 15 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_x 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)—cofunders

Location

Cassville, Grant County, WI (Wisconsin Power and Light Company's Nelson Dewey Station, Unit No. 2)

Technology

The Babcock & Wilcox Company's coal-reburning system, Coal Reburn

Plant Capacity/Production

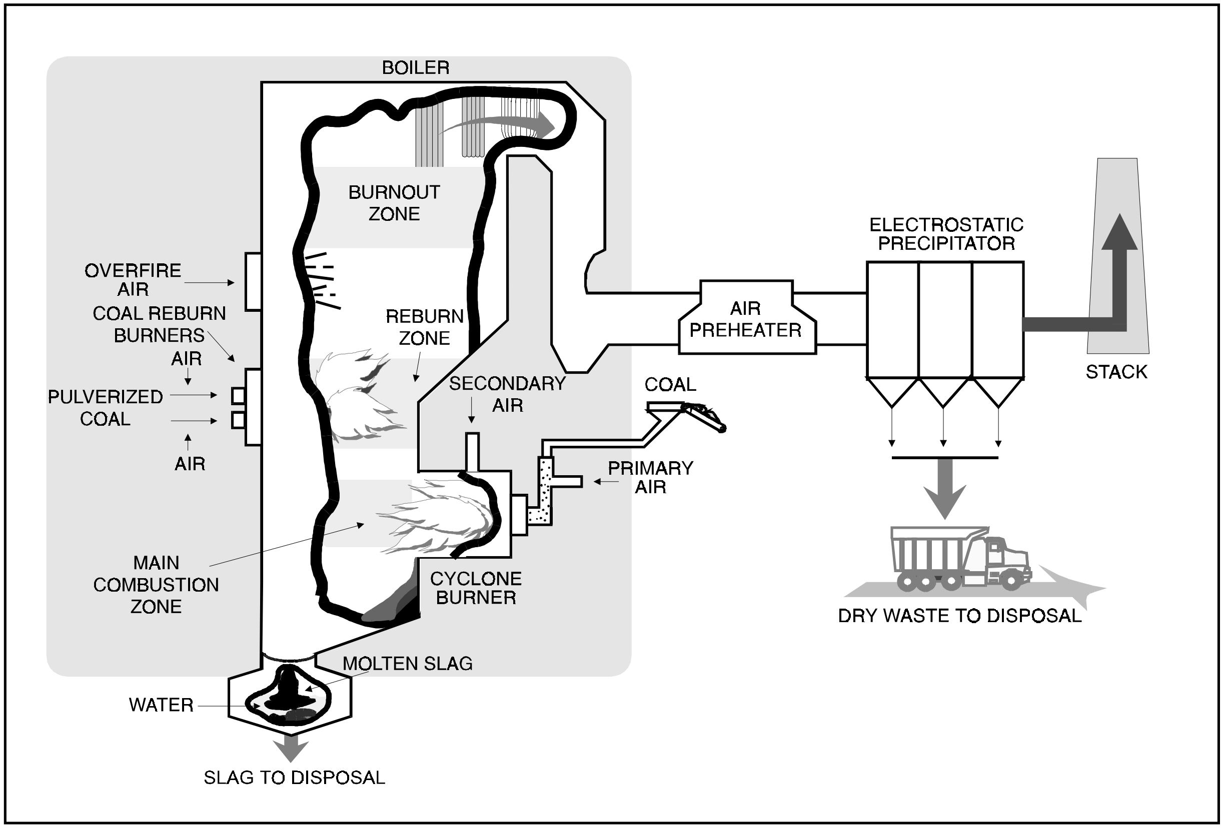
100 MWe

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

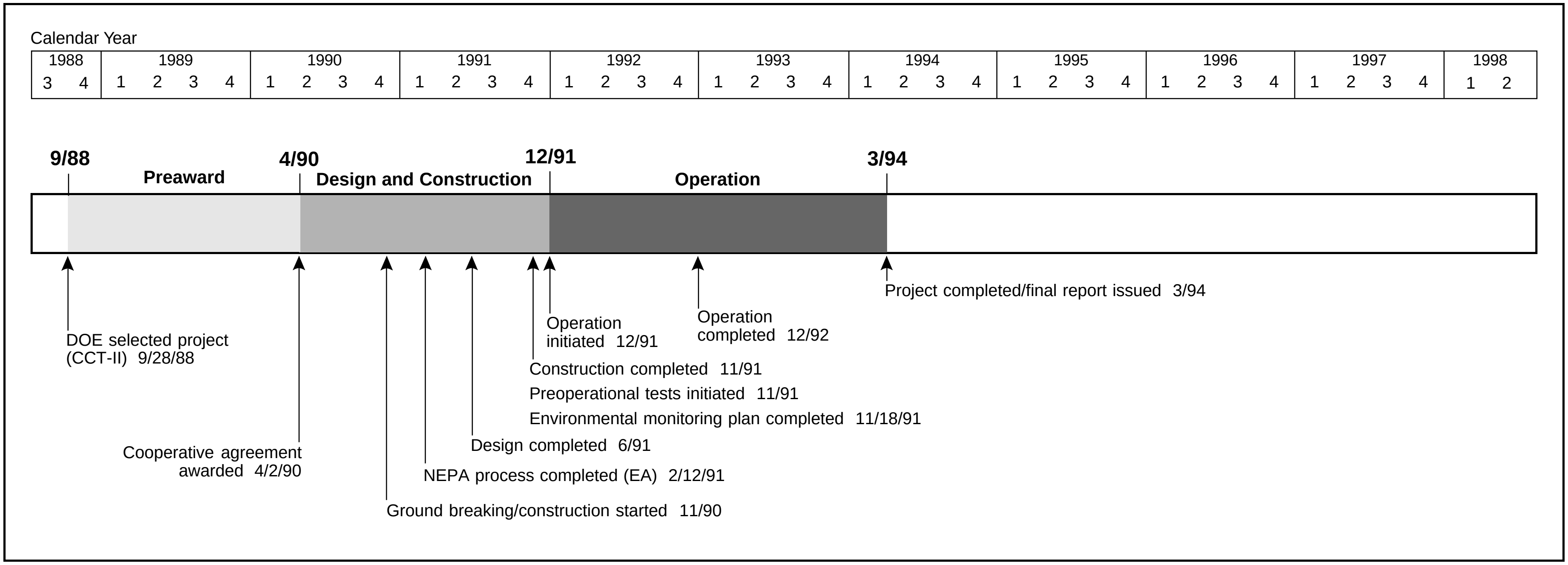
To demonstrate the technical and economic feasibility of achieving greater than 50% reduction in NO_x emissions with no serious impact on cyclone combustor operation, boiler performance, or other emission streams.

Technology/Project Description

Babcock & Wilcox Coal Reburn reduces NO_x in the furnace through the use of multiple combustion zones. The main combustion zone uses 70–80% of the total heat-equivalent fuel input to the boiler and slightly less than normal combustion air input. The balance of the coal (20–30%), along with significantly less than the theoretically determined requirement of air, is fed to the reburning zone above the cyclones to create an oxygen-deficient condition. The NO_x formed in the cyclone burners reacts with the resultant reducing flue gas and is converted into nitrogen in this zone. The completion of the combustion process occurs in the third zone, called the burnout zone, where the balance of the combustion air is introduced.

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_x reduction at full load with Lamar bituminous and PRB subbituminous coals.
- Reburn-zone stoichiometry had the greatest effect on NO_x control.
- Gas recirculation was vital to maintaining reburn-zone stoichometry 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_x 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_x 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_x 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_x 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_x-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 16 shows changes in NO_x 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_x emissions levels. The reburn-zone stoichiometry can be varied by alternating the air flow quantities (oxygen availability) to the reburn burners, the percent reburn heat input, the gas recirculation flow rate, or the cyclone stoichiometry.

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.

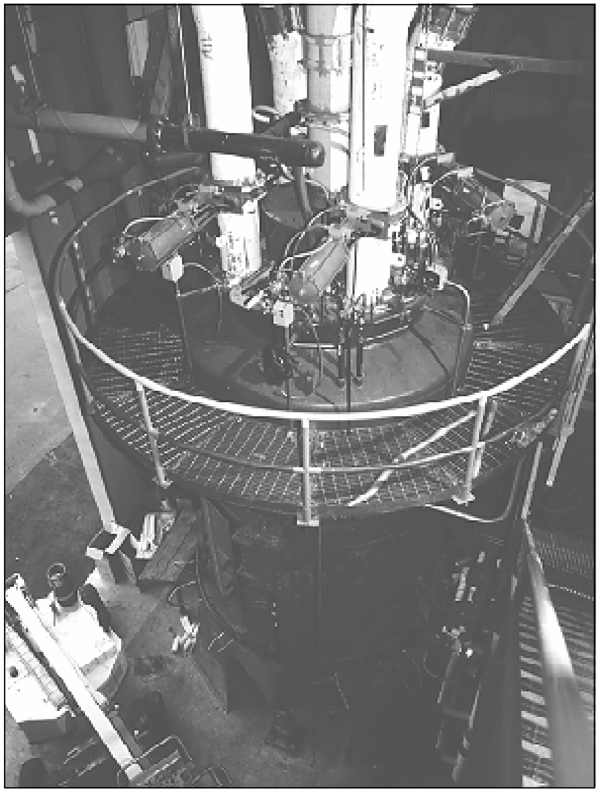
▲ Wisconsin Power and Light Company's Nelson Dewey Station hosted the successful demonstration of Coal Reburn.

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 coal feed out of the cyclone to the

Exhibit 16
Coal Reburn Test Results

	Boiler Load		
	110 MWe	82 MWe	60 MWe
Lamar coal			
NO_x (lb/10^6 Btu/% reduction)	0.39/52	0.36/50	0.44/36
Boiler efficiency losses due to unburned carbon (%)	0.1	0.25	1.5
Powder River Basin coal			
NO_x (lb/10^6 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_x emission control at the Nelson Dewey Station.

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_x removed were developed for 110- and 605-MWe plants over both 10 and 30 years. The results of these analyses are shown in Exhibit 17. 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.

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Exhibit 17
Coal Reburn Economics

Costs	Plant Size 110 MWe	Plant Size 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_x removed)		
10-year life	1,075	408
30-year life	692	263

Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit

Project completed.

Participant

The Babcock & Wilcox Company

Additional Team Members

The Dayton Power and Light Company—cofunder and host
Electric Power Research Institute—cofunder
Ohio Coal Development Office—cofunder
Tennessee Valley Authority—cofunder
New England Power Company—cofunder
Duke Power Company—cofunder
Allegheny Power System—cofunder
Centerior Energy Corporation—cofunder

Location

Aberdeen, Adams County, OH (Dayton Power and Light Company's J.M. Stuart Plant, Unit No. 4)

Technology

The Babcock & Wilcox Company's low-NO_x cell burner (LNCB®) system

Plant Capacity/Production

605 MWe

Coal

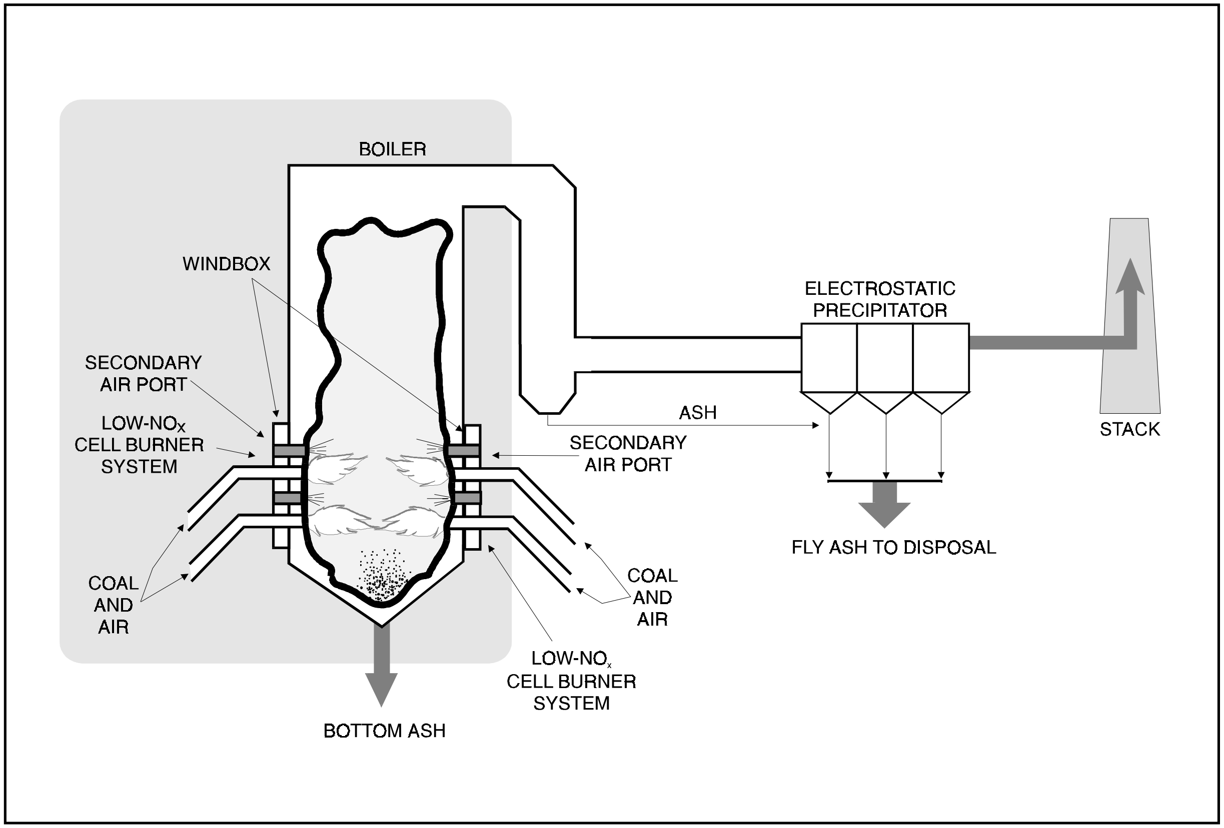
Bituminous, medium sulfur

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_x from a large baseload coal-fired utility boiler with LNCB® technology; to achieve at least a 50% NO_x reduction without degradation of boiler performance at less cost than that of conventional low-NO_x burners.

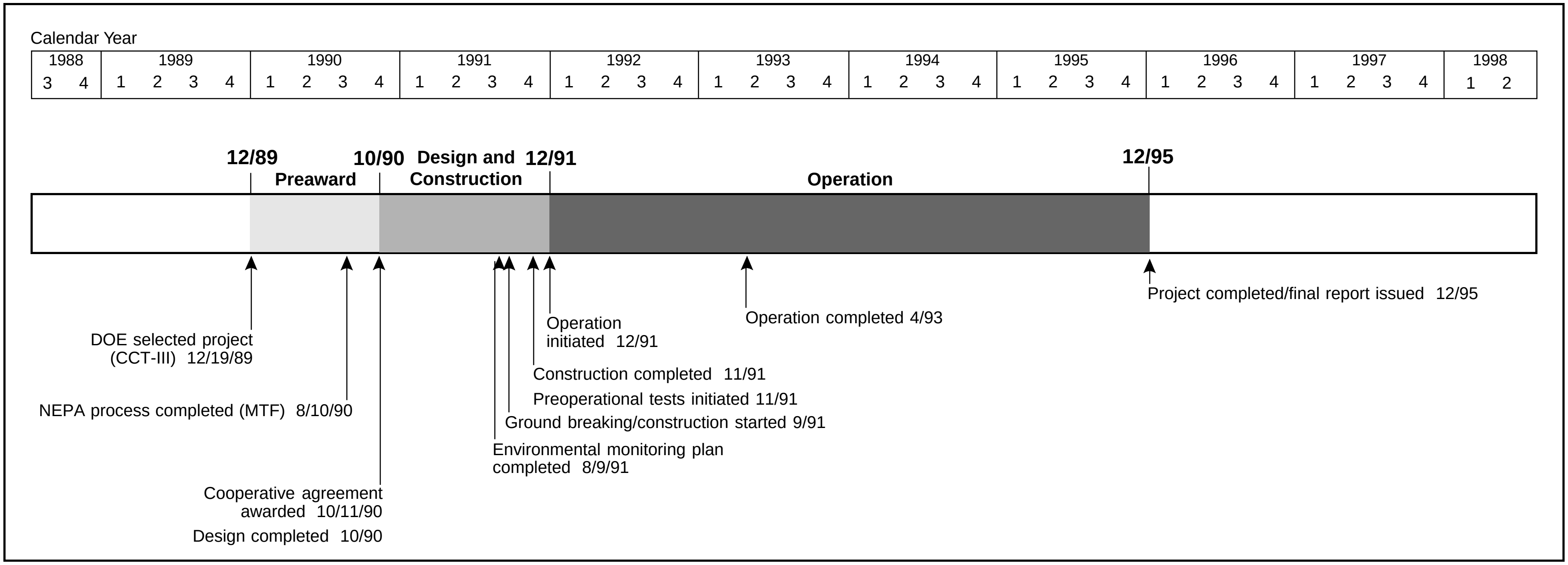


Technology/Project Description

The LNCB® technology replaces the upper coal nozzle of the standard two-nozzle cell burner with a secondary air port. The lower burner coal nozzle is enlarged to the same fuel input capacity as the two standard coal nozzles. The LNCB® operates on the principle of staged combustion to reduce NO_x emissions. Approximately 70% of the total air (primary, secondary, and excess air) is supplied through or around the coal-feed nozzle. The remainder of the air is directed to the upper port of each cell to complete the combustion process. The fuel-bound nitrogen compounds are converted to nitrogen gas, and the reduced flame temperature minimizes the formation of thermal NO_x.

The 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.

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



Results Summary

Environmental

- Short-term optimization testing (all mills in service) showed NO_x 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_x reduction of 58% (over 8 months).
- Long-term testing at full load (one mill out of service) showed an average NO_x reduction of 60% (over 8 months).
- CO emissions averaged 28–55 ppm at full load with LNCB® 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® 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_x 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_x.

To reduce NO_x emissions, the LNCB® 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_x burners. LNCB® provides a lower cost alternative to address NO_x 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_2S 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_x 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_x reduction ranged from 53.3% to 54.5%.

Average NO_x reduction at intermediate load (about 460 MWe) ranged from 52.5% to 54.7%. At low loads (about 350 MWe), average NO_x reduction ranged from 46.9% to 47.9%.

NO_x 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_x 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_2 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_3 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 ºF but eventually rose to within 10 ºF 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_2S levels were monitored in the boiler. After optimizing LNCB® 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® were roughly equivalent to pre-retrofit rates.

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

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_x emission level of 1.2 lb/10^6 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_x removed.

Commercial Applications

The low cost and short outage time for retrofit make the LNCB® design the most cost-effective NO_x control technology available today for cell burner boilers. The LNCB® system can be installed at about half the cost and time of other commercial low-NO_x burners.

Dayton Power & Light has retained the LNCB® for use in commercial service. Seven commercial contracts have been awarded for 172 burners, valued at $27 million. LNCB® have already been installed on more than 4,600 MWe of capacity.

The project received *R&D* magazine's 1994 R&D Award.

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

▲ The connections to the LNCB® are viewed from outside the boiler.

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

Project completed.

Participant

Energy and Environmental Research Corporation

Additional Team Members

Public Service Company of Colorado—cofunder and host
Gas Research Institute—cofunder
Colorado Interstate Gas Company—cofunder
Electric Power Research Institute—cofunder
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_x burners (LNB)

Plant Capacity/Production

172 MWe

Coal

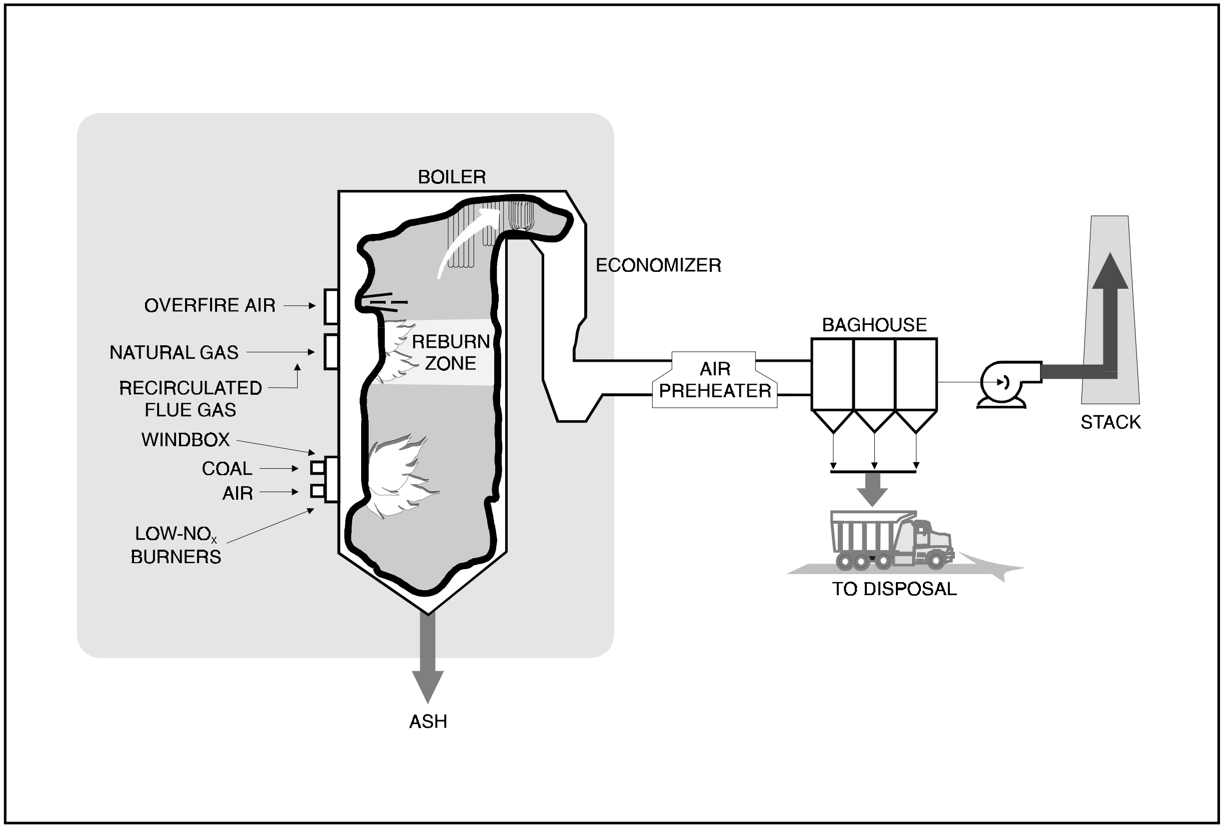
Western bituminous, 0.35–0.66% sulfur

Project Funding

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

Project Objective

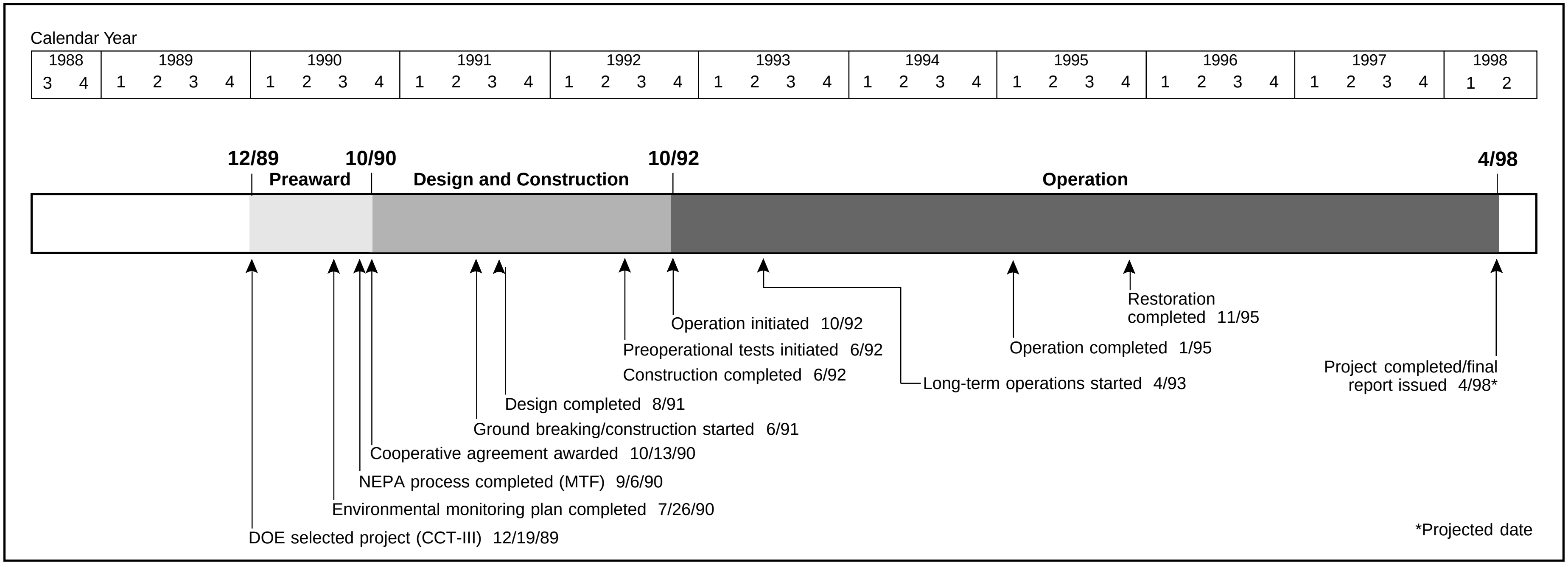
To attain up to a 70% decrease in the emissions of NO_x from an existing wall-fired utility boiler firing low-sulfur coal using both gas reburning and low-NO_x burners (GR–LNB); and to assess the impact of GR–LNB on boiler performance.



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_x drifting upward from the lower region of the furnace is "reburned" in this zone and converted to molecular nitrogen. Low-NO_x burners positioned in the coal combustion zone retard the production of NO_x by staging the burning process so that the coal-air mixture can be carefully controlled at each stage. The synergistic effect of adding a reburning stage to wall-fired boilers equipped with low-NO_x burners was intended to lower NO_x 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_x reduction.
- First-generation GR, which incorporated flue gas recirculation, in combination with LNB achieved a 65% NO_x reduction at an 18% gas heat input rate.
- Second-generation GR, without flue gas recirculation, in combination with LNB achieved 64% NO_x reduction at 13% gas heat input.
- Both first- and second-generation GR with LNB were capable of reducing NO_x 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_2 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_2 emission allowances (because GR reduces SO_2 emissions when displacing coal).

Project Summary

The demonstration established that GR–LNB offers a cost-effective option for deep NO_x reduction on wall-fired boilers. GR–LNB NO_x control performance approached that of selective catalytic reduction (SCR) but at significantly lower cost. SCR typically achieves 70–80% NO_x reduction at capital costs in the range of $100–$150/kW for retrofit applications. GR–LNB achieved 60–70% NO_x 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_x$ burners according to the literature). The importance of cost-effective technology for deep NO_x reduction is reflected in ongoing deliberations on the need for NO_x 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_x 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_x reduction, SO_2 reduction, CO emissions, carbon-in-ash, and heat rates were analyzed. The baseline condition of the LNB was also established.

Environmental Performance

At a constant load (150 MWe) and a constant oxygen level at the boiler exit, both NO_x and SO_2 emissions decreased when natural gas was introduced in the GR operation. In general, the NO_x emissions were reduced with increasing gas heat input. At gas heat inputs greater than 10%, NO_x emissions were reduced marginally as gas heat input increased. Natural gas also reduced SO_2 emissions in proportion to the gas heat input. At Cherokee Station, low-sulfur (0.35–0.66%) coal was used, and typical SO_2 emissions were 0.65 lb/10^6 Btu. With a gas heat input of 20%, SO_2 emissions decreased by 20% to 0.52 lb/10^6 Btu.

▲ A worker inspects the support ring for the Foster Wheeler low-NO_x burner installed in the boiler wall.

The CO_2 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_2 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_x 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.)
- 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 18.

Exhibit 18
NO_x Data from Cherokee Station, Unit 3

	GR Generation	
	First	**Second**
Baseline (lb/10^6 Btu)	0.73	0.73
Avg NO_x reduction (%)		
LNB	37	37
GR–LNB	65	64
Avg gas heat input (%)	18	13

Although the NO_x reduction performance of LNB (37% NO_x 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_2 removal requirements
- Value of SO_2 emission credits

Based on the demonstration, GR–LNB is expected to achieve at least 60% NO_x 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_2 emission credits received due to absence of sulfur in the gas.

Commercial Applications

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.

Public Service Company of Colorado, the host utility, decided to retain the low-NO_x burners and the gas-reburning system for immediate use; however, a restoration was required to remove the flue gas recirculation system.

Energy and Environmental Research Corporation has been awarded two contracts to provide gas-reburning systems for five cyclone coal-fired boilers: TVA's Allen Unit 1, with options for Units 2 and 3, (identical 330-MWe Units); Baltimore Gas & Electric's C.P. Crane, Unit 2, with an option for Unit 1, (similar 200-MWe Units). Start-up of the first two units is planned for mid-1998.

This project was one of two that received the Air and Waste Management Association's 1997 J. Deanne Sensenbaugh Award.

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References

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▲ The Public Service Company of Colorado has retained the gas-reburning and low-NO_x burner system for commercial use.

Micronized Coal Reburning Demonstration for NO_x 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
New York State Energy Research and Development Authority

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

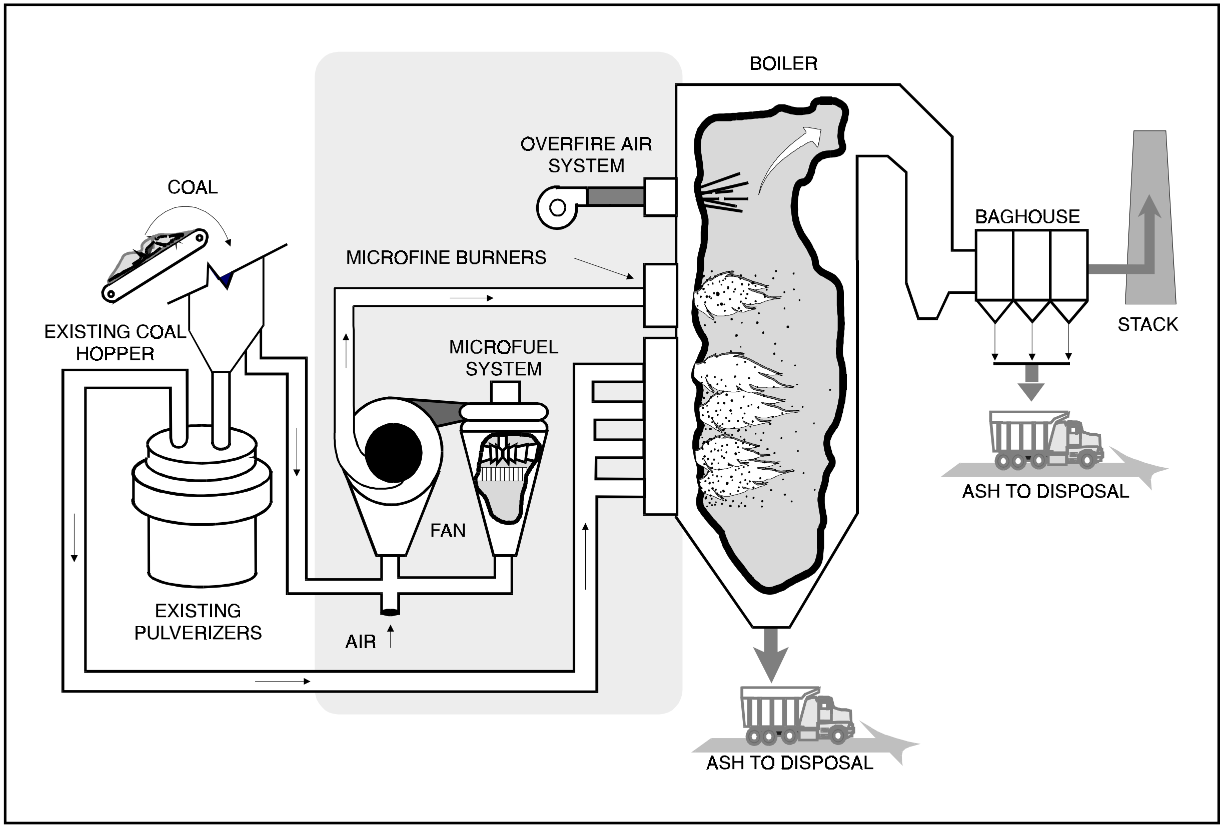
ABB Combustion Engineering's Low-NO_x Concentric Firing System (LNCFS™)
D.B. Riley's MPS mill (at Milliken Station)
Fuller's MicroMill™ technologies for producing micronized coal (at Eastman Kodak)

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



Project Objective

To reduce NO_x 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_x 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_x formation are affected by coal fineness.

The combination of micronized coal, supplying 30% of the total furnace fuel requirements, and advanced reburning, utilizing that requirement in conjunction with fuel/air staging, provides flexible options for significant combustion operations and environmental improvements. These options can prevent higher operating costs or furnace performance derating often associated with conventional environmental controls.

At the Milliken site, coal will be reburned for NO_x 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

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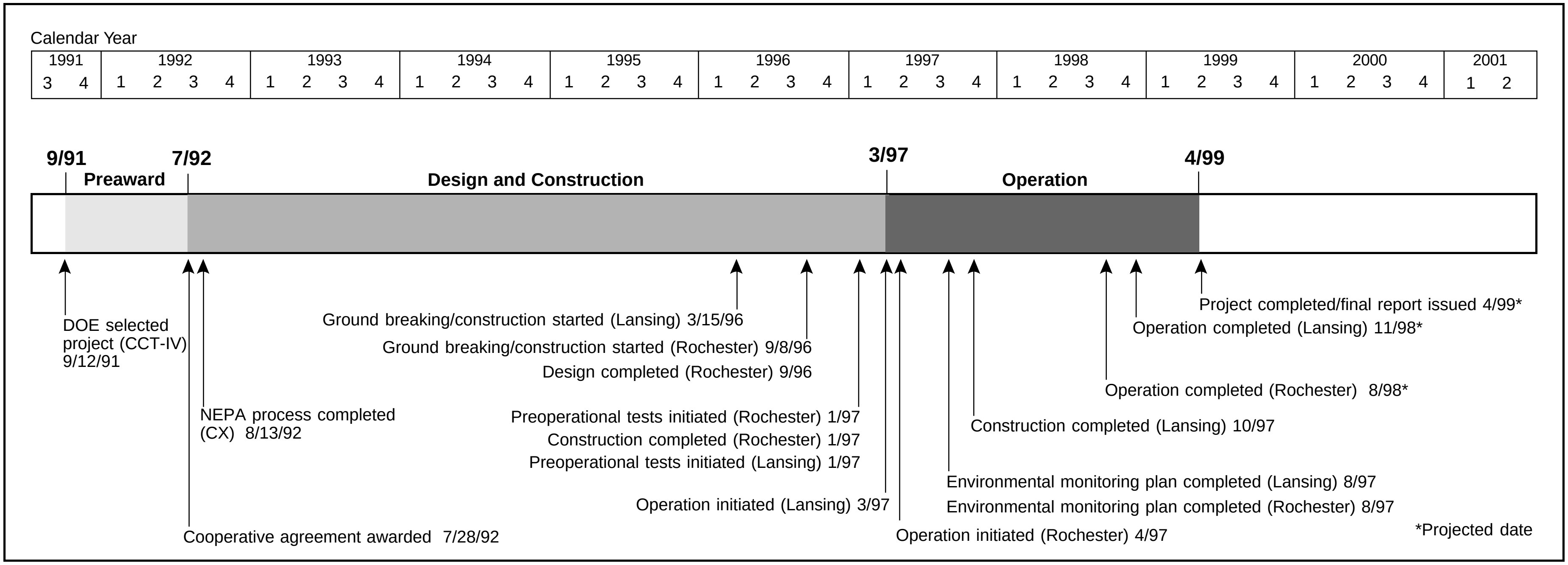
MicroMill is a trademark of the Fuller Company.
LNCFS is a trademark of ABB Combustion Engineering, Inc.



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

Operational testing at the Kodak site in Rochester began in April 1997 and will continue into March 1998. Initial readings show performance may be better than projected. Minor problems with flue gas leakage and opacity are being addressed.

Preoperational testing of the reburn system at Milliken Station near Lansing began in March 1997. Sieve testing and analysis involved 49 samples. Sieve test results have been forwarded to ABB Combustion Engineering and CONSOL for analysis. A draft report is in preparation. 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_x emissions by 50–60% with minimal furnace modifications for existing units. For greenfield units, the technology can be designed as an integral part of the system. Either way, the technology enhances boiler performance with the improved burning characteristics of micronized coal. About 25% of the more than 1,000 existing units could benefit from 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_x emissions reductions will enable lost capacity to be restored, creating a very economic source of generation. For both retrofit and greenfield facilities, reburn burners also can serve as low-load burners, and commercial units can achieve a turndown of 8:1 on nights and weekends without consuming expensive auxiliary fuel. Existing pulverizers can be operated on a variety of coals with improved performance. The combination of micronized-coal-reburning fuel and better pulverizer performance will increase overall pulverized-fuel surface area for better carbon burnout.

This demonstration will provide methods for NO_x control at a low capital cost for utilities and industrial users to meet the current and upcoming NO_x regulations. Utilities that install low-NO_x 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_x also will be provided a low-cost option, particularly cyclone boiler users who have been without low-NO_x 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$_x$ burner (LNB) with advanced overfire air (AOFA)
EPRI's Generic NO$_x$ Control Intelligent System (GNOCIS) for plant optimization

Plant Capacity/Production

500 MWe

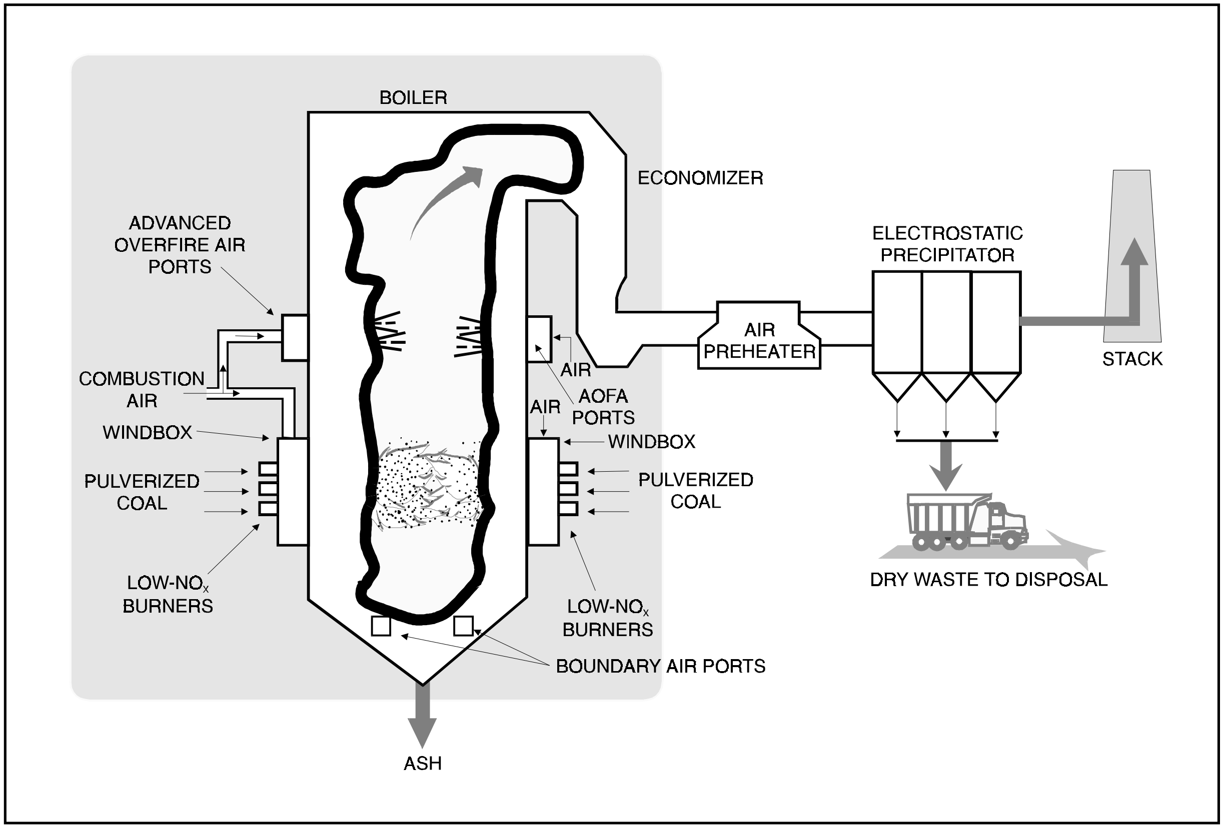
Project Funding

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$_x$ reduction with the AOFA/LNB system; to determine the contributions of AOFA and the LNB to NO$_x$ 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$_x$ reduction and boiler performance.



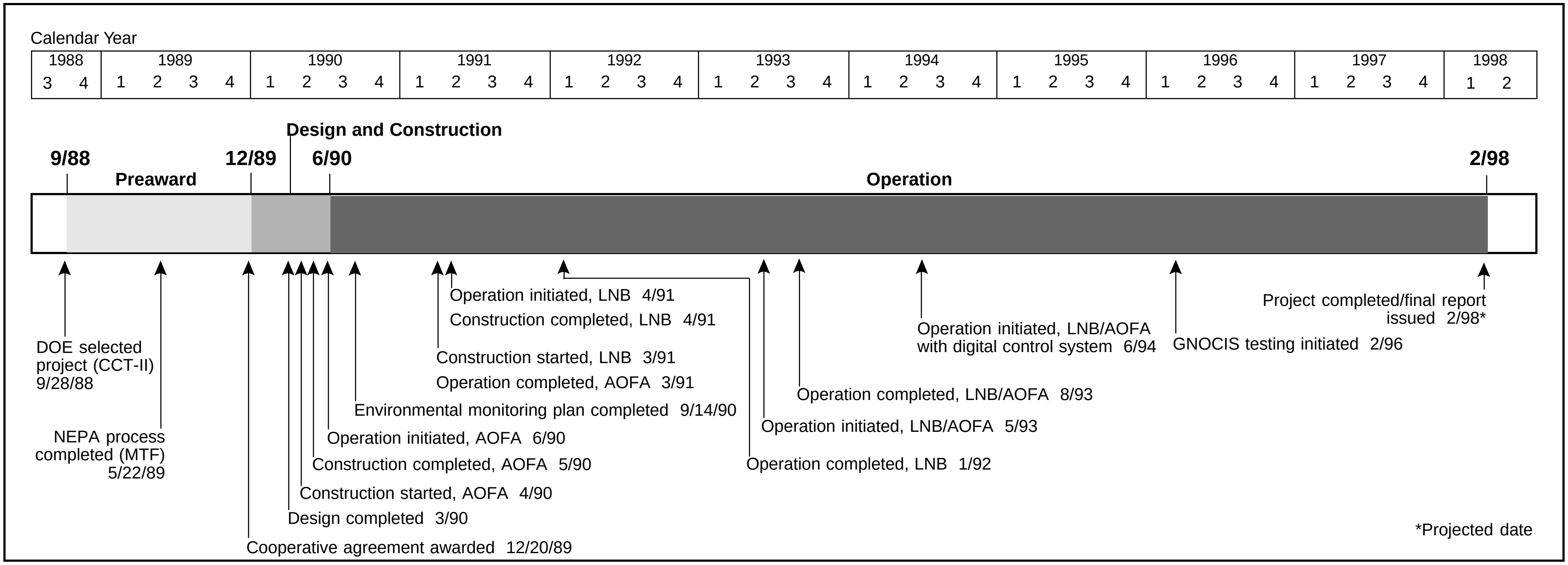
Technology/Project Description

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$_x$ formation, and (3) supplying air over furnace wall tube surfaces to prevent slagging and furnace corrosion. The AOFA technique was expected to reduce NO$_x$ emissions by about 35%.

In an LNB, fuel and air mixing is controlled to preclude the formation of NO$_x$. This is accomplished by regulating the initial fuel-air mixture, velocities, and turbulence to create a fuel-rich flame core and by controlling the rate at which additional air required to complete combustion is mixed with the flame solids and gases so as to maintain a deficiency of oxygen. Typical results for utilities indicate that LNB technology is capable of reducing NO$_x$ emissions by about 45%.

Based on earlier experience, the use of AOFA in conjunction with LNB can reduce NO$_x$ emissions by as much as 65% compared with conventional burners.

The demonstration is located at the Georgia Power Company's Plant Hammond, Unit No. 4. The boiler is a nominal 500-MWe pulverized coal, 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.



Project Status/Accomplishments

Baseline, AOFA, LNB, and LNB/AOFA test segments have been completed. Analysis of more than 80 days of AOFA operating data has provided statistically reliable results indicating that, depending upon load, NO_x reductions of 24% are achievable under normal long-term operation. Analysis of the 94 days of LNB long-term data collected show the full-load NO_x emission levels to be approximately 0.65 lb/10^6 Btu. This NO_x level represents a 48% reduction when compared to the baseline, full-load value of 1.23 lb/10^6 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_x emissions were approximately 0.41 lb/10^6 Btu with a corresponding flyash LOI value of nearly 8%. Full-load, long-term NO_x emission reductions in the LNB/AOFA configuration were about 63%. However, analysis of emissions data showed that the incremental NO_x reduction effectiveness of the AOFA system (beyond the use of the LNB) was approximately 17% with additional reductions resulting from other operational changes.

GNOCIS testing for optimizing NO_x reduction and boiler efficiency began in February 1996. GNOCIS is fully operational and testing has achieved an efficiency gain of 0.5 percentage points, a reduction in LOI levels of 1–3 percentage points, and a reduction in NO_x emissions by 10–15% at full load.

Remaining modeling and testing is in progress to evaluate the applicability of postcombustion NO_x control (SNCR) on large, coal-fired boilers, including an evaluation of GNOCIS. A final report on the baseline, AOFA, LNB, and LNB-AOFA tests has been drafted and reviewed. A report on the on-line carbon-in-ash monitors evaluated in the project has been prepared.

A report on air toxic testing was issued in December 1993.

Commercial Applications

The technology is applicable to the 422 existing pre-NSPS U.S. wall-fired boilers which burn a variety of coals. The GNOCIS technology is applicable to all fossil-fuel-fired boilers, including units fired with natural gas and units co-firing coal and natural gas.

The host retained the technologies for commercial use. GNOCIS software has been installed in eight other units: Georgia Power's Branch Unit 3 and Wansley Unit 1, Alabama Power's Gaston Units 3 and 4, Duquesne Light & Power's Cheswick Unit 1, TVA's Kingston Unit 4, and PowerGen's Kingsnorth Units 3 and 4. Feasibility studies are under way at a number of utilities in England.

Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x 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

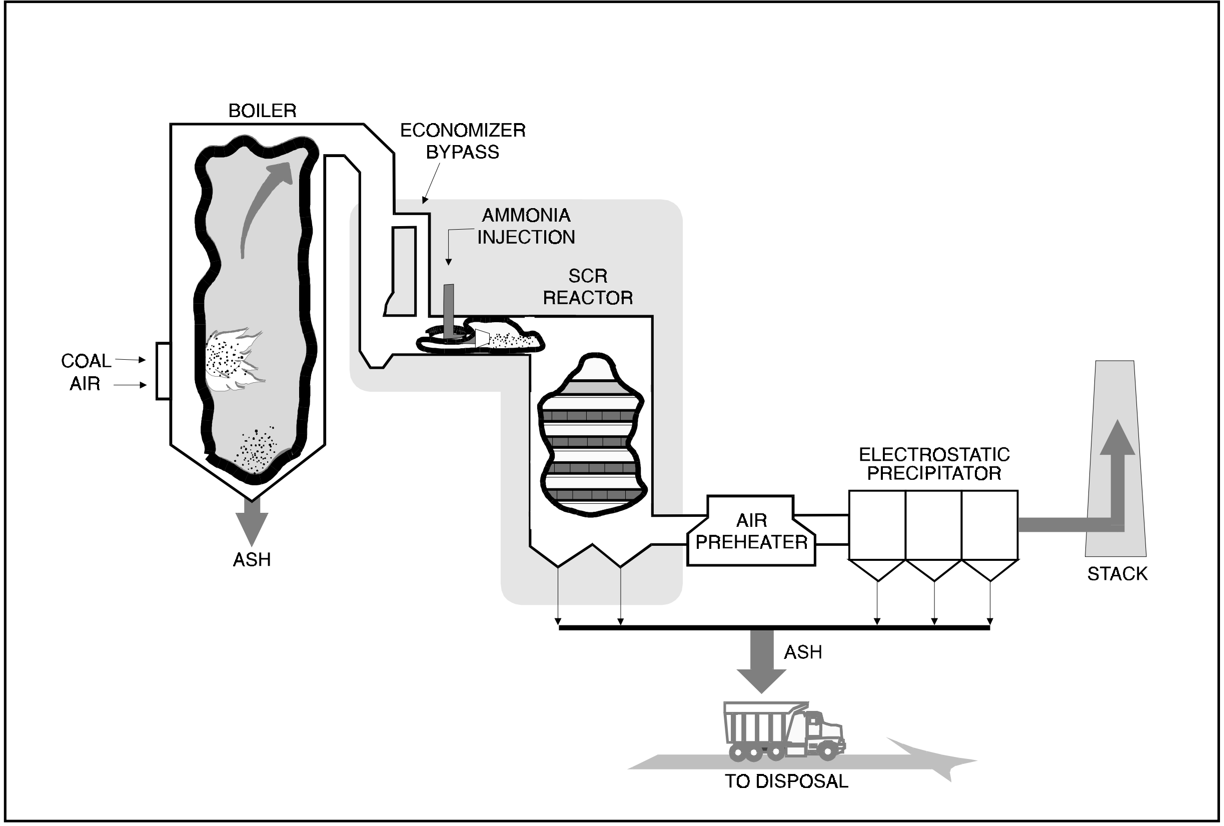
Illinois bituminous, 2.7% sulfur

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_x removal.



Technology/Project Description

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

In this demonstration project, the SCR facility consisted of three 2.5-MWe-equivalent SCR reactors, supplied by separate 5,000 std ft^3/min flue gas slipstreams, and six 0.20-MWe-equivalent SCR reactors. These reactors were calculated to be large enough to produce design data that will allow the SCR process to be scaled up to commercial size. Catalyst suppliers (two U.S., two European, and two Japanese) provided eight catalysts with various shapes and chemical compositions for evaluation of process chemistry and economics of operation during the demonstration.

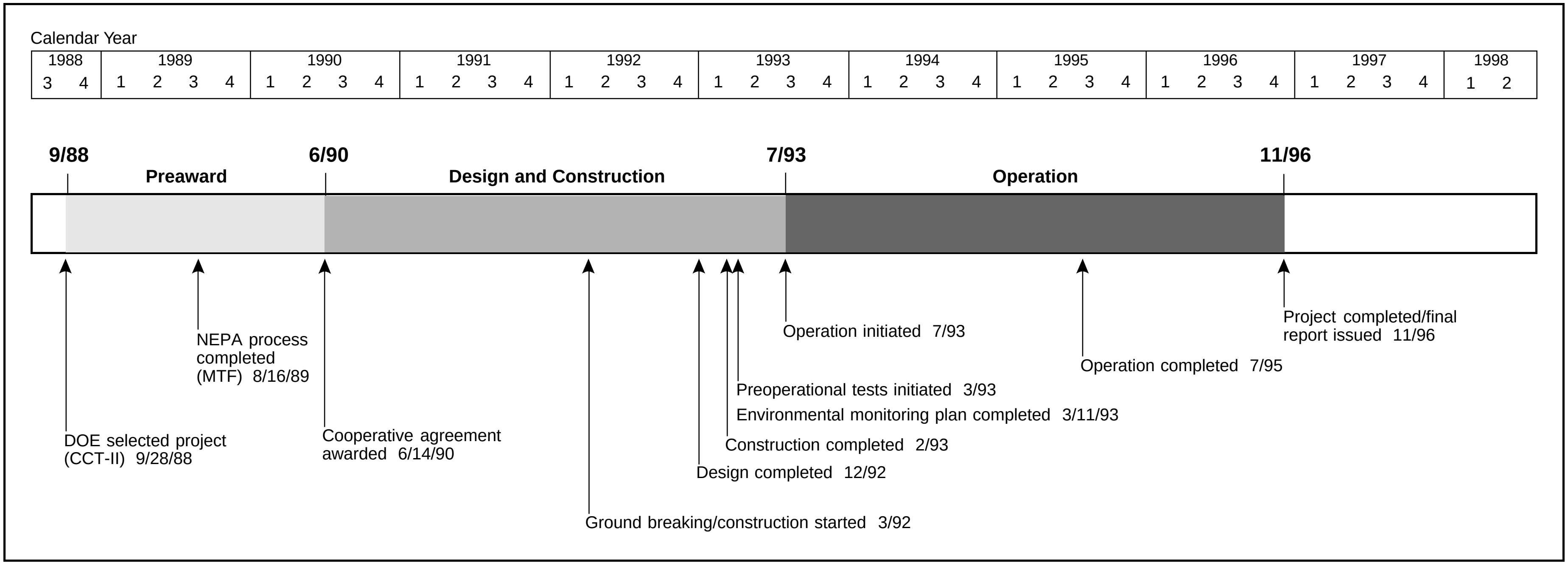
The project demonstrated, at high- and low-dust loadings of flue gas, the applicability of SCR technology to provide a cost-effective means of reducing NO_x emissions from power plants burning high-sulfur U.S. coal.

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_x and particulate levels.

Results Summary

Environmental

- NO_x 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_x reduction.
- While catalyst performance increased above 700 ºF, 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_2 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_x removal levels for a 250-MWe unit at 0.35 lb/10^6 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_2 and SO_3, 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 (ºF)	620	700	750
NH_3/NO_x molar ratio	0.6	0.8	1.0
Space velocity (1% design flow)	60	100	150
Flow rate (std ft^3/min)			
Large reactor	3,000	5,000	7,500
Small reactor	240	400	600

The catalysts tested are listed in Exhibit 19. Catalyst suppliers were given great latitude in providing the amount of catalyst for this demonstration.

Exhibit 19
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^3/min Small = 0.2 MWe; 400 std ft^3/min

Environmental Results

Ammonia slip, the controlling factor in the long-term operation of commercial SCR, was usually ≤5 ppm because of plant and operational considerations. Ammonia slip was dependent on catalyst exposure time, flow rate, temperature, NH_3/NO_x distribution, and NH_3/NO_x ratio (NO_x reduction). Changes in NH_3/NO_x ratio and consequently NO_x reduction generally produced the most significant changes in ammonia slip. The ammonia slip at 60% NO_x reduction was at or near the detection limit of 1 ppm. As NO_x reduction was increased above 80%, ammonia slip also increased and remained at reasonable levels up to NO_x reductions of 90%. Over 90%, the ammonia slip levels increased dramatically.

The flow rate and temperature effects on 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% 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 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.

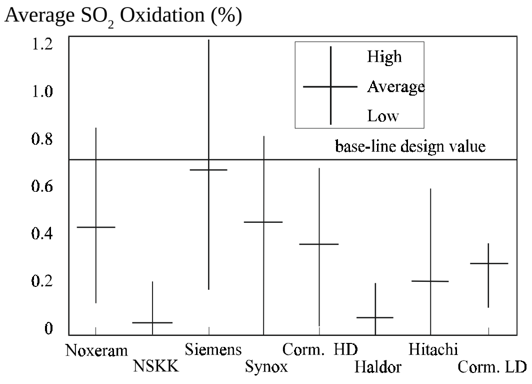
It has been observed that the catalytic active species that results in NO_x reduction often contributed to SO_2 oxidation (i.e., SO_3 formation), which can be detrimental to downstream equipment. In general, NO_x reduction can be increased as the tolerance for SO_3 is also increased. The upper bound for SO_2 oxidation for the demonstration catalyst was set at 0.75% at baseline conditions. The average SO_2 oxidation rate for each of the catalysts is shown in Exhibit 20. 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 SO_2 oxidations are listed below:

- **Flow Rate.** Most of the catalysts exhibited fairly constant SO_2 oxidation with respect to flow rate (i.e., space velocity). In theory, SO_2 oxidation should be inversely proportional to flow rate.
- **Temperature.** Theoretically the relationship between SO_2 oxidation and temperature should be exponential as temperature increases; however, measurements showed the relationship to be linear with little difference in SO_2 oxidation between 620 ºF and 700 ºF. However, between 700 °F and 750 °F, the 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 attributed to aggressive sootblowing.

Exhibit 20
Avg SO_2 Oxidation Rate
(Baseline)



NH_3/NO_x = 0.8, 700 ºF, design flow

- **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 21.

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 system with a NO_x removal efficiency of 60% follow:

	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

Results of the economic analysis of capital, O&M, and levelized cost for various NO_x removal efficiencies for a 250-MWe unit with 0.35 lb of inlet $NO_x/10^6$ Btu follow:

	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

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 $1,850–5,100/ton (current $).

Exhibit 21
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_x inlet concentration	0.35 lb/10^6 Btu
Design NO_x reduction	60%
Design ammonia slip	5 ppm
Catalyst life	16,000 hr
Ammonia cost	$250/ton
SCR cost	$400/ft^3

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_x 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.

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- *Demonstration of SCR Technology for the Control of NO_x Emissions from High-Sulfur Coal-Fired Utility Boilers: Final Report.* Vol. 1. Southern Company Services. October 1996. (Available from NTIS, Vol. 1 as DE97050873, Vol. 2: Appendixes A–N as DE97050874, and Vol. 3: Appendixes O–T as DE97050875.)
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180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers

Project completed.

Participant

Southern Company Services, Inc.

Additional Team Members

Gulf Power Company—cofunder and host
Electric Power Research Institute—cofunder
ABB Combustion Engineering, Inc.—cofunder and technology supplier

Location

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

Technology

ABB Combustion Engineering's Low-NO_x Concentric Firing System (LNCFS™) with advanced overfire air (AOFA), clustered coal nozzles, and offset air

Plant Capacity/Production

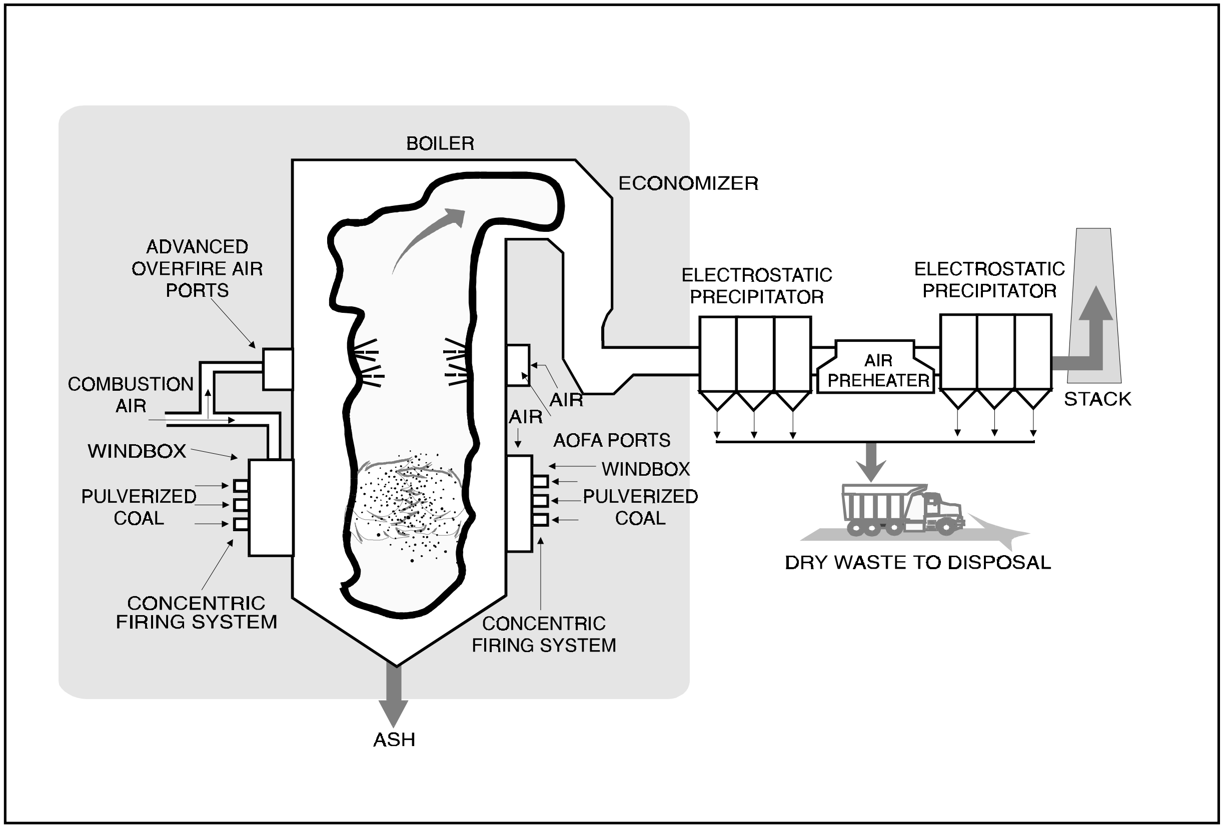
180 MWe

Coal

Eastern bituminous, high reactivity

Project Funding

Total project cost	$9,153,383	100%
DOE	4,440,184	49
Participant	4,713,199	51



Project Objective

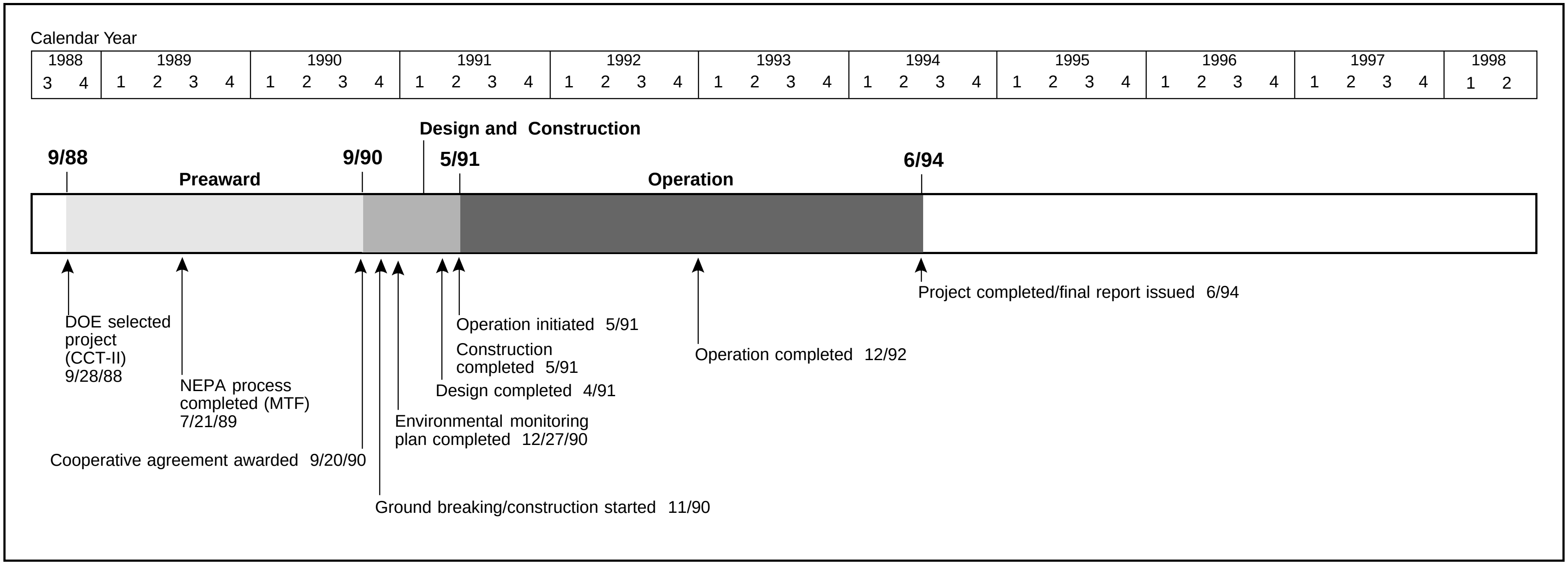
To demonstrate in a stepwise fashion the short- and long-term NO_x reduction capabilities of Low-NO_x Concentric Firing System levels I, II, and III on a single reference boiler.

Technology/Project Description

Technologies demonstrated included the Low-NO_x 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_x reductions. With the LNCFS™, primary air and coal are surrounded by oxygen-rich secondary air that blankets the outer regions of the combustion zone. LNCFS™ 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.

LNCFS is a trademark of ABB Combustion Engineering, Inc.



Results Summary

Environmental

- At full load, the NO_x emissions using LNCFS™ I, II, and III were 0.39, 0.39, and 0.34 lb/10^6 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_x removed; LNCFS™ II, \$444/ton; and LNCFS™ III, \$400/ton.

Project Summary

At the time of the demonstration, specific NO_x 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_x 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_x 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_x emissions and key operating parameters.

Exhibit 22
LNCFS™ Configurations

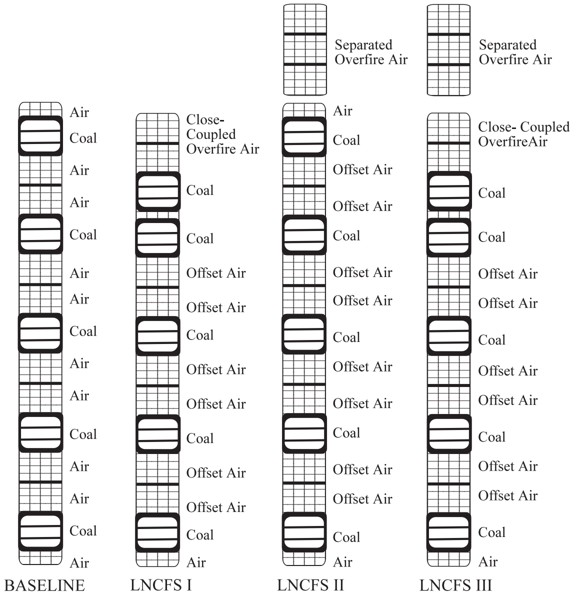
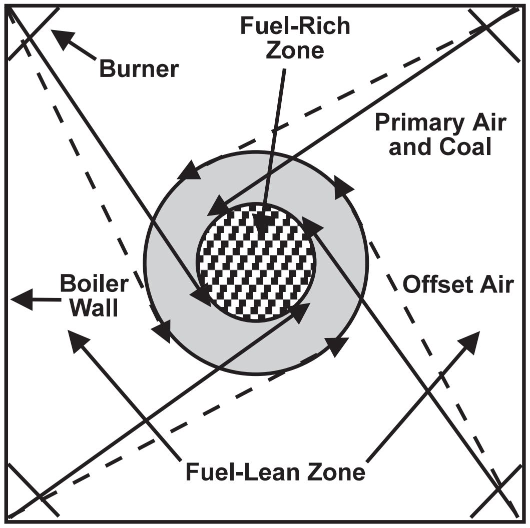


Exhibit 22 shows the various LNCFS™ configurations used to achieve staged combustion. In addition to overfire air, as shown in Exhibit 23, the LNCFS™ incorporates other NO_x-reducing techniques into the combustion process. Using offset air, two concentric circular combustion regions are formed. The majority of the coal is contained in the fuel-rich inner region. This region is surrounded by a fuel-lean zone containing combustion air. The size of this outer annulus of combustion air can be varied using adjustable offset air nozzles.

Operational Performance

Exhibit 24 summarizes the impacts of LNCFS™ on unit performance.

Exhibit 23
Concentric Firing Concept



Environmental Performance

At full load, LNCFS™ I, II, and III reduced NO_x emissions by 37%, 37%, and 45%, respectively.

Exhibit 25 presents the NO_x emission estimates obtained in the assessment of the average annual NO_x 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_x removal efficiency of the technologies. The cost effectiveness of the LNCFS™ technologies is listed below (based on a levilization factor of 0.144):

- LNCFS™ I—$103/ton of NO_x removed
- LNCFS™ II—$444/ton of NO_x removed
- LNCFS™ III—$400/ton of NO_x 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.

LNCFS™ has been retained at the host site for commercial use.

Exhibit 24
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_2 at full load (%)	3.7	3.2	4.5	4.3
LOI at full load (%) O_2 (%)	4.8 4.0	4.6 3.9	4.2 5.3	5.9 4.7
Steam outlet conditions	Satisfactory at full load; low temperpatures at low loads	Full load: 5–10 ºF lower than baseline Low loads: 10–30 ºF lower than baseline	Same as baseline	160–200 MWe: OK 80 MWe: 15–35 ºF 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 (%) Efficiency change	90 N/A	90.2 +0.2	89.7 -0.3	89.85 -0.15
Turbine heat rate (Btu/kWh)	9,000	9,011	9,000	9,000
Unit net heat rate (Btu/kWh) Change (%)	9,995 N/A	9,986 -0.1	10,031 +0.36	10,013 +0.18

Exhibit 25
Average Annual NO_x Emissions and % Reduction

Boiler Duty Cycle	**Units**	**Baseline**	**LNCFS™ I**	**LNCFS™ II**	**LNCFS™ III**
Baseload (161.8 MWe avg)	Avg NO_x emissions (lb/10^6 Btu) Avg reduction (%)	0.62	0.41 38.7	0.41 38.7	0.36 42.2
Intermediate load (146.6 MWe avg)	Avg NO_x emissions (lb/10^6 Btu) Avg reduction (%)	0.62	0.40 39.2	0.41 35.9	0.34 45.3
Peaking load (101.8 MWe avg)	Avg NO_x emissions (lb/10^6 Btu) Avg reduction (%)	0.59	0.45 36.1	0.47 20.3	0.43 28.0

Contacts

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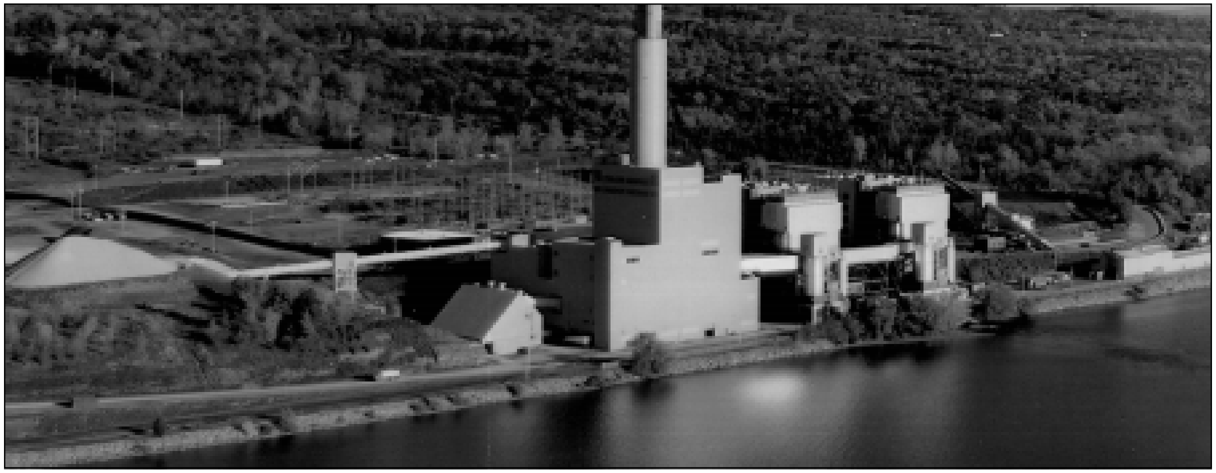
Combined SO_2/NO_x Control Technology

Combined SO_2/NO_x 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_x-NO_x-Rox Box™ incorporates an SCR catalyst in a high-temperature filter bag for NO_x control and applies sorbent injection for SO_2 control. The high-temperature filter bag, operated in a standard pulsed jet baghouse, protects the SCR catalyst, allows operation at optimal NO_x control temperatures, forms a sorbent cake on the surface to enhance SO_2 capture, and provides high-efficiency particulate capture.

SNOX™ uses SCR followed by catalytic oxidation of SO_2 to SO_3 with condensation of the SO_3 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 condensing unit. The system produces no solid waste.



▲ New York State Electric & Gas Corporation's Milliken Station is hosting the demonstration of a combination of unique SO_2 and NO_x control technologies.

NOXSO uses a single, regenerable adsorber (spherical alumina beads impregnated with sodium carbonate) to capture both SO_2 and NO_x. 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_x and SO_2 before return to the fluidized bed.

Five of the seven combined SO_2/NO_x control technology projects have been completed, one is in operation, and one is in the project definition and design phase. Exhibit 26 briefly summarizes the characteristics and performance of the technologies that are described in more detail in the project fact sheets.

Exhibit 26
CCT Program Combined SO_2/NO_x Control Technology Characteristics

Project	Process	Coal Sulfur Content	SO_2/NO_x Reduction	Fact Sheet
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%	62
Integrated Dry NO_x/SO_2 Emissions Control System	LNB/SNCR/sorbent injection—calcium- and sodium-based sorbents used in duct injection	0.4%	70%/62–80%	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%	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)	74
SO_x-NO_x-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%	66
SNOX™ Flue Gas Cleaning Demonstration Project	SCR/oxidation catalyst/sulfuric acid condenser—synergistic catalyst effect and no solid waste	3.4%	95%/94%	58
Commercial Demonstration of the NOXSO SO_2/NO_x 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)	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

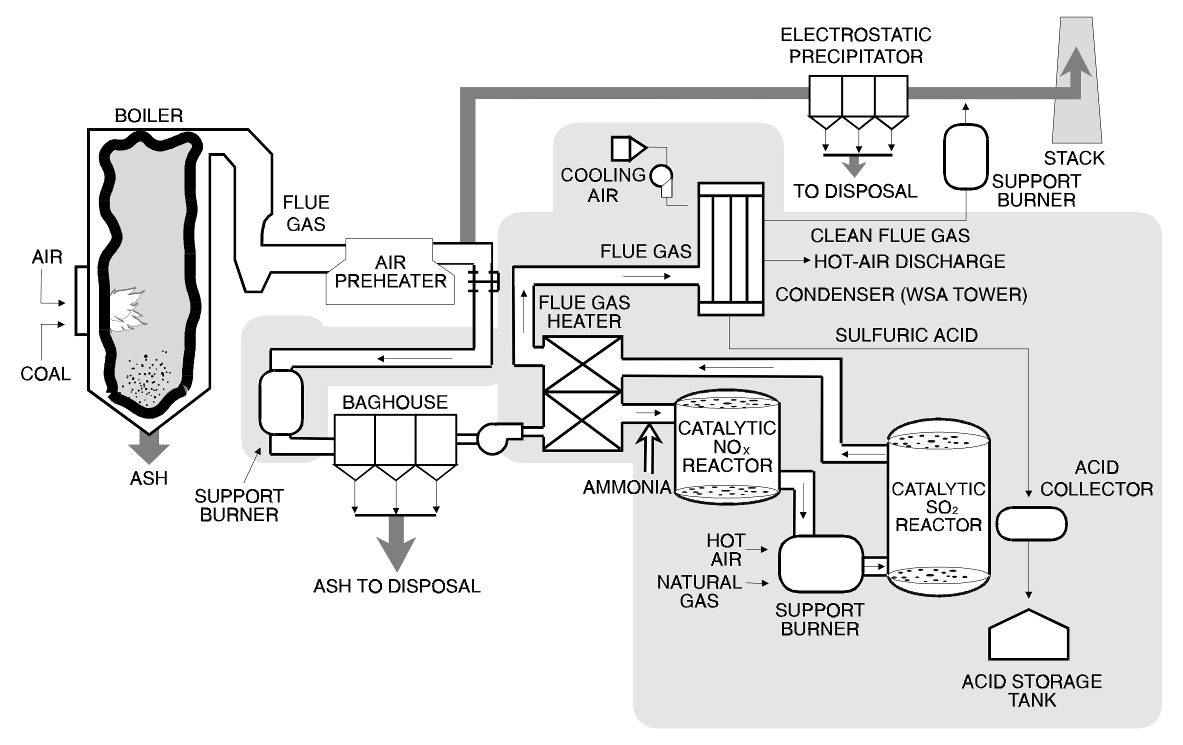
Ohio bituminous, 3.4% sulfur

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_2 and more than 90% of NO_x from flue gas and produce a salable by-product of concentrated sulfuric acid.



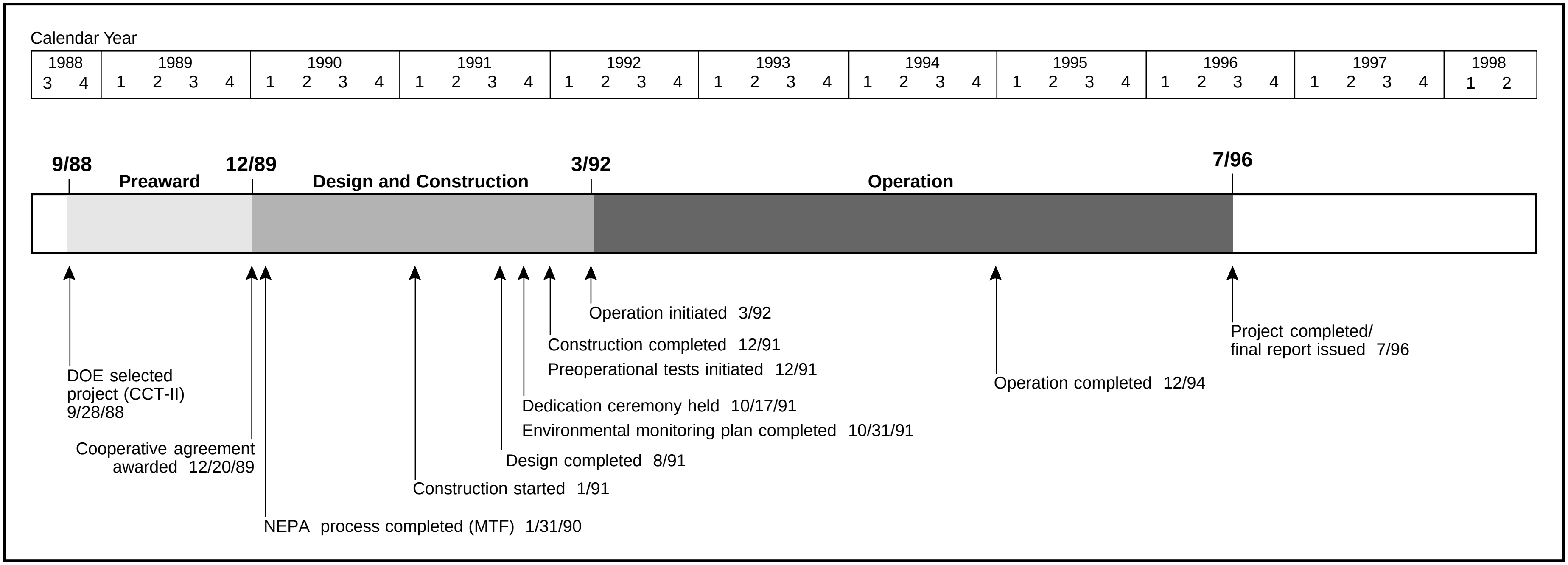
Technology/Project Description

In the SNOX™ process, the stack gas leaving the boiler is cleaned of fly ash in a high-efficiency fabric filter baghouse to minimize the cleaning frequency of the sulfuric acid catalyst in the downstream SO_2 converter. The ash-free gas is reheated, and NO_x is reacted with small quantities of ammonia in the first of two catalytic reactors where the NO_x is converted to harmless nitrogen and water vapor. The SO_2 is oxidized to SO_3 in a second catalytic converter. The gas then passes through a novel glass-tube condenser that allows SO_3 to hydrolyze to concentrated sulfuric acid.

The technology, while using U.S. coals, was designed to remove 95% of the SO_2 and more than 90% of the NO_x from flue gas and produce a salable sulfuric acid by-product. This 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.

SNOX is a trademark of Haldor Topsoe a/s.



Results Summary

Environmental

- SO_2 removal efficiency was normally in excess of 95% for inlet concentrations averaging about 2,000 ppm.
- NO_x 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_2 emissions.
- SO_2 catalyst virtually eliminated CO and hydrocarbon emissions.

Operational

- SO_2 catalyst downstream of the NO_x 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_2 removal on a constant dollar basis. Comparable current dollar costs were 7.8 mills/kWh and $284/ton of SO_2.

Project Summary

Because the SNOX™ process utilized an oxidation catalyst to convert SO_2 to SO_3 and ultimately to sulfuric acid, no reagent was required for the SO_2 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^3) due to the characteristics of the SO_2 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_2 catalyst. At operating temperature, the SO_2 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_2 emissions by the process was tied to two features—the lack of a carbonate-based alkali reagent that releases CO_2 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_2 generation per unit of power.

With respect to CO and hydrocarbons, the SO_2 catalyst acted to virtually eliminate these compounds as well. This aspect also positively affected the interaction of the NO_x and SO_2 catalysts. Because the SO_2 catalyst followed the NO_x catalyst, any unreacted ammonia (slip) was oxidized in the SO_2 catalyst to nitrogen, water vapor, and a small amount of NO_x. 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_2-to-SO_3 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_2 oxidation, reaction. During the test program, SO_2 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_2 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_x 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_2 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_x and SO_2 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_2 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 ºF, compared to approximately 300 ºF 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_2 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_x and SO_2 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_2/NO_x 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.

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◄ The SNOX™ demonstration at Ohio Edison's Niles Station Unit No. 2 achieved SO_2 removal efficiencies exceeding 95% and NO_x 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_x burners
Consolidation Coal Company's Coolside duct injection of lime sorbents

Plant Capacity/Production

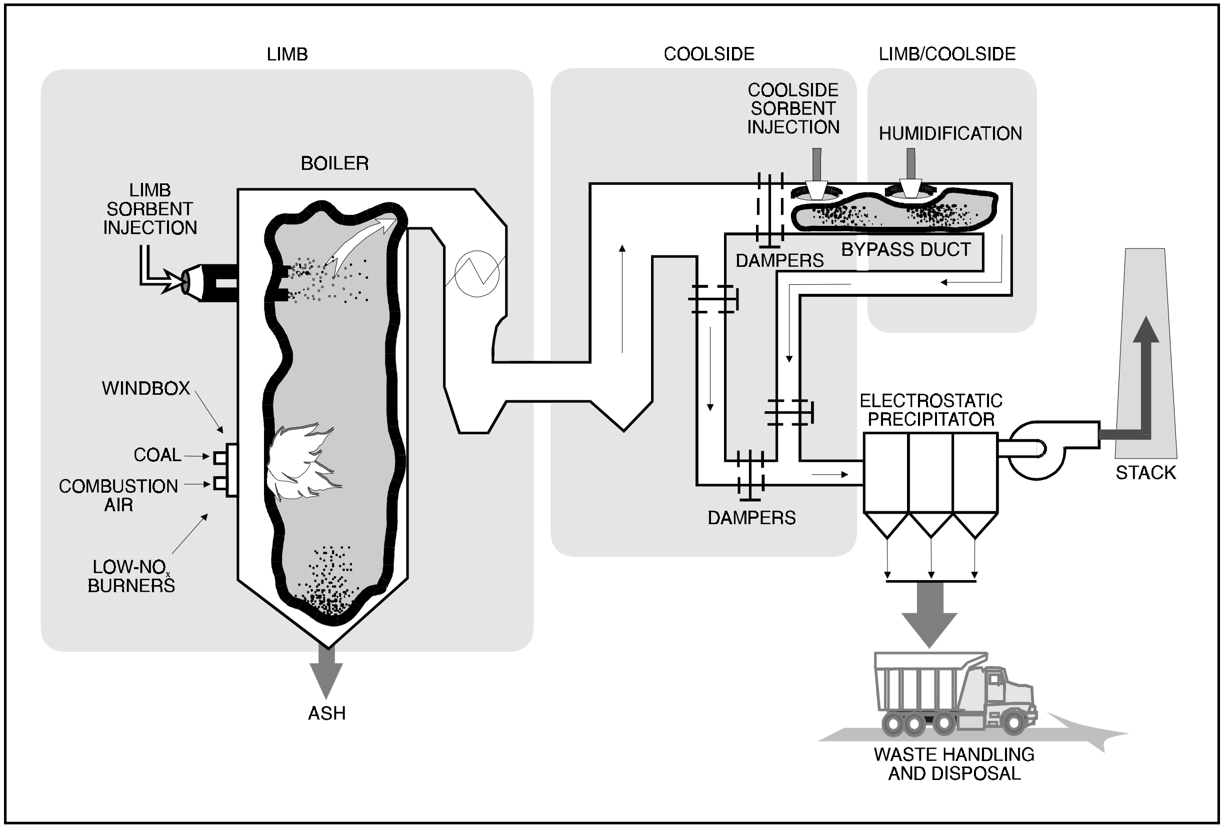
105 MWe

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



Project Objective

To demonstrate, with a variety of coals and sorbents, the LIMB process as a retrofit system for simultaneous control of NO_x and SO_2 in the combustion process, and that LIMB can achieve up to 70% NO_x and SO_2 reductions; to test alternate sorbent and coal combinations using the Coolside process; to demonstrate in-duct sorbent injection upstream of the humidifier and precipitator; and to show SO_2 removal of up to 70%.

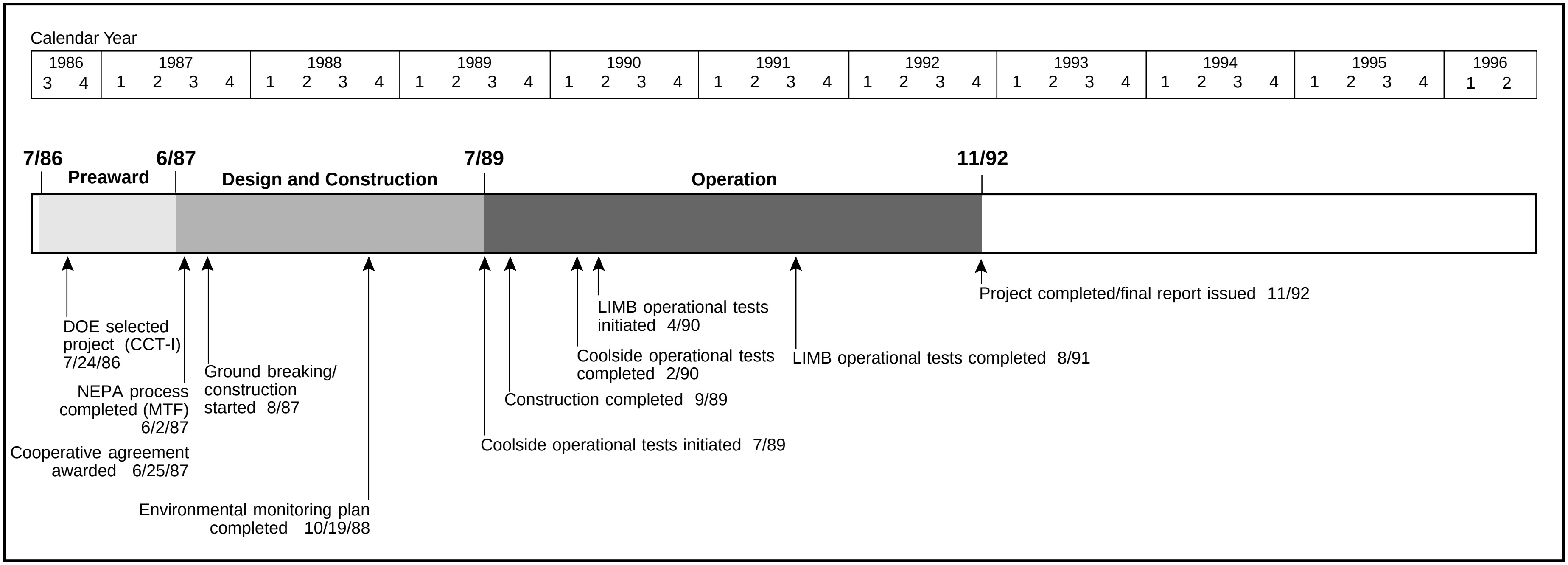
Technology/Project Description

The LIMB process reduces SO_2 by injecting dry sorbent into the boiler at a point above the burners. The sorbent then travels through the boiler and is removed along with fly ash in an electrostatic precipitator (ESP) or baghouse. Humidification of the flue gas before it enters an ESP is necessary to maintain normal ESP operation and to enhance SO_2 removal. Combinations of three bituminous coals (1.6%, 3.0%, and 3.8% sulfur) and four sorbents were tested. Other variables examined were stoichiometry, humidifier outlet temperature, and injection level.

In the Coolside process, dry sorbent is injected into the flue gas downstream of the air preheater, followed by flue gas humidification. Humidification enhances ESP performance and SO_2 absorption. SO_2 absorption is improved by dissolving NaOH or Na_2CO_3 in the humidification water. The spent sorbent is collected with the fly ash, as in the LIMB process. Bituminous coal with 3.0% sulfur was used in testing.

Babcock & Wilcox DRB-XCL® low-NO_x burners, which control NO_x through staged combustion, were used in demonstrating both LIMB and Coolside technologies.

DRB-XCL is a registered trademark of The Babcock & Wilcox Company.
TAG is a trademark of the Electric Power Research Institute.



Results Summary

Environmental

- LIMB SO_2 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_2 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_2 removal efficiencies were enhanced by about 10% when humidification down to 20 ºF approach-to-saturation temperature was used.
- LIMB, which incorporated Babcock & Wilcox DRB-XCL® low-NO_x burners, achieved 40–50% NO_x reduction.
- Coolside SO_2 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 ºF 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_2 reduction of 60%. Annual levelized costs (15-year) for this range of conditions were $392–791/ton of SO_2 removed (1992$).
- Coolside capital costs were $69–160/kW for plants 100–500 MWe and coals with 1.5–3.5% sulfur, with a target SO_2 reduction of 70%. Annualized levelized costs (15-year) for this range of conditions were $482–943/ton of SO_2 removed (1992$).

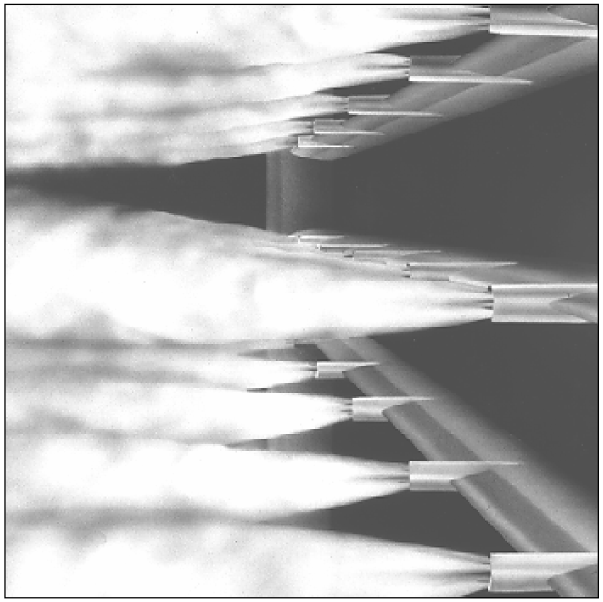
Project Summary

The initial expectation with LIMB technology was that limestone calcined by injection into the furnace would achieve adequate SO_2 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 sodium hydroxide (NaOH) or sodium carbonate (Na_2CO_3) 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 27 summarizes SO_2 removal efficiencies for the range of sorbents and coals tested.



▲ Water mist, sprayed into the flue gas, enhanced sulfur capture by the sorbent by approximately 10% in the LIMB process when 20 ºF approach-to-saturation was used.

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 ºF. Testing confirmed that injection at this level, just above the nose of the boiler, yielded the highest SO_2 removal. Injection was also performed at the 187-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 ºF approach-to-saturation temperature was used.

The continued use of the low-NO_x burners resulted in an overall average NO_x emissions level of 0.43 lb/10^6 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%.

Exhibit 27

LIMB SO_2 Removal Efficiencies

(Percent)

	Nominal Coal Sulfur Content		
Sorbent	**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.

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.

The test program demonstrated that the Coolside process routinely achieved 70% SO_2 removal at design conditions of 2.0 Ca/S, 0.2 Na/Ca, and 20 ºF approach-to-adiabatic-saturation temperature using commercially available hydrated lime. Coolside SO_2 removal depended on Ca/S, Na/Ca, approach-to-adiabatic-saturation, and the physical properties of the hydrated lime. Sorbent recycle showed significant potential to improve sorbent utilization. The observed SO_2 removal with recycled sorbent

Exhibit 28
Capital Cost Comparison
($/kW)

Coal (%S)	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO
	100 MWe			**150 MWe**		
1.5	93	150	413	66	116	312
2.5	95	154	421	71	122	316
3.5	102	160	425	73	127	324
	250 MWe			**500 MWe**		
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 29
Annual Levelized Cost Comparison
($/Ton of SO$_2$ Removed)

Coal (%S)	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO
	100 MWe			**150 MWe**		
1.5	791	943	1418	653	797	1098
2.5	595	706	895	520	624	692
3.5	525	629	665	461	570	527
	250 MWe			**500 MWe**		
1.5	549	704	831	480	589	623
2.5	456	567	539	416	502	411
3.5	419	526	413	392	482	321

alone was 22% at 0.5 available Ca/S and 18 °F approach-to-adiabatic-saturation. The observed SO$_2$ removal with simultaneous recycle and fresh sorbent feed was 40% 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 performance were SO$_2$ removal efficiencies of 60%, 70%, and 95% for LIMB, Coolside, and LSFO, respectively. EPRI TAG™ methodology was used. Exhibits 28 and 29 summarize results.

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.

LIMB has been sold to an independent power plant in Canada. Babcock & Wilcox has signed 85 contracts (61 domestic, 24 foreign) for DLB-XCL® low-NO$_x$ burners, representing 1,515 burners for 20,396 MWe of capacity.

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SO_x-NO_x-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_x-NO_x-Rox Box™ (SNRB™) process

Plant Capacity/Production

5-MWe equivalent slipstream from a 156-MWe boiler

Coal

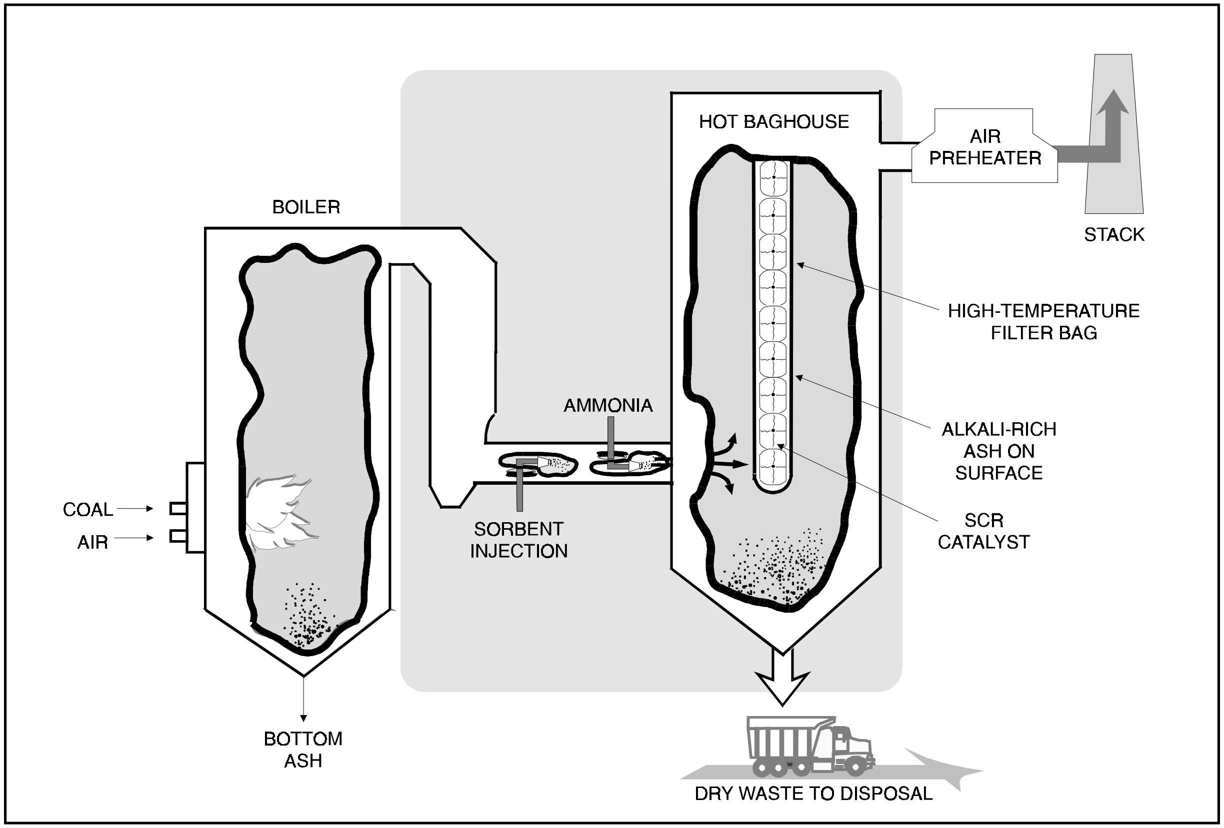
Bituminous coal blend, 3.7% sulfur avg

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_2 removal and 90% or higher reduction in NO_x emissions while maintaining particulate emissions below 0.03 lb/10^6 Btu.



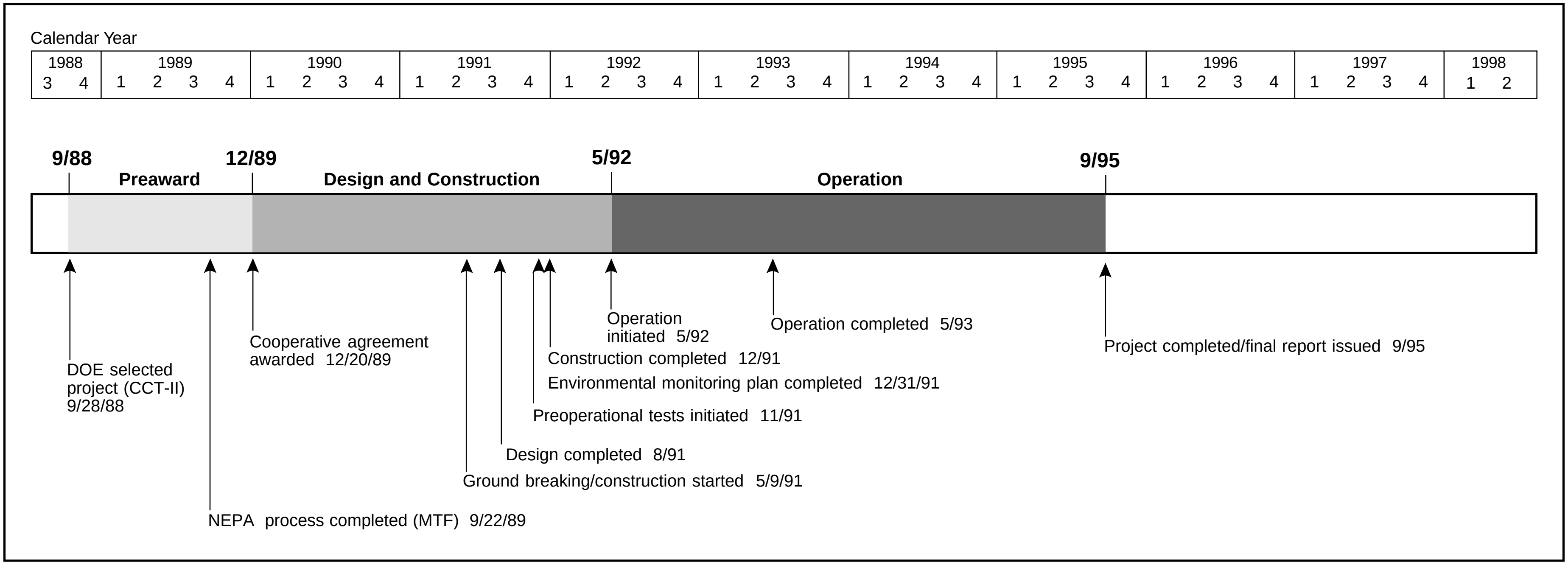
Technology/Project Description

The SNRB™ process combines the removal of SO_2, NO_x, and particulates in one unit—a high-temperature baghouse. SO_2 removal is accomplished using either calcium- or sodium-based sorbent injected into the flue gas. NO_x removal is accomplished by injecting ammonia (NH_3) to selectively reduce NO_x in the presence of a selective catalytic reduction, or SCR, catalyst. Particulate removal is accomplished by high-temperature fiber bag filters.

The 5-MWe SNRB™ demonstration unit is large enough to demonstrate commercial-scale components while minimizing the demonstration cost. Operation at this scale also permitted cost-effective control of the flue gas temperature, which allowed for evaluation of performance over a wide range of sorbent injection and baghouse operating temperatures. Thus several different arrangements for potential commercial installations could be simulated.

The 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_2 removal, more than 90% NO_x 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.

SO_x-NO_x-Rox Box and SNRB are trademarks of The Babcock & Wilcox Company.



Results Summary

Environmental

- SO_2 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 ºF.
- SO_2 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 ºF.
- SO_2 removal efficiency of 80% was achieved with sodium bicarbonate at a sodium-to-sulfur (Na_2/S) molar ratio of 1.0 and temperature of 425 ºF.
- SO_2 emissions were reduced to less than 1.2 lb/10^6 Btu with 3–4% sulfur coal with a Ca/S molar ratio as low as 1.5 and NA_2/S ratio of 1.0.
- Injection of calcium-based sorbents directly upstream of the baghouse at 825–900 ºF resulted in higher overall SO_2 removal than injection further upstream at temperatures up to 1,200 ºF.
- NO_x reduction of 90% was achieved with an NH_3/NO_x ratio of 0.9 and temperature of 800–850 ºF.
- 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_2 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_x generation of 1.2 lb/10^6 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_2/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_2 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_2 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 ºF, injection of commercial-grade hydrated lime at Ca/S molar ratio of 1.8 and above resulted in SO_2 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_2 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 ºF resulted in higher overall SO_2 removal than injection further upstream at temperatures up to 1,200 ºF.

SO_2 removal using sodium bicarbonate was 80% at an Na_2/S ratio of 1.0 and 98% at an Na_2/S ratio of 2.0 at a significantly reduced baghouse temperature of 450–460 ºF. SO_2 emissions while burning a 3–4% sulfur coal were reduced to less than 1.2 lb/10^6 Btu with a Ca/S molar ratio as low as 1.5 and Na_2/S ratio less than 1.0.

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

▲ 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_x emissions reduction of 90% was readily achieved with ammonia slip limited to less than 5 ppm. This performance reduced NO_x emissions to less than 0.10 lb/10^6 Btu. NO_x reduction was insensitive to temperatures over the catalyst design temperature range of 700–900 ºF. Catalyst space velocity (volumetric gas flow/catalyst volume) had a minimal effect on NO_x removal over the range evaluated.

Turndown capability for tailoring the degree of NO_x reduction by varying the rate of ammonia injection was demonstrated for a range of 50–95% NO_x reduction. No appreciable physical degradation or change in the catalyst activity was observed over the duration of the test program. The degree of oxidation of SO_2 to SO_3 over the zeolite catalyst appeared to be less than 0.5%. (SO_2 oxidation is a concern for SCR catalysts containing vanadium.) Leach potential analysis of the catalyst after completion of the field test showed that the catalyst remained nonhazardous for disposal.

Particulate emissions were consistently below NSPS standards of 0.03 lb/10^6 Btu, with an average over 30 baghouse particulate emission measurements of 0.018 lb/10^6 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/10^6 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^2 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_x emissions of 1.2 lb/10^6 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_2 sorbent for a system designed for 85–90% SO_2 removal. Fixed operating costs primarily consist of system operating labor and projected labor and material for the hot baghouse and ash-handling systems.

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_2, NO_x, or combined emissions to meet current performance requirements while providing flexibility to address future needs.

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▲ 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

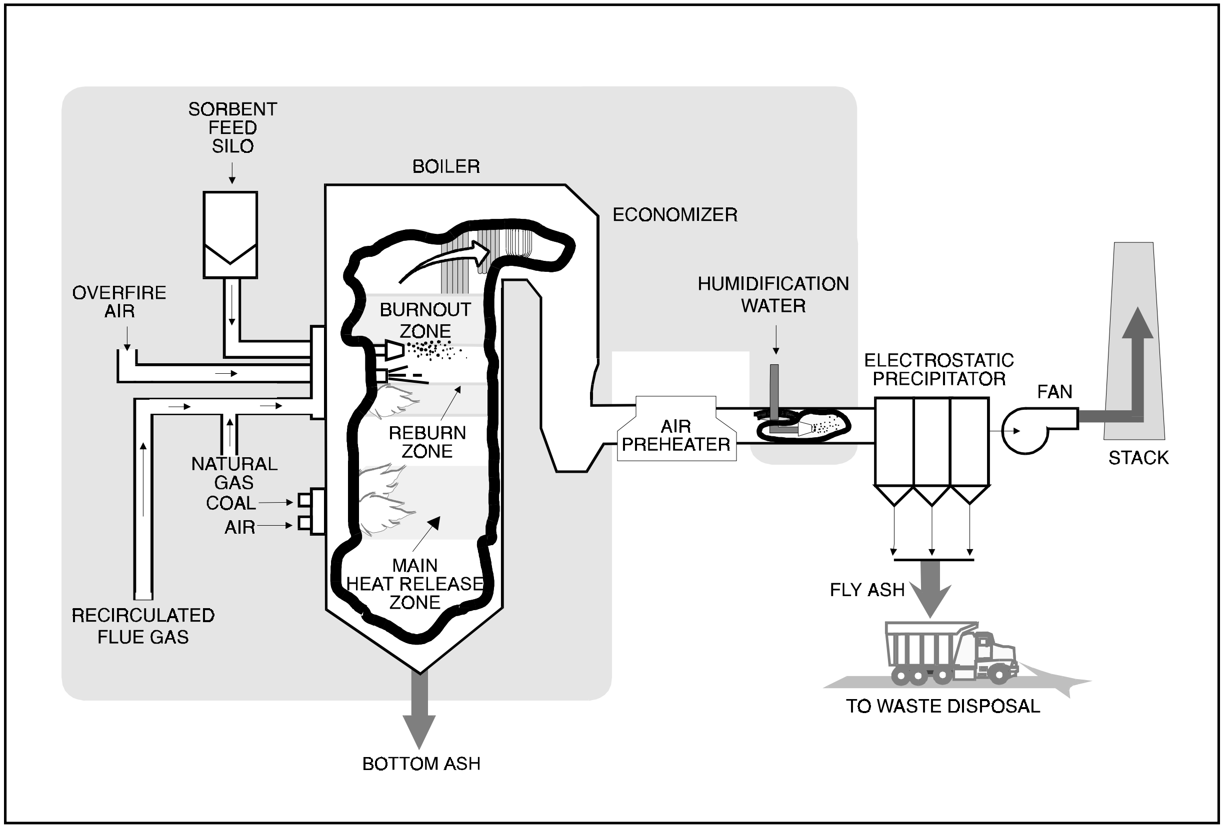
Illinois bituminous, 3.0% sulfur

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_x reduction along with sorbent injection to capture at least 50% of the SO_2 on two different boiler configurations—tangentially fired and cyclone-fired—while burning high-sulfur midwestern coal.

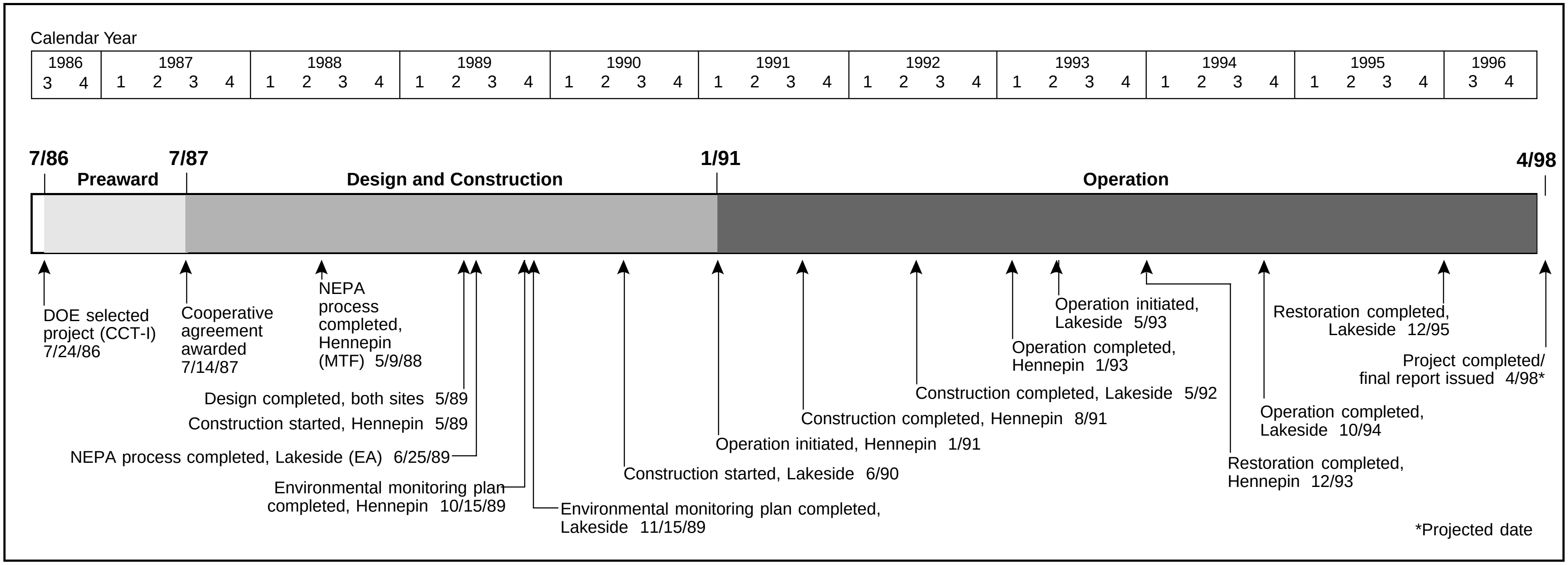


Technology/Project Description

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_x 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 $Ca(OH)_2$ (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_x and SO_2 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_x 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_2 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_x 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_2 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_2 capture efficiencies than the baseline Linwood hydrated lime. PromiSORB™ A achieved 53% SO_2 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_2 reduction and 38% utilization, and High-Surface-Area Hydrated Lime achieved 60% SO_2 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_2 emission allowances (because GR replaces some coal with gas, it also reduces SO_2 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_2 removed.

Project Summary

The GR–SI project demonstrated the success of gas reburning and sorbent injection technologies in reducing NO_x and 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 NO_x reduction was approximately 67%. The average 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 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 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 lb/10^6 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 lb/10^6 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 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.

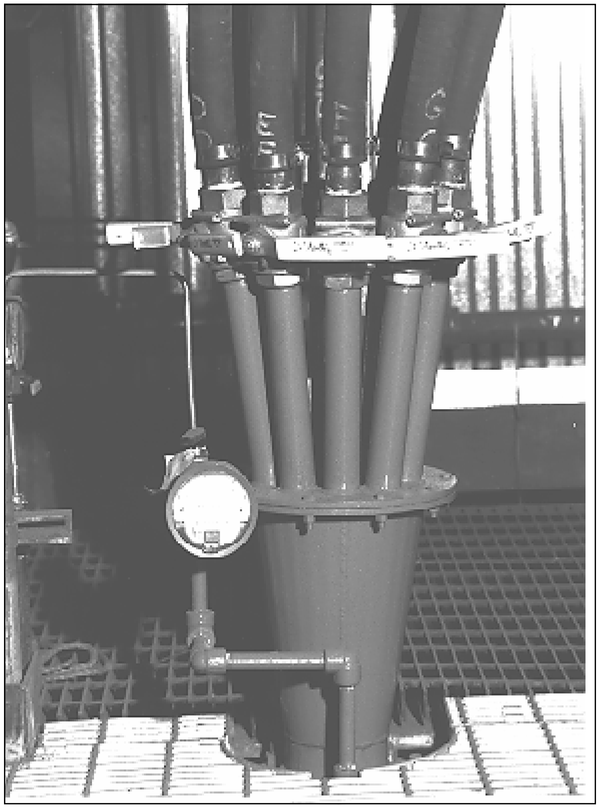
The SO_2 capture without GR, at a nominal 1.75 Ca/S molar ratio, was 53% for PromiSORB™ A, 66% for PromiSORB™ B, 60% for High-Surface-Area Hydrated Lime, and 42% for Linwood lime. At a 2.6 Ca/S molar ratio, the PromiSORB™ B yielded 81% SO_2 removal efficiency.

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 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 NO_x reduction performance.

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

In the GR–SI optimization tests, the two technologies were integrated. Modifications were made to the reburning fuel injection nozzles based on the results of the initial GR parametric tests and flow modeling studies. The total cross-sectional area of the reburning jets was decreased by 32% to increase the reburning jet's penetration characteristics. The decrease in nozzle diameter increased NO_x reduction by an additional 3–5% compared to the initial parametric tests. With GR–SI, total SO_2 reductions resulted from partial replacement of coal with natural gas and sorbent injection. At a gas heat input of 22% and Ca/S molar ratio of 1.8, average NO_x reduction during the long-term testing of GR–SI was 66% and the average SO_2 reduction was 58%.

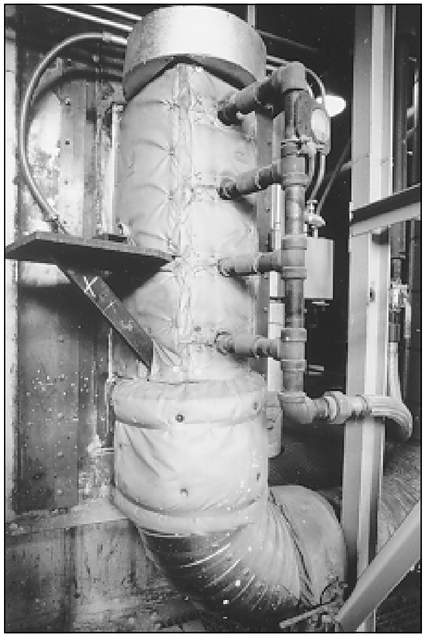


▲ The flexible lime-sorbent distribution lines lead from the sorbent splitter to the top of the cyclone-fired boiler at Lakeside Station.

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.



▲ The natural gas injector was installed on the corner of Hennepin Station's tangentially fired boiler.

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_2 removal requirements, and value of SO_2 allowances. It was estimated that for most installation, a 15% gas heat input will achieve 60% NO_x 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_2 emission allowances.

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_2 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_x and SO_2 removal exceeding 60% and 50%, respectively, these technologies have the potential to extend the life of a boiler or power plant and also provide a way to use higher sulfur coals.

Illinois Power has retained the gas-reburning system and City Water, Light & Power has retained the full technology for commercial use.

The project was one of two receiving the Air and Waste Management Association's 1997 J. Deanne Sensenbaugh Award.

Contacts

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Milliken Clean Coal Technology Demonstration Project

Participant

New York State Electric & Gas Corporation

Additional Team Members

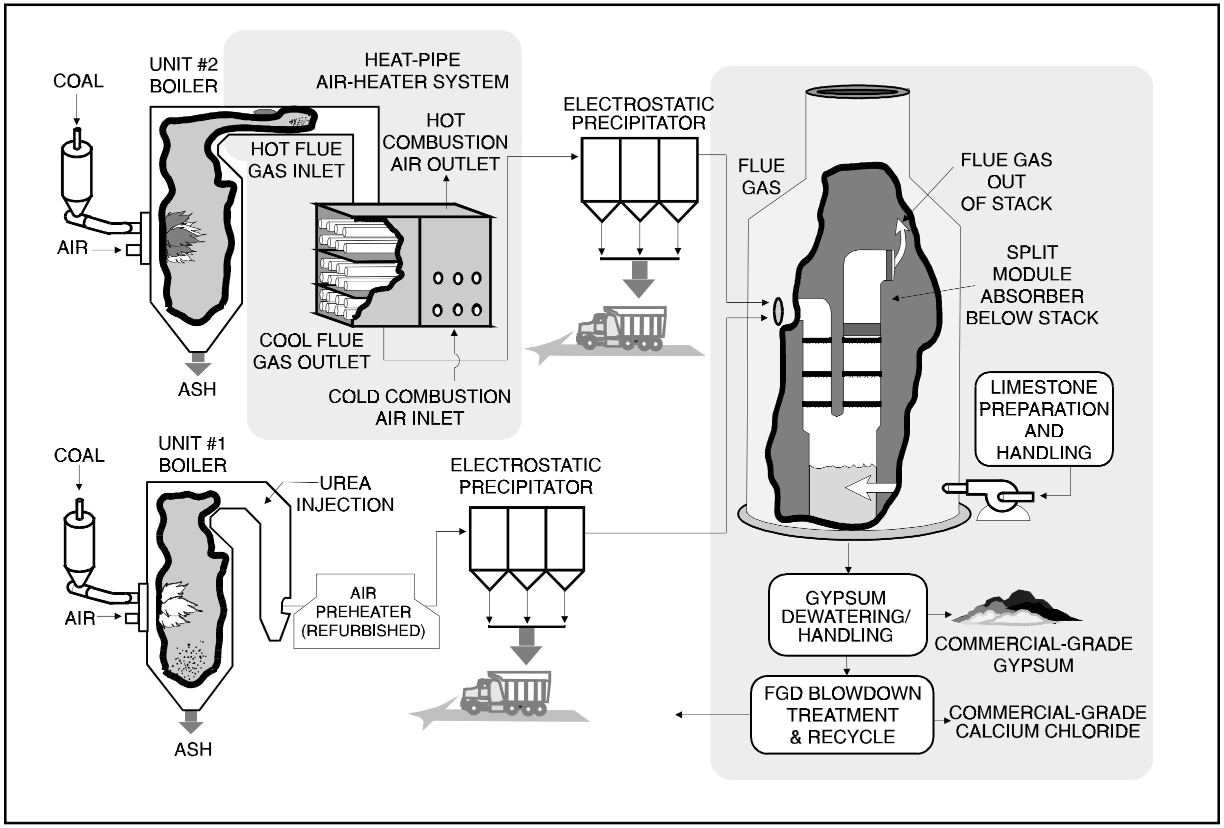
New York State Energy Research and Development Authority—cofunder
Empire State Electric Energy Research Corporation—cofunder
Consolidation Coal Company—technical consultant
Saarberg-Hölter-Umwelttechnik, GmbH—technology supplier
The Stebbins Engineering and Manufacturing Company—technology supplier
Nalco 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_x 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

Project Funding

Total project cost	$158,607,807	100%
DOE	45,000,000	28
Participant	113,607,807	72

Project Objective

To demonstrate at a 300-MWe utility-scale a combination of cost-effective and innovative emission reduction and efficiency improvement technologies, including the S-H-U wet scrubber system enhanced with formic acid to increase SO_2 removal in a Stebbins tile-lined scrubber, low-NO_x burner, urea injection for NO_x removal, and a heat-pipe air preheater.

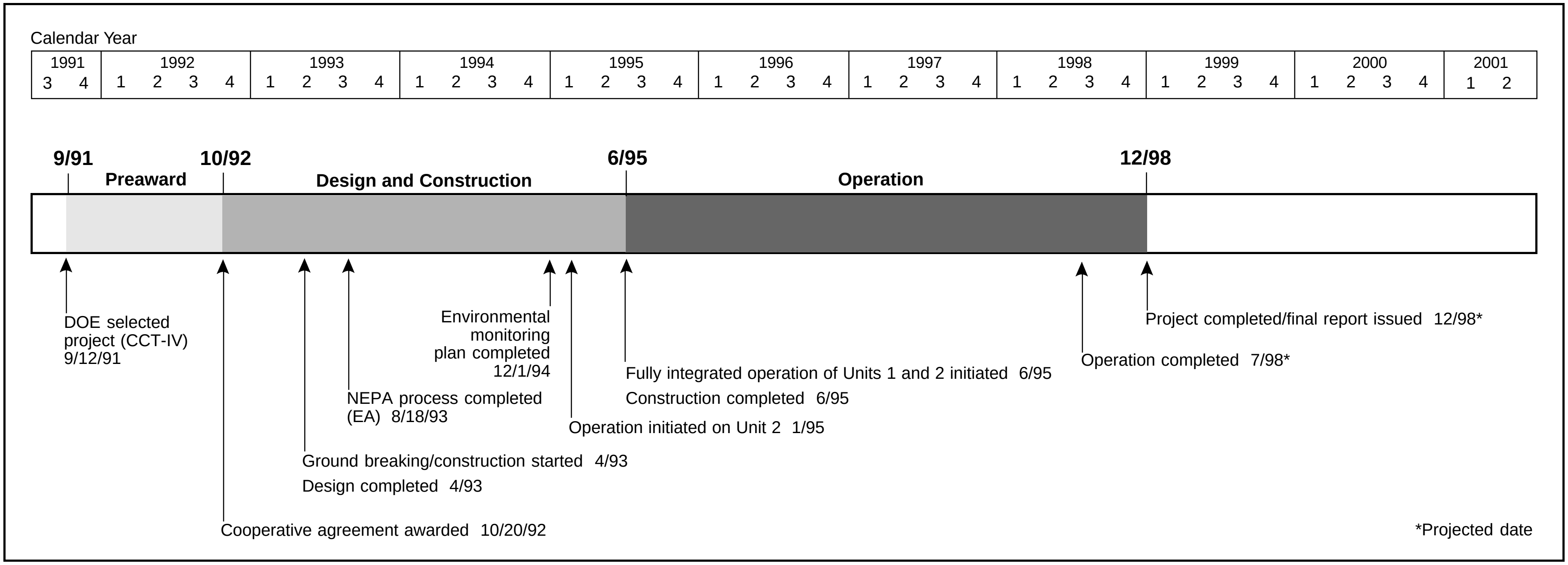
Technology/Project Description

The S-H-U wet flue gas desulfurization process is a formic-acid-enhanced, wet limestone process, which results in very high SO_2 removal with low energy consumption and the production of commercial-grade gypsum.

The flue gas desulfurization absorber is a Stebbins tile-lined split-module vessel, which has superior corrosion and abrasion resistance, leading to decreased life-cycle costs and reduced maintenance. The split-module design is constructed below the stack to save space and provide operational flexibility.

The Nalco Fuel Tech NOxOUT® system is used to remove NO_x 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_x burner system), reduces NO_x emissions and produces marketable fly ash.

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.



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, Plant Emission Optimization Advisor (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_2 removal efficiency (or up to 98%) using limestone while burning high-sulfur coal. NO_x reductions have been achieved using selective noncatalytic reduction technology and separate combustion modifications. NO_x emissions have been reduced from 0.65 to 0.40 lb/10^6 Btu (38%) by retrofitting the two boilers with low-NO_x burners. NOxOUT® is expected to reduce NO_x emissions from Unit 1 by an additional 15–20%. The system has zero wastewater discharge and produces marketable byproducts (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 in final review.

Design coal FGD testing began in May 1996. Testing was delayed due to the sulfur content of coal received being below design specifications for the scrubber. Testing resumed in November 1997 and will continue until summer of 1998.

Mist eliminator testing is complete; a report is expected to be issued in first quarter 1998.

Commercial Applications

The S-H-U SO_2 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 byproducts, offer significant incentives to generating stations with limited space.

Four sales of NOxOUT®, worth more than $3 million, have been made. PEOA™ has been sold to one utility; several bids are pending. S-H-U has formed a U.S. company, SHN, to market the scrubber; several bids are pending.

Commercial Demonstration of the NOXSO SO_2/NO_x 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

Location

Site under negotiation

Technology

NOXSO Corporation's dry, regenerable flue gas cleanup process

Plant Capacity/Production

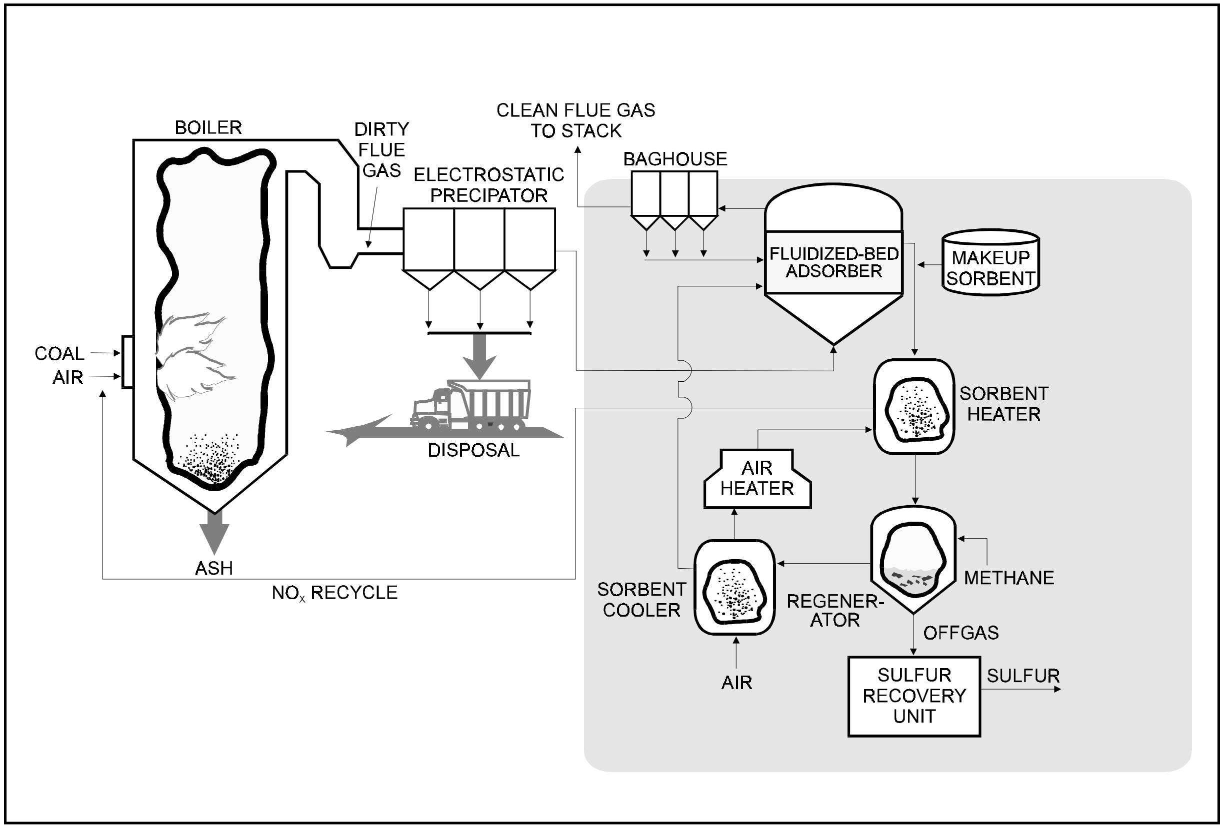
30 MWe

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_2 and 75% of the NO_x from a coal-fired boiler's flue gas using the NOXSO process.



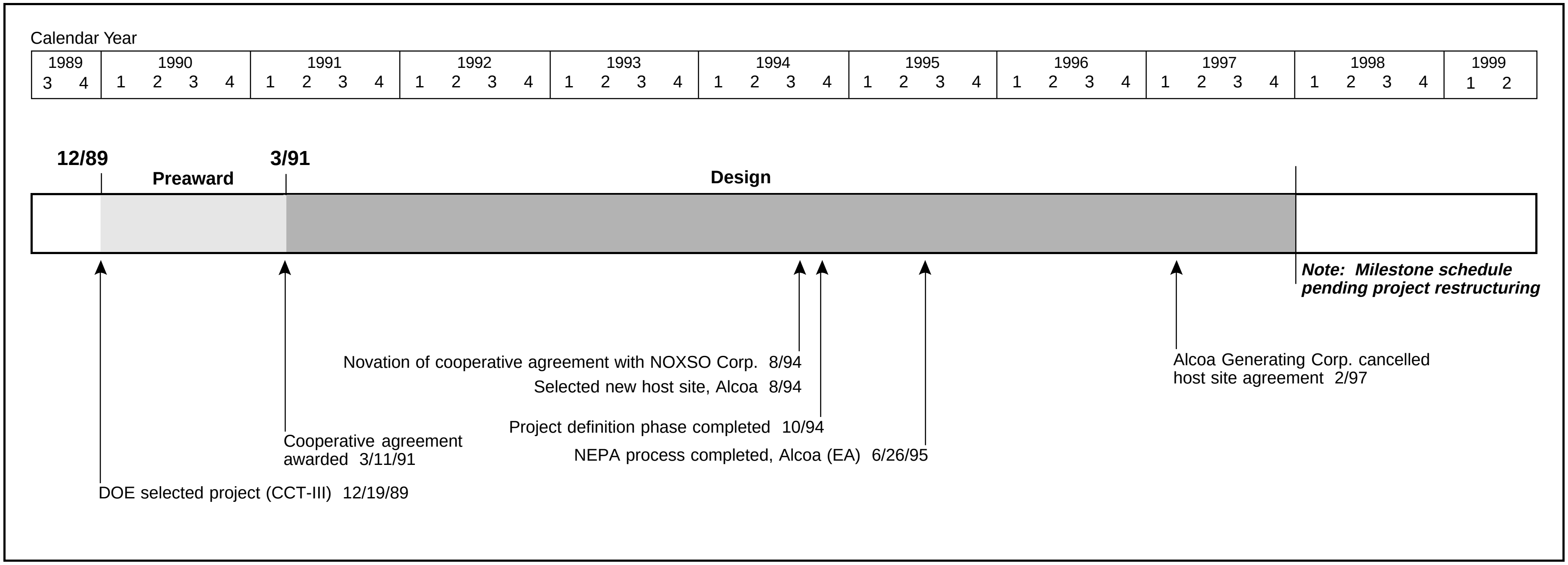
Technology/Project Description

The NOXSO process is a dry, regenerable system capable of removing both SO_2 and NO_x in flue gas from coal-fired utility boilers burning medium- to high-sulfur coals. In the basic process, the flue gas passes through a fluidized-bed adsorber located downstream of the precipitator; SO_2 and NO_x 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_x is desorbed from the NOXSO sorbent when heated by a stream of hot air. Hot air containing the desorbed NO_x is recycled to the boiler where equilibrium processes cause destruction of the NO_x. The adsorbed sulfur is recovered from the sorbent in a regenerator where it reacts with methane at high temperature to produce an offgas with high concentrations of SO_2 and hydrogen sulfide (H_2S). This offgas is processed to produce elemental sulfur, which can be further processed to produce liquid SO_2, a higher valued by-product.

The process is expected to achieve SO_2 reductions of 98% and NO_x reductions of 75%.

A full-scale design based on data from the proof-of-concept facility at Ohio Edison's Toronto power plant is in preparation.



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. 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_2. A readily available market exists for these products.

The technology is expected to be especially attractive to utilities that require high removal efficiencies for both SO_2 and NO_x, need to eliminate solid wastes, and/or have inadequate water supply for a wet scrubber.

Integrated Dry NO_x/SO_2 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® low-NO_x burners, in-duct sorbent injection, and furnace (urea) injection

Plant Capacity/Production

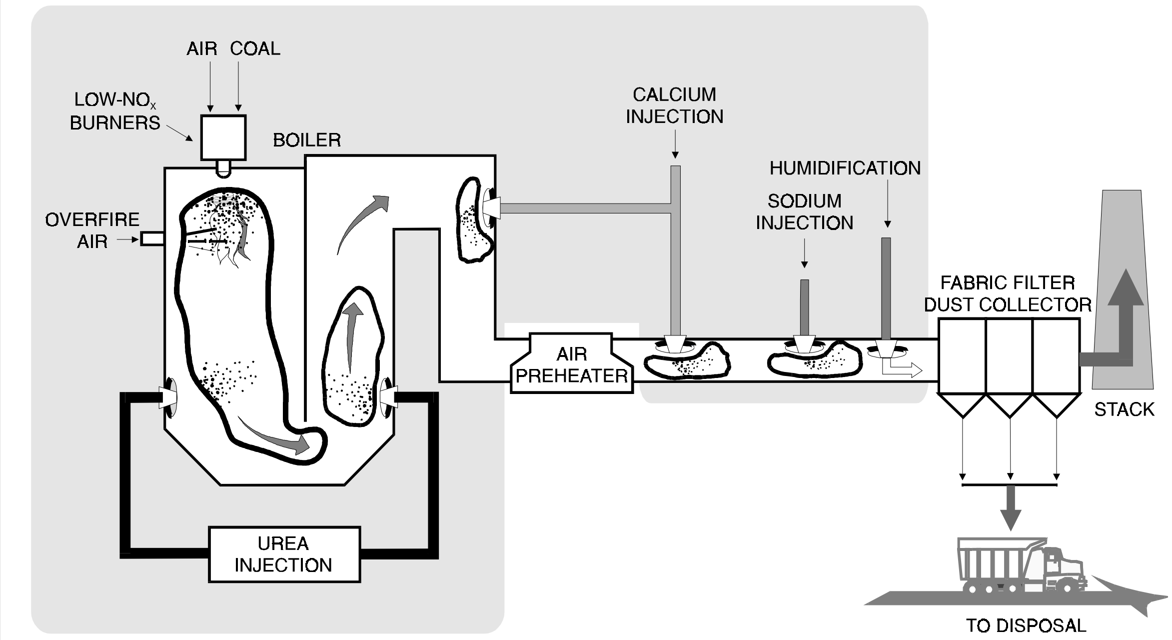
100 MWe

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



Project Objective

To demonstrate the integration of five technologies to achieve up to 70% reduction in NO_x and SO_2 emissions; more specifically, to assess the integration of a down-fired low-NO_x burner with in-furnace urea injection for additional NO_x removal and dry sorbent in-duct injection with humidification for SO_2 removal.

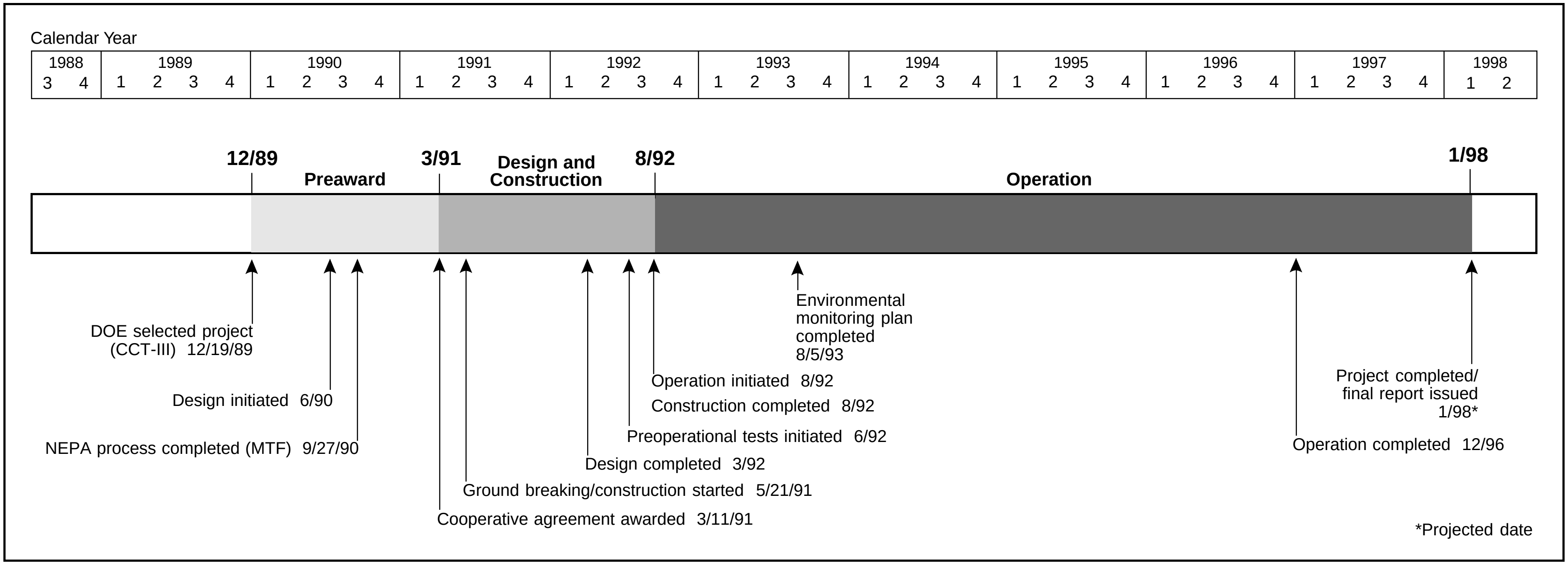
Technology/Project Description

All of the testing used Babcock & Wilcox's low-NO_x DRB-XCL® down-fired burners with overfire air. These burners control NO_x 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_x removal. A urea-based selective noncatalytic reduction (SNCR) system was tested to determine how much additional NO_x can be removed from the combustion gas.

Two types of dry sorbents were injected into the ductwork downstream of the boiler to reduce SO_2 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_2 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.

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



Results Summary

Environmental

- With maximum overfire air (24% of total combustion air), a NO_x reduction of 62–69% was achieved across the 50–110-MWe load range.
- DRB-XCL® burners with minimum overfire air reduced NO_x emissions by more than 63% under steady state conditions.
- NO_x 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_x removal of 30–50% at an ammonia (NH_3) slip of 10 ppm, thus increasing performance of the total NO_x control system to greater than 80% NO_x reduction.
- SO_2 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_2 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_2 removal of approximately 70% at a normalized stoichiometric ratio (NSR) of 1.0.
- Sodium sesquicarbonate injection ahead of the fabric filter achieved 70% SO_2 removal at an NSR of 2.0.
- NO_2 emissions were generally higher when using sodium biocarbonate than when using sodium sesquicarbonate.
- Integrated SNCR and sodium dry sorbent injection tests showed reduced NH_3 and NO_2 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_x 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_3 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_x/SO_x Emissions Control System combines five major control technologies to form an integrated system to control both NO_x and SO_2. The low-NO_x combustion system consists of 12 Babcock & Wilcox DRB-XCL® low-NO_x burners installed on the roof. The low-NO_x combustion system also incorporated three Babcock & Wilcox dual-zone NO_x 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_x control was achieved with the urea-based SNCR system. The SNCR when used with the low-NO_x combustion system would allow the goal of 70% NO_x 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_2 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_x combustion system resulted in a decrease in furnace exit gas temperature by approximately 200 ºF, 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_x 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 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 mal distributions of flue gas velocity, temperature, or baseline NO_x 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.

▲ Public Service Company of Colorado demonstrated low-NO_x burners, induct injection, and SNCR at Arapahoe Station near Denver.

The SO_2 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 ºF, (2) air heater entrance where the temperature was approximately 600 ºF, or (3) the boiler economizer region where the flue gas temperature was approximately 1,000 ºF. To improve SO_2 removal with calcium hydroxide, a humidification system capable of achieving 20 ºF 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_x emissions by over 63% under steady-state conditions and with carefully supervised operations. Under load-following conditions, NO_x emissions were about 10–25% higher. At maximum overfire air (4% of total combustion air), the low-NO_x combustion system reduced NO_x emissions by 62–69% across the load range (50–110 MWe). The results indicated that the low-NO_x burners were responsible for most of the NO_x 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_x reduction of 45%. However, the performance decreased significantly as load decreased; at 60 MWe, NO_x 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_x removal of 30–50%, at a NH_3 slip limited to 10 ppm at the fabric filter inlet, thus increasing the total NO_x 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_2 removal in the range of 5–8% at a Ca/S molar ratio of 2.0. Higher SO_2 removal was achieved with duct injection of calcium hydroxide and humidification, with SO_2 removals approaching 40% at a Ca/S molar ratio of 2.0 and approach-to-saturation temperature of 20–30 ºF. Sodium-based reagents were found to be much more effective than calcium-based sorbents and achieved significantly higher SO_2 removals during dry injection. Sodium bicarbonate injection before the air heater demonstrated short-time SO_2 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_2. Even though 5–10% of the NO_x was reduced during the conversion process, the net NO_2 exiting at the stack was increased. While NO is colorless, small quantities of brown/orange NO_2 caused a visible plume.

A major objective was the demonstration of the integrated performance of the NO_x emissions control systems and the SO_2 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_3 slip from the SNCR process suppressed the NO_2 emissions associated with NO to NO_2 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_x reductions using low-NO_x 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 ºF approach-to-saturation temperature or an excursion caused by a rapid decrease in load.

The performance of the ARIL lances in NO_x 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_x reduction and NH_3 slip performance were slightly less than for the ARIL lance.

When the SNCR and dry sodium systems were operated concurrently, an NH_3 odor problem was encountered around the ash silo. Reducing the NH_3 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_x/SO_2 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.

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Advanced Electric Power Generation Technology

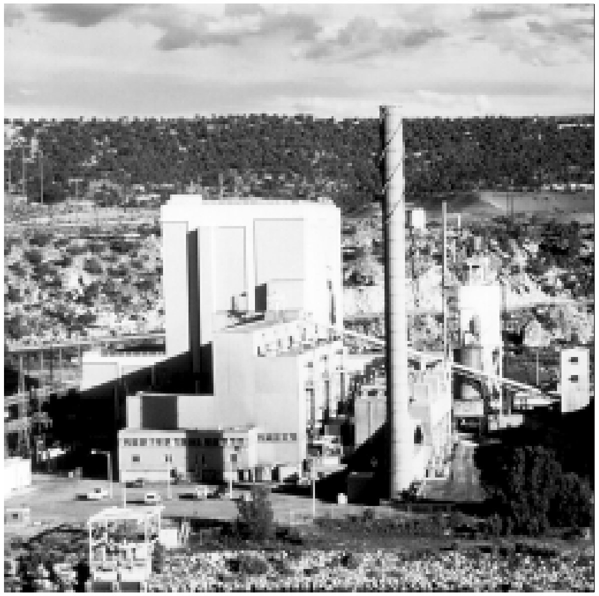
Advanced electric power generating systems employ the technologies that enable the efficient and environmentally superior generation of electric power. The advanced electric power generation projects selected under the CCT Program are responsive to the long-term capacity expansion needs requisite to 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_2 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.

Fluidized-Bed Combustion

Fluidized-bed combustion (FBC) reduces emissions of SO_2 and NO_x by controlling combustion parameters and by injecting a sorbent (such as crushed limestone) into the combustion chamber along with the coal. Pulverized coal mixed with the limestone is fluidized on jets of air in the combustion chamber. Sulfur released from the coal as SO_2 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_2 released can be captured this way.

At combustion temperatures of 1,400–1,600 ºF, 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 at which thermally induced NO_x is formed. In fact, fluidized-bed NO_x emissions are about 70–80 percent lower than those for conventional pulverized coal boilers. Thus, fluidized-bed combustors substantially reduce both SO_2 and NO_x 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.



▲ Tri-State Generation and Transmission Association's Nucla Station was host to demonstration of the world's first utility-scale AFBC.

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.

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 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 ºF, 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.

▲ 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.

High levels of nitrogen removal are also possible. Some of the coal’s nitrogen is converted to ammonia, which can be almost totally removed by commercially available chemical processes. NO_x formed 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

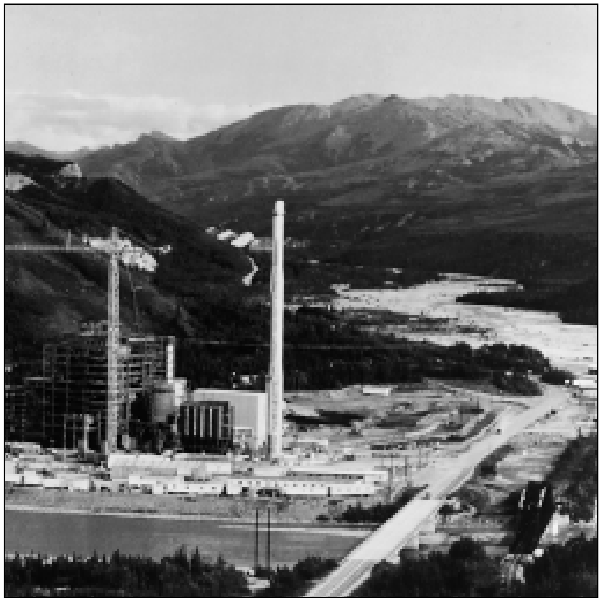
The diesel-engine-driven electric generation system is fueled with a coal-oil or coal-water slurry. The hot exhaust from the diesel engine is routed through a heat-recovery unit to produce steam for a steam-turbine electric generating system (combined cycle). Environmental control systems for SO_2, NO_x,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



▲ Golden Valley Electric Association is adding capacity to its Healy Plant with a 50-MWe slagging combustor unit using 65% waste coal.

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, construction was completed in November 1997 on the advanced slagging combustor project, and the coal diesel project is in the project definition and design phase.

Exhibit 30 summarizes the process characteristics and size of the advanced electric power generating technologies presented in more detail in the project fact sheets.

Exhibit 30
CCT Program Advanced Electric Power Generation Technology Characteristics

Project	Process	Size	Fact Sheet
Fluidized-Bed Combustion			
McIntosh Unit 4A PCFB Demonstration Project	Pressurized circulating fluidized-bed combustion	157 MWe	86
McIntosh Unit 4B Topped PCFB Demonstration Project	McIntosh 4A with pyrolyzer and topping combustor	157 MWe + 12 MWe	88
Tidd PFBC Demonstration Project	Pressurized bubbling fluidized-bed combustion	70 MWe	90
Jacksonville Electric Authority Large-Scale CFB Combustion Demonstration Project	Atmospheric circulating fluidized-bed combustion	265 MWe	94
Nucla CFB Demonstration Project	Atmospheric circulating fluidized-bed combustion	100 MWe	96
Integrated Gasification Combined Cycle			
Clean Energy Demonstration Project	Oxygen-blown, slagging fixed-bed gasifier with cold gas cleanup, fuel cell slipstream	477 MWe	100
Piñon Pine IGCC Power Project	Air-blown, fluidized-bed gasifier with hot gas cleanup	99 MWe	102
Tampa Electric Integrated Gasification Combined-Cycle Project	Oxygen-blown, entrained-flow gasifier with hot and cold gas cleanup	250 MWe	104
Wabash River Coal Gasification Repowering Project	Oxygen-blown, two-stage entrained-flow gasifier with cold gas cleanup	262 MWe	106
Advanced Combustion/Heat Engines			
Healy Clean Coal Project	Advanced slagging combustor, spray dryer with sorbent recycle	50 MWe	108
Clean Coal Diesel Demonstration Project	Coal-fueled diesel engine	6.4 MWe	110

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

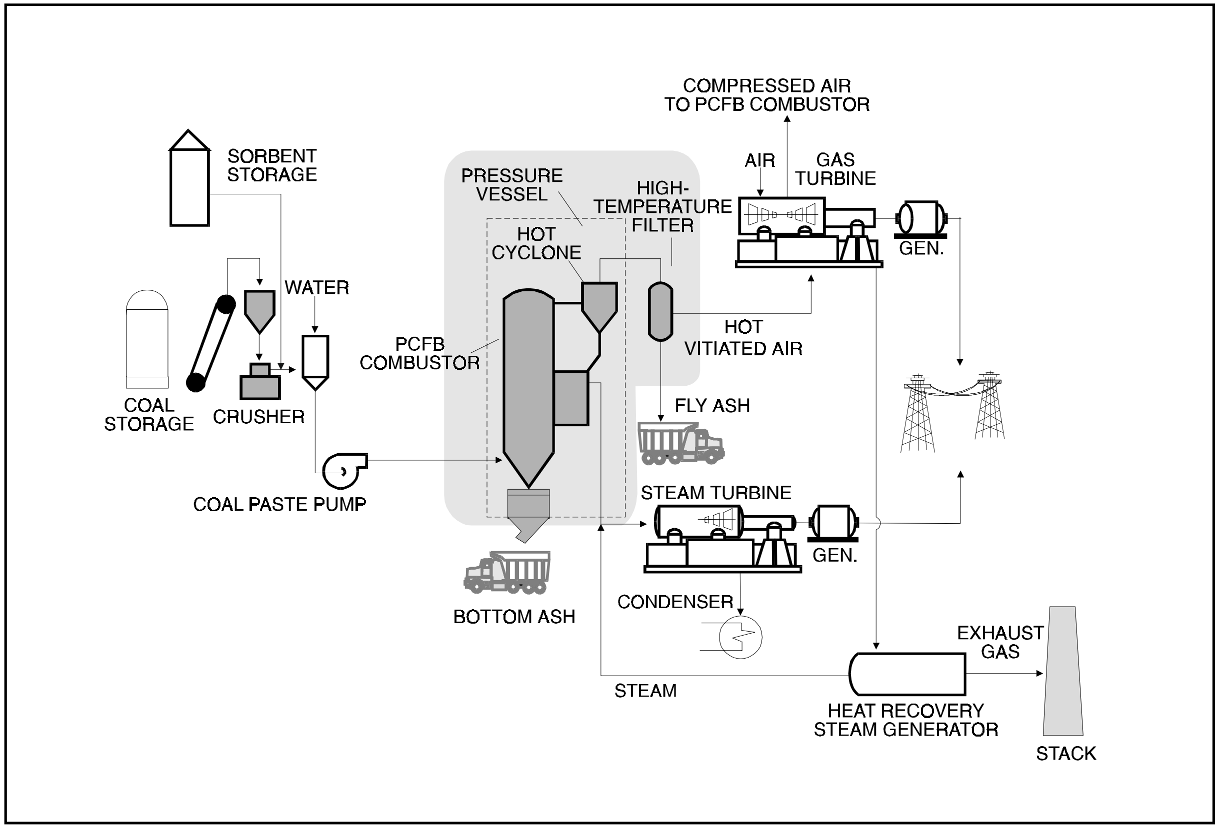
157 MWe (net)

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.

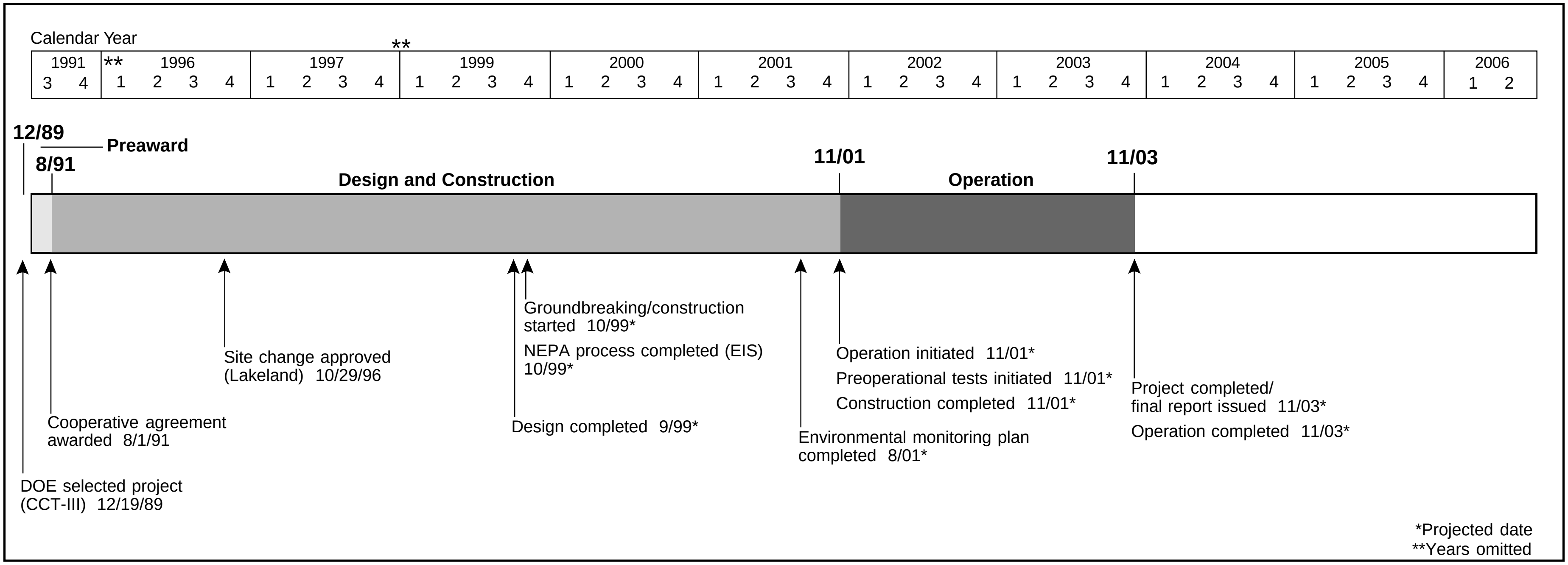


Technology/Project Description

The project resulted from a restructuring of the DMEC-1 PCFB Demonstration Project awarded under the third solicitation. In the first of the two Lakeland projects, McIntosh Unit 4 is being repowered with a PCFB combustor. In the second project, the integration of a gasifier and topping combustor (topping cycle) with the PCFB technology will be demonstrated (see 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 turbine, 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 repowered 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

Negotiations are in progress with all participants to transfer the cooperative agreement to the City of Lakeland, Department of Electric & Water Utilities. 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.

The Lakeland City Council gave approval for the 10-year plan of Lakeland's Department of Electric & Water Utilities in September 1997. The plan included this clean coal project.

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_x emissions less than 0.3 lb/10^6 Btu, and particulate matter discharge less than 0.03 lb/10^6 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

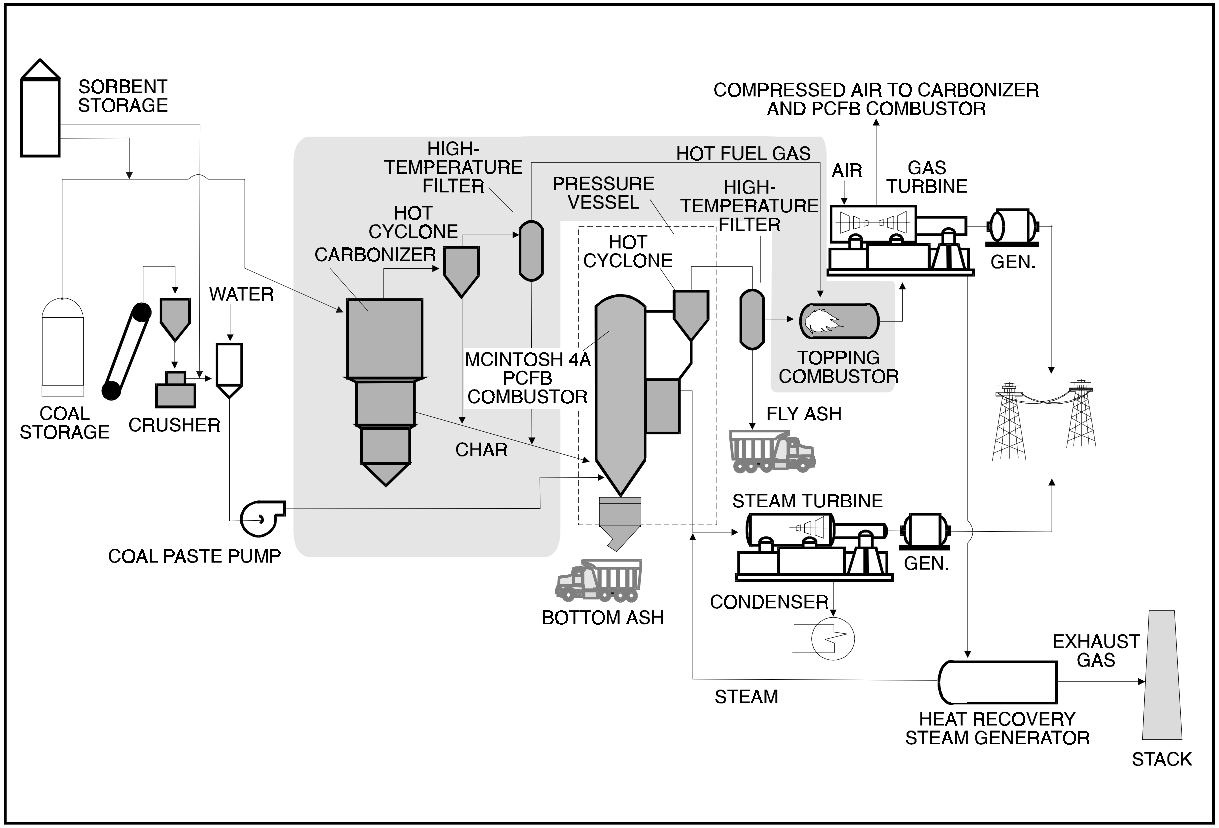
12 MWe (net) addition to the 157 MWe (net) McIntosh 4A project

Project Funding

Total project cost	$218,741,300	100%
DOE	109,204,000	50
Participant	109,537,300	50

Project Objective

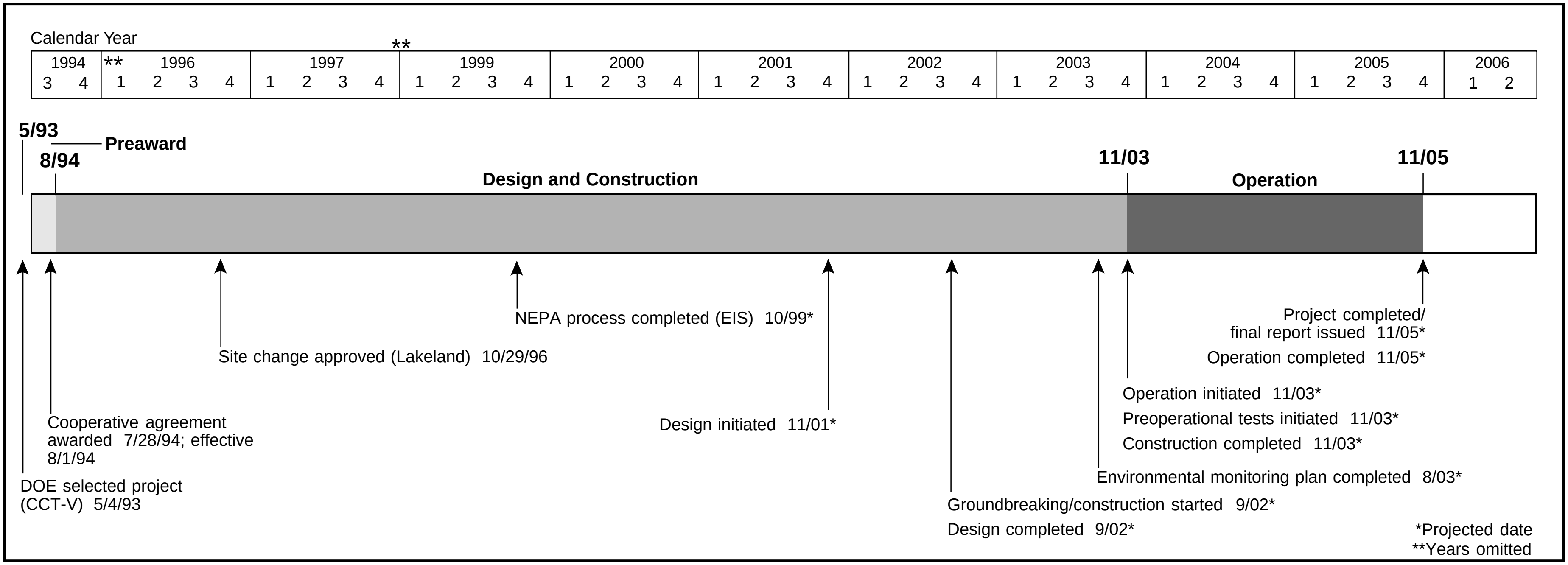
To demonstrate topped PCFB technology in a fully commercial power generating setting, thereby advancing the technology for future plants that will operate at higher gas turbine inlet temperatures and that are expected to achieve cycle efficiencies in excess of 45%.



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 in a repowering application.

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 generated 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

Negotiations are in progress with all participants to transfer of the cooperative agreement to the City of Lakeland, Department of Electric & Water Utilities. 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.

The Lakeland City Council has approved the utility department's 10-year plan, which includes this project.

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) operate 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_2 emissions. Other environmental attributes include in-situ sulfur retention that can meet 95% removal, NO_x emission that will be lower than 0.3 lb/10^6 Btu, and particulate matter discharge of approximately 0.03 lb/10^6 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

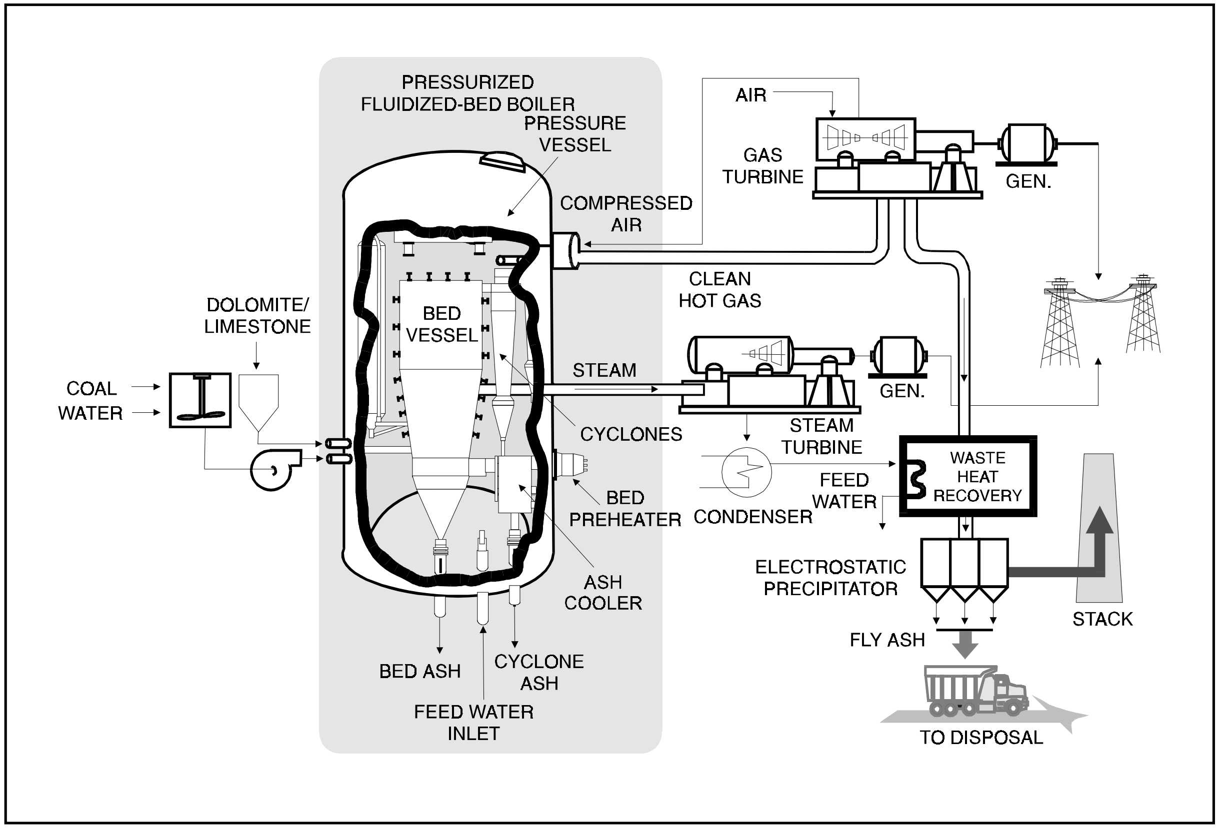
Ohio bituminous, 2–4% sulfur

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_2 removal and NO_x emission level of 0.2 lb/10^6 Btu at full load.



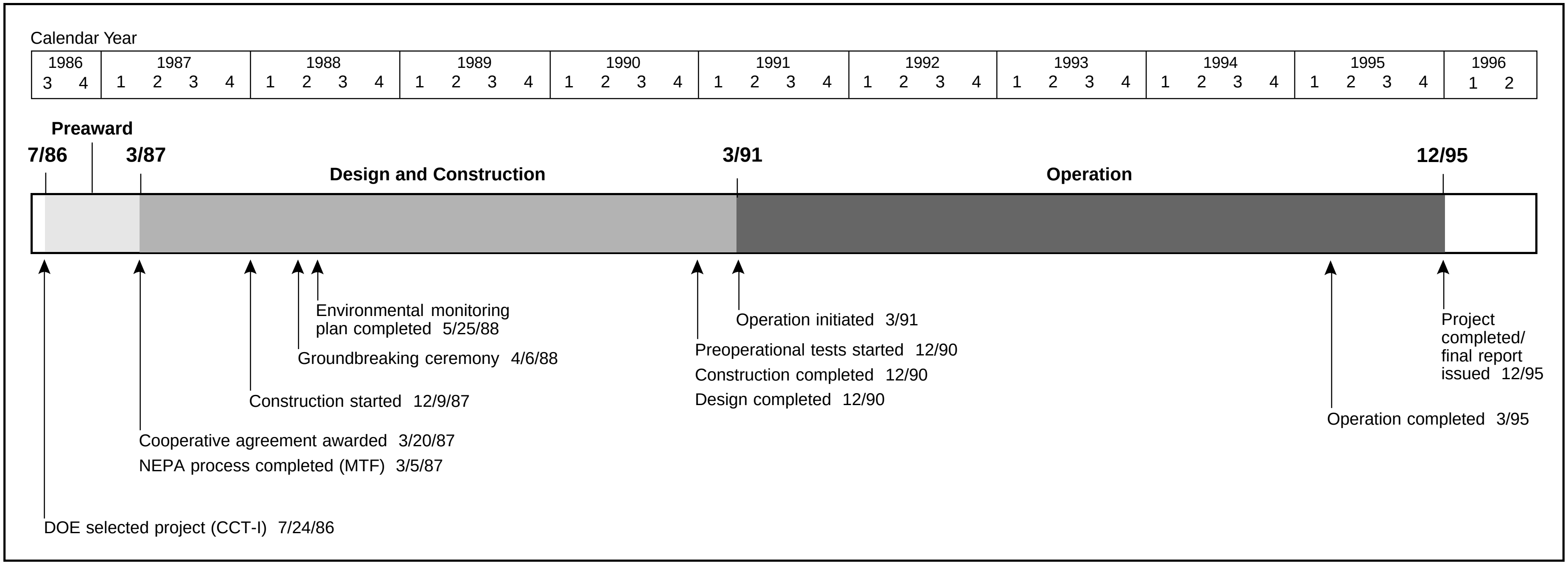
Technology/Project Description

Tidd was the first large-scale operational demonstration of PFBC in the United States and one of only five worldwide. The project represented a 13:1 scaleup from the pilot facility.

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 ºF limits NO_x formation.

The hot combustion gases exit the bed vessel with entrained ash particles, 98% of which are removed when the gases pass through cyclones. The cleaned gases are then expanded through a 15-MWe gas turbine. 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_2 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 ºF.
- SO_2 removal efficiency of 95% was achieved at full load with a Ca/S of 1.5 and temperature of 1,580 ºF.
- NO_x emissions were 0.15–0.33 lb/10^6 Btu.
- CO emissions were less than 0.01 lb/10^6 Btu.
- Particulate emissions were less than 0.02 lb/10^6 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_x 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 ºF 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_x 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 alternative sorbent feed system was added in 1993; it injected 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_2 capture was achievable with a Ca/S molar ratio of 1.1 and that 95% SO_2 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 ºF 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_x emissions in the range of 0.15–0.33 lb/10^6 Btu. These emissions were inherent to the process, which was operating at approximately 1,580 ºF. No NO_x control enhancements, such as ammonia injection, were required. Emissions of carbon monoxide and particulates were less than 0.01 and 0.02 lb/10^6 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 main- tenance. 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 could operate in a PFBC flue gas environment, and it was concluded that erosion was manageable with a scheduled maintenance program.

Efficiency of the PFBC combustion process was calculated during testing from the amount of unburned carbon in cyclone and bed ash, together with 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%.

▲ The PFBC demonstration at the repowered 70-MWe unit at Ohio Power's Tidd Plant led to significant refinements and understanding of the technology.

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 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_x emission levels less than 0.1 lb/10^6 Btu. Although the system generates slightly more solid waste compared to conventional systems, the dry material is either readily disposable or potentially usable.

The Tidd project received *Power* magazine's 1991 Powerplant Award. In 1992, the project received the National Energy Resource Organization award for demonstrating energy-efficient technology.

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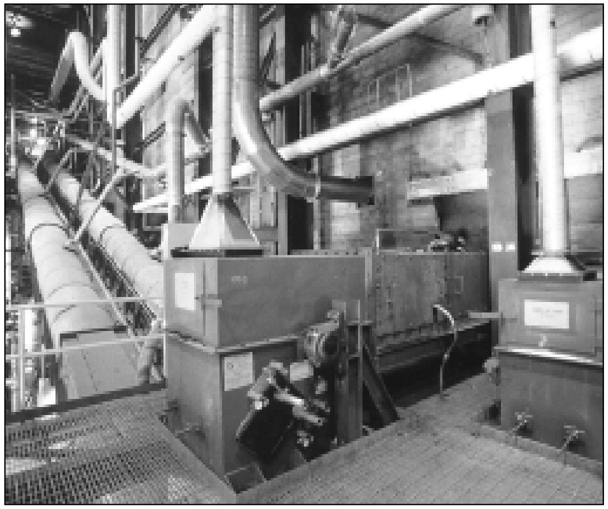


▲ Coal and sorbent conveyors can be seen just after entering the Tidd Plant.

Jacksonville Electric Authority Large-Scale CFB Combustion Demonstration Project

Participant

Jacksonville Electric Authority

Additional Team Member

Foster Wheeler Energy Corp.—co-owner and technology supplier

Location

Jacksonville, Duval County, FL (Jacksonville Electric Authority's Northside Station, Unit 2)

Technology

Foster Wheeler's atmospheric circulating fluidized-bed (ACFB) combustor

Plant Capacity/Production

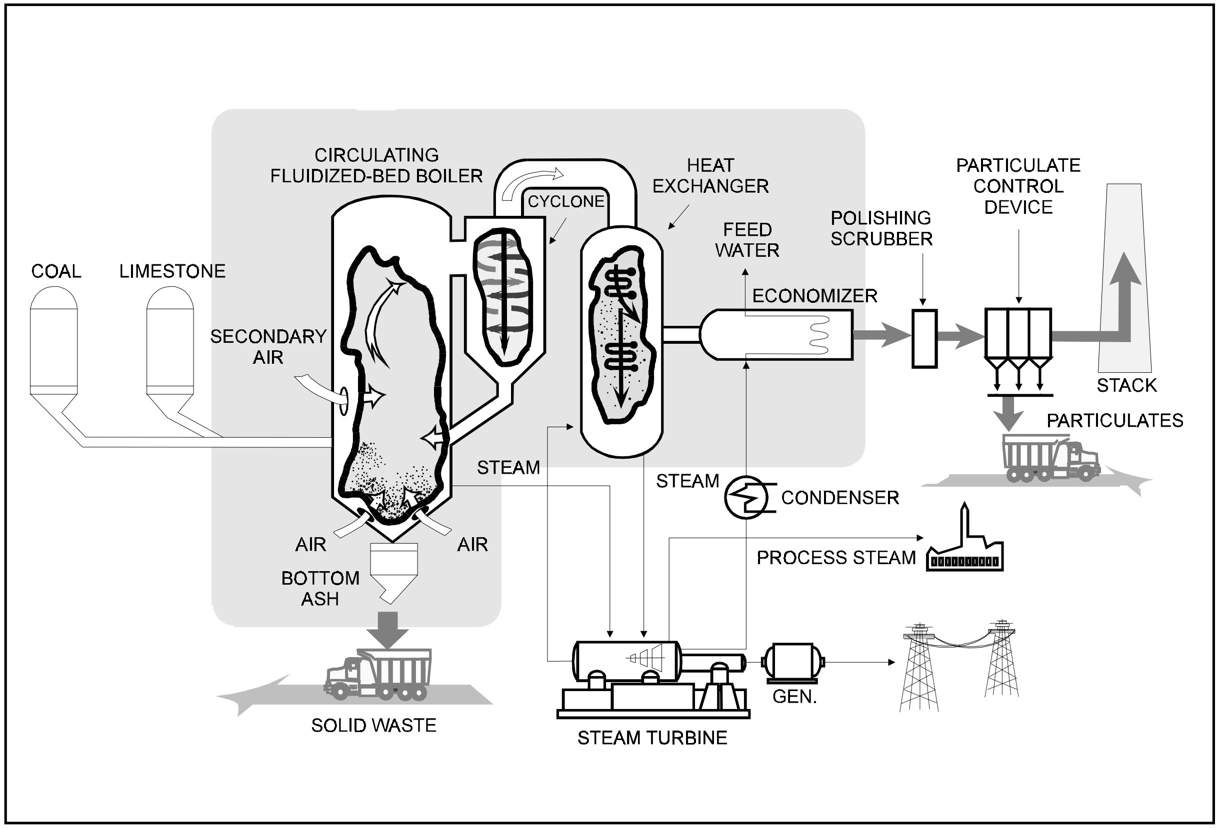
297.5 MWe (gross), 265 MWe (net)

Project Funding

Total project cost	$309,096,512	100%
DOE	74,733,633	24
Participant	234,362,679	76

Project Objective

To demonstrate ACFB at 297.5 MWe gross (265 MWe net) 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_2 removal and to reduce NO_x emissions by 60% when compared with conventional technology.

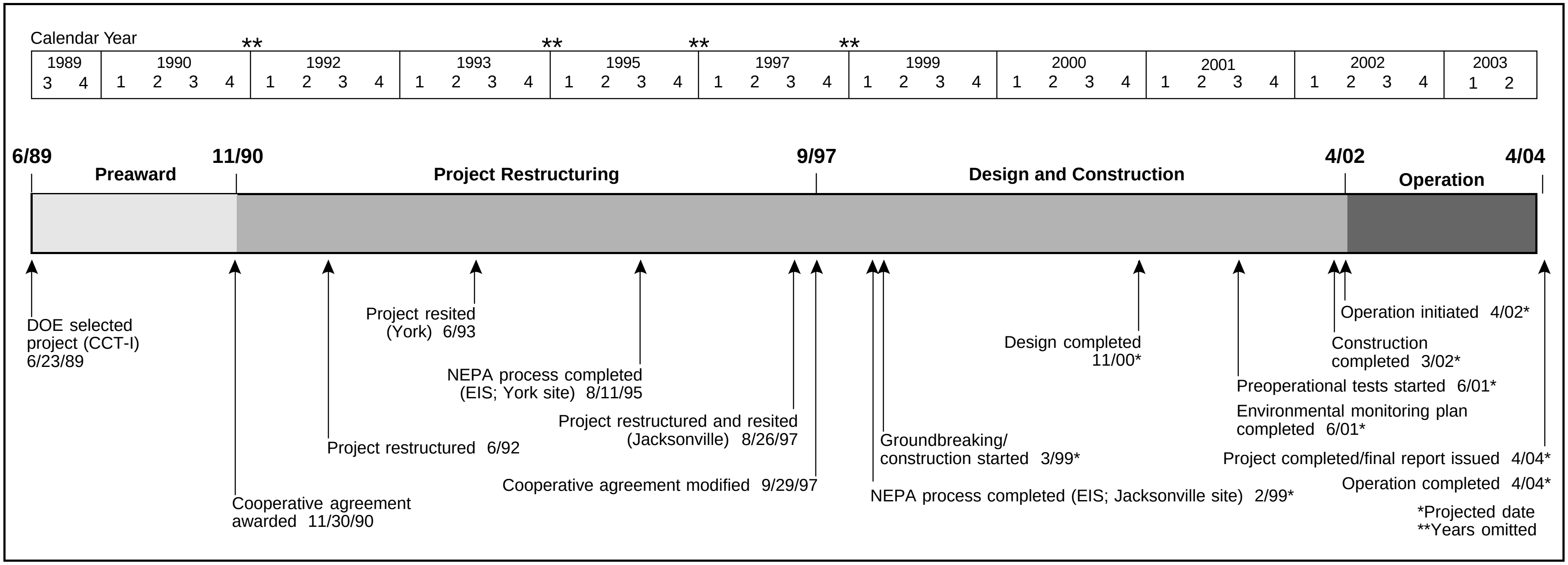


Technology/Project Description

A circulating fluidized-bed combustor, operating at atmospheric pressure, will be retrofitted into Unit 2 of the Northside Station. Coal or the secondary fuel, petroleum coke, primary air, and a solid sorbent, such as limestone, are introduced into the lower part of the combustor where initial combustion occurs. As the coal particles decrease in size due to combustion, they are carried higher in the combustor when 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. Primary sulfur capture is achieved by limestone sorbent in the bed. However, additional SO_2 capture is achieved through the use of a polishing scrubber to be installed ahead of the particulate control equipment.

Steam is generated in tubes placed along the combustor's walls and superheated in tube bundles placed downstream of the particulate separator to protect against erosion. The system will produce approximately 2 million lb/hr of main steam at about 2,400 psig and 1,005 ºF and 1.73 million lb/hr of reheat steam at 600 psig and 1,005 ºF. The steam will be used in an existing 297.5 MWe (nameplate) steam turbine and its generator.

The heat rate for the retrofit plant is expected to be approximately 9,950 Btu/kWh (34% efficiency). SO_2 emissions from the common stack for Units 1 and 2 would be on the order of 0.17 lb/10^6 Btu. (Unit 1 is a 275-MWe oil-fired unit similar to Unit 2.)



Project Status/Accomplishments

The project was successfully resited to Jacksonville after York County Energy partners and Metropolitan Edison Company terminated activities on the ACFB in September 1996. On August 26, 1997, DOE approved the transfer of the ACFB clean coal project from York, PA, to Jacksonville, FL. On September 29, 1997, DOE signed a modified cooperative agreement and repayment agreement with Jacksonville Electric Authority to cost-share refurbishment of the first (Unit 2) of two units at Northside Generating Station.

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.

In its commercial configuration, ACFB technology offers several potential benefits when compared to conventional pulverized coal-fired systems: lower capital costs; reduced SO_2 and NO_x emissions at lower costs; higher combustion efficiency; and dry, granular solid material that is easily disposed of or potentially salable.

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)—cofunder
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

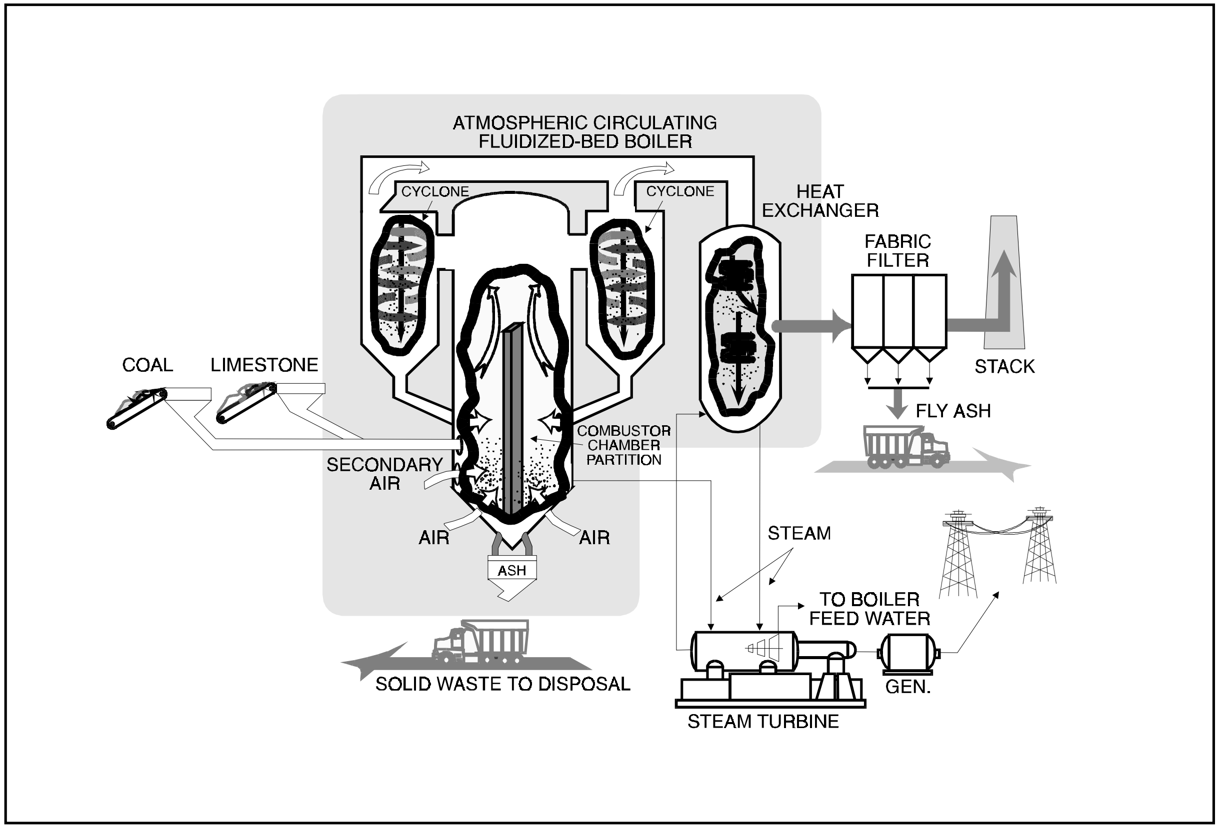
Western bituminous—
  Salt Creek, 0.5% sulfur, 17% ash
  Peabody, 0.7% sulfur, 18% ash
  Dorchester, 1.5% sulfur, 23% ash

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 NO_x formation. Calcium in the sorbent combines with 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. Flue gas passes through a baghouse where particulate matter is removed. Steam generated in the ACFB is used to produce 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.

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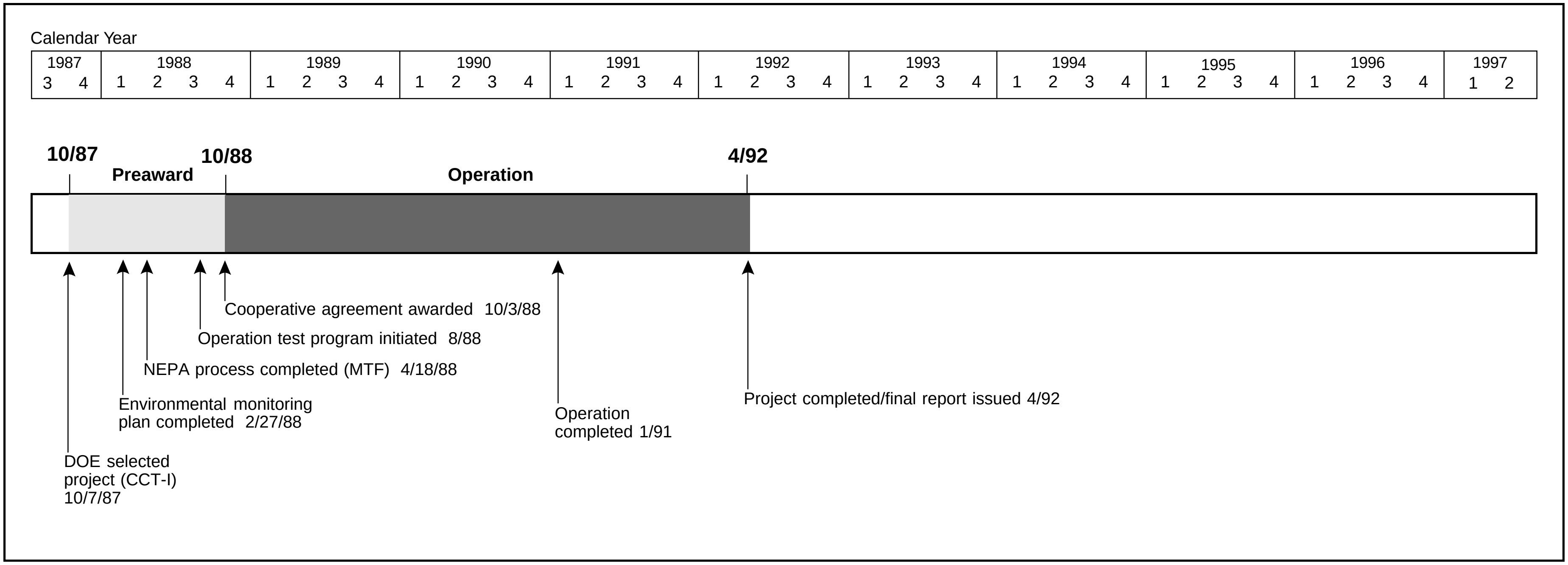
*Pyropower Corporation, the original technology developer and supplier, was acquired by Foster Wheeler Energy Corp.



Results Summary

Environmental

- Bed temperature had the greatest effect on pollutant emissions and boiler efficiency.
- At bed temperatures below 1,620 ºF, 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_x emissions averaged 0.18 lb/10^6 Btu and did not exceed 0.34 lb/10^6 Btu.
- CO emissions varied between 70 and 140 ppmv.
- Particulate emissions ranged from 0.0072 to 0.0125 lb/10^6 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 ºF, well below the thermal NO_x generation temperature (2,500 ºF), and high SO_2-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_2, 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 31 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 1,500–1,620 °F range, the Ca/S requirement jumped to 5.0 or more at 1,700 °F or greater.

Exhibit 32 shows the effect of Ca/S molar ratio on sulfur retention at average bed temperatures below 1,620 ºF. Salt Creek and Peabody coals contain 0.5% and 0.7% sulfur, respectively. To achieve 70% SO_2 reduction, or the 0.4 $lb/10^6$ Btu emission rate required by the licensing agreement, a Ca/S molar ratio of approximately 1.5 is required. To achieve an SO_2 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_x emissions measured throughout the demonstration were less than 0.34 $lb/10^6$ Btu, which is well below the regulated value of 0.5 $lb/10^6$ Btu. The average level of NO_x emissions for all tests was 0.18 $lb/10^6$ Btu. NO_x emissions indicate a relatively strong correlation with temperature, increasing from 40 ppmv (0.06 $lb/10^6$ Btu) at 1,425 ºF to 240 ppmv (0.34 $lb/10^6$ Btu) at 1,700 °F. Limestone feed rate was also identified as a variable affecting NO_x emissions, i.e., somewhat higher NO_x emissions resulted from increasing calcium-to-nitrogen (Ca/N) ratios. The mechanism was believed to be oxidation of volatile nitrogen in the form of ammonia (NH_3) catalyzed by calcium oxide.

CO emissions decrease as temperature increases, from 140 ppmv at 1,425 ºF to 70 ppmv at 1,700 ºF.

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

Exhibit 31

Effect of Bed Temperature on Ca/S Requirement

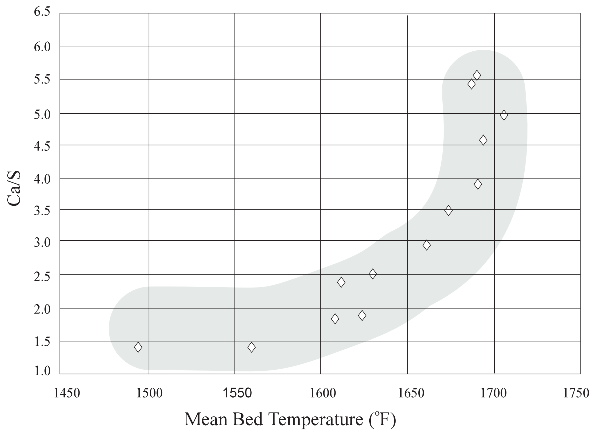
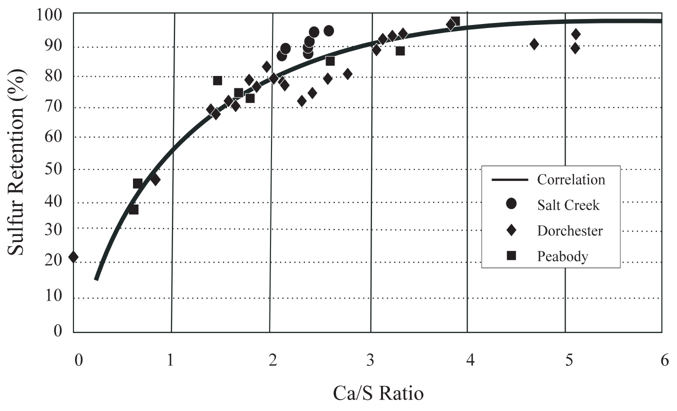


Exhibit 32

Calcium Requirements and Sulfur Retentions for Various Fuels



equated to emission levels of 0.0125 lb/10^6 Btu for Peabody coal and 0.0072 lb/10^6 Btu for Salt Creek coal, well below the required 0.03 lb/10^6 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%).

▲ 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.

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 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.

The Nucla ACFB project prompted wide dissemination of the technical progress of ACFB technology and showed the viability of scaling up. When the Nucla ACFB boiler was sold, it was 44% larger than any other U.S. ACFB unit and 41% larger than any other ACFB boiler sold anywhere in the world. It was not until after the Nucla unit was built and the first coal firing occurred that another ACFB boiler of comparable size was sold. The project enabled Pyropower (now owned by Foster Wheeler) to save almost 3 years in establishing a commercial line of ACFB units. A total of 22 ACFB units larger than 100 MWe, representing 3,800 MWe of capacity and worth more than $5 billion are being planned, engineered, built, or operated; 11 are in the United States.

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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

Deutsche Aerospace AG—cofunder

National Rural Electric Cooperative Association—cofunder

Location

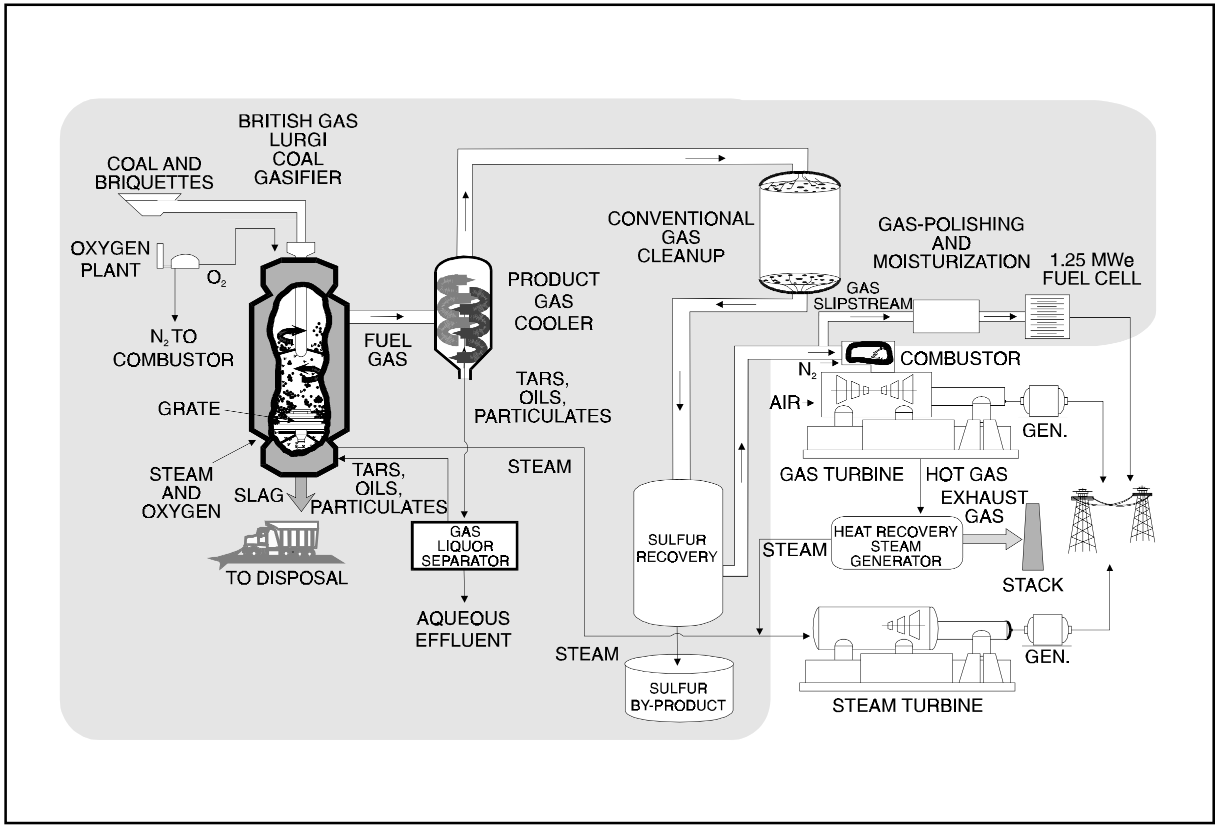
Evaluating site locations.

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

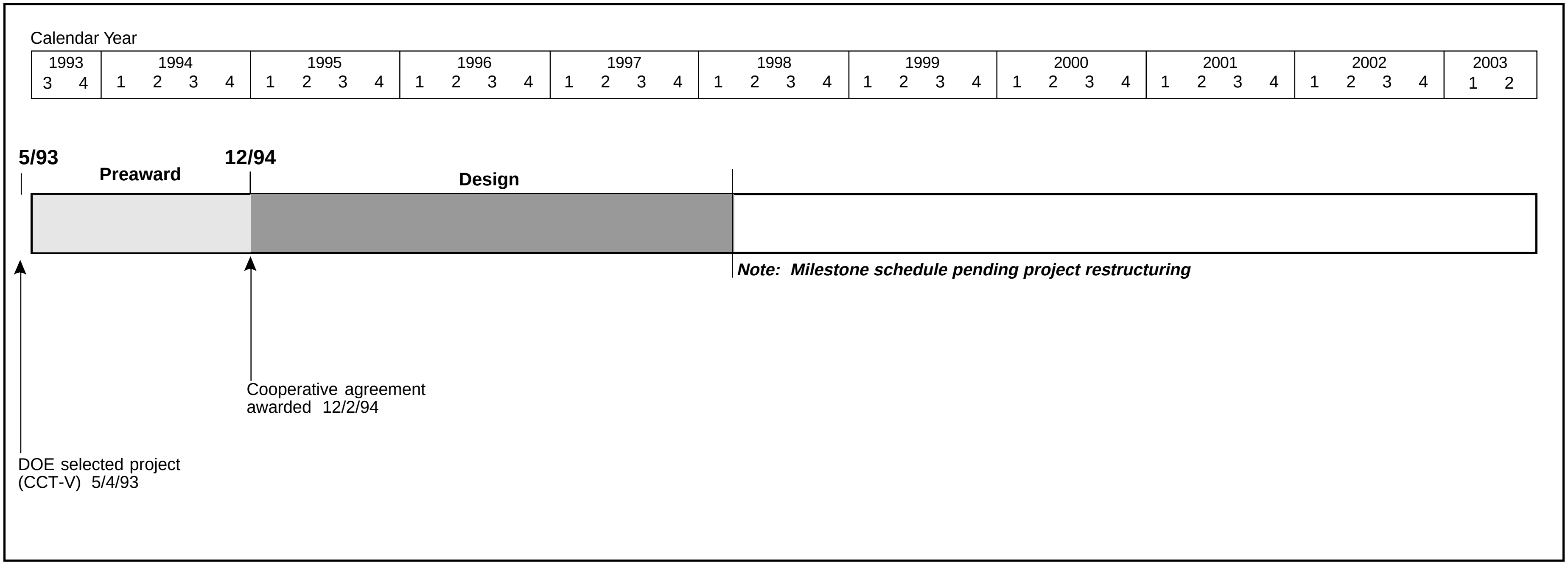
To demonstrate and assess the reliability, availability, and maintainability of a utility-scale IGCC system using high-sulfur bituminous coal in an oxygen-blown, fixed-bed, slagging gasifier and the operability of a molten carbonate fuel cell fueled by coal gas, by an independent power producer under 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 fires the gas turbine. 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.

Eastern bituminous coal will be used.



Project Status/Accomplishments

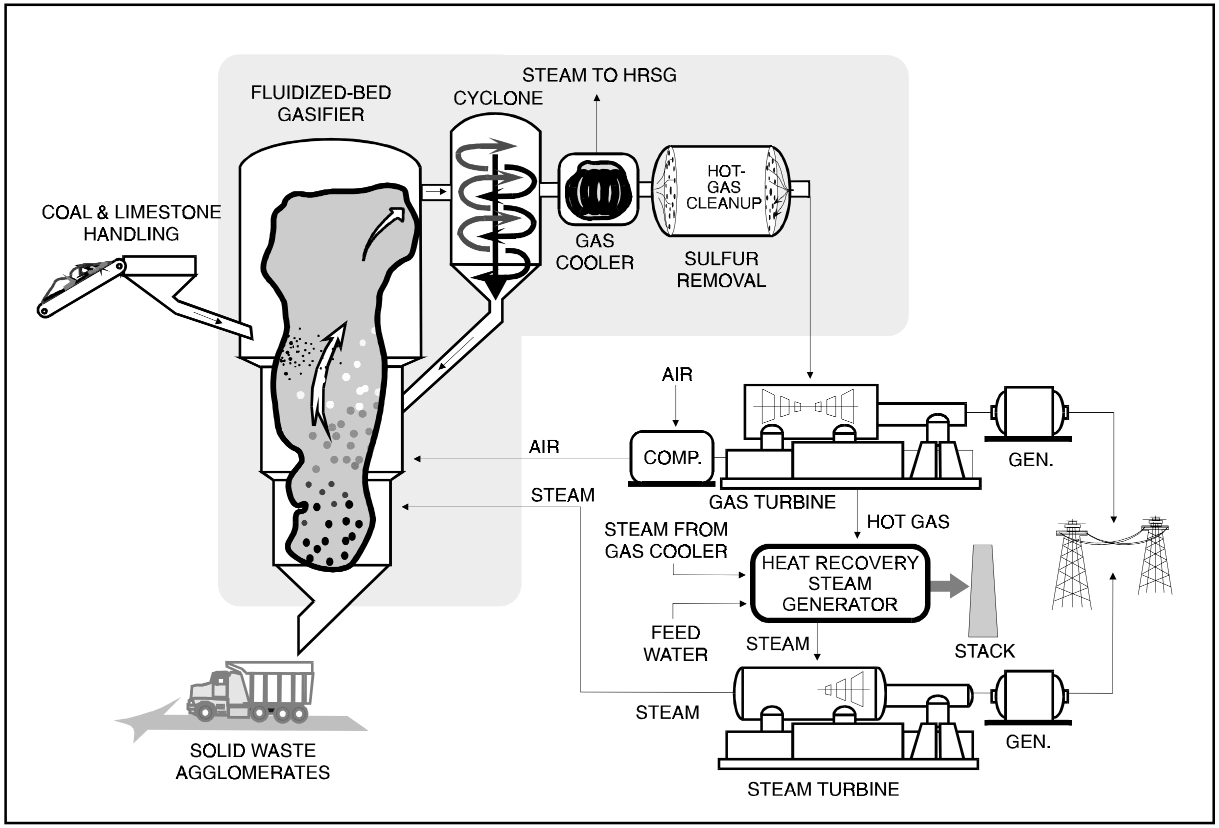
The cooperative agreement was awarded December 2, 1994. The participant is evaluating sites.

Commercial Applications

The IGCC system being demonstrated in this project is suitable for both repowering applications and new power plants. The technology is expected to be adaptable to a wide variety of potential market applications because of several factors. First, the BG/L gasification technology has successfully used a wide variety of U.S. coals. Also, the highly modular approach to system design makes the BG/L-based IGCC and molten carbonate fuel cell competitive in a wide range of plant sizes. In addition, the high efficiency and excellent environmental performance of the system are competitive with or superior to other fossil-fuel-fired power generation technologies.

The heat rate of the IGCC demonstration facility is 8,560 Btu/kWh (40% efficiency) and the commercial embodiment of the system has a projected heat rate of 8,035 Btu/kWh (42.5% efficiency). The commercial version of the molten carbonate fuel cell fueled by a BG/L gasifier is anticipated to have a heat rate of 7,379 Btu/kWh (46.2% efficiency). These efficiencies represent greater than 20% reduction in emissions of CO_2 when compared to a conventional pulverized coal plant equipped with a scrubber. SO_2 emissions from the IGCC system are expected to be less than 0.1 lb/10^6 Btu (99% reduction); NO_x emissions, less than 0.15 lb/10^6 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

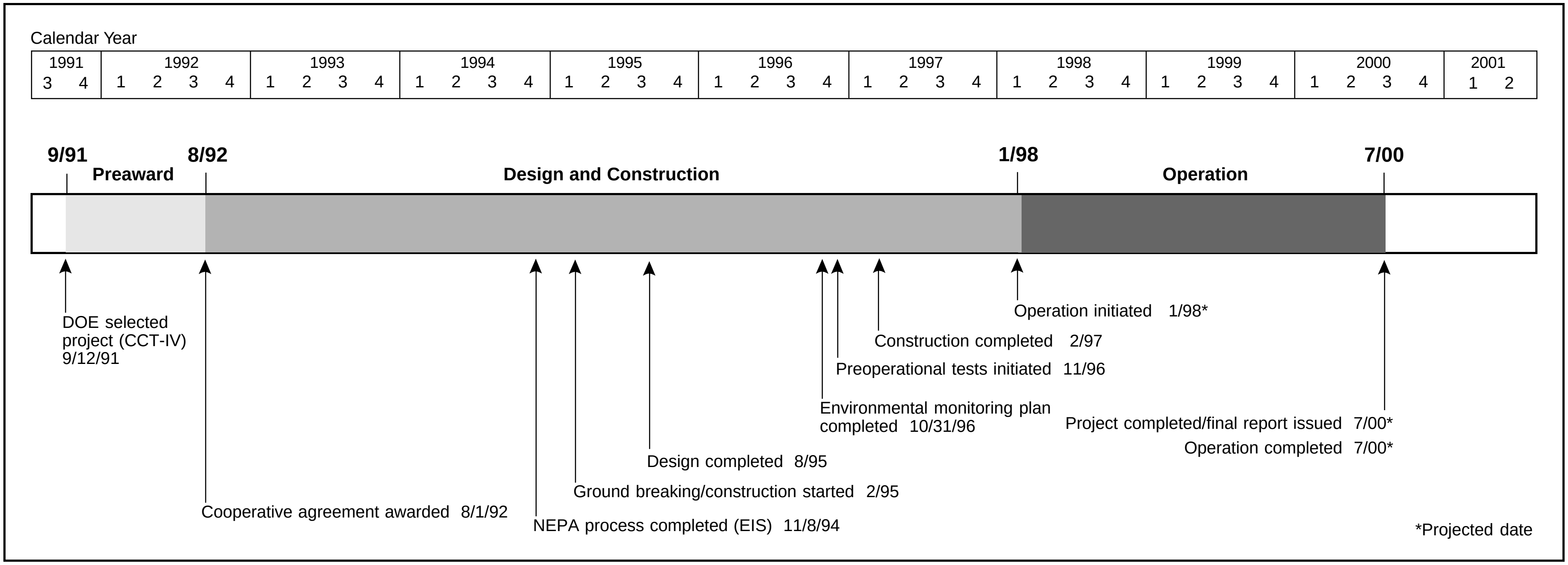
Dried and crushed coal and limestone are introduced into a pressurized, air-blown, fluidized-bed gasifier. Crushed limestone is used to capture a portion of the sulfur and to inhibit conversion of fuel nitrogen to ammonia. The sulfur reacts with the limestone to form calcium sulfide which, after oxidation, 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 ºF, is cooled to about 1,100 ºF 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_x emissions are 0.069 lb/10^6 Btu (94% reduction). Due to the combination of in-bed sulfur capture and hot gas cleanup, SO_2 emissions are 0.069 lb/10^6 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, which began during the second half of 1996, are continuing, and final commissioning is in progress. However, plant start-up is proceeding slower than planned due to problems encountered during equipment commissioning and the need to relocate the flare.

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. Preoperational testing and shakedown of the coal-gasification combined cycle continued through 1997 with syngas produced in January 1998. Additional shakedown testing is planned with test-plan operations scheduled to begin in April 1998.

Commercial Applications

The Piñon Pine IGCC system concept is suitable for new power generation, repowering needs, and cogeneration applications. The net effective heat rate for a proposed greenfield plant using this technology is projected to be 7,800 Btu/kWh (43.7% efficiency), representing a 20% increase in thermal efficiency as compared to a conventional pulverized coal plant with a scrubber and a comparable reduction in CO_2 emissions. The compactness of 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, high-ash, low-rank, 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

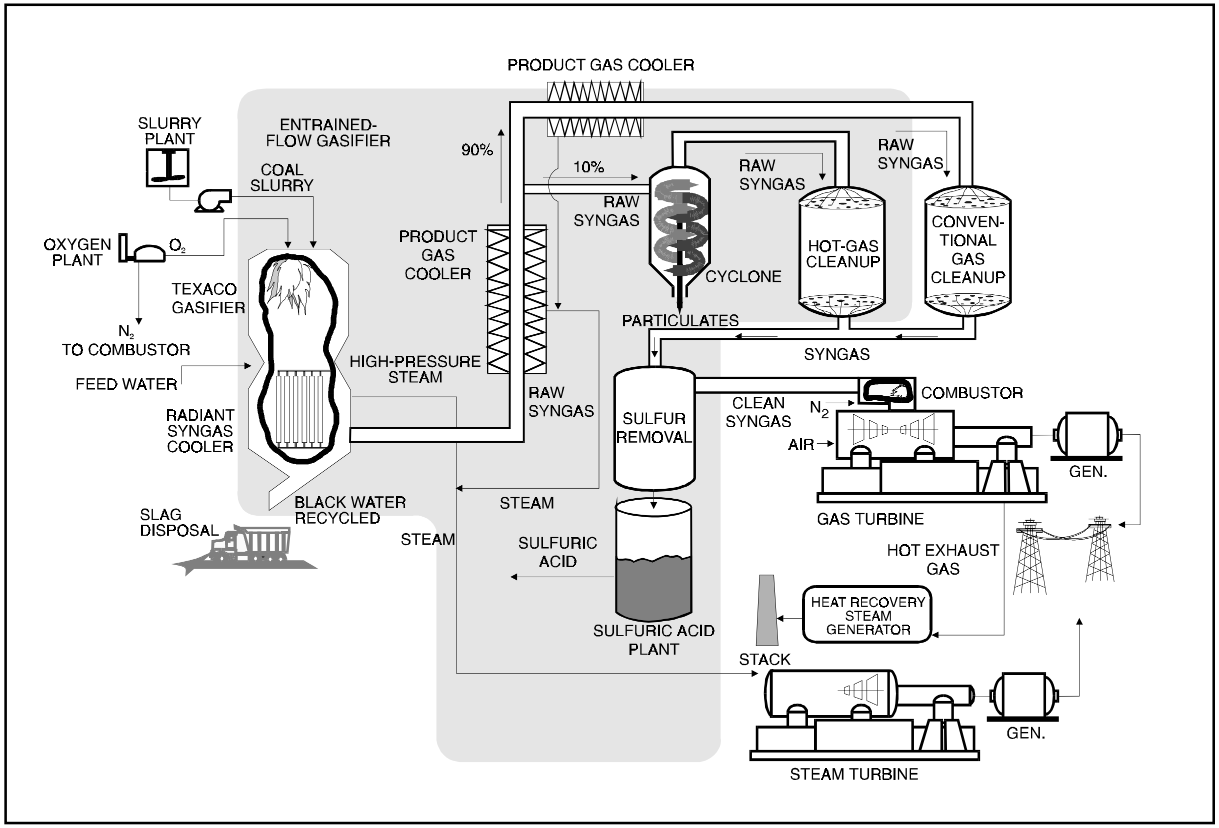
Integrated gasification combined-cycle (IGCC) system using Texaco's pressurized, oxygen-blown, entrained-flow gasifier technology and incorporating both conventional, low-temperature acid-gas removal and hot-gas moving-bed desulfurization

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

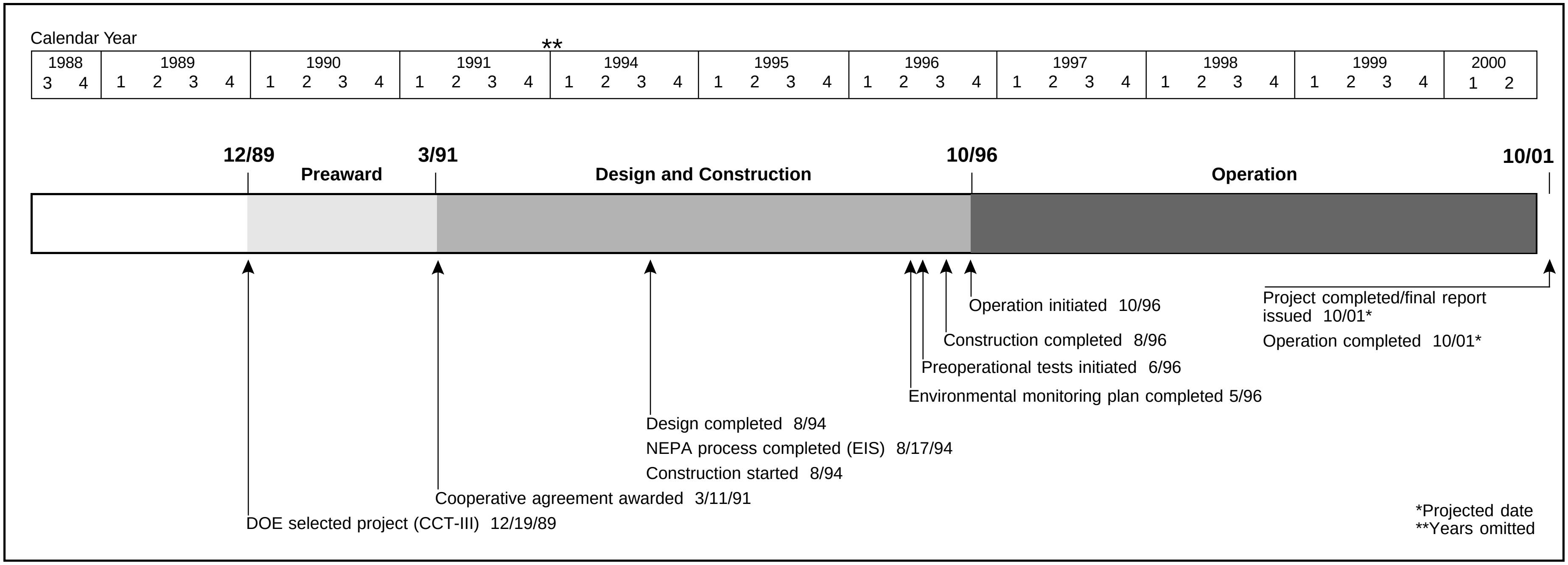
To demonstrate IGCC technology in a greenfield, commercial, electric utility application at the 250-MWe size with a Texaco gasifier. To demonstrate the integrated performance of a metal oxide hot-gas cleanup system, conventional cold-gas cleanup, and an advanced gas turbine with nitrogen injection (from the air separation plant) for power augmentation and 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 vessel's bottom and into a water-filled quench tank where it is forms 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 lb/10^6 Btu (96% capture). The cleaned gases are then routed to a combined-cycle system for power generation. Sulfuric acid and slag are salable by-products.

A GE MS 7001F gas turbine generates about 192 MWe (gross). Thermally generated NO_x is controlled to below 0.27 lb/10^6 Btu by injecting nitrogen as a dilutent in the turbine's combustion section. A heat-recovery



steam-generator produces an additional 121 MWe (gross). Polk's 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. Illinois 6 and Pittsburgh 8 bituminous coals (2.5–3.5% sulfur) are being used.

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.

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. In July 1997, the plant operated continuously for 20 days; plant efficiency improved, with a heat rate of 9,250 Btu/kWh. The plant operated at full load for most of August. However, the plant was brought off-line on August 26 to repair a gas leak in the radiant syngas cooler and then restarted in September on Illinois 6 coal.

The unit was dedicated on January 10, 1997.

Commercial Applications

The Texaco-based IGCC is suitable for new electric power generation, repowering needs, and cogeneration applications. Commercial IGCCs should achieve better than 98% SO_2 capture with a NO_x emissions reduction of 90%.

Texaco and RJB Mining have proposed a 400-MWe IGCC minemouth unit in West Yorkshire (U.K.) Texaco and ASEA Brown Boveri have signed an agreement forming an alliance to market IGCC technology in Europe. This demonstration project is scaling up the technology from a 100-MWe pilot unit (Cool Water plant) tested without full system integration.

The project was presented the 1997 Powerplant Award by *Power* magazine. In 1996 the project received the Association of Builders and Contractors Award for construction quality. Several awards were presented for using an innovative siting process: 1993 Ecological Society of America Corporate Award, 1993 Timer Powers Conflict Resolution Award from the state of Florida, and the 1991 Florida Audubon Society Corporate Award.

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

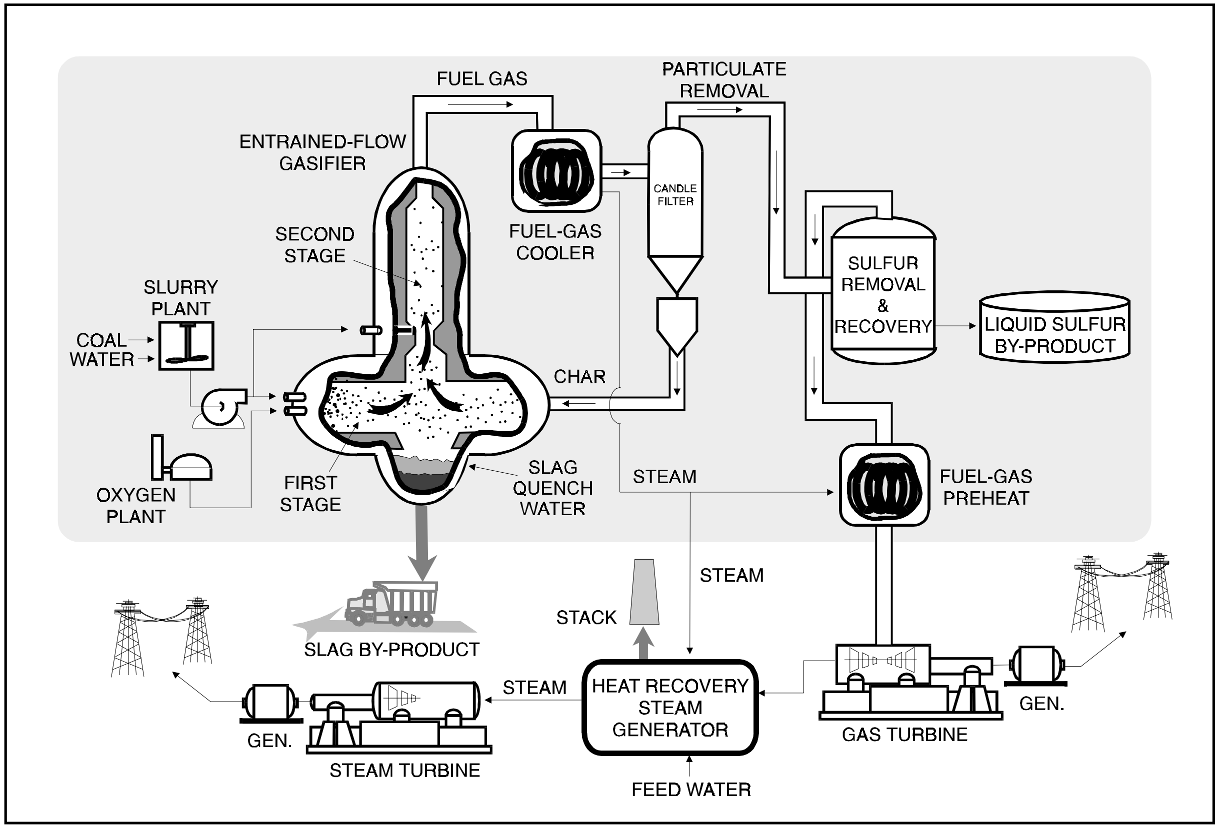
262 MWe (net)

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 bituminous coal; and to assess long-term reliability, availability, and maintainability of the system at a fully commercial scale.



Technology/Project Description

Coal is ground, slurried with water, and gasified in a pressurized, two-stage (slagging first stage and non-slagging entrained-flow second stage), oxygen-blown, gasifier. The product gas is cooled through heat exchangers and passed through a conventional cold gas cleanup system which removes particulates, ammonia, and sulfur. The clean, medium-Btu gas is then reheated and burned in an advanced 192-MWe (gross) 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 approximately 9,000 Btu/kWh (38% efficiency). Using high-sulfur bituminous coal, SO_2 emissions are expected to be less than 0.1 lb/10^6 Btu (98% reduction). NO_x emissions are expected to be less than 0.1 lb/10^6 Btu (90% reduc-

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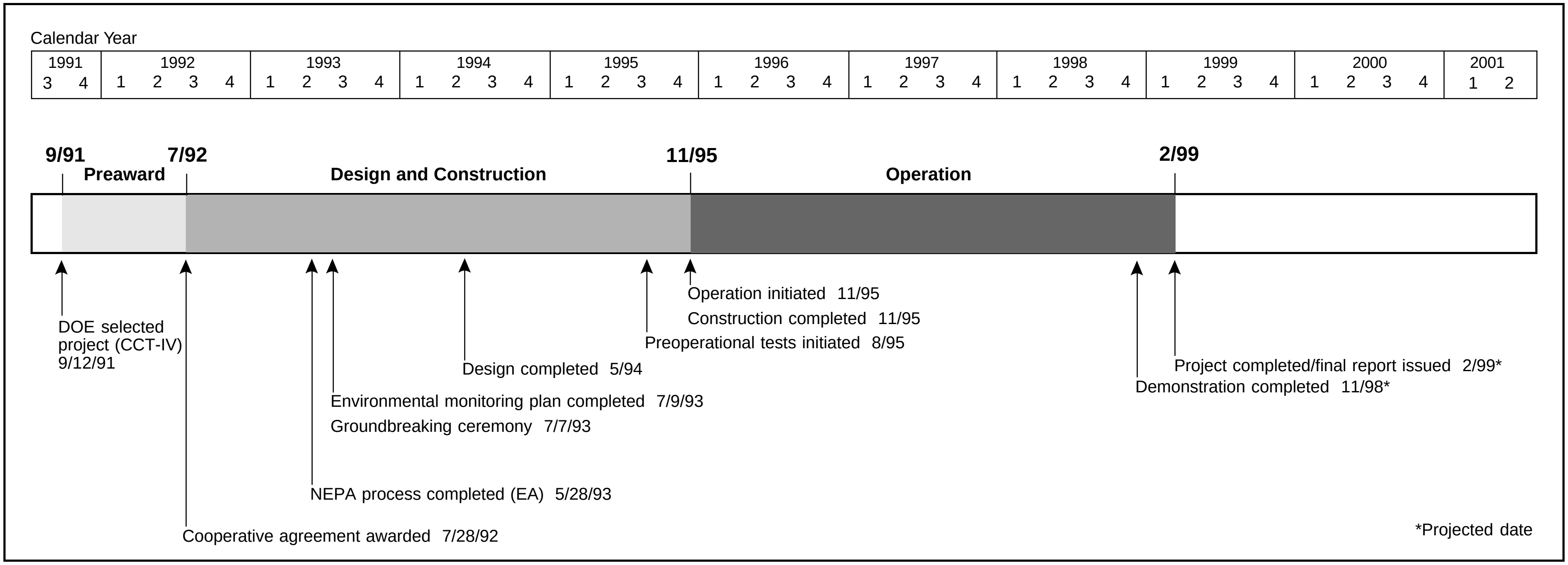
*Destec Energy has been acquired by NGC Corporation and will operate as a subsidiary, retaining the same name.



tion). 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 September 30, 1997, the plant has operated for about 4,000 hours on syngas in combined-cycle mode and has produced about 1 million 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 4,500 hours on coal and produced over 7 trillion Btu (dry) of syngas by processing over 400,000 tons of coal. Gasifier operation has attained over 74% cold gas efficiency.

The project has completed the first 2 years of a 3-year demonstration period. Early operation has demonstrated the ability to run at full-load capability while meeting the environmental requirements for sulfur and NO_x 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).

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_2, NO_x, and CO_2 emissions. The modularity of the gasifier technology will permit a range of units to be considered for repowering, and the relatively short construction schedule for the technology will allow utilities greater flexibility in designing strategies to meet load requirements. Also, the high degree of fuel flexibility inherent in the gasifier design 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_2 emissions.

Destec Energy and CINergy Corp./PSI Energy received the 1996 Powerplant Award from *Power* magazine. Sargent & Lundy, engineer for the combined-cycle facility, won the American Consulting Engineers Council's 1996 Engineering Excellence Award.

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

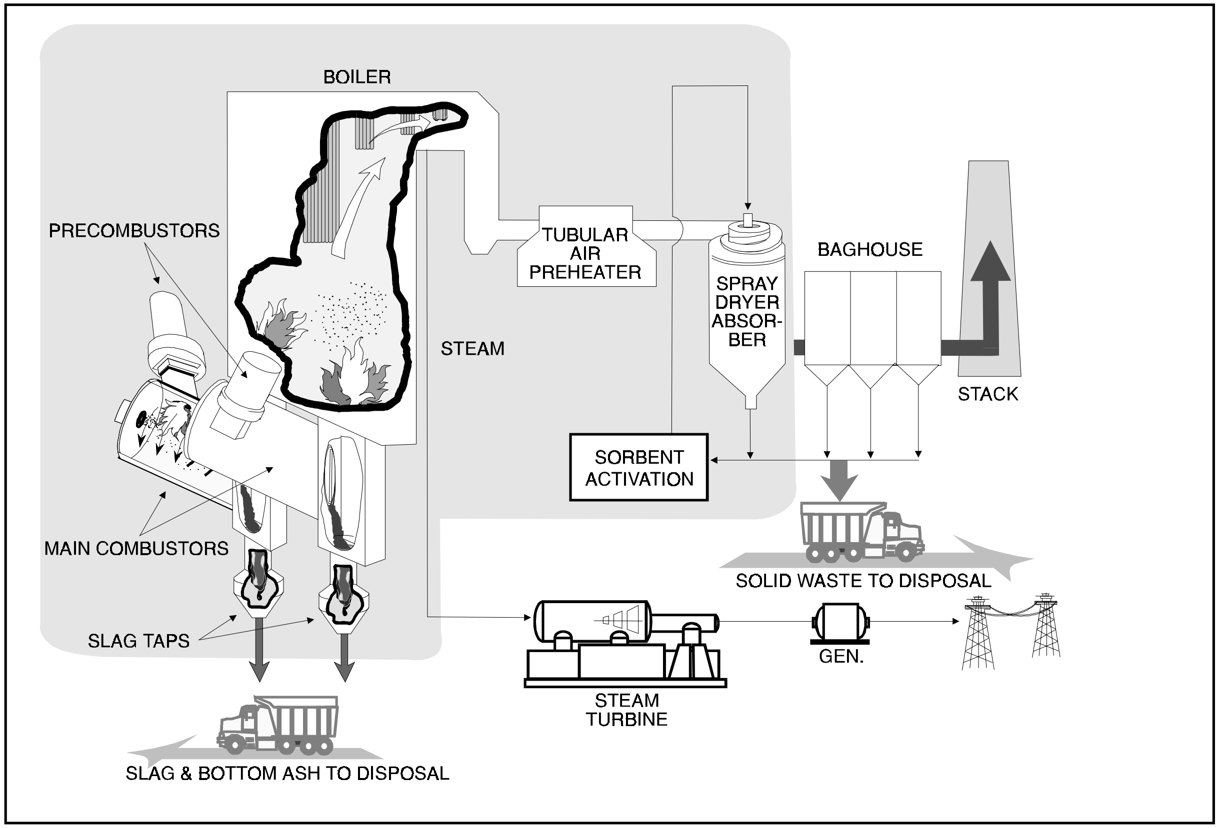
50 MWe (nominal electric output)

Project Funding

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

Project Objective

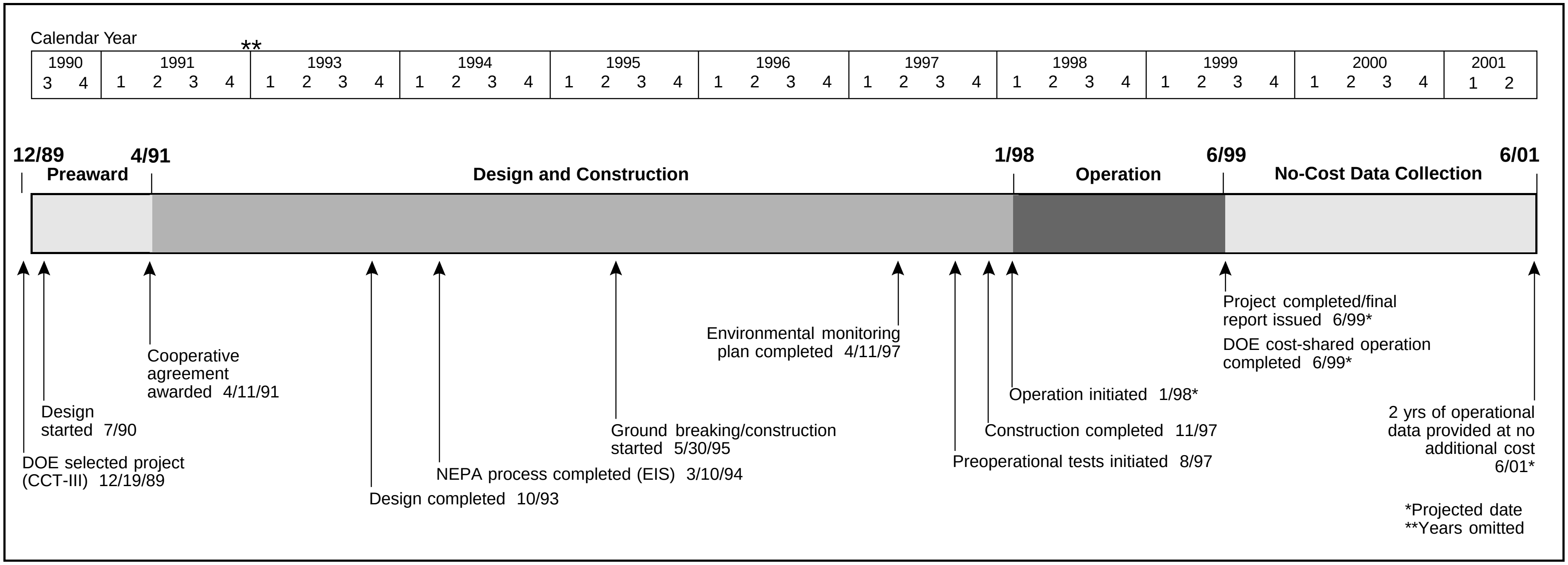
To demonstrate an innovative new power plant design featuring integration of an advanced combustor and heat recovery system coupled with both high- and low-temperature emissions control processes.



Technology/Project Description

The project is to be a nominal 50-MWe facility consisting of two pulverized-coal-fired combustor systems. Emissions of SO_2 and NO_x will be controlled using TRW's slagging combustion systems with staged fuel and air, a boiler that controls fuel- and thermal-related conditions, and limestone injection. Additional SO_2 will be removed using Babcock & Wilcox's activated recycle spray-dryer absorber system. Performance goals are NO_x emissions of less than 0.2 lb/10^6 Btu, particulate emissions of 0.015 lb/10^6 Btu, and 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 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 NO_x ports and to final overfire air ports.



Pulverized limestone ($CaCO_3$) for SO_2 control is fed into the combustor where most is flash calcined. The mixture of this lime (CaO) and the ash not slagged, called flash-calcined material, is removed in the fabric filter (baghouse) system. A small part of the flash-calcined material is disposed of, but most is conveyed to a mixing tank where water is added to form a 45% flash-calcined-material solids slurry. The slurry leaving the mixing tank is pumped to a grinding mill where it is mechanically activated by abrasive grinding. Feed slurry is pumped from the feed tank to the spray-dryer absorber where the slurry is atomized using Babcock & Wilcox's dry scrubbing technology. SO_2 in the flue gas reacts with the slurry droplets as water is simultaneously evaporated. SO_2 is further removed from the flue gas by reacting with the dry flash-calcined material on the baghouse filter bags.

The project site is adjacent to the existing Healy Unit #1 near Healy, AK, 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

Construction was completed on November 15, 1997, and startup and commissioning is under way. In July 1997, the boiler was fired on oil, and the turbine was loaded to produce 5 MW of electricity. Initial firing of the slagging combustiors on coal is scheduled for January 1998 when demonstration operations are initiated. The retrofit of Unit No. 1 (low-NO_x burners with overfire air) was completed, and its performance testing is expected early in 1998.

Commercial Applications

This technology has a wide range of applications. It is appropriate for any size utility or industrial boiler in new and retrofit uses. It can be used in coal-fired boilers as well as in oil- and gas-fired boilers because of its high ash-removal capability. However, cyclone boilers may be the most amenable type to retrofit with the slagging combustor because of the limited supply of high-Btu, low-sulfur, low-ash-fusion-temperature coal that cyclone boilers require. The commercial availability of cost-effective and reliable systems for SO_2, NO_x, and particulate control is important to potential users planning new capacity, repowering, or retrofits to existing capacity in order to comply with CAAA of 1990 requirements.

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
Alaskan Science & Technology Foundation—cofunder
Coltec Industries Inc.—diesel engine technology vendor
Energy and Environmental Research Center, University of North Dakota—fuel preparation technology vendor
R.W. Beck, Inc.—architect/engineer, designer, constructor
Usibelli Coal Mine, Inc.—coal supplier

Location

Fairbanks, AK (University of Alaska facility)

Technology

Coltec's coal-fueled diesel engine

Plant Capacity/Production

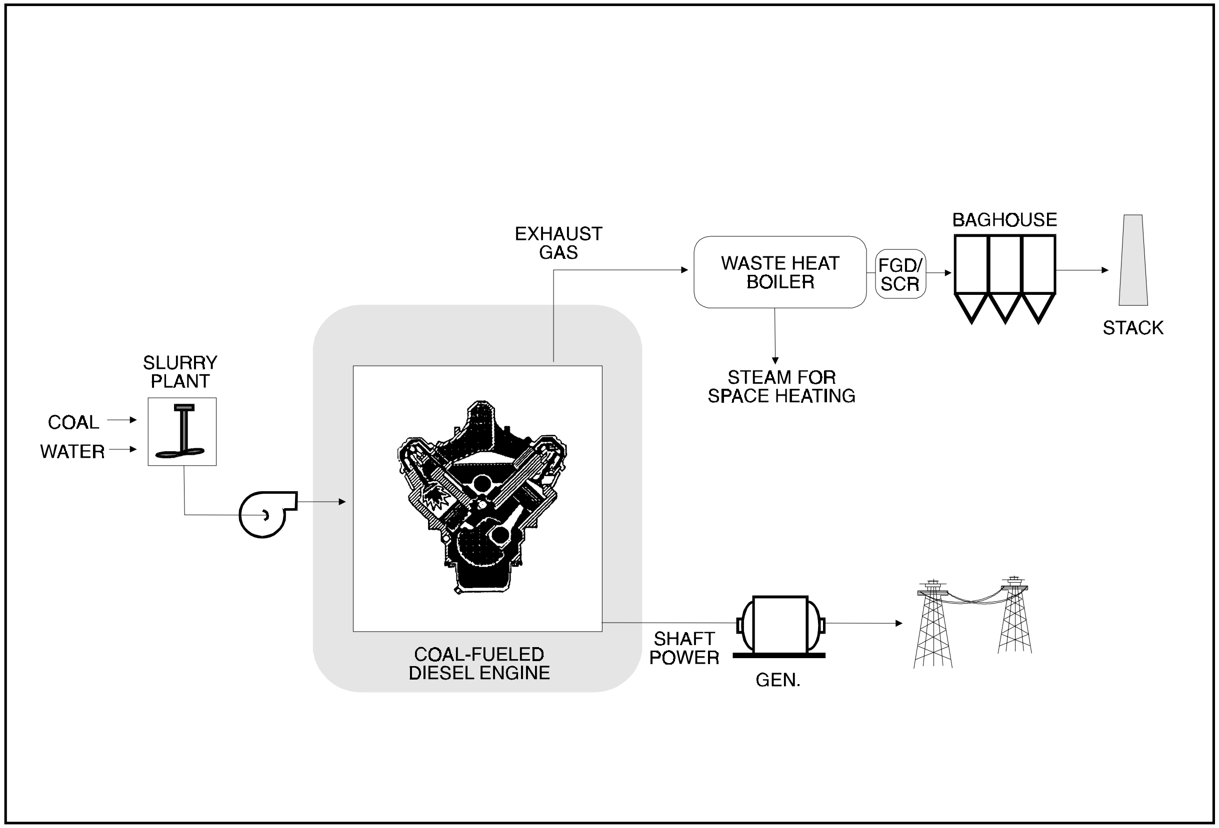
6.4 MWe (net)

Project Funding

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

Project Objective

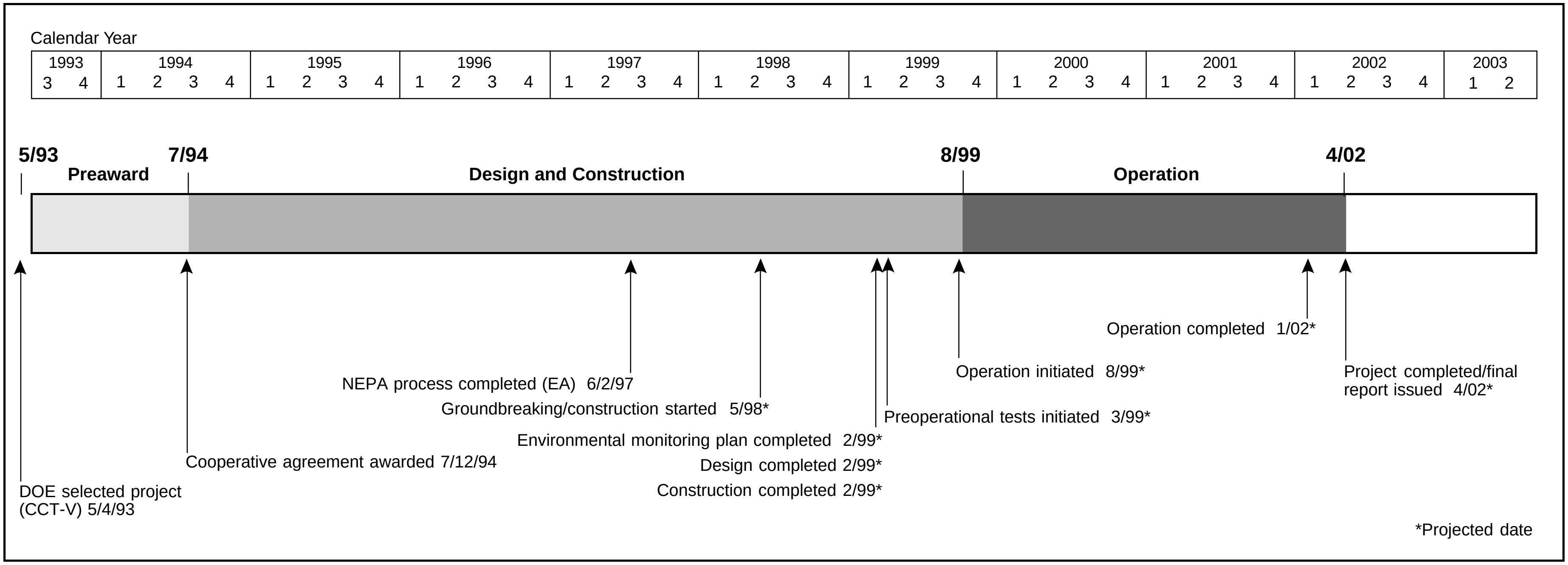
To prove the design, operability, and durability of the coal diesel engine during 6,000 hours of operation and verify the design and operation of an advanced drying/slurrying process for subbituminous Alaskan coals and for testing the coal slurry in the diesel and a retrofitted oil-fired boiler.



Technology/Project Description

The project is based on the demonstration of an 18-cylinder, heavy duty engine (6.4 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 NO_x and SO_2 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 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, AK. 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. On August 21, 1997, DOE 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, and restructure 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. Environmental 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.

The U.S. diesel market is projected to exceed 60,000 MWe (over 7,000 engines) through 2020. The worldwide market is 70 times the U.S. market. The technology is particularly applicable to dispersed power generation in the 5–20-MWe range, using indiginous coal in developing countries.

The JGC Corporation of Japan, a coal-water mixture and power supplier, has approached Coltec Industries about using the clean coal diesel engine for a 10-MWe power plant in Indonesia. JGC is processing Chinese coal shipments to Indonesia and recently has been using the same hot water drying/slurrying technique as in this CCT project.

Coal Processing for Clean Fuels Technology

Introduction

The coal processing 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_2 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, which completed operational testing in July 1997, has used 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 processed 500 tons per day of subbituminous coal and produced 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 have undergone 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.

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.

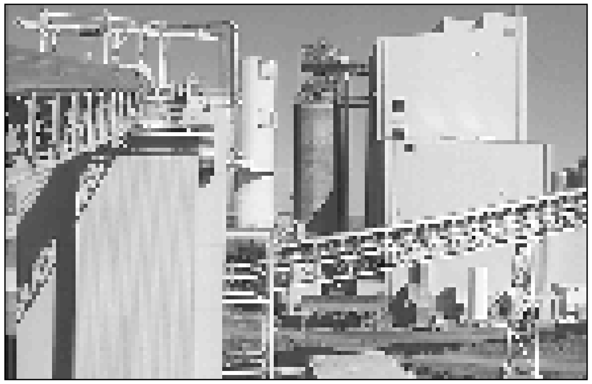
Exhibit 33 summarizes the process characteristics and size of the coal processing for clean fuels technologies presented in more detail in the project fact sheets.

Exhibit 33
CCT Program Coal Processing for Clean Fuels Technology Characteristics

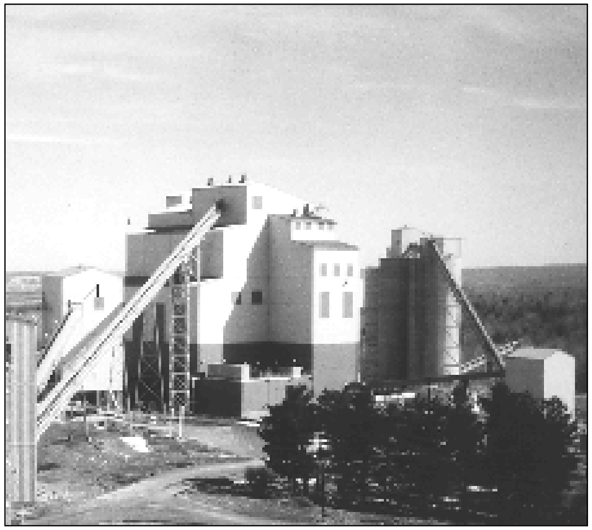
Project	**Process**	**Size**	**Fact Sheet**
Development of the Coal Quality Expert™	Coal Quality Expert™ computer software	Tested at 250–880 MWe	114
Self-Scrubbing Coal™: An Integrated Approach to Clean Air	Dense-medium cyclones with finely sized magnetite and sorbent addition for bituminous coals	500 tons/hr	118
Advanced Coal Conversion Process Demonstration	Advanced coal conversion process for upgrading low-rank coals	45 tons/hr	120
ENCOAL® Mild Gasification Project	Liquids-from-coal (LFC®) mild gasification to produce solid and liquid fuels	1,000 tons/day	122
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	124

▼ 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 12,800 hours and processed approximately 247,000 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

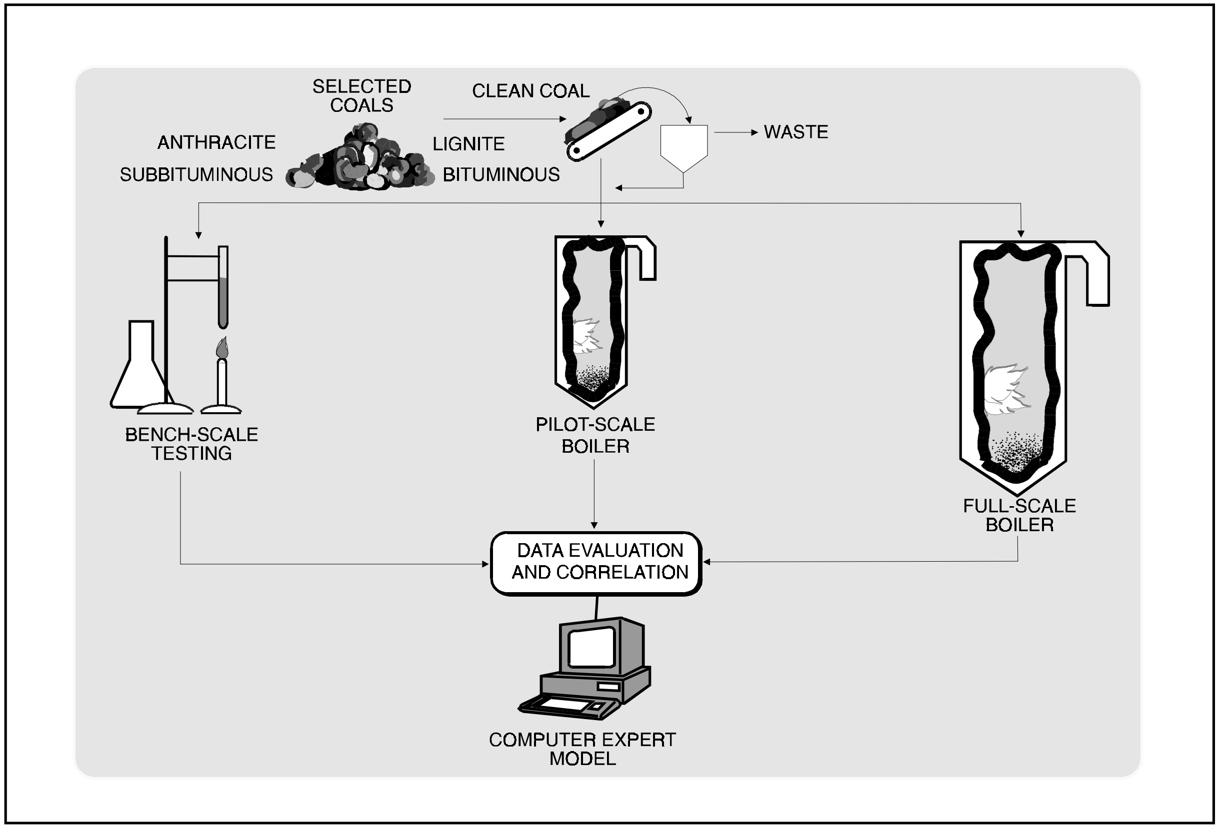
ABB Combustion Engineering, Inc.
CQ Inc.

Additional Team Members

Black & Veatch—cofunder and software developer
Electric Power Research Institute—cofunder
The Babcock & Wilcox Company—cofunder 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)



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 impact of fuel purchase decisions on coal-fired 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,

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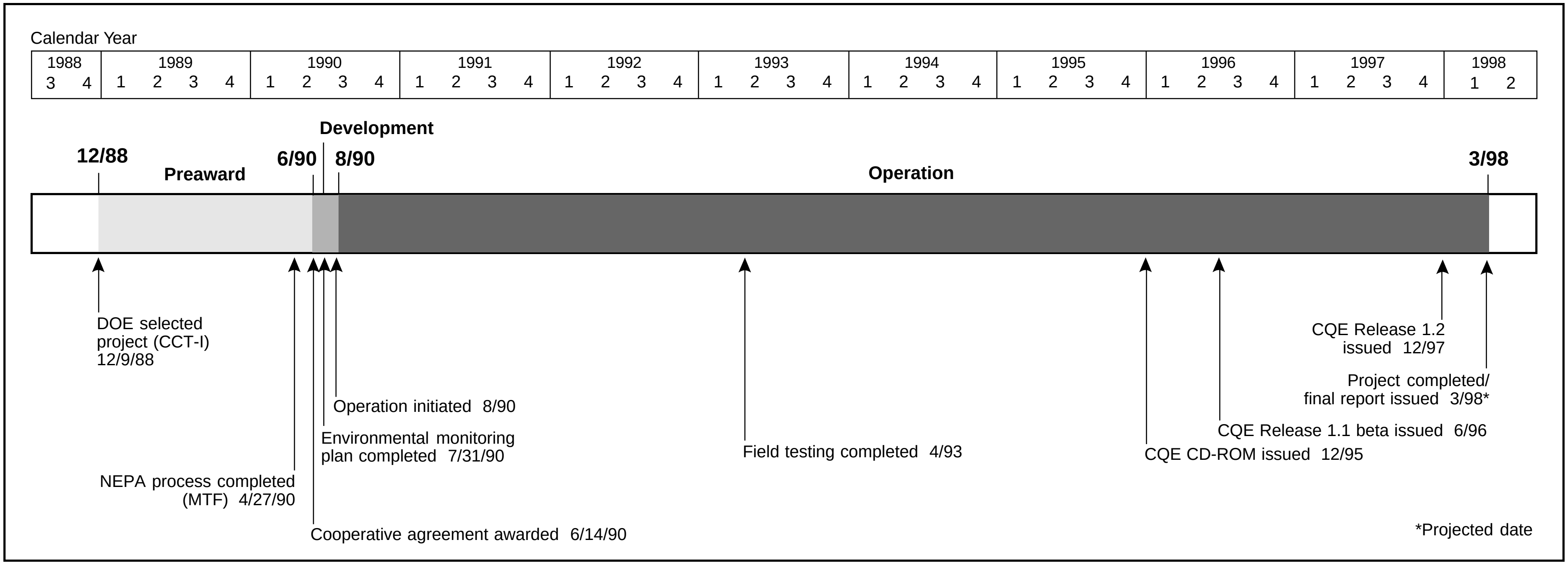
Coal Quality Expert, CQE, CQIS, and CQIM are trademarks of the Electric Power Research Institute.



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 dimensions: 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 performance 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 34. Technical support is available from Black & Veatch for licensed users.

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. 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) and the EPRI Fuels Web Server 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 manual. The Home Page also helps attract the interest of international utilities and consulting firms.

Exhibit 34
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	OS/2 WARP (3.0)

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

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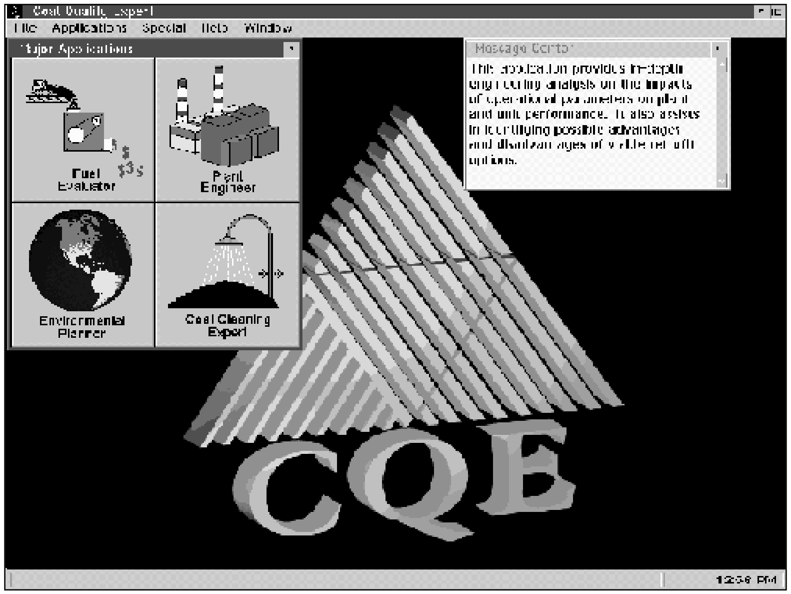
Scott M. Smouse, FETC, (412) 892-5725

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.)



This application provides in-depth engineering analysis on the impacts of operational parameters on plant and unit performance. It also assists in identifying possible advantages and disadvantages of viable retrofit options.

▲ 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

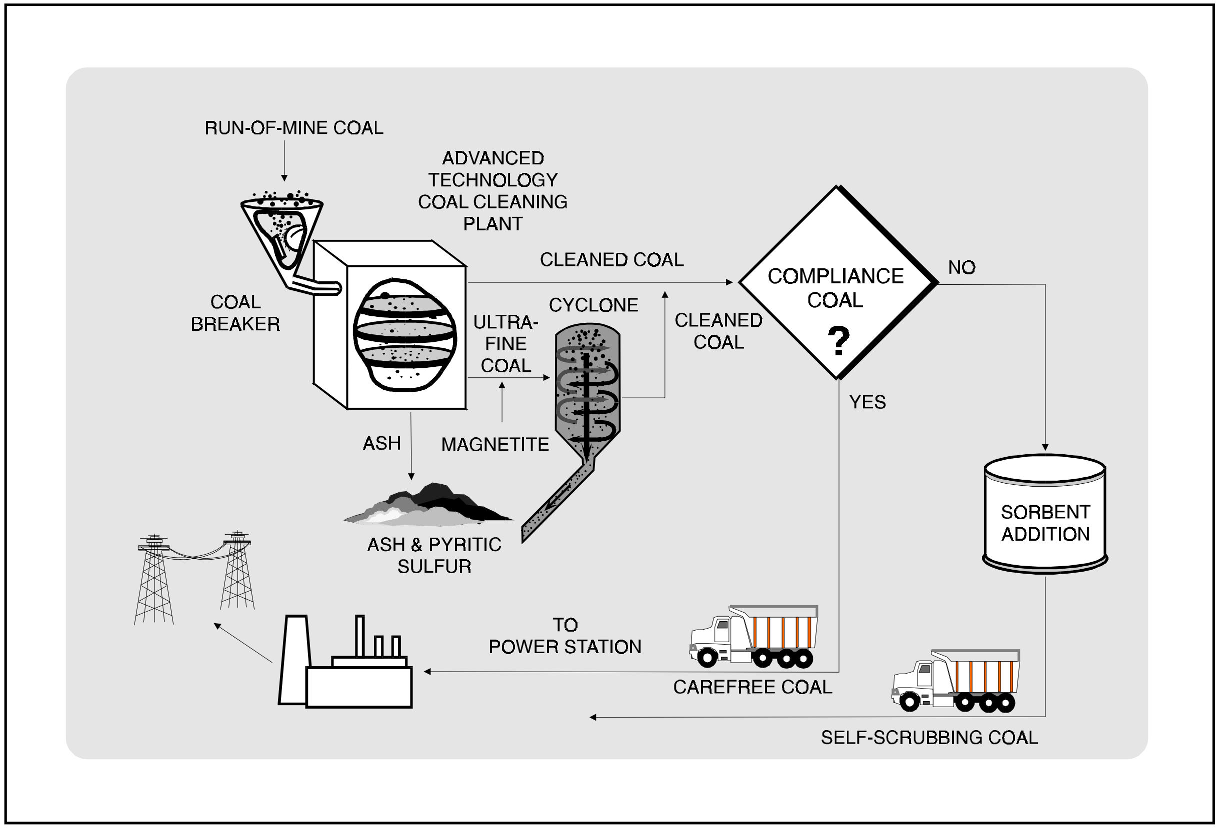
Plant Capacity/Production

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

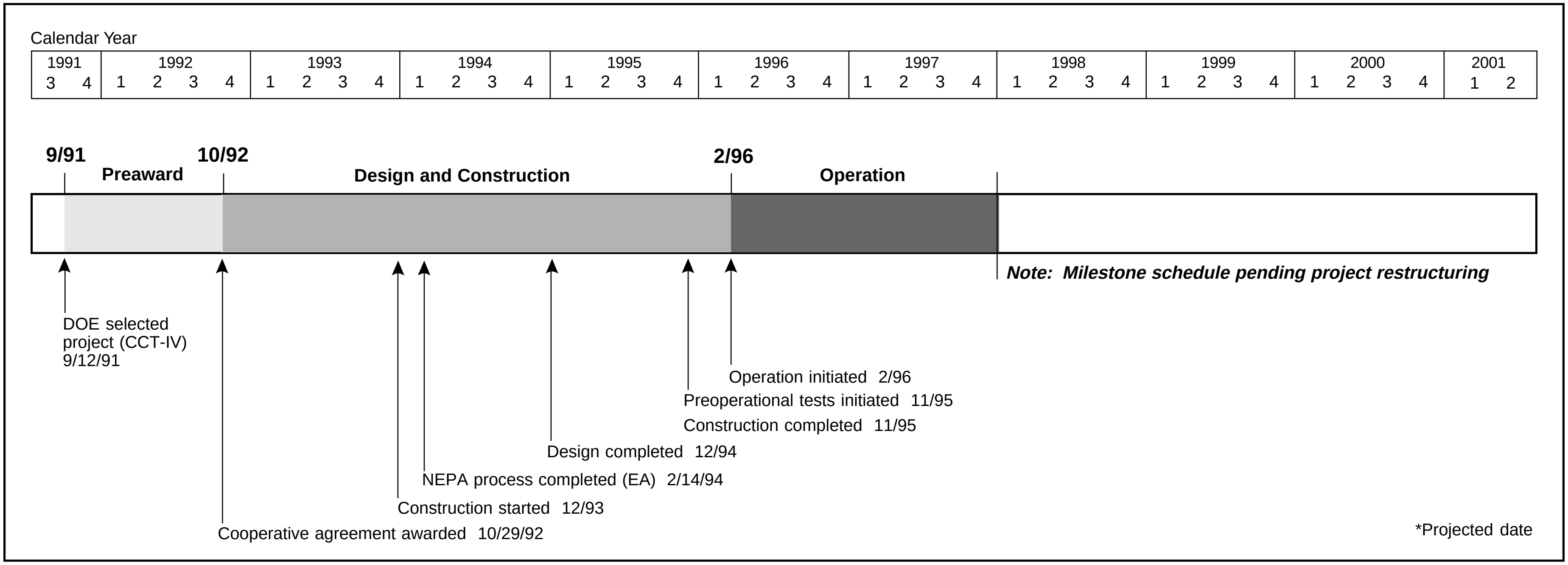
To demonstrate advanced coal-cleaning unit processes to produce low-cost compliance coals that can meet full requirements for commercial-scale utility power plants to satisfy provisions of the CAAA.

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_2 emissions limits, others cannot due to the high content of organic sulfur in their coal feedstocks. When compliance coal cannot be produced by reducing pyritic sulfur, Self-Scrubbing Coal™ can be produced to achieve compliance.

Self-Scrubbing Coal™ is produced by taking Carefree Coal™, with its reduced pyritic sulfur and ash content, and adding to it sorbents, promoters, and catalysts. Self-Scrubbing Coal™ is expected to achieve compliance with virtually any U.S. coal feedstock through in-boiler absorption of SO_2 emissions. The reduced ash content of the Self-Scrubbing Coal™ permits 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.

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.

Due to the inability to run the plant, financial strains have been placed on Custom Coals. On May 13, 1997, Custom Coals filed for Chapter 11. Tanoma Coal Sales, Inc., has made an offer to buy the site and continue the project. On August 28, 1997, Custom Coals formally accepted Tanoma's offer. The Federal Bankruptcy Court approved the sale in a hearing on September 30, 1997. Tanoma is preparing a detailed proposal to DOE concerning project completion. A market analysis has been completed. A cost analysis has been prepared for the project. DOE is evaluating Tanoma's offer; DOE must approve the proposal before the project can proceed.

Commercial Applications

Commercialization of Self-Scrubbing Coal™ has the potential of bringing into compliance about 164 million tons/yr of bituminous coal that cannot meet emissions limits through conventional coal-cleaning. This represents 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%.

Custom Coals has been 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.

Advanced Coal Conversion Process Demonstration

Participant

Rosebud SynCoal Partnership (a partnership of Western Energy Company, and Western SynCoal)

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)

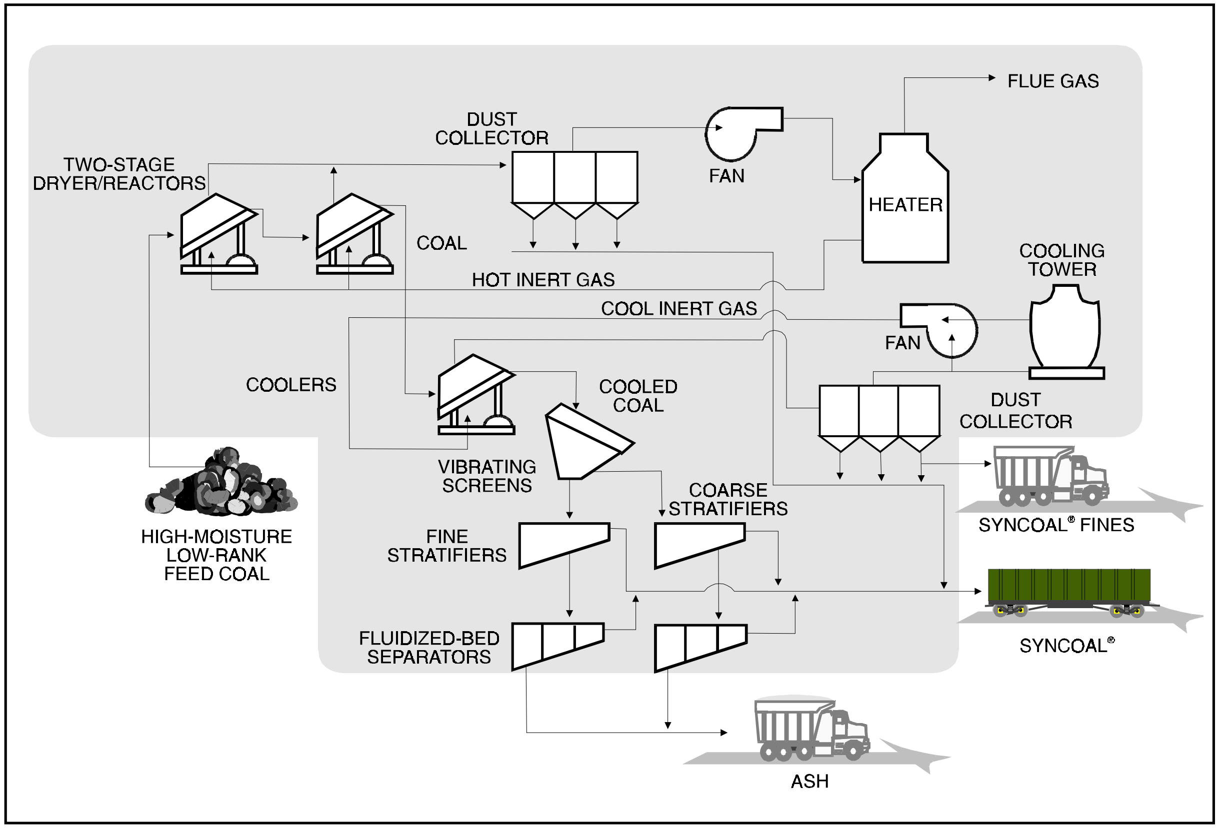
Project Funding

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.

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; for example, for the month of September 1997, the plant achieved a 91% capacity factor. It has processed more than 1.8 million tons of coal, and on April 19, 1997, the plant produced its one millionth ton of SynCoal®. Total sales of SynCoal® product have reached nearly 2 million tons.

SynCoal® products totaling over 220,000 tons have been delivered over an extended period of time to several industrial customers, including Ash Grove Cement, Bentonite Corporation, Wyoming Lime, Continental Lime,

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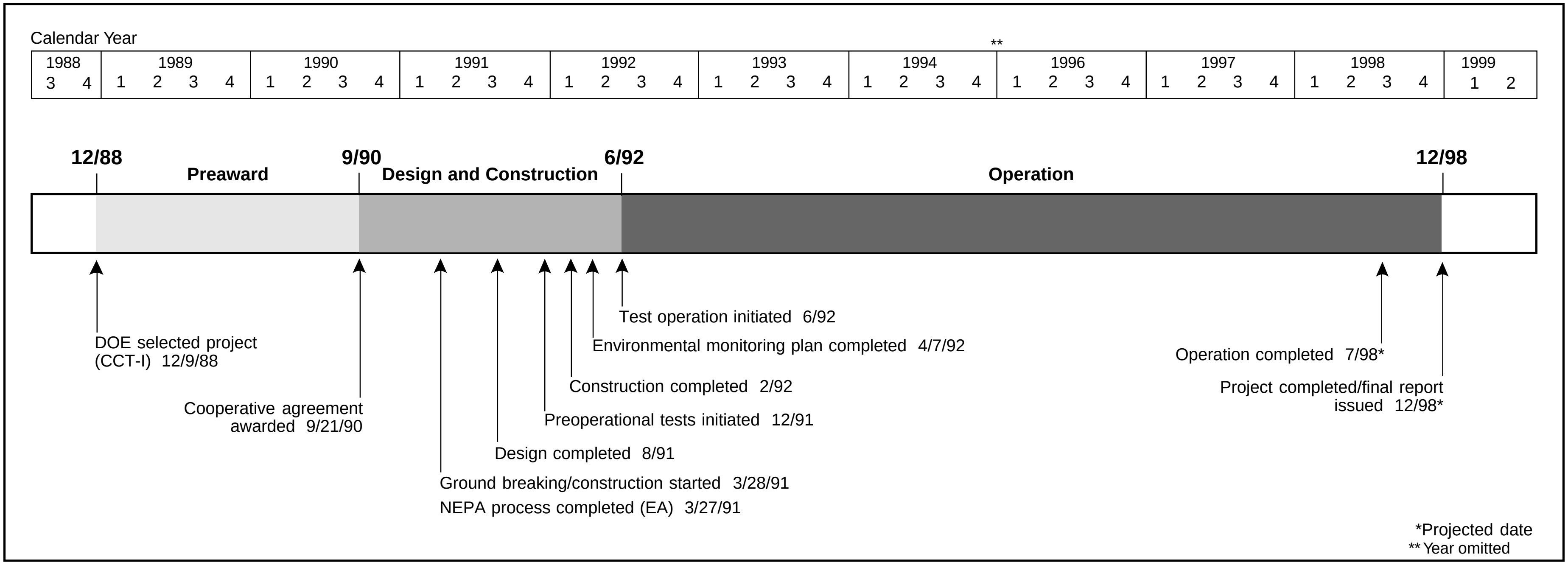
SynCoal is a registered trademark of the Rosebud SynCoal Partnership.



and Empire Sand and Gravel. In May 1997, tests were performed on several petroleum 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_2 emissions were reduced by 21% overall, generation increased at normal operating loads, and there was no noticeable impact on NO_x emissions.

SynCoal® and a blend of regular SynCoal® and fines are being sent to Montana Power's Colstrip Project Units 1 and 2, where tests will provide information on boiler efficiency, output, and air emissions. Feasibility testing had been successful and showed that by properly blending the product with DSE (dust stabilization enhancement) dust was controlled, making it possible to deliver the blend. In November 1996, 25 tons of specific-sized 1.7 sulfur 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_2 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 closely with a Japanese equipment and technology company to expand into Asian markets. Prospects also are being pursued in Europe. In September 1997, Rosebud SynCoal signed a non-exclusive technology license with NRG Energy.

ENCOAL® Mild Coal Gasification Project

Project completed.

Participant

ENCOAL® Corporation (a subsidiary of Bluegrass Coal Development Company, which is a unit of Zeigler Coal Holding Company)

Additional Team Members

Bluegrass Coal Development Company (formerly named SMC Mining Company)—cofunder

TEK-KOL (partnership between SGI International and a subsidiary of Zeigler Coal Holding Company)—technology owner, supplier, and licenser

SGI International—technology developer

Triton Coal Company—host and coal supplier

The M.W. Kellogg Company—engineer and constructor

Location

Near Gillette, Campbell County, WY (Triton Coal Company's Buckskin Mine)

Technology

SGI International's Liquids-From-Coal (LFC®) process

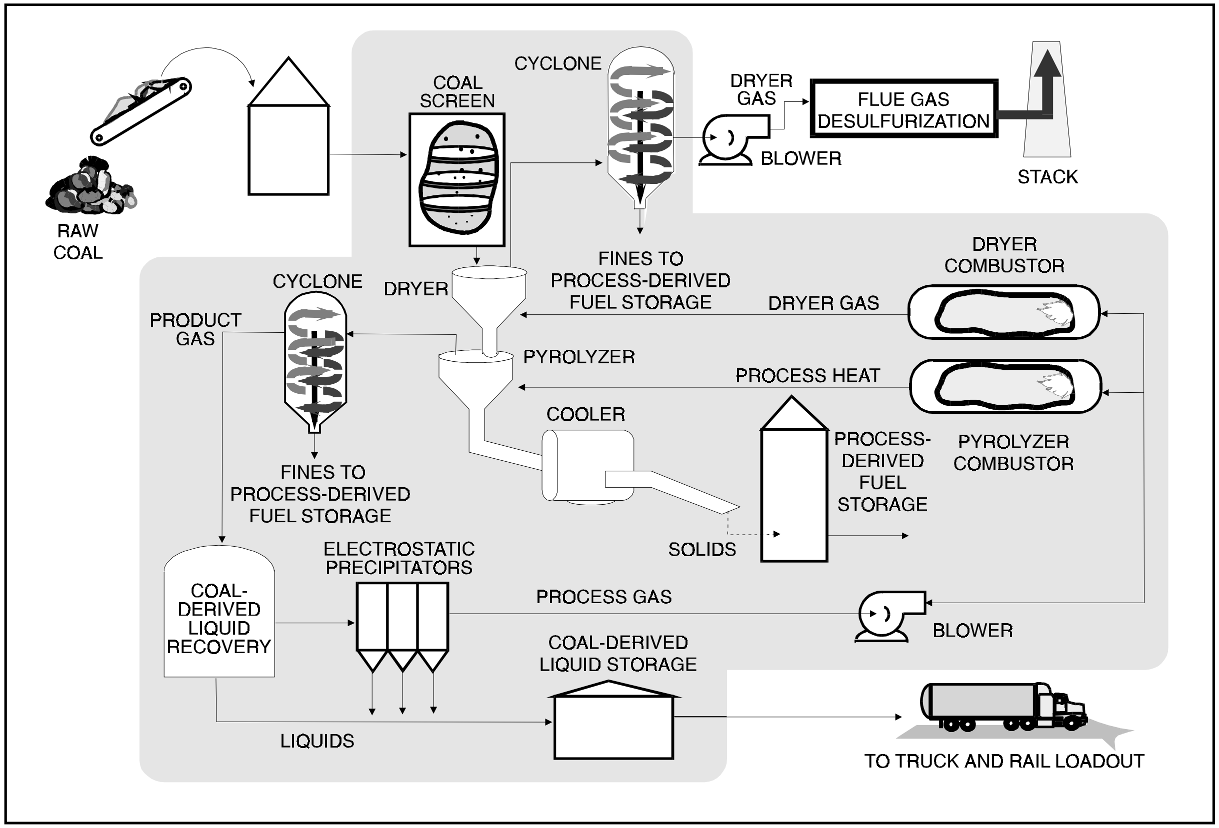
Plant Capacity/Production

1,000 tons/day of subbituminous coal feed

Project Funding

Total project cost	$90,664,000	100%
DOE	45,332,000	50
Participant	45,332,000	50

ENCOAL, LFC, CDL, and PDF are registered trademarks of TEK-KOL.



Project Objective

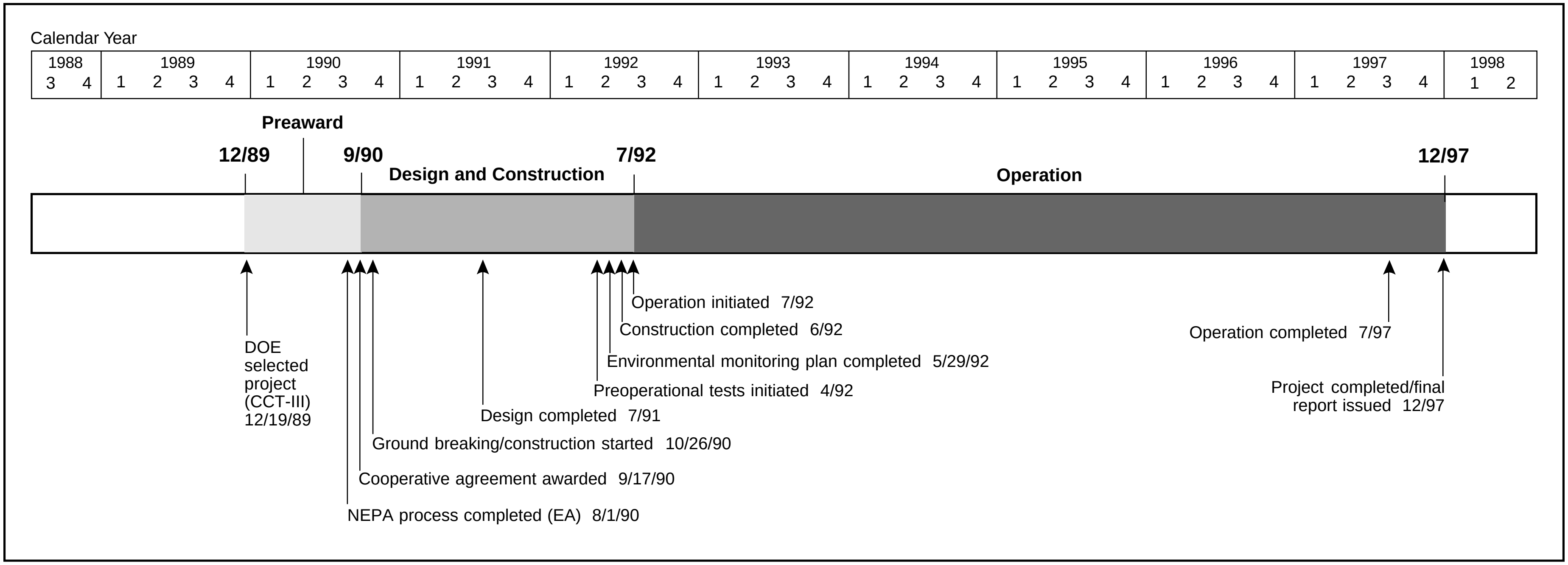
To demonstrate the integrated operation of a number of novel processing steps to produce two higher value fuel forms from mild gasification of low-sulfur subbituminous coal; to provide sufficient products for potential end users to conduct burn tests.

Technology/Project Description

The ENCOAL® mild coal gasification process involves heating coal under carefully controlled conditions. Coal is fed into a rotary grate dryer where it is heated by a hot gas stream to reduce the coal's moisture content. The solid bulk temperature is controlled so that no significant amounts of methane, CO, or CO_2 are released from the coal. The solids from the dryer are conveyed to a pyrolyzer where the rate of heating of the solids and residence time are controlled to achieve desired properties of the fuel products. During processing in the pyrolyzer, all remaining free water is removed, and a chemical reaction occurs that results in the release of volatile gaseous material. Solids exiting the pyrolyzer are cooled and transferred to a Process-Derived Fuel (PDF®) storage bin.

The gas produced in the pyrolyzer is sent through a cyclone for removal of the particulates and then cooled to condense the liquid-fuel products, or Coal-Derived Liquids (CDL®). Most of the gas from the condensation unit is recycled to the pyrolyzer. The rest of the gas is burned in combustors to provide heat for the pyrolyzer and the dryer. NO_x emissions are controlled by staged air injection.

The offgas from the dryer is treated in a wet venturi scrubber to remove particulates and a horizontal scrubber



to remove SO_2, both using a sodium carbonate solution. The treated gas is vented to a stack, and the spent solution is discharged into a pond for evaporation.

The ENCOAL® project is located within Campbell County, WY, at Triton Coal Company's Buckskin Mine, 10 miles north of Gillette. The plant has made use of the present coal-handling facilities at the mine. Subbituminous coal with 0.4–0.9% sulfur content was used.

Project Status/Accomplishments

The project completed operational testing in July 1997. During the 5-year operational demonstration, the plant operated approximately 12,800 hours. The plant processed approximately 247,000 tons of coal, operating at a coal feed rate of 500 tons/day, as constrained by the capacity of the new vibrating fluid-bed subsystem, and producing 250 tons/day of PDF® and 280 barrels/day of CDL®. By project's end, more than 83,000 tons of specification PDF® had been shipped to seven utility and industrial customers in six states, and 203 tank cars of CDL® had been shipped to light industrial customers in seven states.

In addition to Buckskin coal, ENCOAL® tested two other coals: 3,280 tons of North Rochelle mine subbituminous coal and 3,000 tons of Wyodak coal. Also, Alaskan subbituminous coal, North Dakota lignite, and Texas lignites were laboratory tested.

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 feedstock, and the production of low-sulfur liquid products requiring no further treatment for the fuel oil market. The product fuels are expected to be used economically in commercial boilers and furnaces and to reduce significantly SO_2 emissions at industrial and utility facilities currently burning high-sulfur bituminous coals or fuel oils.

ENCOAL® is continuing plant operation as a commercial facility. Feasibility studies have been completed for two Indonesian projects and one Russian project; a follow-up study has been approved by the Russian government and private participants.

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—utility advisor

Location

Kingsport, Sullivan County, TN (Eastman Chemical Company's Integrated Coal Gasification Facility)

Technology

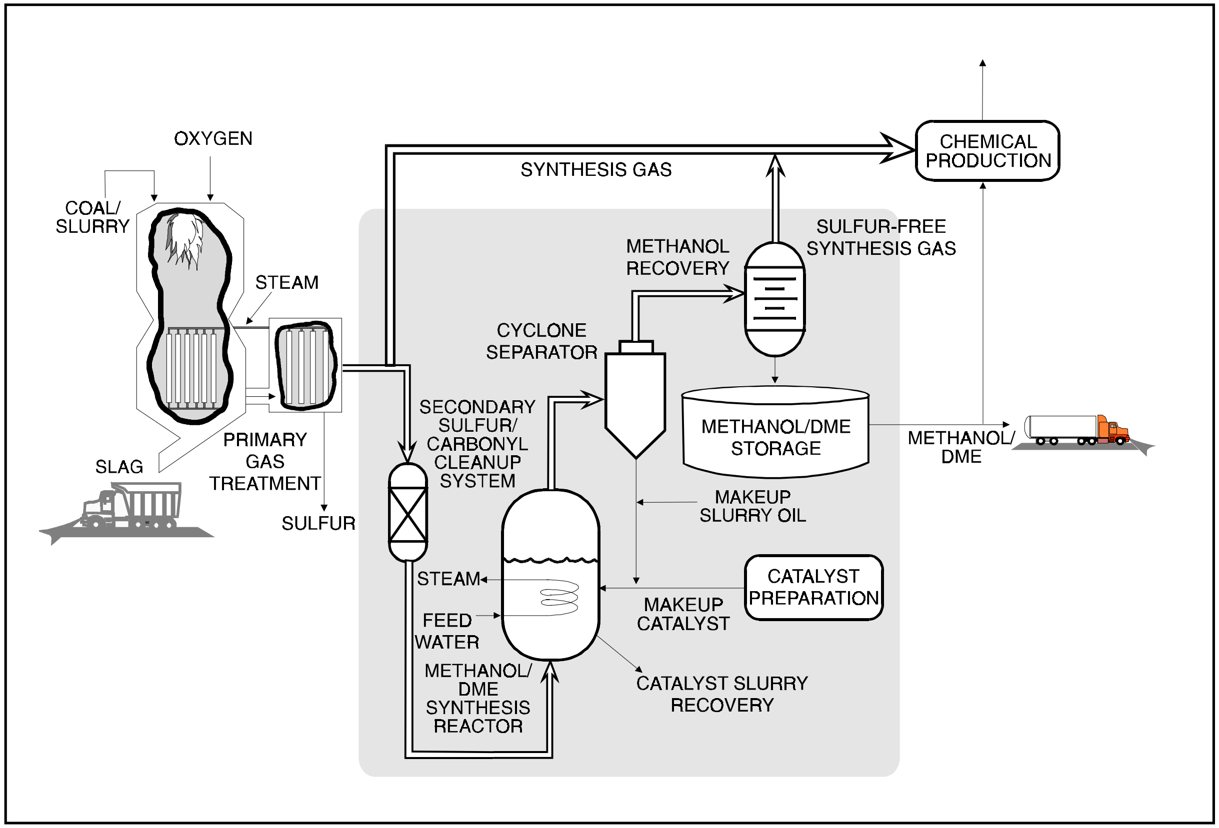
Air Products and Chemicals' liquid-phase methanol (LPMEOH™) process

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



Project Objective

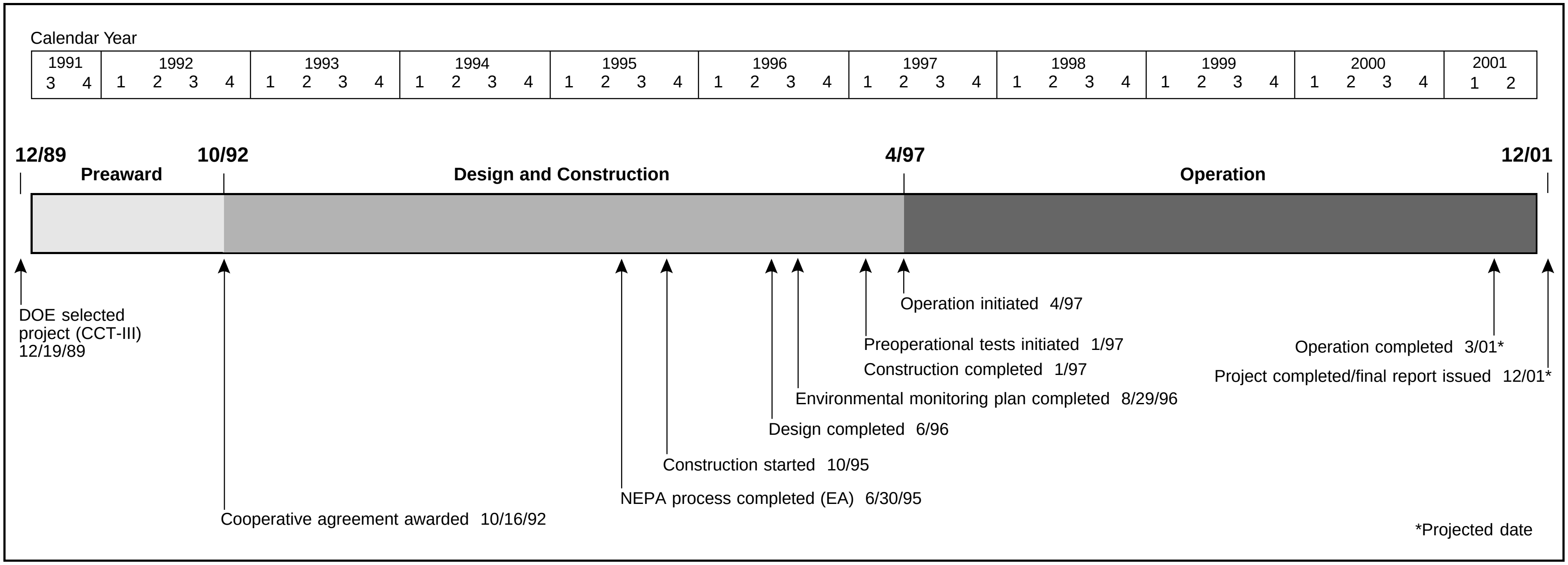
To demonstrate on a commercial scale the production of methanol from coal-derived synthesis gas using the LPMEOH™ process; and to determine the suitability of methanol produced during this demonstration for use as a chemical feedstock or as a low-SO_x, low-NO_x alternative fuel in stationary and transportation applications. To demonstrate, if practical, the production of dimethyl ether (DME) as a mixed coproduct with methanol.

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.

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 storable 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.

LPMEOH is a trademark of Air Products and Chemicals, Inc.



Project Status/Accomplishments

Construction was completed and commissioning and start-up began in January 1997. 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. Eastman accepted all 1.67 million gallons of product methanol from the initial run for use in its onsite chemicals production.

The second operating period ended July 28, 1997 following 985 hours on stream with 100% unit availability. During August, a 12-day test using CO-rich, coal-derived synthesis gas feed was completed; methanol production rates averaged 58,500 gal/day (190 tons/day).

The third operating period ended on November 3, 1997, with the longest continuous period (31 days) of operation. Catalyst concentration was increased to the design condition of 40% (wt), and the reactor temperature was increased from 482 ºF (the design condition) to 500 ºF. Overall unit availability from start-up has approached 90%.

Reactor performance has shown faster decline than expected. Follow-up sampling has confirmed the presence of arsine at levels similar to those measured in 1994, prior to installation of an arsine guard bed. Recently, the arsine guard bed material and the aged reactor catalyst were replaced in preparation for the resumption of demonstration operations. To assist in the restart, the Alternative Fuels Field Test Unit, a transportable laboratory equipped with an autoclave and analytical equipment, was set up at the Kingsport site. In addition, laboratory autoclave testing and catalyst evaluations continue at Air Products' Allentown facilities.

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_x characteristics when burned. Methanol can be produced from coal as a coproduct in an IGCC facility.

DME has several commercial uses. In a storable blend with methanol, the mixture can be used as peaking fuel in IGCC electric power generating facilities. 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 is an environmentally friendly aerosol for 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 expects to market the technology through licensing, owning/operating, and tolling arrangements.

Industrial Applications Technology

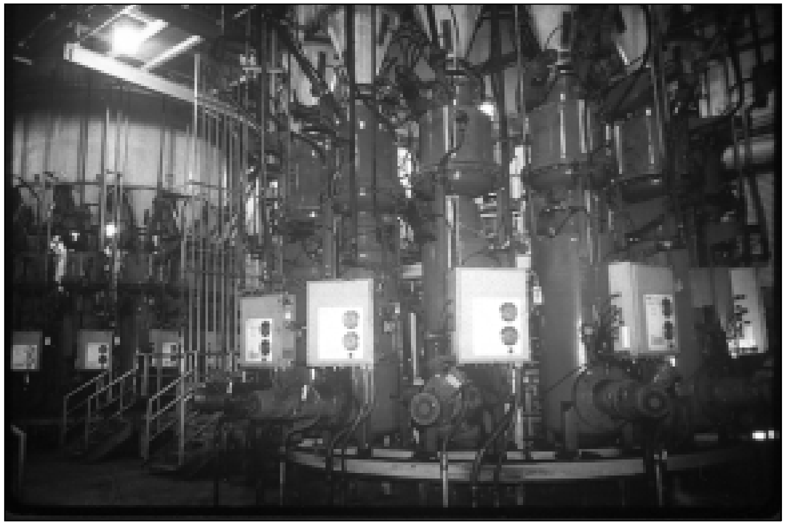
Introduction

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_2 emissions and also to address growing solid waste management problems, industry sponsored the demonstration of an innovative SO_2 scrubber. The successfully demonstrated Passamaquoddy Technology Recovery Scrubber™ uses cement kiln dust, otherwise discarded as waste, to control SO_2 emissions, 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_2 and NO_x controls, tube fouling, and the need for a coolant water circuit for the combustor. Oil/gas-fired units are not high SO_2 or NO_x 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



▲ 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 35
CCT Program Industrial Applications Technology Characteristics

Project	Process	Size	Fact Sheet
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	128
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	Advanced slagging combustor with staged combustion and sorbent injection	23 million Btu/hr	130
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	134
Cement Kiln Flue Gas Recovery Scrubber	Cement kiln dust used to capture SO_2; dust converted to feedstock; and fertilizer and distilled water produced	1,450 tons/day of cement	136

combustor stages introduction of air to control NO_x, injects sorbent to control SO_2, slags the ash in the combustor to prevent tube 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.

Exhibit 35 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

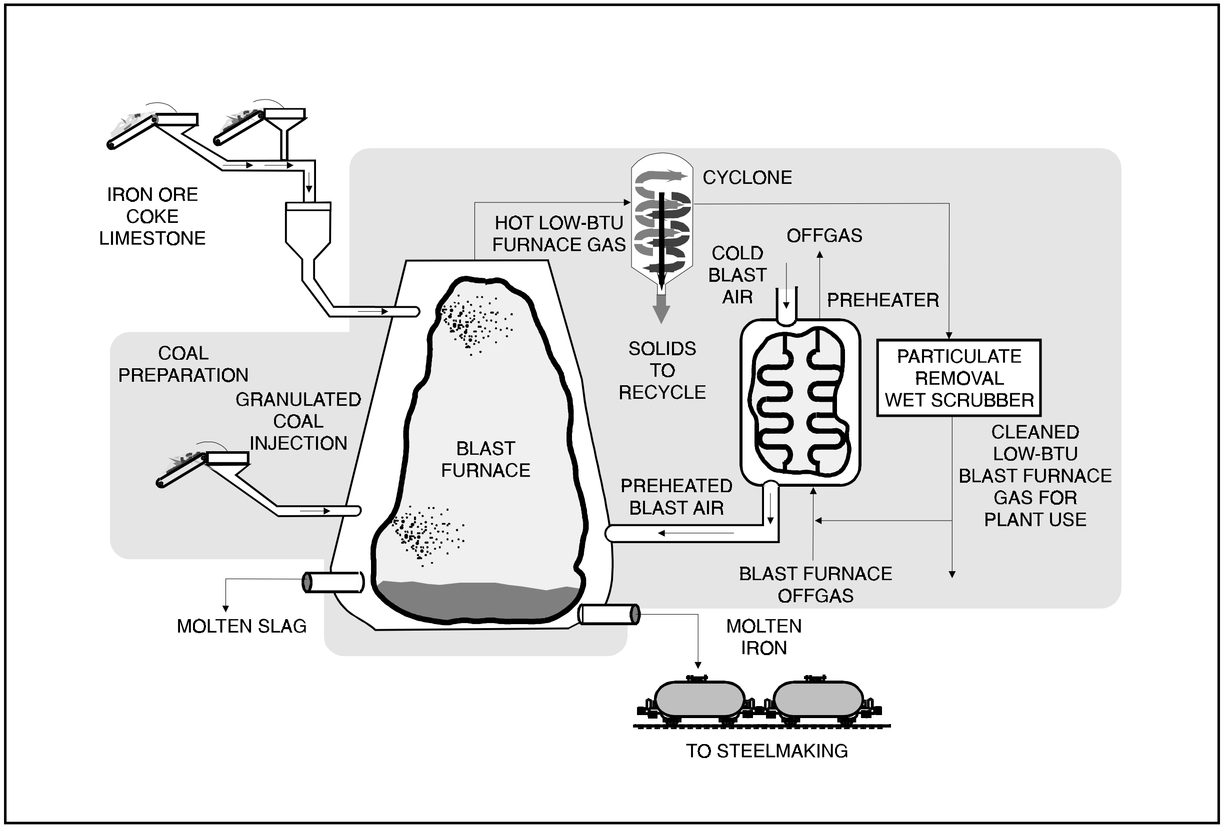
7,000 net tons/day of hot metal (each blast furnace)

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.

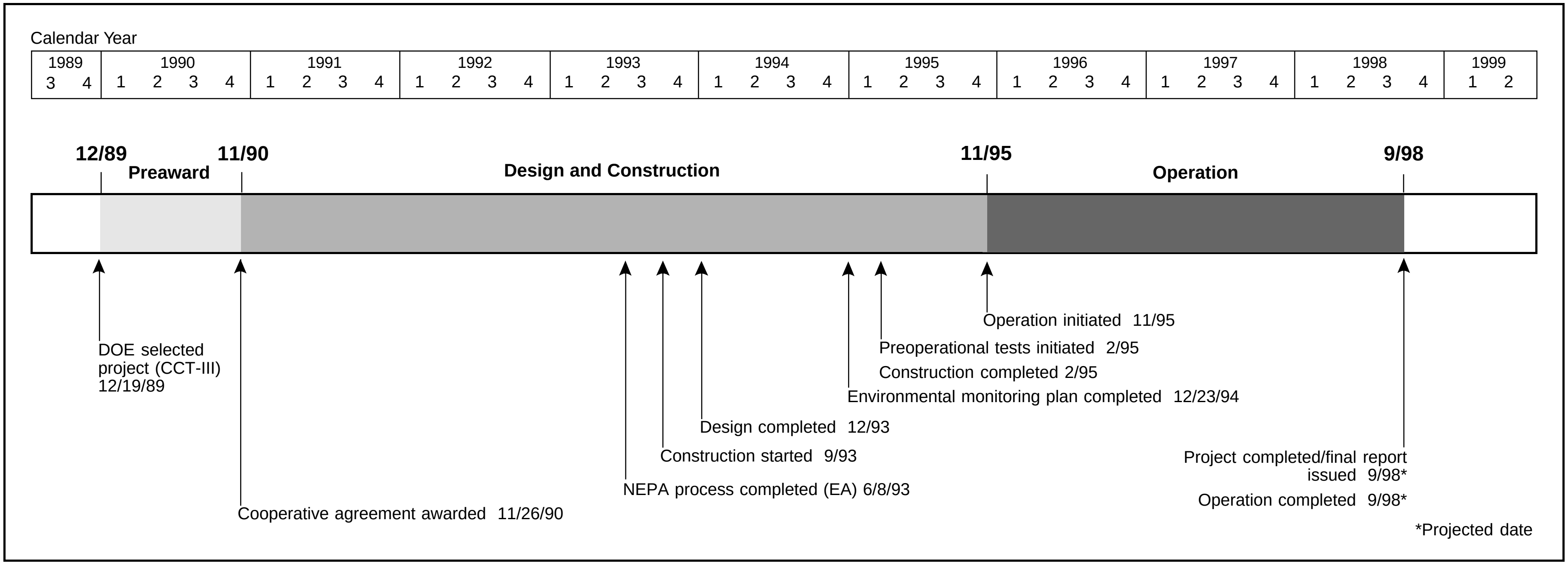


Technology/Project Description

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 NO_x, SO_2, and air toxics and coal could replace up to 40% of the coke requirement, BFGCI technology has significant potential to reduce 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 SO_2 or NO_x. Sulfur from the coal is removed by the limestone flux and bound up in the slag, which is a salable by-product. In addition to the net 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 coal having 0.4–0.9% sulfur will be tested also.

Project Status/Accomplishments

From July to September 1997, Furnace C was operated with an average coal injection rate of 261–271 lb/net ton of hot metal on low-volatile bituminous coal. With coal injection, the furnace continued to operate with a coke rate of approximately 663–674 lb/net ton of hot metal, down from a reference point of 770 lb/net ton of hot metal using natural gas.

During the same time frame, the injection rate on Furnace D averaged 193–201 lb/net ton of hot metal and a coke rate of 702–718 lb/net 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.

Operational testing of Furnace C on high ash, low volatile coal has been completed and is being analyzed. It appears that as ash increases, the coke rate begins to increase.

Operating experience during the past year seems to indicate that the coal injection rate can increase if the overall furnace iron production rate is held constant or slightly decreased. Coal injection rates much greater than 300 lb/net ton of hot metal may require major modifications in burden distribution practices.

Burden compositions and oxygen injection are still being adjusted to increase permeability and improve operation and yield of hot metal. Tuyere replacement rate has been significantly reduced.

In further testing, injection rates will be increased while maintaining stable, high iron production rates. Modifications will continue on primary feed cyclones to convert to all stainless steel. Further testing of different coals will include a direct comparison of granular versus pulverized coal injection.

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 10%. 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 United States Steel's Fairfield 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

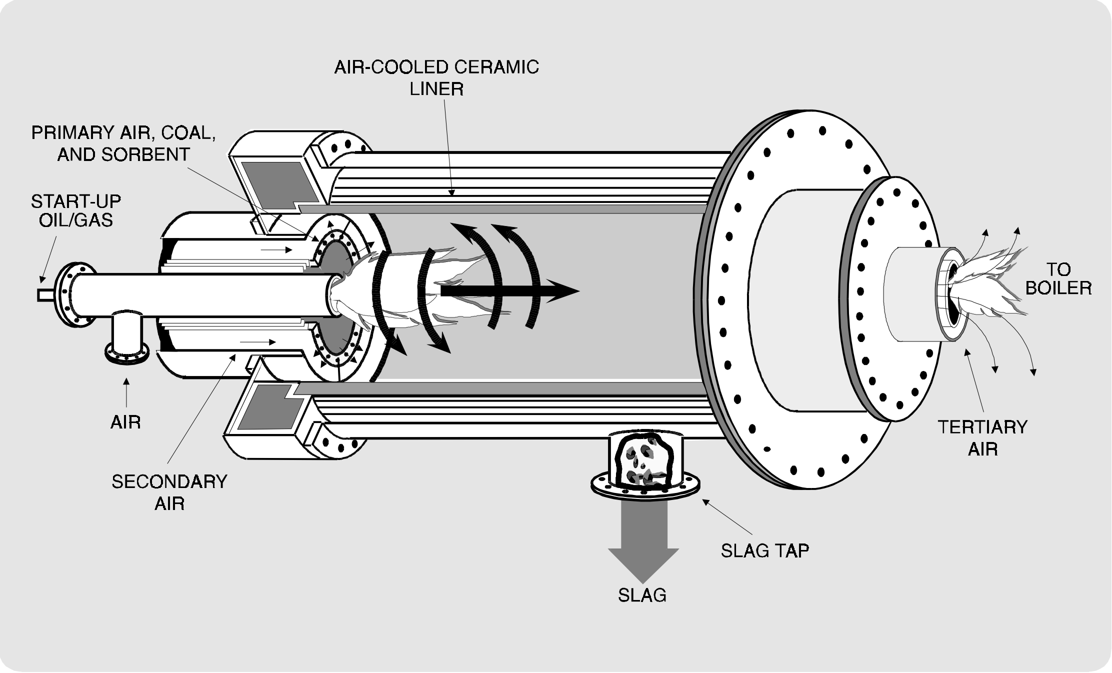
Pennsylvania bituminous, 1.0–3.3% sulfur

Project Funding

Total project cost	$984,394	100%
DOE	490,149	50
Participant	494,245	50

Project Objective

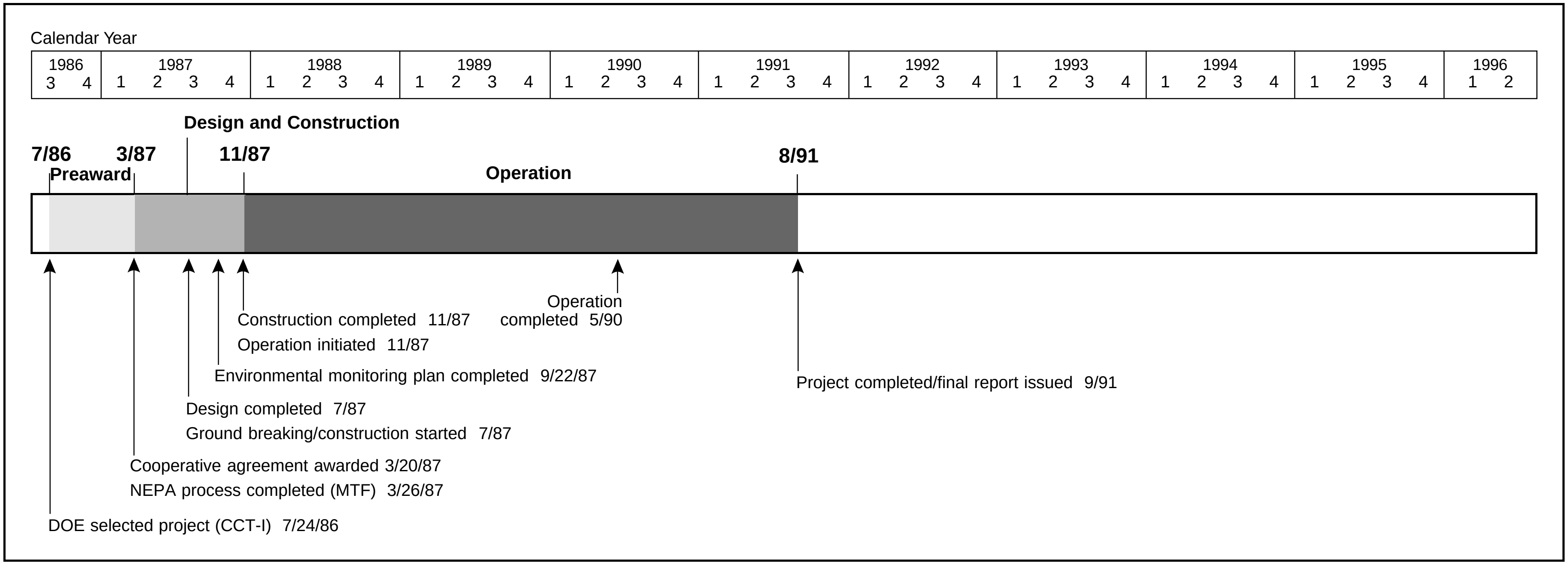
To demonstrate that an advanced cyclone combustor can be retrofitted to an industrial boiler and that it can simultaneously remove up to 90% of the SO_2 and 90–95% of the ash within the combustor and reduce NO_x to 100 ppm.



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 combustor was designed to retain as slag a high percentage of the ash and sorbent fed to the combustor. For NO_x control, the combustor is operated fuel rich, with final combustion taking place in the boiler furnace to which the combustor is attached. SO_2 is captured by injection of limestone into the combustor. The cyclonic action inside the combustor forces the coal ash and sorbent to the walls where it can be collected as liquid slag. Under optimum operating conditions, the slag contains a significant fraction of vitrified coal sulfur. Downstream sorbent injection into the boiler provides additional sulfur removal capacity.

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_2 removal efficiencies of over 80% were achieved with sorbent injection in the furnace at various calcium-to-sulfur molar ratios (Ca/S).
- SO_2 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_x 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_x, SO_2, 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_x reduction was achieved by staged combustion, and SO_2 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

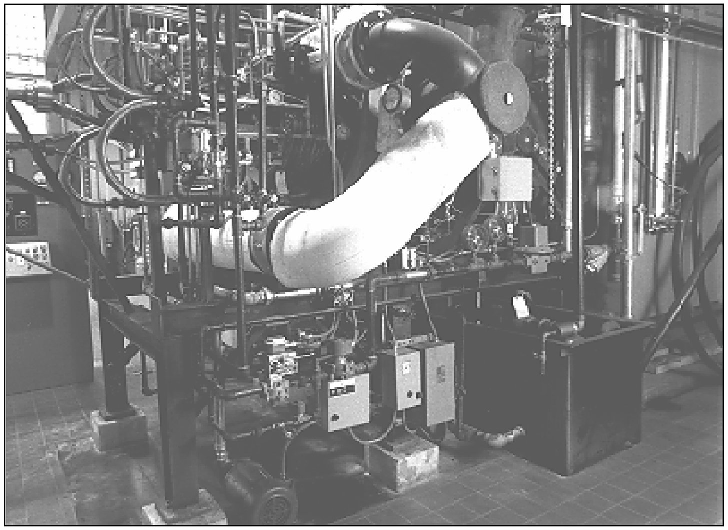
A maximum of over 80% SO_2 reduction measured at the boiler outlet stack was achieved using sorbent injection in the furnace at various Ca/S molar ratios. A maximum SO_2 reduction of 58% was measured at the stack with limestone injection into the combustor at a Ca/S of 2. A maximum of one-third of the 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_x 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_x 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 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.



▲ The slagging combustor, associated piping, and control panel for Coal Tech's advanced ceramic-lined slagging combustor are shown.

Operational Performance

Combustion efficiencies exceeded 99% after proper operating procedures were achieved. Combustor turndown 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.

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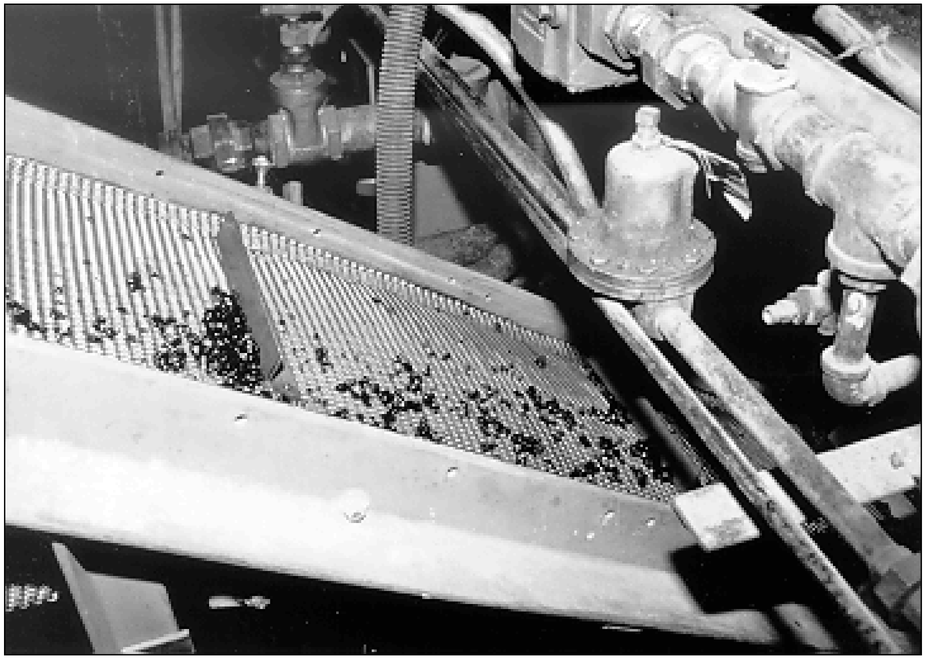


▲ Coal Tech's slagging combustor demonstrated the capability to retain, as slag, a high percentage of the non-fuel components injected into the combustor. The slag, shown on the conveyor, is essentially an inert glassy by-product with value in the construction industry as aggregate or in the manufacture 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 Centerior Energy Corporation, Air Products and Chemicals, Inc., and the Geneva Steel Company)

Additional Team Members

Geneva Steel Company—cofunder and host; constructor and operator of COREX® unit

Centerior Energy Corporation—cofunder

Air Products and Chemicals, Inc.—cofunder; 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

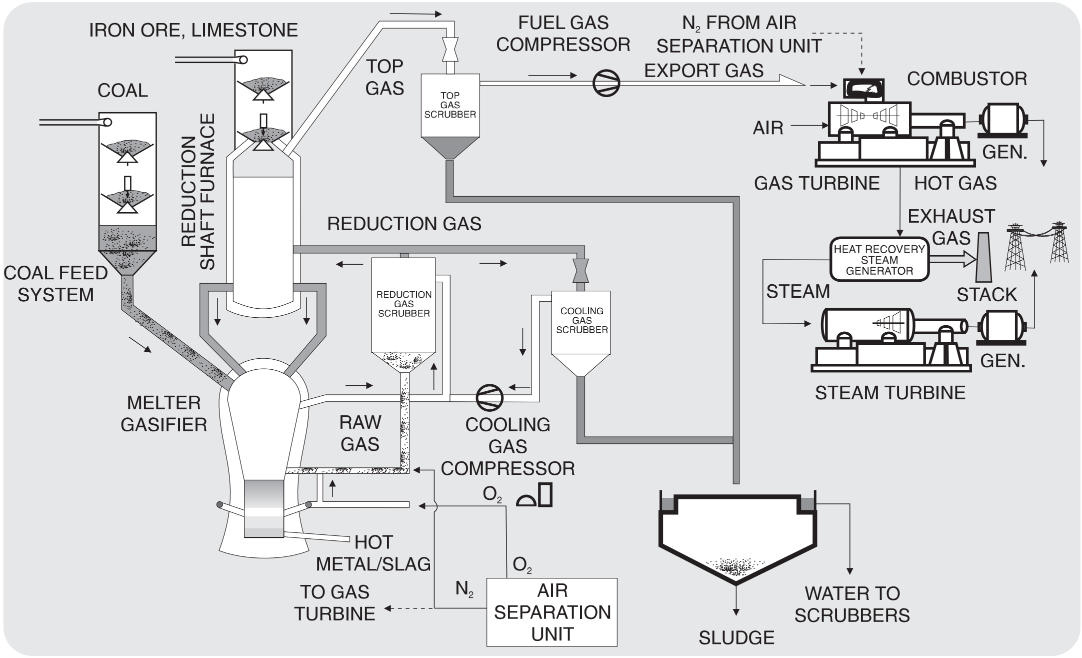
Vineyard, Utah County, UT (Geneva Steel Company's mill)

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)



Project Funding

Total project cost	$1,065,805,000	100%
DOE	149,469,242	14
Participant	916,335,758	86

Project Objective

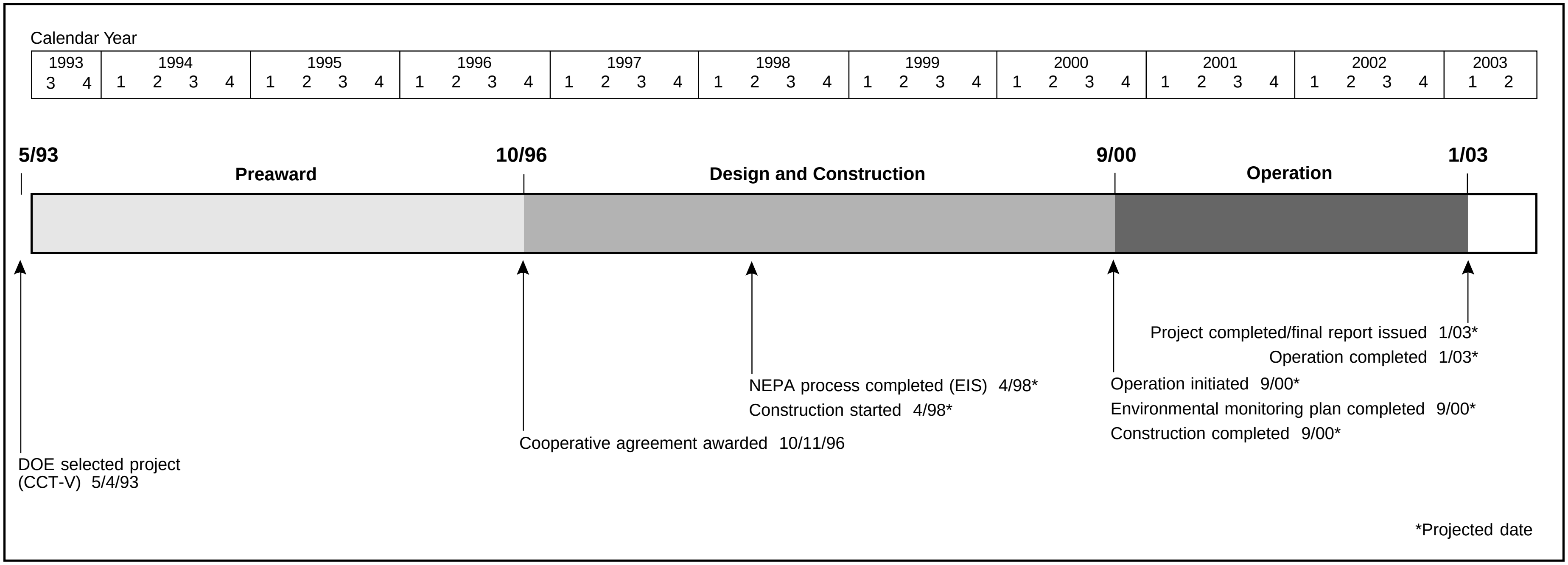
To demonstrate the integration of a direct iron-making process with the co-production of electricity using various U.S. coals in an efficient and environmentally responsible manner.

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.

COREX is a registered trademark of Deutsche Voest-Alpine Industrieanlagenbau GmbH.



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. Negotiations with the technology vendor are continuing. Baseline air monitoring is in progress at the Geneva Steel Plant. The participant is continuing discussions on economic modeling of export gas production and power generating/marketing. Establishing acceptable technical baseline is proceeding slower than planned.

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_2 and NO_x, 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 blast.

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 furnaces, 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^3/min of kiln gas; and up to 274 tons/day of coal

Coal

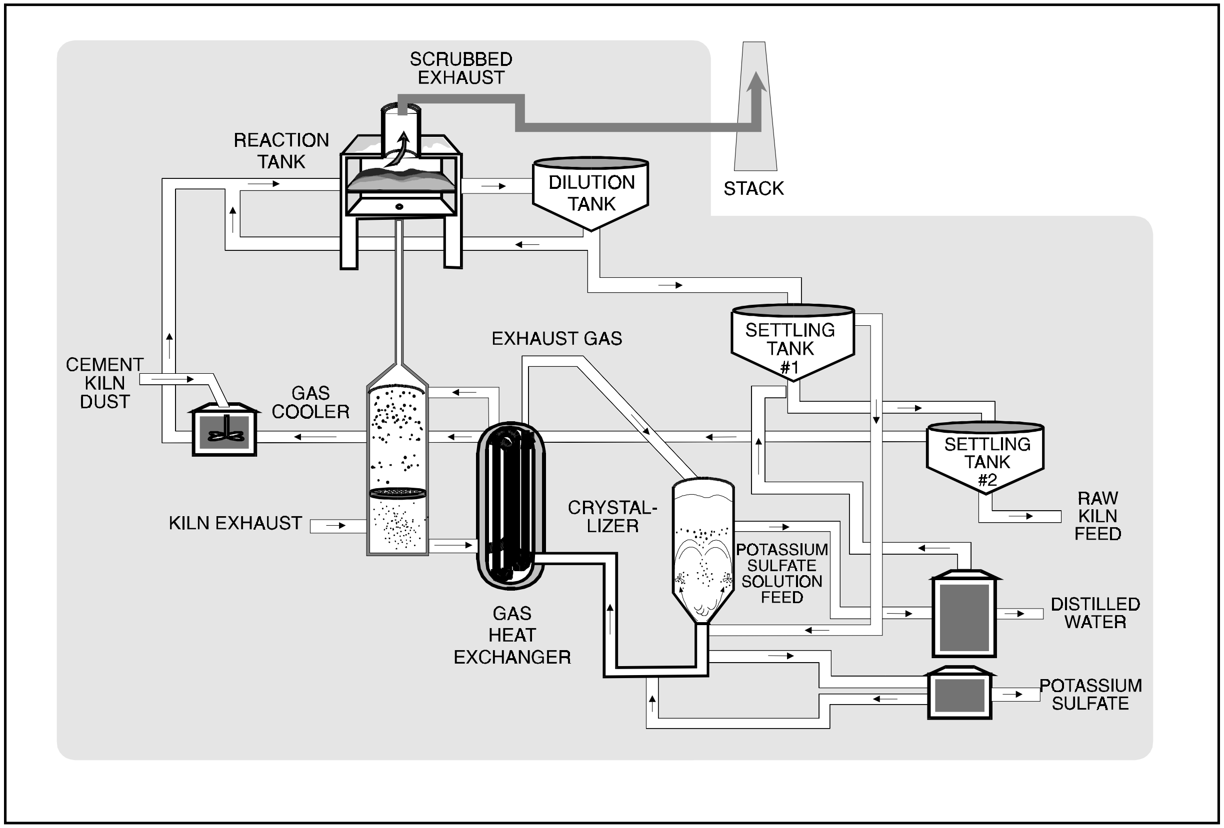
Pennsylvania bituminous, 2.5–3.0% sulfur

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_2 reduction using high-sulfur eastern coals; and to produce a commercial by-product, potassium-based fertilizer.

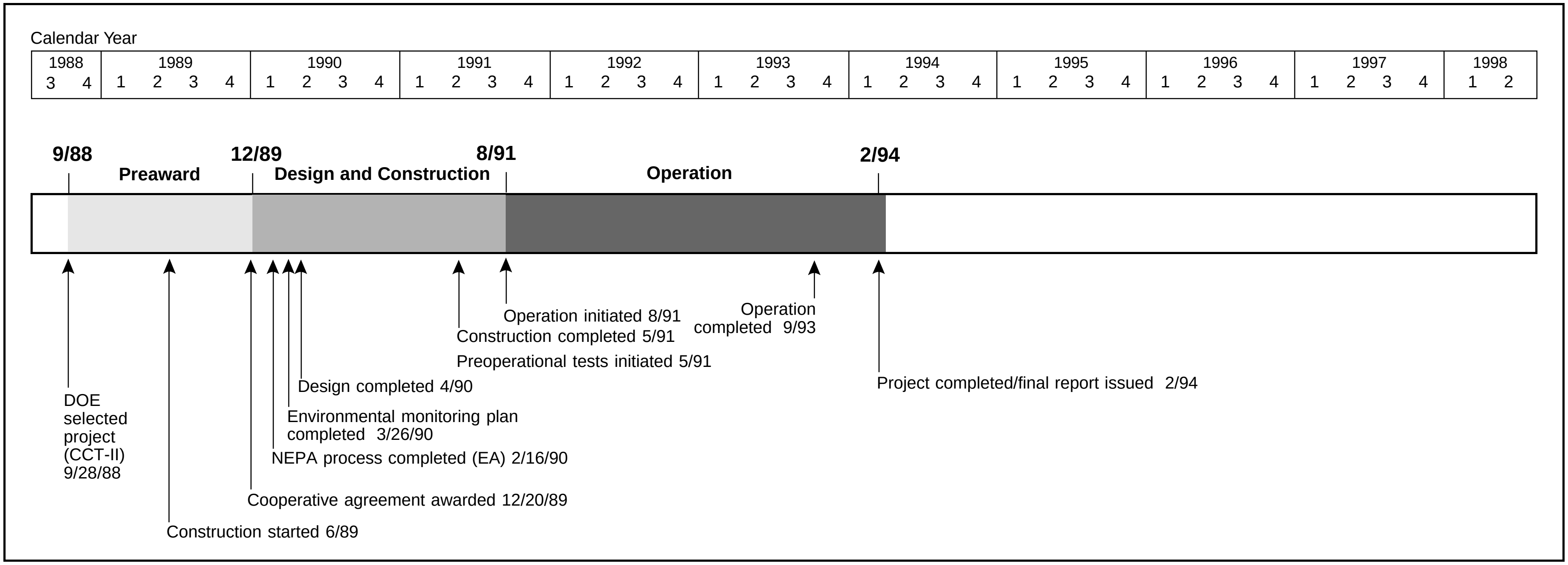


Technology/Project Description

The Passamaquoddy Technology Recovery Scrubber™ uses 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_2 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.

Passamaquoddy Technology Recovery Scrubber is a trademark of the Passamaquoddy Tribe.



Results Summary

Environmental

- The SO_2 removal efficiency averaged 94.6% during the last several months of operation and 89.2% for the entire operating period.
- The NO_x 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^3, about 1/10 that allowed for cement kilns, were achieved with dust loadings of approximately 0.04 gr/std ft^3.
- 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_2 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 payback 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_2 and particulate capture, some NO_x 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^3/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 36 lists the number of hours per operating period, SO_2 and NO_x 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_2 and 18.8% for NO_x emissions. No definitive explanation for the NO_x control mechanics was available at the conclusion of the demonstration.

Aside from the operating period emissions data, an assessment was made of inlet SO_2 load impact on removal efficiency. For SO_2 inlet loads in the range of 100 lb/hr or less, recovery scrubber removal efficiency averaged 82.0%. For SO_2 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^3 and demonstrated particulate emission rates of 0.005–0.007 gr/std ft^3—less than 1/10 the current allowable limit.

Exhibit 36
Summary of Emissions and Removal Efficiencies

Operating Period	Operating Time (hr)	Inlet (lb/hr) SO_2	Inlet (lb/hr) NO_x	Outlet (lb/hr) SO_2	Outlet (lb/hr) NO_x	% Removal Efficiency SO_2	% Removal Efficiency NO_x
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						
Weighted Avg		**109**	**289**	**12**	**234**	**89.2**	**18.8**

▲ The Passamaquoddy Technology Recovery Scubber™ 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 payback 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_2 (only three plants have SO_2 controls, one of which is the Passamaquoddy Technology Recovery Scrubber™). The applicable market for SO_2 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_2 reduction could be achieved.

The scrubber became a permanent part of the cement plant at the end of the demonstration. A feasibility study has been completed for a Taiwanese cement plant.

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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.

Appendix A: 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_2 Control Technologies

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Environmental Control Devices—NO_x Control Technologies

Demonstration of Coal Reburning for Cyclone Boiler NO_x Control

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Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit

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

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Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler

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

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180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers

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Environmental Control Devices—Combined SO_2/NO_x Control Technologies

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Advanced Electric Power Generation— Fluidized-Bed Combustion

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Advanced Electric Power Generation—Advanced Combustion/Heat Engines

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Coal Processing for Clean Fuels—Coal Preparation Technologies

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Advanced Coal Conversion Process Demonstration

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Coal Processing for Clean Fuels—Mild Gasification

ENCOAL® Mild Coal Gasification Project

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Coal Processing for Clean Fuels—Indirect Liquefaction

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Industrial Applications

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Appendix B: Acronyms and Abbreviations

Acronyms

ABB CE	ABB Combustion Engineering, Inc.
ABB ES	ABB Environmental Systems
ACFB	atmospheric circulating fluidized bed
AFBC	atmospheric fluidized-bed combustion
AFGD	advanced flue gas desulfurization
AIDEA	Alaska Industrial Development and Export Authority
AOFA	advanced overfire air
AR&TD	advanced research and technology development
BFGCI	blast furnace granular-coal injection
BG	British Gas
BG/L	British Gas/Lurgi
B&W	The Babcock & Wilcox Company
CAAA	Clean Air Act Amendments of 1990
CAPI	Clean Air Power Initiative
CCOFA	close-coupled overfire air
CCT	clean coal technology
CCT Program	Clean Coal Technology Demonstration Program
CDL	coal-derived liquid
CEQ	Council on Environmental Quality
CFB	circulating fluidized bed
CKD	cement kiln dust
COP	Conference of Parties
CT-121	Chiyoda Thoroughbred-121
CQE	Coal Quality Expert
CX	categorical exclusion
CZD	confined zone dispersion
DER	discrete emissions reduction
DME	dimethyl ether
DOE	U.S. Department of Energy
DOE/HQ	U.S. Department of Energy Headquarters
EA	environmental assessment
EER	Energy and Environmental Research Corporation
EFCC	externally fired combined cycle
EIA	Energy Information Administration
EIS	environmental impact statement
EMP	environmental monitoring plan
EPA	U.S. Environmental Protection Agency
EPAct	Energy Policy Act of 1992
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
EWG	exempt wholesale generator
FBC	fluidized-bed combustion
FCCC	Framework Convention on Climate Change
FERC	Federal Energy Regulatory Commission
FETC	Federal Energy Technology Center
FGD	flue gas desulfurization
FONSI	finding of no significant impact
FRP	fiberglass-reinforced plastic
FY	fiscal year
GE	General Electric
GHG	greenhouse gases
GNOCIS	Generic NO_x Control Intelligent System
GPM	gallons per minute
GR	gas reburning
GR–LNB	gas reburning and low-NO_x burner
GR–SI	gas reburning and sorbent injection
GSA	gas suspension absorption
HAP(s)	hazardous air pollutant(s)
HHV	high heating value
HRSG	heat recovery steam generator
IEA	International Energy Agency
IGCC	integrated gasification combined cycle
JBR	Jet Bubbling Reactor®
LHV	low heating value
LIMB	limestone injection multistage burner
LNB	low-NO_x burner
LNCFS	Low-NO_x Concentric-Firing System
LOI	loss on ignition
LSFO	limestone forced oxidation
MASB	multi-annular swirl burner
MCFC	molten carbonate fuel cell
MTCI	Manufacturing and Technology Conversion International
MTF	memorandum (memoranda)-to-file
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NOPR	Notice of Proposed Rulemaking
NSPS	New Source Performance Standards

NTIS	National Technical Information Service
NYSEG	New York State Electric & Gas Corporation
O&M	operating and maintenance
OTAG	Ozone Transport Assessment Group
OTC	Ozone Transport Commission
PC	personal computer
PCFB	pressurized circulating fluidized bed
PDF	process-derived fuel
PEIA	programmatic environmental impact assessment
PEIS	programmatic environmental impact statement
PEOA	Plant Emission Optimization Advisor
PEP	progress evaluation plan
PFBC	pressurized fluidized-bed combustion
PJBH	pulse jet baghouse
PM	particulate matter
PON	program opportunity notice
PRB	Powder River Basin
PSCC	Public Service Company of Colorado
PSD	Prevention of Significant Deterioration
PUHCA	Public Utility Holding Company Act of 1935
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 demonstration
REA	Rural Electrification Administration
SBIR	Small Business Innovation Research
SCR	selective catalytic reduction
SCS	Southern Company Services, Inc.
SFC	Synthetic Fuels Corporation
SI	sorbent injection
SIP	state implementation plan
SNCR	selective noncatalytic reduction
SOFA	separated overfire air
STTR	Small Business Technology Transfer Program
SVGA	super video graphics adapter
TCLP	toxicity-characteristics leaching procedure
TVA	Tennessee Valley Authority
UARG	Utility Air Regulatory Group
UBCL	unburned carbon boiler efficiency losses
U.K.	United Kingdom
U.S.	United States
VOC	volatile organic compound
WES	wastewater evaporation system
WLFO	wet limestone, forced oxidation

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
$CaCO_3$	calcium carbonate (calcitic limestone)
CaO	calcium oxide (lime)
$Ca(OH)_2$	calcium hydroxide (calcitic hydrated lime)
$Ca(OH)_2$•MgO	dolomitic hydrated lime
Ca/N	molar ratio of calcium to nitrogen
Ca/S	molar ratio of calcium to sulfur
$CaSO_3$	calcium sulfite
$CaSO_4$	calcium sulfate
CO	carbon monoxide
CO_2	carbon dioxide
°F	degrees Fahrenheit
ft, ft^2, ft^3	foot (feet), square feet, cubic feet
gal	gallon(s)
GB	gigabyte(s)
GW	gigawatt(s)
GWe	gigawatt(s)-electric
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid
HCl	hydrogen chloride
HF	hydrogen fluoride
hr	hour(s)
in, in^2, in^3	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^3	standard cubic feet
yr	year(s)