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

DOE/FE-0419

Clean Coal Technology Demonstration Program

Project Fact Sheets 2000

Status as of June 30, 2000

September 2000

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Section 1. The Clean Coal Technology Demonstration Program

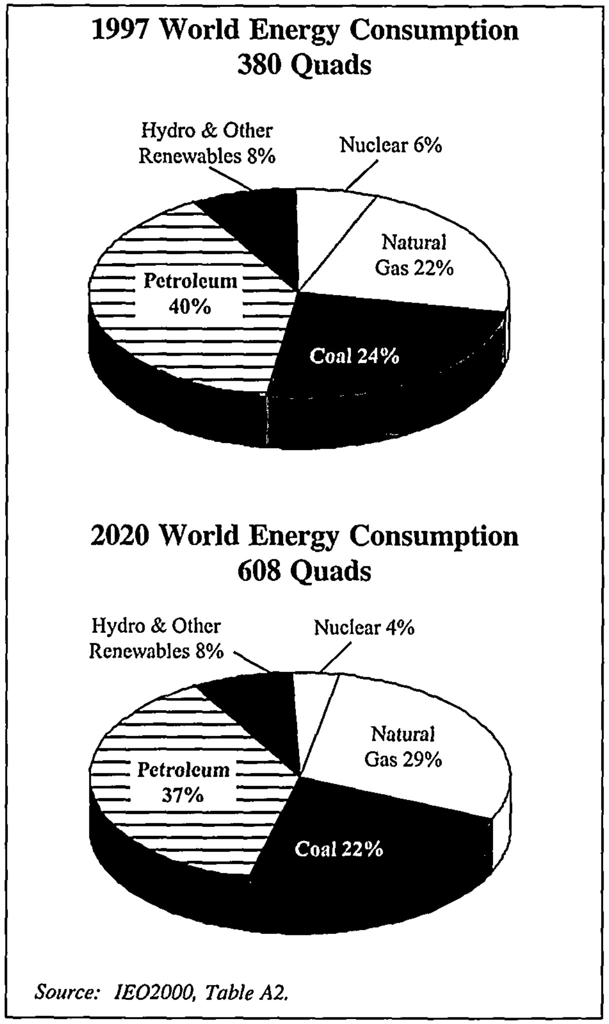
Introduction

The Clean Coal Technology Demonstration Program (CCT Program), a model of government and industry cooperation, responds to the Department of Energy's (DOE) mission to foster a secure and reliable energy system that is environmentally and economically sustainable. The CCT Program represents an investment of over $5.2 billion in advanced coal-based technology, with industry and state governments providing an unprecedented 66 percent of the funding. With 26 of the 38 active projects having completed operations, the CCT Program has yielded clean coal technologies (CCTs) that are capable of meeting existing and emerging environmental regulations and competing in a deregulated electric power marketplace.

The CCT Program is providing a portfolio of technologies that will assure that U.S. recoverable coal reserves of 274 billion tons can continue to supply the nation's energy needs economically and in an environmentally sound manner. As the nation embarks on a new millennium, many of the clean coal technologies have realized commercial application. Industry stands ready to respond to the energy and environmental demands of the 21st century, both domestically and internationally. For existing power plants, there are cost-effective environmental control devices to control sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM). Also ready is a new generation of technologies that can produce electricity and other commodities, such as steam and synthetic gas, and provide efficiencies and environmental performance responsive to global climate change concerns. The CCT Program took a pollution prevention approach as well, demonstrating technologies that remove pollutants or their precursors from coal-based fuels before combustion. Finally, new technologies were introduced into the major coal-based industries, such as steel production, to enhance environmental performance. Thanks in part to the CCT Program, coal—abundant, secure, and economical—can continue in its role as a key component in the U.S. and world energy markets.

The CCT Program also has global importance in providing clean, efficient coal-based technology to a burgeoning energy market in developing countries largely dependent on coal. Based on 1997 data, world energy consumption is expected to increase 60 percent by 2020, with almost half of the energy increment occurring in developing Asia (including China and India). By 2020, energy consumption in developing Asia is projected to surpass consumption in North America. The energy form contributing most to the growth is electricity, as developing Asia establishes its energy infrastructure. Coal, the predominant indigenous fuel, in that region will be the fuel of choice in electricity production. The CCTs offer a means to mitigate potential environmental problems associated with unprecedented energy growth, and to enhance the U.S. economy through foreign equipment sales and engineering services.

▼ World energy consumption by fuel type for the years 1997 and 2020.



Evolution of the Coal Technology Portfolio

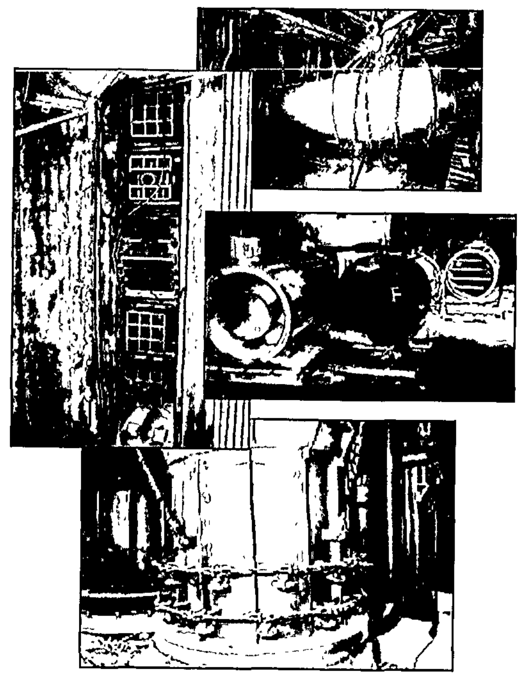
The CCT Program has been implemented through a series of five nationwide competitive solicitations. The first solicitation was directed toward demonstrating the feasibility of future commercial application of clean coal technologies, which would balance the goals of expanding coal use and minimizing environmental impact. The next two solicitations sought 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 situation with SO_2 emissions capped under the Clean Air Act Amendments of 1990 (CAAA), increased need for electric power, and the need to alleviate concerns over global climate change—a situation requiring technologies with very high efficiencies and extremely low emissions.

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

In response to the initial thrust of the program, operations have been completed for 17 of 18 projects that address SO_2 and NO_x control for coal-fired boilers. (One project was reopened and extended to demonstrate an overall unit optimization system.) The resultant technologies provide a suite of cost-effective control options for the full range of boiler types. The 18 environmental control device projects are valued at more than $620 million. These include seven NO_x emission control systems installed on more than 1,750 MWe of utility generating capacity, five SO_2 emissions systems installed on approximately 770 MWe of capacity, and six combined SO_2/NO_x emission control systems installed on more than 665 MWe of capacity.

To respond to increasing demand, as well as growing environmental concerns, the CCT Program provides a range of advanced electric power generation options for both repowering and new generation. These advanced options offer greater than 20 percent reductions in greenhouse gas emissions; SO_2, NO_x, and PM emissions far below New Source Performance Standards (NSPS); and salable solid and liquid by-products in lieu of wastes that require disposal. Over 1,800 MWe of capacity are represented by 11 projects valued at nearly $2.9 billion. These projects include five fluidized-bed combustion (FBC) systems, four integrated gasification combined-cycle (IGCC) systems, and two advanced combustion/heat engine systems. These projects will not only provide environmentally sound electric generation now, but also will provide the demonstrated technology base necessary to meet new capacity requirements in the 21st century.

Also addressed are approaches to converting raw, run-of-mine (ROM) coals to high-energy-density, low-sulfur products. These products have application domestically for compliance with the CAAA. Internationally, both the products and processes have excellent market potential. Valued at $432 million, the four projects in the coal processing for clean fuels category represent a diversified portfolio of technologies. Two projects involve the production of high-energy-density solid fuels, one of which also produces a liquid product equivalent to No. 6 fuel oil. A third project is demonstrating a new methanol production process. A fourth effort complements the process demonstrations by providing an expert computer



◄ Low-NO_x burner technologies: ABB Combustion Engineering's LNCFS™ for tangentially fired boilers (top left), Foster Wheeler's low-NO_x burner for wall-fired boilers (top right), Babcock & Wilcox's LNCB® for cell-burner boilers (center), and Babcock & Wilcox's DRB-XCL® for down-fired boilers (bottom).

▼ NO_x emissions at Georgia Power's Plant Hammond were reduced by 63 percent with Foster Wheeler's low-NO_x burners, shown here, and advanced overfire air.

software system that enables a utility to assess the environmental, operational, and economic impacts of using coals not previously burned at a facility, including upgraded coals and coal blends.

Projects were undertaken to address pollution problems associated with coal use in the industrial sector. These problems included dependence of the steel industry on coke and the inherent pollutant emissions in coke making; reliance of the cement industry on low-cost indigenous, and often high-sulfur, coal fuels; and the need for many industrial boiler operators to consider switching to coal fuels to reduce operating costs. The five industrial applications projects have a combined value of nearly $1.3 billion. Projects encompass substitution of coal for 40 percent of coke in iron making, integration of a direct iron making process with the production of electricity, reduction of cement kiln emissions and solid waste generation, demonstration of an industrial-scale slagging combustor, and a pulse combustor system.

Program Status

The CCT Program has extended the technical, economic, and environmental performance envelope of a broad portfolio of advanced coal technologies. As of June 30, 2000, a total of 26 CCT demonstration projects have completed operations, 5 are in operation, 2 are in construction, and 5 are in design. Exhibit 1-1 shows the number of projects having completed operations, by application category. Exhibit 1-2 provides a schedule for the 38 projects as of June 30, 2000.

Program Accomplishments

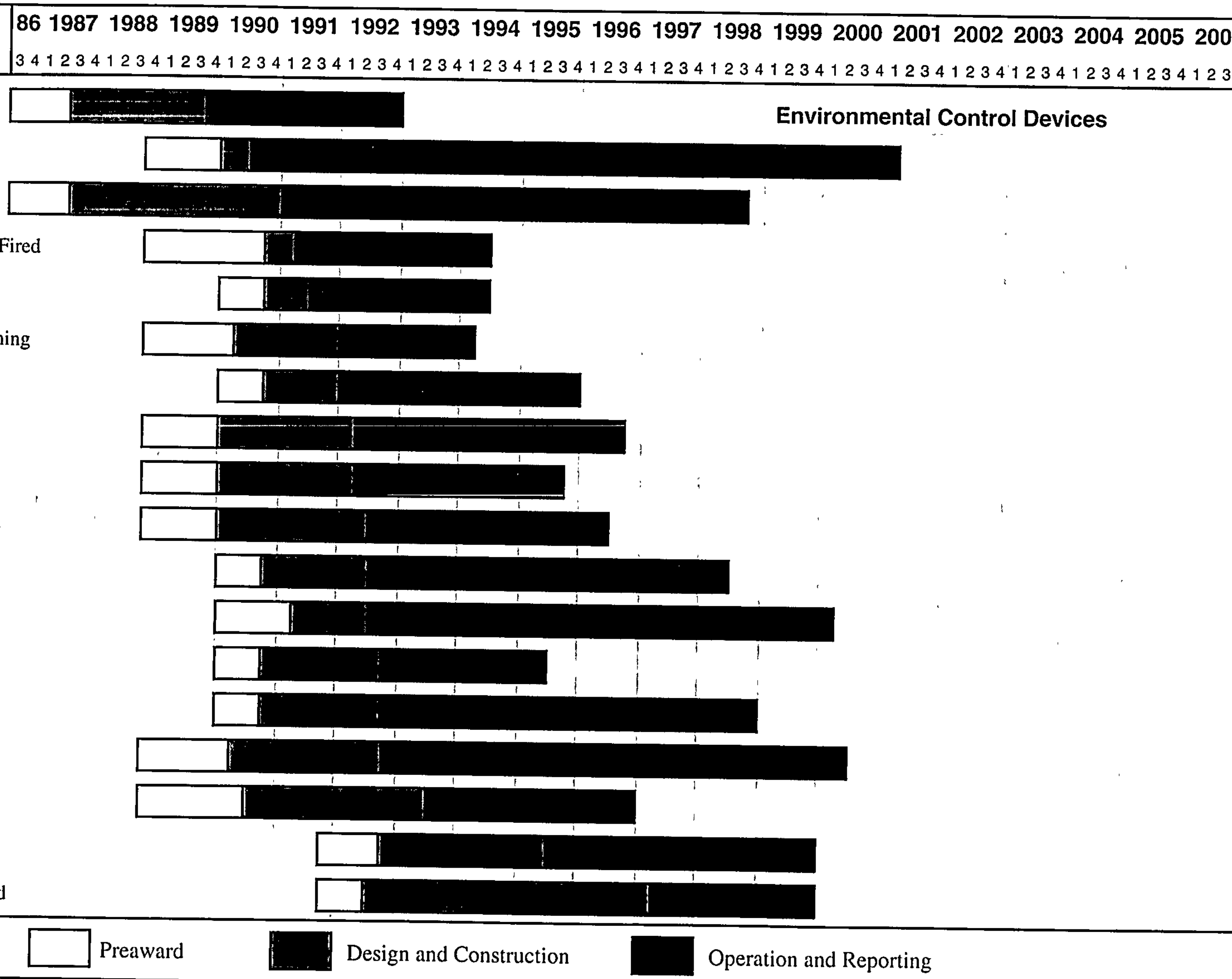
Some of the accomplishments of the CCT Program to date are summarized below.

- The CCT Program enabled the utility industry to respond cost-effectively to the first wave of NO_x control requirements (using low-NO_x burners), and has positioned the utility industry to respond to NO_x control requirements in the 21st century. The CCT Program also provided valuable input to the regulatory process by furnishing real-time NO_x control data. To date, about one-half of the coal-fired generating capacity in the United States has low-NO_x burners, worth more than $1.5 billion.
- The CCT Program also has provided a portfolio of SO_2 control technologies that enables utilities to respond cost effectively to year 2000 CAAA requirements. Technologies are available for the full range of units from old space-constrained boilers to relatively new large boilers. The two advanced wet flue gas desulfurization technologies demonstrated under the CCT Program redefined the state-of-the-art for sorbent-based scrubbers by (1) halving operating costs and significantly reducing capital costs; (2) producing by-products instead of waste; and (3) mitigating plant efficiency loses by using high-capture-efficiency devices.
- The CCT Program was instrumental in commercializing atmospheric circulating fluidized-bed combustion (ACFB) technology through the Tri-State Generation and Transmission Association, Inc. project in Nucla, Colorado. An industry consortium joined

Exhibit 1-1
Completed Projects by Category

Application Category	Number of Projects: Completed Operations	Total
Environmental Control Devices		
SO_2 Control Technology	5	5
NO_x Control Technology	6	7
Combined SO_2/NO_x Control Technology	6	6
Advanced Electric Power Generation		
Fluidized-Bed Combustion	2	5
Integrated Gasification Combined-Cycle	1	4
Advanced Combustion/Heat Engines	1	2
Coal Processing for Clean Fuels	2	4
Industrial Applications	3	5
Total	26	38

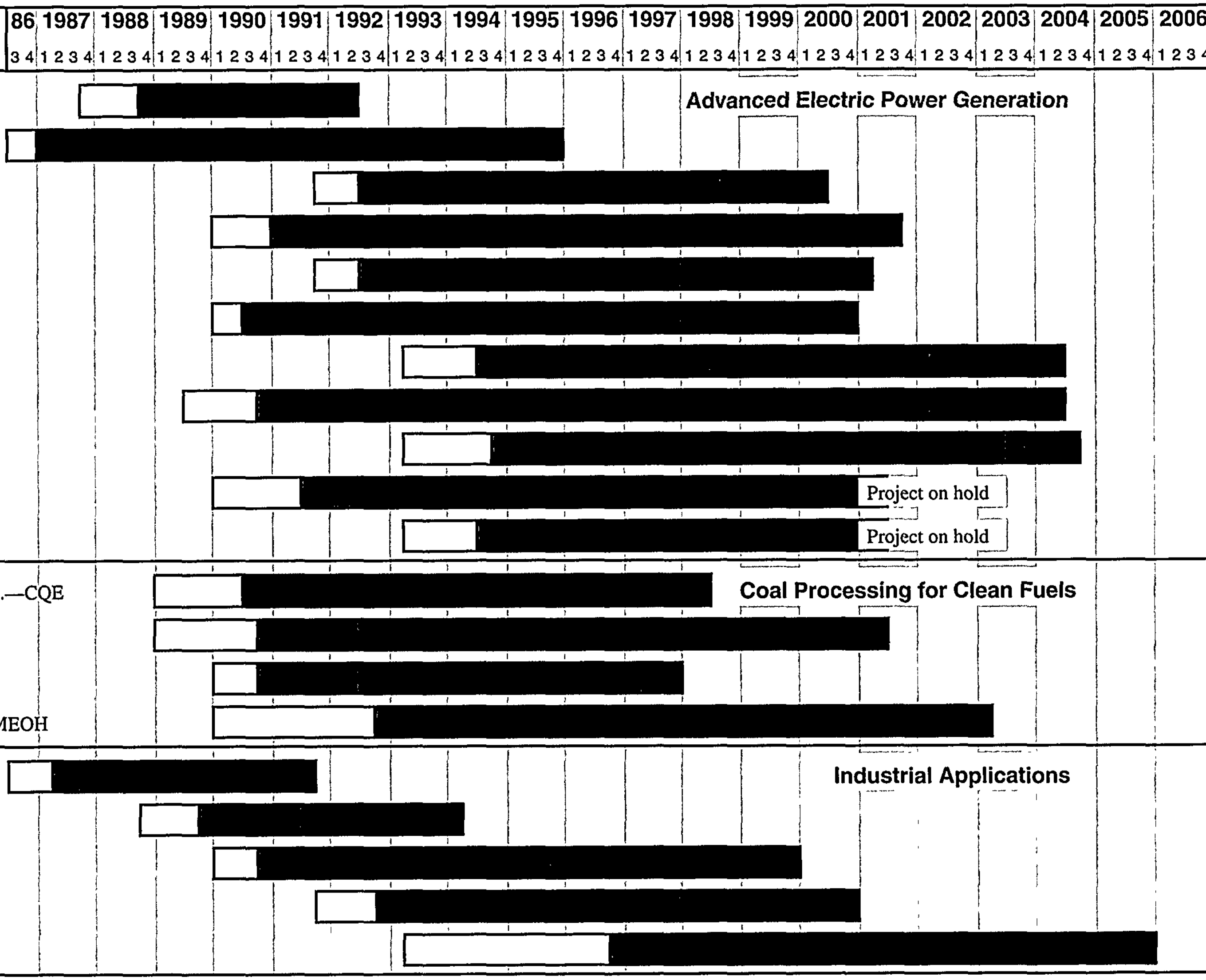
Exhibit 1-2
Project Schedules and Funding by Application Category



Calendar Year	DOE ($1,000)	Total ($1,000)
B&W—LIMB	7,592	19,311
SCS—Wall-Fired	6,554	15,854
GE-EER—GR/SI	18,748	37,589
SCS—Tangentially Fired	4,149	8,554
Bechtel—CZD	5,206	10,412
B&W—Coal Reburning	6,341	13,647
B&W—LNCB	5,443	11,233
ABB ES—SNOX	15,719	31,438
B&W—SNRB	6,078	13,272
Pure Air on the Lake	63,913	151,708
LIFAC	10,637	21,394
PSC of Colorado	13,083	26,165
AirPol—GSA	2,315	7,717
GE-EER—GR-LNB	8,896	17,807
SCS—CT-121	21,085	43,075
SCS—SCR	9,407	23,230
NYSEG—Milliken	45,000	158,608
NYSEG—Micronized	2,701	9,096

Exhibit 1-2 (continued)

Project Schedules and Funding by Application Category



Project	DOE ($1,000)	Total ($1,000)
Advanced Electric Power Generation		
Tri-State—Nucla	17,130	160,050
Ohio Power	66,957	189,886
Wabash River	219,100	438,200
Tampa Electric	150,894	303,288
Sierra Pacific	167,957	335,913
AIDEA	117,327	242,058
ADL—Coal Diesel	23,818	47,636
JEA	74,734	309,097
KY Pioneer	78,086	431,933
McIntosh 4A	93,253	186,588
McIntosh 4B	109,609	219,636
Coal Processing for Clean Fuels		
ABB CE & CQ Inc.—CQE	10,864	21,746
Western SynCoal	43,125	105,700
ENCOAL	45,332	90,664
Air Products—LPMEOH	92,708	213,700
Industrial Applications		
Coal Tech	490	984
Passamaquoddy	5,983	17,800
Bethlehem Steel	31,824	194,302
ThermoChem	4,306	8,612
CPICOR	149,469	1,065,805

Preaward   Design and Construction   Operation and Reporting with DOE to fully evaluate the potential of the technology for utility application. The results and the attendant comprehensive database served to establish ACFB as a commercial offering, with an estimated 9.5 gigawatts of capacity installation worldwide.

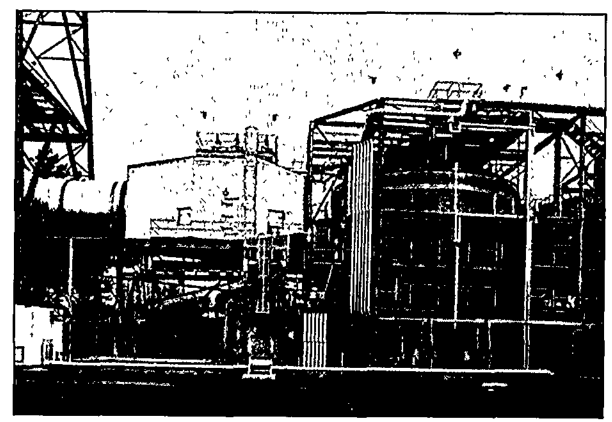
- Pressurized fluidized-bed combustion (PFBC) technology is beginning to make market penetration as a result of work performed at The Ohio Power Company's Tidd Plant. The CCT Program demonstration and associated development work have resulted in several commercial sales, including a 360-MWe unit in Japan and a 220-MWe unit in Germany. The technology represents a new generation of advanced power systems, with efficiencies far higher than conventional coal-fired systems and pollutant emissions far below NSPS, without the need of add-on emission controls. The work at Tidd also provided the basis for second-generation PFBC demonstrations to be conducted in Lakeland, Florida.
- Four IGCC demonstration projects, representing a diversity of gasifier types and cleanup systems, are pioneering the introduction of a new approach to power generation. The Wabash IGCC plant has successfully completed operations. Two of the demonstrations are currently operating in a commercial dispatch mode, providing valuable performance data. The units are attracting worldwide interest because of their potential to significantly improve efficiency, reduce pollutant emissions, and serve as building blocks for even more advanced systems.
- ENCOAL has completed the successful demonstration of a coal processing technology that produces a high-energy-density solid fuel and a liquid product from low-rank coal. The solid fuel is low enough in sulfur to be considered a compliance fuel,—capable of meeting CAAA standards for 2000. Also, the solid product has demonstrated combustion characteristics that enable reduced NO_x emissions. The liquid product has the most potential as a chemical feedstock and can be used as a low-sulfur boiler fuel.
- The liquid phase methanol process (LPMEOH™) at the Eastman Chemical Company in Kingsport, Tennessee is demonstrating a cost-effective means of coproducing electricity and methanol. Continued stable production of methanol at or beyond design rates from high-sulfur bituminous coal suggests that IGCC with LPMEOH™ offers a very clean, highly efficient means of using high-sulfur coal in chemical and electricity production.
- Demonstration of granular-coal injection at Bethlehem Steel's Burns Harbor blast furnace operations proved that coal can replace up to 40 percent of the coke requirement in iron making. This has significant environmental and economic ramifications because of the magnitude and extent of pollutant emissions from coke production. Emissions from granular-coal injection are controlled within the blast furnace.

Technology Overview

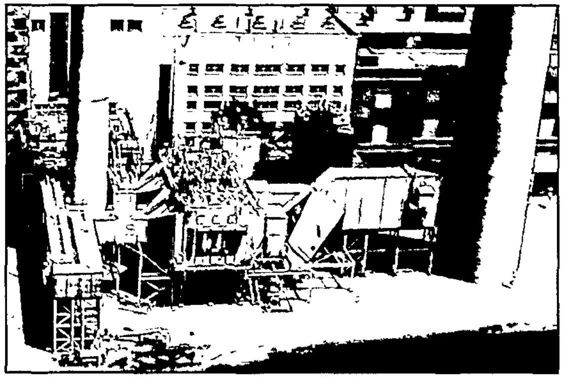
Environmental Control Devices

Environmental control devices are those technologies retrofitted to existing facilities or installed on 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 remain unchanged with these technologies.

SO_2 Control Technology. Sulfur dioxide 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 the formation of acid rain, SO_2 was targeted in Title IV of the 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. This year, Phase II of Title IV became effective, impacting all fossil fuel-fired units, but most of all, the approximately 700 pre-NSPS coal-fired facilities. 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



▲ Unique CT-121 SO_2 scrubber at Plant Yates combined a number of functions and eliminated process steps.



▲ The CZD technology achieved 50% SO_2 removal efficiency. The extended ductwork, where the lime slurry was injected, is shown on the left.

Program has sought to provide a portfolio of SO_2 control technologies.

Sulfur dioxide control devices embody those technologies that condition and act upon the flue gas resulting from combustion, not the combustion itself, for the sole purpose of removing SO_2. Three basic approaches, discussed below, have evolved and are 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 for these boilers.

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 (Ca/S) molar ratio of about 2.0 for sulfur capture efficiencies of 50 to 70 percent.

In the mid-range of the spectrum are 100- to 300-MWe boilers less than 30 years old and somewhat space constrained. For many of these, an increase in equipment 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 is used, as opposed to limestone, and sulfur capture efficiencies up to 90 percent can be achieved at Ca/S molar ratios of 1.3 to 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 larger) existing boilers, with some latitude in space availability, and new plants. For these boilers, 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 the lower cost limestone, which reduces operating costs. In addition, new technologies reduce capital costs, improve reliability, and increase overall plant efficiency. The AFGD achieved SO_2 removal efficiencies of greater than 90 percent at a Ca/S molar ratio 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.

The CCT Program successfully demonstrated two sorbent injection systems, one spray dryer system, and two AFGD systems. All have completed testing. Exhibit 1-3 briefly summarizes the characteristics and performance of the SO_2 control technologies that are described in the project fact sheets in Section 2.

NO_x Control Technology. Nitrogen oxides are formed from oxidation of nitrogen contained within the coal (fuel-bound NO_x) and oxidation of the nitrogen in the air at high temperatures of combustion (thermal NO_x). To control fuel-bound 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.

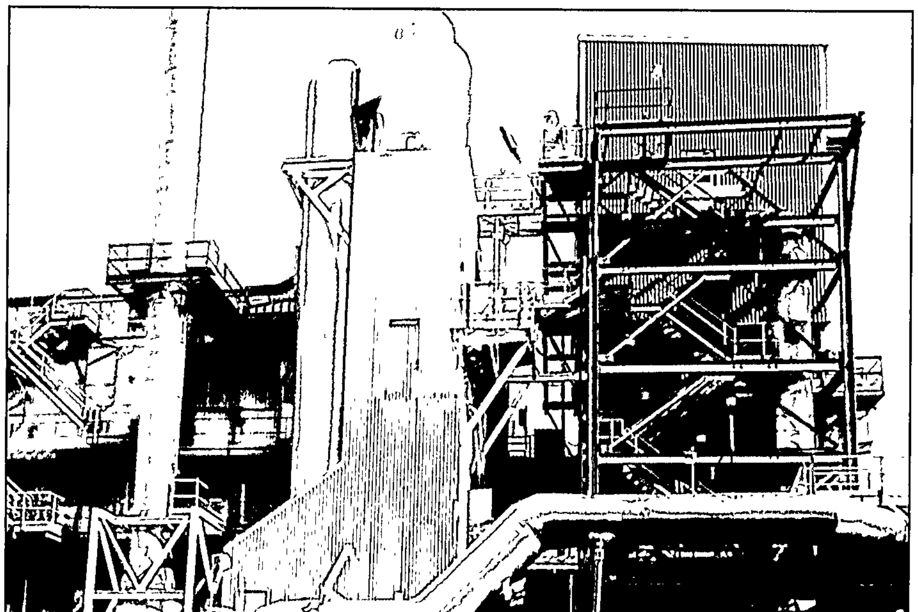
Nitrogen oxides were identified both as a precursor to acid rain (targeted under Title IV of the CAAA) and as a contributor to ozone formation (targeted under Title I). Phase I of Title IV, effec-

▲ The Babcock & Wilcox Company DRB-XCL® burners, installed on a down-fired boiler, were used in the Integrated Dry NO_x/SO_2 Emissions Control System project.

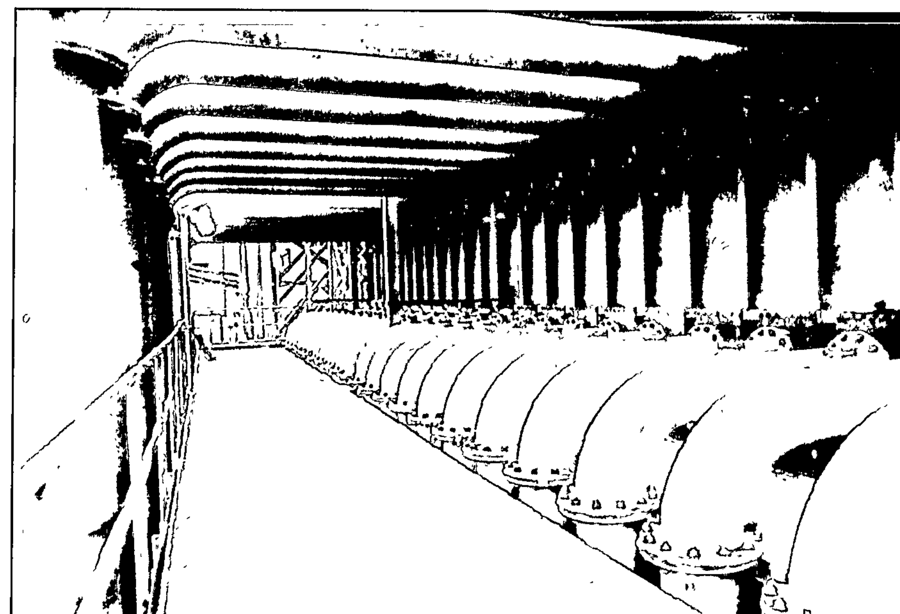
Exhibit 1-3
CCT Program SO_2 Control Technology Characteristics

Project	Process	Coal Sulfur Content	SO_2 Reduction	Page
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%	2-8
Confined Zone Dispersion Flue Gas Desulfurization Demonstration	Sorbent injection—in-duct lime sorbent injection and humidification	1.5–2.5%	50%	2-12
LIFAC Sorbent Injection Desulfurization Demonstration Project	Sorbent injection—furnace sorbent injection (limestone) with vertical humidification vessel and sorbent recycle	2.0–2.9%	70%	2-16
Advanced Flue Gas Desulfurization Demonstration Project	AFGD—cocurrent flow, integrated quench absorber tower, and reaction tank with combined agitation/oxidation (gypsum by-product)	2.25–4.7%	94%	2-20
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+%	2-24

▼ The 10-MWe AirPol gas suspension absorption demonstration unit.



▼ The water inlet connections to the Pure Air absorber module used in the Advanced Flue Gas Desulfurization Demonstration Project.



tive in 1995, required 265 wall- and tangentially fired coal units to reduce emissions to 0.50 and 0.45 lb/10^6 Btu, respectively. In 2000, Phase II of Title IV impacts all fossil-fueled units, but most notably, the balance of the pre-NSPS coal-fired units (see Exhibit 1-4). Ozone nonattainment prompted the U.S. Environmental Protection Agency (EPA) to issue a NO_x transport State Implementation Plan (SIP) call for 22 states and the District of Columbia to cut NO_x emissions to 85 percent below 1990 rates or achieve a 0.15 lb/10^6 Btu emission rate by May 2003. The fate of the SIP call is uncertain as litigation proceeds.

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 either by modifying the combustion process or by 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 natural gas or coal. Postcombustion processes used to act upon flue gas include selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR). Advanced controls can also help in NO_x reductions.

The 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-bound NO_x and thermal NO_x formation. Alone, LNBs typically can achieve 40–50 percent NO_x reduction.

The AOFA technology involves injection of air above the primary combustion zone to allow the primary combustion to occur without the amount of oxygen needed for complete combustion. This oxygen deficiency mitigates fuel-bound NO_x formation. The 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. The LNB/AOFA systems generally can achieve NO_x emission reductions of 37 to 68 percent, depending upon boiler type.

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 to 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). The NO_x entering this zone is stripped of oxygen, resulting in 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.

The SCR and SNCR technologies 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. The SNCR system can only be used at high temperatures (1,600 °F to 2,200 °F) where a catalyst is not needed. The SCR system is typically applied at temperatures between 600–800 °F. Generally, SNCR and SCR systems alone can achieve NO_x emission reductions of 30–50 percent and 80–90+ percent, respectively.

Advanced control systems using artificial intelligence are also becoming an integral part of NO_x control systems. These systems can handle the numerous parameters and optimize performance to reduce NO_x while enhancing boiler performance.

Under the CCT Program, seven NO_x control technologies were assessed encompassing LNBs, AOFA, reburning, SNCR, SCR, and combinations thereof. Six of the seven projects have completed operations. One project has been extended. Exhibit 1-5 briefly summarizes the characteristics and performance of the technologies that are described in more detail in the project fact sheets.

Exhibit 1-4
Group 1 and 2 Boiler Statistics and Phase II NO_x Emission Limits

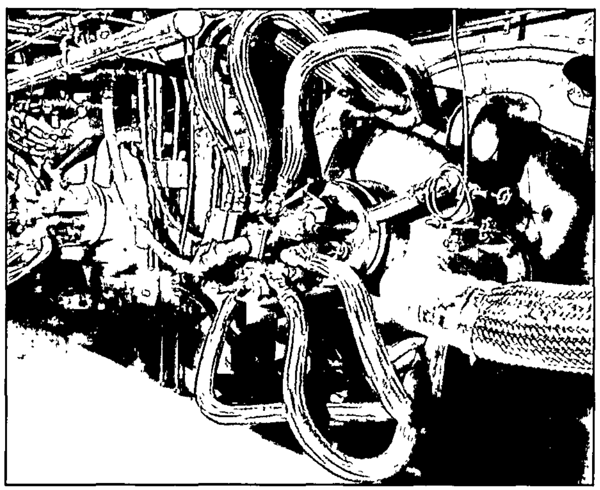
Boiler Types	Number of Boilers	Phase II NO_x Emission Limits (lb/10^6 Btu)
Group 1		
Tangentially fired	299	0.40
Dry-bottom, wall-fired	308	0.46
Group 2		
Cell burner	36	0.68
Cyclone >155 MWe	55	0.86
Wet-bottom, wall-fired >65 MWe	26	0.84
Vertically fired	28	0.80

Source: U.S. Environmental Protection Agency, Nitrogen Oxides Emission Reduction Program, Final Rule for Phase II, Group 1 and Group 2 Boilers (http://www.epa.gov/docs/acidrain/noxfs3.html).

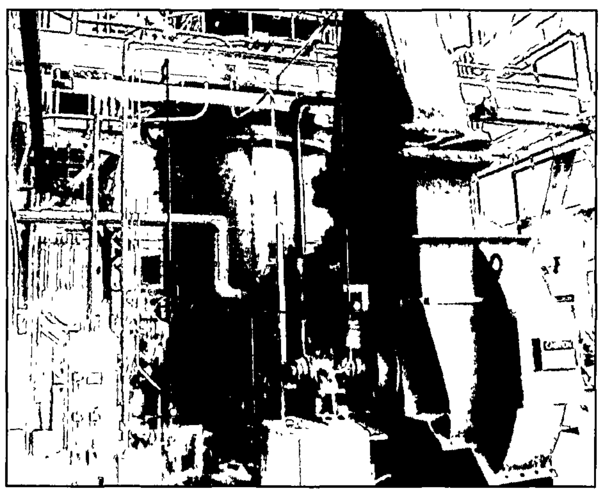
Exhibit 1-5
CCT Program NO_x Control Technology Characteristics

Project	Process	Boiler Size/ Type	NO_x Reduction	Page
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	LNB/AOFA—advanced LNB with separated AOFA and artificial intelligence controls	500-MWe/wall	68%	2-30
Demonstration of Coal Reburning for Cyclone Boiler NO_x Control	Coal reburning—30% heat input	100-MWe/cyclone	52–62%	2-34
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%	2-38
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%	2-42
Micronized Coal Reburning Demonstration for NO_x Control	Coal reburning—14% heat input (tangentially fired) and 17% heat input (cyclone)	148-MWe/tangential 50-MWe/cyclone	28% 59%	2-46
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%	2-50
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%	2-54

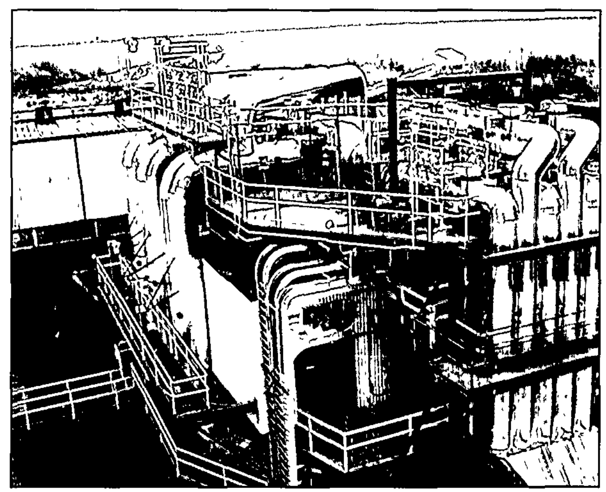
▼ Foster Wheeler's LNBs used at Cherokee Station for the GR-LNB demonstration.



▼ New air fan in the foreground and new pulverizer in the background for the micronized coal reburning project.



▼ The SCR demonstration facility at Southern Company's Plant Crist.



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 six 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 into water vapor, nitrogen, and a small amount of NO_x). Furthermore, most particulates passing through the upstream baghouse are captured in the sulfuric acid condensing unit. The system produces no solid waste.

All six of the combined SO_2/NO_x control technology projects have completed operations. Exhibit 1-6 briefly summarizes the characteristics and performance of the technologies that are described in the project fact sheets.

Advanced Electric Power Generation Technology

Advanced electric power generation technologies enable the efficient and environmentally superior generation of electricity. The advanced electric power generation projects selected under the CCT Program are responsive to capacity expansion needs requisite to meeting long-term demand, offsetting nuclear retirements, and meeting 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 technologies may be deployed in modules, allowing phased construction to better match demand growth, and to meet the smaller capacity requirements of municipal, rural, and nonutility generators.

There are five generic advanced electric power generation technologies demonstrated in 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 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 and construction applications. More than 90 percent of the SO_2 can be captured in this manner.

At combustion temperatures of 1,400–1,600 °F, the fluidized mixing of the fuel and sorbent enhances both combustion and sulfur capture. The operating temperature range is about half that of a conventional pulverized-coal boiler and below the temperature that thermal NO_x is formed. In fact, FBC NO_x emissions are about 70 to 80 percent lower than those for conventional pulverized-coal boilers. Thus, fluidized-bed combustors substantially reduce both SO_2 and NO_x emissions. Also, FBC has the capability of using high-ash coal, whereas conventional pulverized-coal units must limit ash content in the coal to relatively low levels.

Two parallel paths were pursued in FBC development—bubbling and circulating beds. Bubbling fluidized-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 that entrains the bed material, in conjunction with hot cyclones, to separate and recirculate the bed material from the flue gas before it passes to a heat exchanger. Hybrid systems have evolved from these two basic approaches.

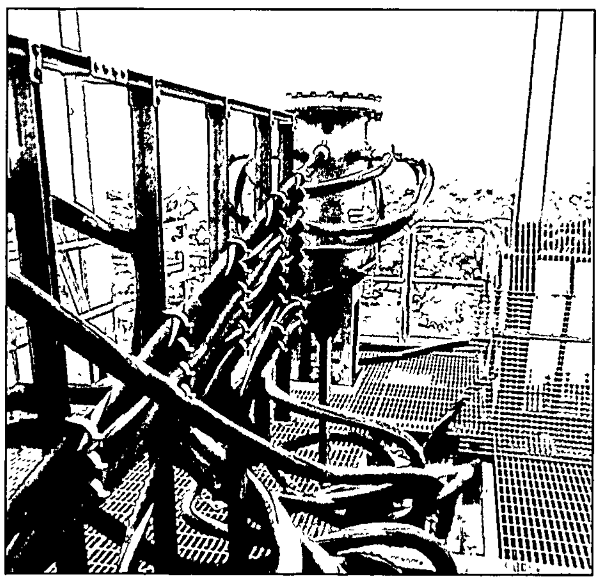
Fluidized-bed combustion can be either atmospheric (AFBC) or pressurized (PFBC). The AFBC systems operate at atmospheric pressure while PFBC operates at pressure 6 to 16 times higher. The PFBC systems offer higher efficiency by using both a gas turbine and steam turbine. Consequently, operating costs and waste are reduced relative to AFBC, as well as boiler size per unit of power output.

Second-generation PFBC integrates the combustor with a pyrolyzer (coal gasifier) to fuel a gas tur-

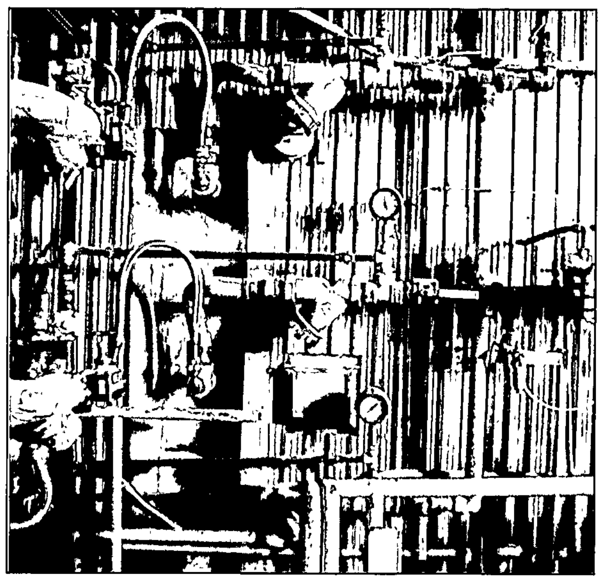
Exhibit 1-6
CCT Program Combined SO_2/NO_x Control Technology Characteristics

Project	Process	Coal Sulfur Content	SO_2/NO_x Reduction	Page
SNOX™ Flue Gas Cleaning Demonstration Project	SCR/oxidation catalyst/sulfuric acid condenser—synergistic catalyst effect and no solid waste	3.4%	95%/94%	2-60
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%	2-64
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%	2-68
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	Gas reburning/sorbent injection (GR-SI)—calcium-based sorbents used in duct injection	3.0%	50–60%/67%	2-72
Milliken Clean Coal Technology Demonstration Project	LNB/SNCR/wet scrubber—sorbent additive and space-saving, durable scrubber design	1.5–4.0%	98%/53–58%	2-76
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%	2-80

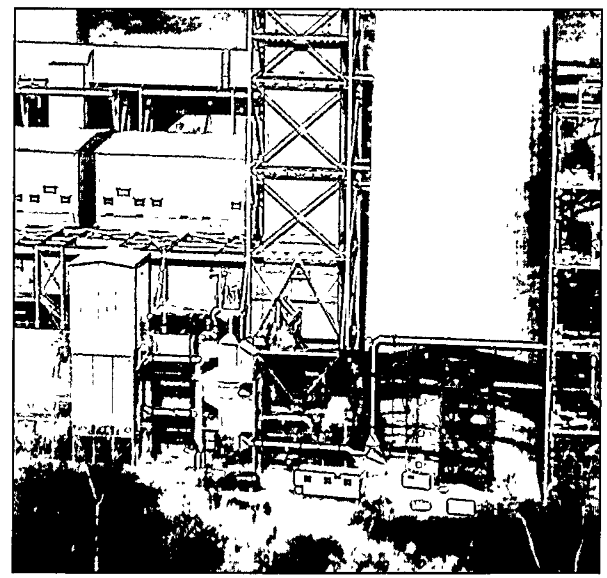
▼ Coolside process sorbent distribution bottle and feed lines on top of bypass duct.



▼ Humidification panels and controls on the side of duct work where water is injected into the flue gas for GR-SI demonstration.



▼ The SO_x-NO_x-Rox Box™ baghouse, silos, duct work, and tie-in.



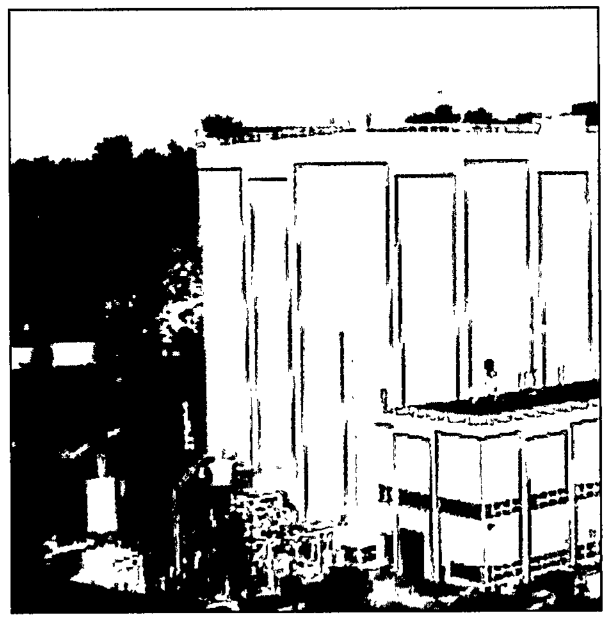
bine (topping cycle), and the waste heat is used to generate steam for a steam turbine (bottoming cycle). The inherent efficiency of the gas turbine and waste heat recovery in this combined-cycle mode significantly increases overall efficiency. Such advanced PFBC systems have the potential for efficiencies over 50 percent.

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.

Integrated Gasification Combined-Cycle. The IGCC process has four basic steps: (1) fuel gas is generated from coal reacting with high-temperature steam and an oxidant (oxygen or air) in a reducing atmosphere; (2) the fuel gas is either passed directly to a hot-gas cleanup system to remove particulates, sulfur, and nitrogen compounds, or the gas is first cooled to produce steam and then cleaned conventionally; (3) the clean fuel gas is combusted in a gas turbine generator to produce electricity; and (4) the residual heat in the hot exhaust from the gas 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 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 chemical composition of the gas requires that 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 and catalysts, from erosion and corrosion.

In a coal gasifier, the sulfur in the coal is released in the form of hydrogen sulfide (H_2S) rather than as SO_2. In some IGCC systems, much of the sulfur-containing gas is captured by a sorbent injected into the gasifier. Others use existing proven commercial hydrogen sulfide removal processes, which remove more than 99 percent of the sulfur, but require the fuel to be cooled, which is an efficiency penalty. Therefore, hot-gas cleanup systems are now being considered. In these hot cleanup systems, the hot coal gas is passed through a bed of metal oxide particles, such as zinc oxides. Zinc oxide can absorb sulfur contaminants at temperatures in excess of 1,000 °F, and the compound can be regenerated and reused with little loss of effectiveness. Produced during the regeneration stage are salable sulfur, sulfuric acid, or sulfur-containing compounds that may be used to produce useful by-products. 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.



▲ The 110-MWe Nucla ACFB demonstration enabled Pyropower Corporation (now owned by Foster Wheeler) to save almost three years in establishing a commercial line of ACFB units.

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. Nitrogen oxides formed in the gas turbine can be held to well within allowable levels by staged combustion in the gas turbine or by adding moisture to control 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 more efficient than traditional energy conversion devices (up to 60 percent, depending on fuel and type of fuel cell). Fuel cells directly transform the chemical energy of a fuel and an oxidant (air or oxygen) into electrical energy instead of going through intermediate steps—burner, boiler, turbines, and generators. Each fuel cell includes an anode and a cathode separated by an electrolyte layer. In a coal gasification/fuel cell application, coal gas is supplied to the anode and air is supplied to the cathode to produce electricity and heat.

Of the four IGCC projects, one has completed operations, two are in operation, and one is in the project definition and design phase. The project in the design phase plans to use a molten carbonate fuel cell (MCFC).

Coal-Fired Diesel. Coal-fired diesels use either a coal-oil or coal-water slurry fuel to drive an electric generation system. 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 a 41–48 percent thermal efficiency. The 5- to 20-MWe capacity range of the technology is most amenable to distributed power applications. The CCT coal-fired diesel project is in construction.

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 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.

An 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.

Results show that by positioning air injection ports so that coal is combusted in stages, NO_x emissions can be reduced by 70 to 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.

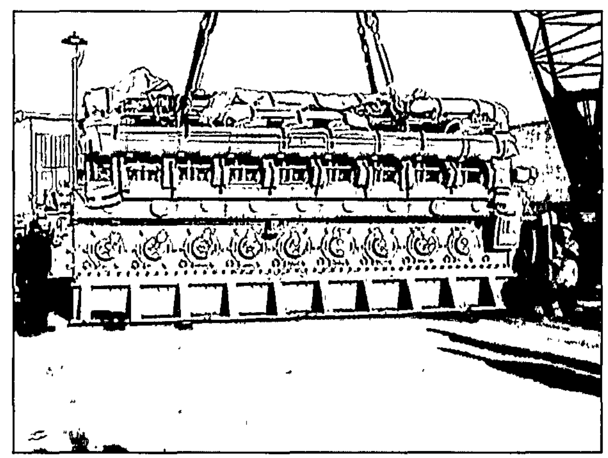
Exhibit 1-7 summarizes the process characteristics and size of the advanced electric power generating technologies presented in the project fact sheets.

Coal Processing for Clean Fuels Technology

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.

The Western SynCoal LLC's advanced coal conversion process 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 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/lb, 25–40 percent moisture content, and 0.5–1.5 percent sulfur is converted to a 12,000 Btu/lb product with 1.0 percent moisture and as low as 0.3 percent sulfur. The SynCoal® product is used at utility and industrial facilities. Project operation was extended through 2001.

The ENCOAL project, which completed operational testing in July 1997, used mild gasification to convert low-Btu, low-sulfur 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 an 11,000 Btu/lb 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 project was successfully completed.

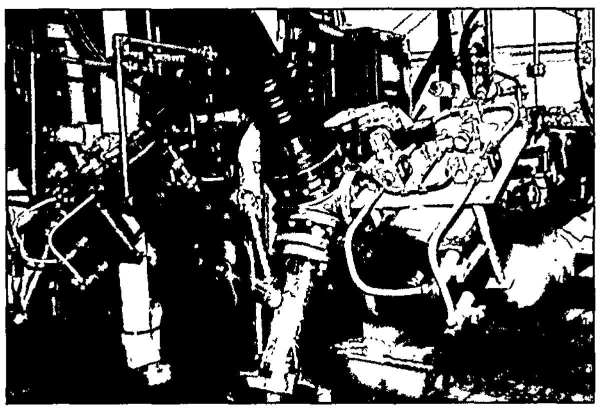


▲ Shown is the Coltec coal-fired diesel being installed at the University of Alaska in Fairbanks.

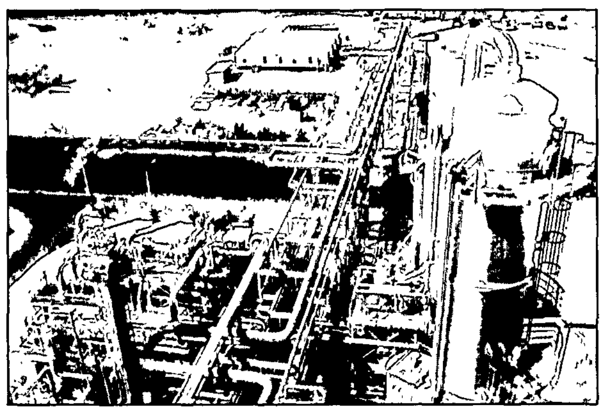
Exhibit 1-7
CCT Program Advanced Electric Power Generation Technology Characteristics

Project	Process	Size	Page
Fluidized-Bed Combustion			
McIntosh Unit 4A PCFB Demonstration Project	Pressurized circulating fluidized-bed combustion	137 MWe (net)	2-86
McIntosh Unit 4B Topped PCFB Demonstration Project	McIntosh 4A with pyrolyzer and topping combustor	240 MWe (net)	2-88
JEA Large-Scale CFB Combustion Demonstration Project	Atmospheric circulating fluidized-bed combustion	297.5 MWe (gross); 265 MWe (net)	2-90
Tidd PFBC Demonstration Project	Pressurized bubbling fluidized-bed combustion	70 MWe	2-92
Nucla CFB Demonstration Project	Atmospheric circulating fluidized-bed combustion	100 MWe	2-96
Integrated Gasification Combined Cycle			
Kentucky Pioneer Energy IGCC Demonstration Project	Oxygen-blown, slagging fixed-bed gasifier with cold gas cleanup	400 MWe (net); 2.0 MWe MCFC	2-102
Piñon Pine IGCC Power Project	Air-blown, fluidized-bed gasifier with hot gas cleanup	107 MWe (gross); 99 MWe (net)	2-104
Tampa Electric Integrated Gasification Combined-Cycle Project	Oxygen-blown, entrained-flow gasifier with hot and cold gas cleanup	313 MWe (gross); 250 MWe (net)	2-106
Wabash River Coal Gasification Repowering Project	Oxygen-blown, two-stage entrained-flow gasifier with cold gas cleanup	296 MWe (gross); 262 MWe (net)	2-108
Advanced Combustion/Heat Engines			
Clean Coal Diesel Demonstration Project	Coal-fueled diesel engine	6.4 MWe (net)	2-114
Healy Clean Coal Project	Advanced slagging combustor, spray dryer with sorbent recycle	50 MWe (nominal)	2-116

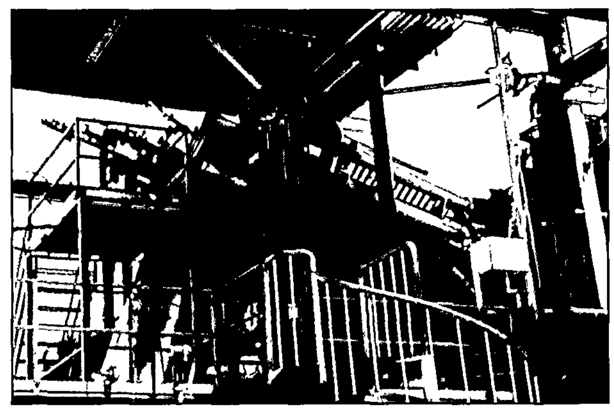
▼ The coal slurry and sorbent injectors for the Tidd PFBC demonstration.



▼ The Wabash IGCC gas cleanup system.



▼ The TRW slagging combustor for the Healy Station.



The liquid phase methanol (LPMEOH™) process being demonstrated is an 80,000 gallon/day 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 eliminates 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 the fuel characteristics of the unrefined product.

ABB Combustion Engineering, Inc. and CQ Inc. have 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, economic, 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 commercial use. More than 35 U.S. utilities and one U.K. utility have received CQE® through Electric Power Research Institute (EPRI) membership. It is estimated that CQE® saves U.S. utilities about $26 million annually.

Exhibit 1-8 summarizes the process characteristics and size of the coal processing for clean fuels technologies presented in the project fact sheets.

Industrial Applications Technology

Technologies applicable to the industrial sector address significant environmental issues and barriers associated with coal use in industrial processes. These technologies are directed at both continuing coal use and introducing coal use in various industrial sectors.

One of the critical environmental concerns has to do with pollutant emissions resulting from producing coke from coal for use in steel making. 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 eliminates the need for coke making by using a direct iron-making process. In this process, raw coal is introduced into a reactor 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 boiler for electric power generation.

Coal is often the fuel of choice in cement production because production costs are largely driven by fuel cost. Faced with the need to control SO_2 emissions and 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- and 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- and gas-fired units are not high SO_2 or NO_x emitters; use relatively tight tube spacing in the absence of potential ash fouling; and the flow of oil or gas cools the combustor, precluding the need for water cooling. For these reasons, the CCT Program demonstrated an advanced air-cooled, slagging combustor that could avoid these potential problems. The cyclone combustor stages introduction of air to control NO_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 pulse combustor to be demonstrated by ThermoChem has a wide range of applications. The technology can be used in many coal processes, including coal gasification and waste-to-energy applications.

The cement kiln, slagging combustor, and blast furnace granular-coal injection projects are completed. The CPICOR™ and the ThermoChem projects are in the design phase and the construction phase, respectively.

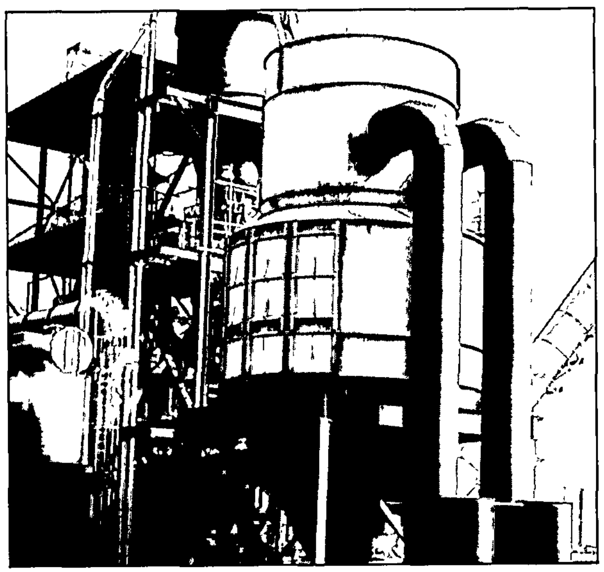
Exhibit 1-9 summarizes process characteristics and size for the industrial applications technologies presented in more detail in the project fact sheets.

Exhibit 1-8
CCT Program Coal Processing for Clean Fuels Technology Characteristics

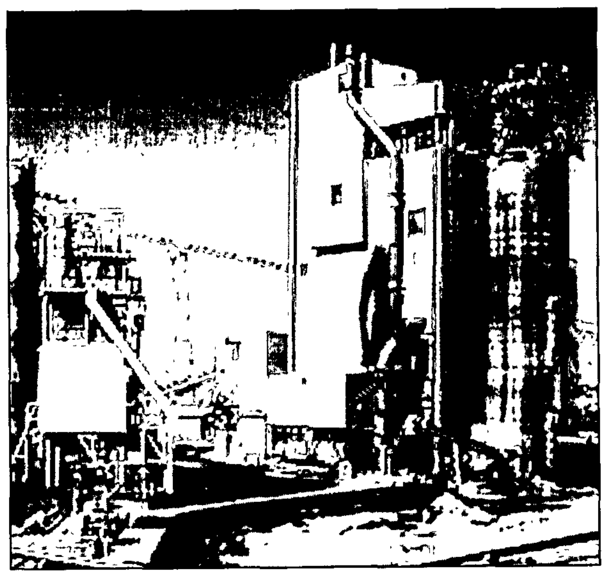
Project	Process	Size	Page
Commercial-Scale Demonstration of the Liquid Phase Methanol (LPMEOH™) Process	Liquid phase process for methanol production from coal-derived syngas	80,000 gal/day	2-122
Advanced Coal Conversion Process Demonstration	Advanced coal conversion process for upgrading low-rank coals	45 tons/hr	2-124
Development of the Coal Quality Expert™	Coal Quality Expert™ computer software	Tested at 250–880 MWe	2-126
ENCOAL® Mild Coal Gasification Project	Liquids-from-coal (LFC®) mild gasification to produce solid and liquid fuels	1,000 tons/day*	2-130

*Operated at 500 tons/day

▼ Western SynCoal Partnership's advanced coal conversion process plant in Colstrip, Montana has produced over 1.5 million tons of SynCoal® products.



▼ The ENCOAL mild gasification plant near Gillette, Wyoming has operated 12,800 hours and processed approximately 260,000 tons of raw coal and produced over 120,000 tons of PDF® and 121,000 barrels of CDL®.



▼ The LPMEOH™ process produces over 80,000 gal/day of methanol, all of which is used by the Eastman Chemical Company in Kingsport, Tennessee.

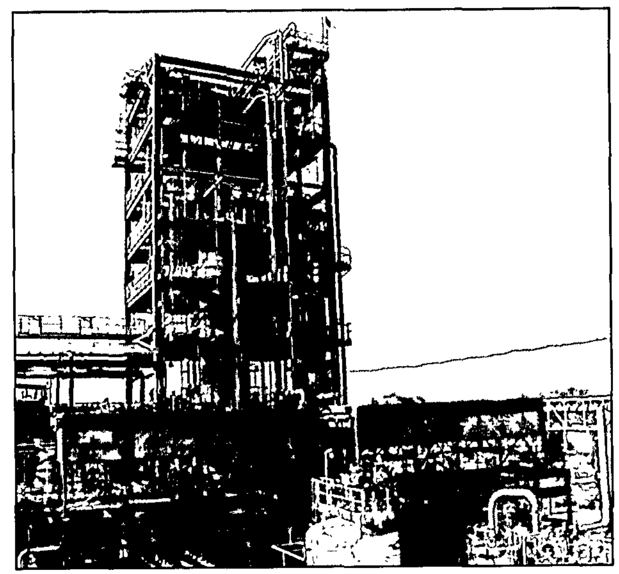
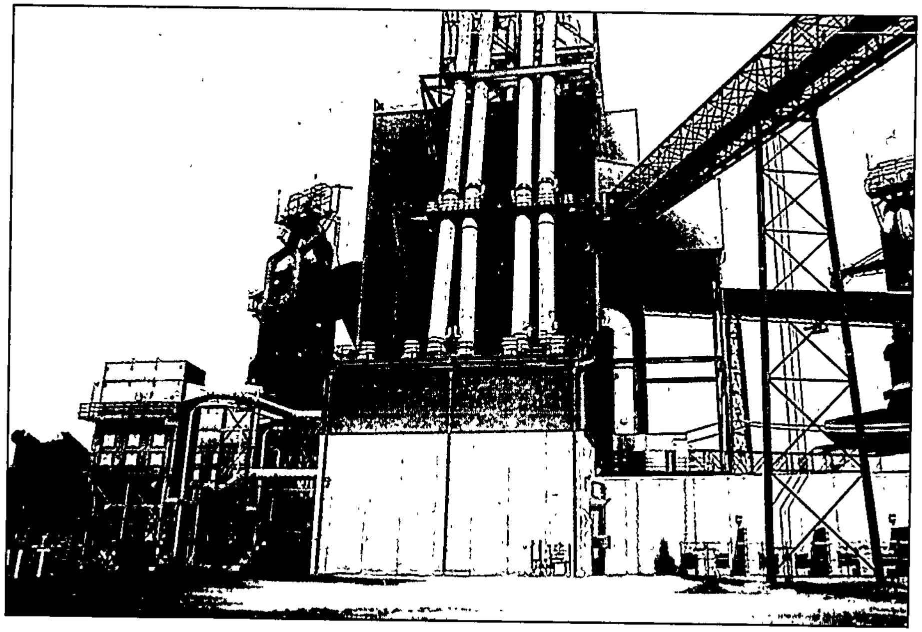


Exhibit 1-9
CCT Program Industrial Applications Technology Characteristics

Project	Process	Size	Page
Clean Power from Integrated Coal/Ore Reduction (CPICOR™)	Direct reduction iron-making process to eliminate coke; combined-cycle electric power generation	3,300 tons/day of hot metal 170 MWe	2-136
Pulse Combustor Design Qualification Test	Advanced combustion using Manufacturing and Technology Conversion International's pulse combustor/gasifier	30×10^6 Btu/hr	2-138
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	2-140
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	Advanced slagging combustor with staged combustion and sorbent injection	23×10^6 Btu/hr	2-144
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	2-148

▼ The Bethlehem Steel Corporation facility, which demonstrated the injection of granulated coal directly into two blast furnaces at Burns Harbor, Indiana.



▼ The Cement Kiln Flue Gas Recovery Scrubber project's crystallizer and condenser in foreground and flue gas condenser in background.

Section 2. The Clean Coal Technology Projects

Project Fact Sheets

The remainder of this document contains fact sheets for all 38 projects. Two types of fact sheets are provided: (1) a brief, two-page overview for ongoing projects and (2) an expanded four-page summary for projects that have successfully completed operational testing. The expanded fact sheets for completed projects contain a summary of the major results from the demonstration as well as sources for obtaining further information, specifically, contact persons and key references. Information provided in the fact sheets includes the project participant and team members, project objectives, significant project features, process description, major milestones, progress (if ongoing) or summary of results (if completed), and commercial applications. To prevent the release of project-specific information of a proprietary nature, process flow diagrams contained in the fact sheets are highly simplified and presented only as illustrations of the concepts involved in the demonstrations. The portion of the process or facility central to the demonstration is demarcated by the shaded area.

An index to project fact sheets by application category is provided in Exhibit 2-1. An index by participant is provided in Exhibit 2-2. Ongoing projects in each category appear first followed by projects having completed operations. A shaded area distinguishes projects having completed operations from ongoing projects. Within these breakdowns, projects are listed alphabetically by participant. In addition, Exhibit 2-1 indicates the solicitation under which the project was selected; its status as of June 30, 2000; and the page number for each fact sheet. Exhibit 2-2 lists the projects alphabetically by participant and provides project location and page numbers. A key to interpreting the milestone charts is provided in Exhibit 2-3.

An appendix containing contact information for all of the projects is provided as Appendix A. A list of acronyms used in this document is provided as Appendix B.

Exhibit 2-1
Project Fact Sheets by Application Category

Project	Participant	Solicitation/Status	Page
Environmental Control Devices			
SO_2 Control Technologies			
10-MWe Demonstration of Gas Suspension Absorption	AirPol, Inc.	CCT-III/completed 3/94	2-8
Confined Zone Dispersion Flue Gas Desulfurization Demonstration	Bechtel Corporation	CCT-III/completed 6/93	2-12
LIFAC Sorbent Injection Desulfurization Demonstration Project	LIFAC-North America	CCT-III/completed 6/94	2-16
Advanced Flue Gas Desulfurization Demonstration Project	Pure Air on the Lake, L.P.	CCT-II/completed 6/95	2-20
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	Southern Company Services, Inc.	CCT-II/completed 12/94	2-24
NO_x Control Technologies			
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	Southern Company Services, Inc.	CCT-II/extended	2-30
Demonstration of Coal Reburning for Cyclone Boiler NO_x Control	The Babcock & Wilcox Company	CCT-II/completed 12/92	2-34
Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit	The Babcock & Wilcox Company	CCT-III/completed 4/93	2-38
Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler	Energy and Environmental Research Corporation	CCT-III/completed 1/95	2-42
Micronized Coal Reburning Demonstration for NO_x Control	New York State Electric & Gas Corporation	CCT-IV/completed 4/99	2-46
Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur, Coal-Fired Boilers	Southern Company Services, Inc.	CCT-II/completed 7/95	2-50
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers	Southern Company Services, Inc.	CCT-II/completed 12/92	2-54
Combined SO_2/NO_x Control Technologies			
SNOX™ Flue Gas Cleaning Demonstration Project	ABB Environmental Systems	CCT-II/completed 12/94	2-60
LIMB Demonstration Project Extension and Coolside Demonstration	The Babcock & Wilcox Company.	CCT-I/completed 8/91	2-64
SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project	The Babcock & Wilcox Company	CCT-II/completed 5/93	2-68
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	Energy and Environmental Research Corporation	CCT-I/completed 10/94	2-72
Milliken Clean Coal Technology Demonstration Project	New York State Electric & Gas Corporation	CCT-IV/completed 6/98	2-76
Integrated Dry NO_x/SO_2 Emissions Control System	Public Service Company of Colorado	CCT-III/completed 12/96	2-80
Advanced Electric Power Generation			
Fluidized-Bed Combustion			
McIntosh Unit 4A PCFB Demonstration Project	Lakeland, City of, Lakeland Electric	CCT-III/design	2-86
McIntosh Unit 4B Topped PCFB Demonstration Project	Lakeland, City of, Lakeland Electric	CCT-V/design	2-88
JEA Large-Scale CFB Combustion Demonstration Project	JEA	CCT-I/design	2-90

Shaded area indicates projects having completed operations.

Exhibit 2-1 (continued)
Project Fact Sheets by Application Category

Project	Participant	Solicitation/Status	Page
Tidd PFBC Demonstration Project	The Ohio Power Company	CT-I/completed 3/95	2-92
Nucla CFB Demonstration Project	Tri-State Generation and Transmission Association, Inc.	CCT-I/completed 1/91	2-96
Integrated Gasification Combined-Cycle			
Kentucky Pioneer Energy IGCC Demonstration Project	Kentucky Pioneer Energy, LLC	CCT-V/design	2-102
Piñon Pine IGCC Power Project	Sierra Pacific Power Company	CCT-IV/operational	2-104
Tampa Electric Integrated Gasification Combined-Cycle Project	Tampa Electric Company	CCT-III/operational	2-106
Wabash River Coal Gasification Repowering Project	Wabash River Coal Gasification Repowering Project Joint Venture	CCT-IV/completed 12/99	2-108
Advanced Combustion/Heat Engines			
Clean Coal Diesel Demonstration Project	Arthur D. Little, Inc.	CCT-V/construction	2-114
Healy Clean Coal Project	Alaska Industrial Development and Export Authority	CCT-III/completed 12/99	2-116
Coal Processing for Clean Fuels			
Commercial-Scale Demonstration of the Liquid Phase Methanol (LPMEOH™) Process	Air Products Liquid Phase Conversion Company, L.P.	CCT-III/operational	2-122
Advanced Coal Conversion Process Demonstration	Western SynCoal LLC	CT-I/operational	2-124
Development of the Coal Quality Expert™	ABB Combustion Engineering, Inc. and CQ Inc.	CCT-I/completed 12/95	2-126
ENCOAL® Mild Coal Gasification Project	ENCOAL Corporation	CCT-III/completed 7/97	2-130
Industrial Applications			
Clean Power from Integrated Coal/Ore Reduction (CPICOR™)	CPICOR™ Management Company LLC	CCT-V/design	2-136
Pulse Combustor Design Qualification Test	ThermoChem, Inc.	CCT-IV/construction	2-138
Blast Furnace Granular-Coal Injection System Demonstration Project	Bethlehem Steel Corporation	CCT-III/completed 11/98	2-140
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	Coal Tech Corporation	CCT-I/completed 5/90	2-144
Cement Kiln Flue Gas Recovery Scrubber	Passamaquoddy Tribe	CCT-II/completed 9/93	2-148

Shaded area indicates projects having completed operations.

Exhibit 2-2
Project Fact Sheets by Participant

Participant	Project	Location	Page
ABB Combustion Engineering, Inc. and CQ Inc.	Development of the Coal Quality Expert™	Homer City, PA	2-126
ABB Environmental Systems	SNOX™ Flue Gas Cleaning Demonstration Project	Niles, OH	2-60
Air Products Liquid Phase Conversion Company, L.P.	Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process	Kingsport, TN	2-122
AirPol, Inc.	10-MWe Demonstration of Gas Suspension Absorption	West Paducah, KY	2-8
Alaska Industrial Development and Export Authority	Healy Clean Coal Project	Healy, AK	2-116
Arthur D. Little, Inc.	Clean Coal Diesel Demonstration Project	Fairbanks, AK	2-114
Babcock & Wilcox Company, The	Demonstration of Coal Reburning for Cyclone Boiler NO_x Control	Cassville, WI	2-34
Babcock & Wilcox Company, The	Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit	Aberdeen, OH	2-38
Babcock & Wilcox Company, The	LIMB Demonstration Project Extension and Coolside Demonstration	Loraine, OH	2-64
Babcock & Wilcox Company, The	SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project	Dilles Bottom, OH	2-68
Bechtel Corporation	Confined Zone Dispersion Flue Gas Desulfurization Demonstration	Seward, PA	2-12
Bethlehem Steel Corporation	Blast Furnace Granular-Coal Injection System Demonstration Project	Burns Harbor, IN	2-140
Coal Tech Corporation	Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	Williamsport, PA	2-144
CPICOR™ Management Company LLC	Clean Power from Integrated Coal/Ore Reduction (CPICOR™)	Vineyard, UT	2-136
CQ Inc.	(see ABB Combustion Engineering and CQ Inc.)		
ENCOAL Corporation	ENCOAL® Mild Coal Gasification Project	Gillette, WY	2-130
Energy and Environmental Research Corporation	Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	Hennepin, IL Springfield, IL	2-72
Energy and Environmental Research Corporation	Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler	Denver, CO	2-42
JEA	JEA Large-Scale CFB Combustion Demonstration Project	Jacksonville, FL	2-90
Kentucky Pioneer Energy, LLC	Kentucky Pioneer Energy IGCC Demonstration Project	Trapp, KY	2-102
Lakeland, City of, Lakeland Electric	McIntosh Unit 4A PCFB Demonstration Project	Lakeland, FL	2-86
Lakeland, City of, Lakeland Electric	McIntosh Unit 4B Topped PCFB Demonstration Project	Lakeland, FL	2-88
LIFAC-North America	LIFAC Sorbent Injection Desulfurization Demonstration Project	Richmond, IN	2-16
New York State Electric & Gas Corporation	Micronized Coal Reburning Demonstration for NO_x Control	Lansing, NY	2-46

Exhibit 2-2 (continued)
Project Fact Sheets by Participant

Participant	Project	Location	Page
New York State Electric & Gas Corporation	Milliken Clean Coal Technology Demonstration Project	Lansing, NY	2-76
Ohio Power Company, The	Tidd PFBC Demonstration Project	Brilliant, OH	2-92
Passamaquoddy Tribe	Cement Kiln Flue Gas Recovery Scrubber	Thomaston, ME	2-148
Public Service Company of Colorado	Integrated Dry NO_x/SO_2 Emissions Control System	Denver, CO	2-80
Pure Air on the Lake, L.P.	Advanced Flue Gas Desulfurization Demonstration Project	Chesterton, IN	2-20
Sierra Pacific Power Company	Piñon Pine IGCC Power Project	Reno, NV	2-104
Southern Company Services, Inc.	Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	Coosa, GA	2-30
Southern Company Services, Inc.	Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	Newnan, GA	2-24
Southern Company Services, Inc.	Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur, Coal-Fired Boilers	Pensacola, FL	2-50
Southern Company Services, Inc.	180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers	Lynn Haven, FL	2-54
Tampa Electric Company	Tampa Electric Integrated Gasification Combined-Cycle Project	Mulberry, FL	2-106
ThermoChem, Inc.	Pulse Combustor Design Qualification Test	Baltimore, MD	2-138
Tri-State Generation and Transmission Association, Inc.	Nucla CFB Demonstration Project	Nucla, CO	2-96
Wabash River Coal Gasification Repowering Project Joint Venture	Wabash River Coal Gasification Repowering Project	West Terre Haute, IN	2-108
Western SynCoal LLC	Advanced Coal Conversion Process Demonstration	Colstrip, MT	2-124

Exhibit 2-3
Key to Milestone Charts in Fact Sheets

Each fact sheet contains a bar chart that highlights major milestones—past and planned. The bar chart shows a project's duration and indicates the time period for three general categories of project activities—preaward, design and construction, and operation. The key provided below explains what is included in each of these categories.

Preaward

Includes preaward briefings, negotiations, and other activities conducted during the period between DOE's selection of the project and award of the cooperative agreement.

Design and Construction

Includes the NEPA process, permitting, design, procurement, construction, preoperational testing, and other activities conducted prior to the beginning of operation of the demonstration.

MTF	Memo-to-file
CX	Categorical exclusion
EA	Environmental assessment
EIS	Environmental impact statement

Operation and Reporting

Begins with startup and includes operational testing, data collection, analysis, evaluation, reporting, and other activities to complete the demonstration project.

Environmental Control Devices
SO_2 Control Technologies

10-MWe Demonstration of Gas Suspension Absorption

Project completed.

Participant
AirPol, Inc.

Additional Team Members
FLS miljo, Inc. (FLS)—technology owner
Tennessee Valley Authority—cofunder and site owner

Location
West Paducah, McCracken County, KY

Technology
FLS' Gas Suspension Absorption (GSA) system for flue gas desulfurization (FGD)

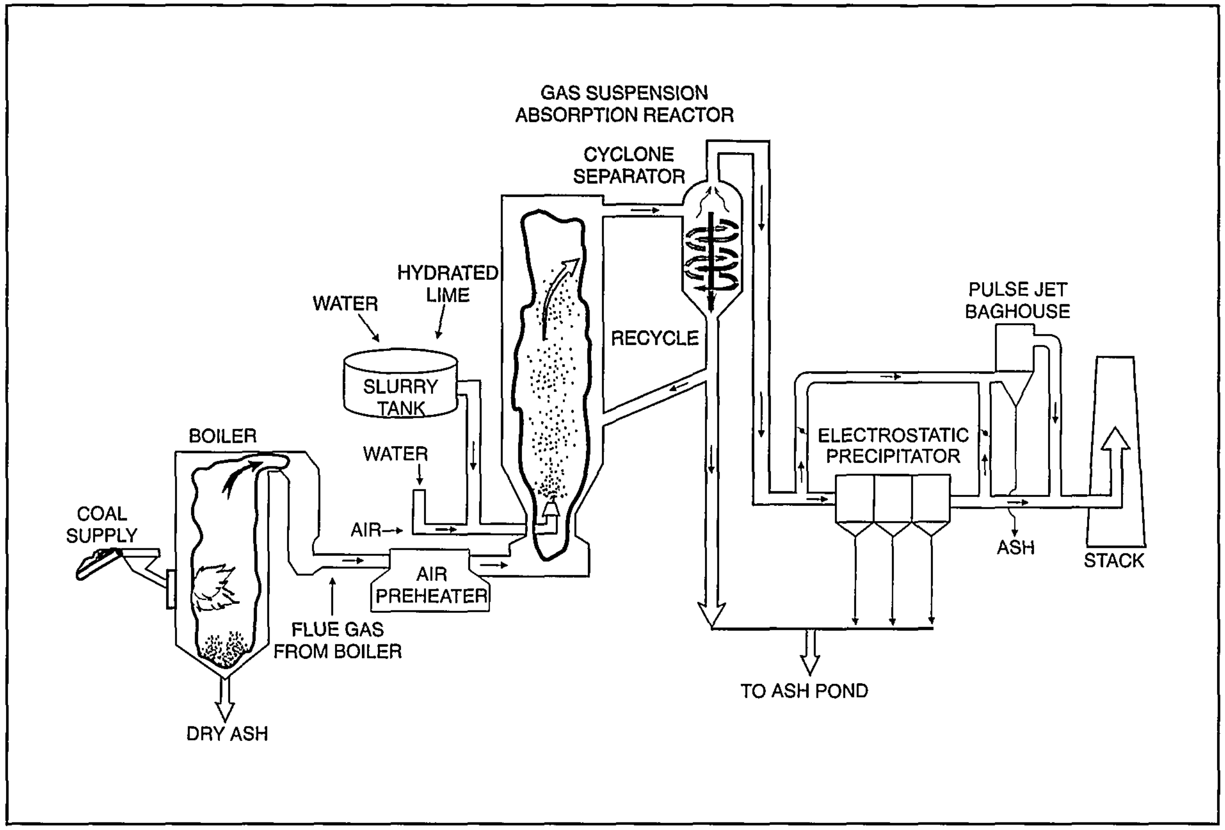
Plant Capacity/Production
10-MWe equivalent slipstream of flue gas from a 175-MWe wall-fired boiler

Coal
Western Kentucky bituminous: Peabody Martwick, 3.05% sulfur; Emerald Energy, 2.61% sulfur; Andalax, 3.06% sulfur; and Warrior Basin, 3.5% sulfur (used intermittently)

Project Funding

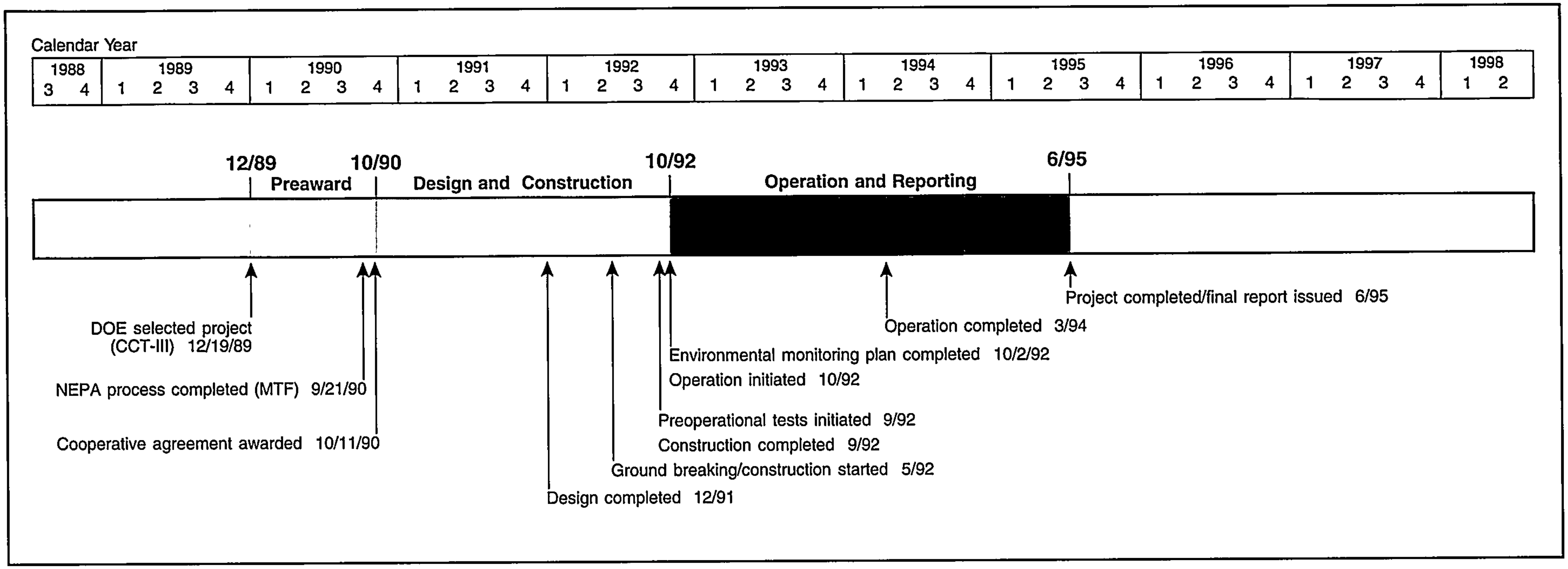
Total project cost	$7,717,189	100%
DOE	2,315,259	30
Participant	5,401,930	70

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 toxics control tests were conducted, and the effectiveness of a GSA/ESP and GSA/PJBH to control both SO_2 and particulates 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 molar ratio of 1.3 with 8 °F approach-to-saturation and 0.04% chloride,
  - 90% sulfur capture at a Ca/S molar ratio of 1.4 with 18 °F approach-to-saturation and 0.12% chloride, and
  - 99.9+% average particulate removal efficiency.
- GSA/PJBH achieved
  - 96% sulfur capture at a Ca/S molar ratio of 1.4 with 18 °F 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% or more of most trace metals, except cadmium, antimony, mercury, and selenium. (GSA/PJBH removed 99+% of the selenium.)
- The solid by-product was usable as low-grade cement.

Operational

- GSA/ESP lime utilization averaged 66.1% and GSA/PJBH averaged 70.5%.
- The reactor achieved the same performance as a conventional spray dryer, but at one-quarter to one-third the size.
- GSA generated lower particulate loading than a conventional 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 constant 1990$) costs for GSA installed in a 300-MWe plant using 2.6% sulfur coal are compared below to costs for a wet limestone scrubber with forced oxidation (WLFO scrubber). EPRI's TAG™ cost method was used. Based on EPRI cost studies of FGD processes, the capital cost (1990$) 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 has a capability of suspending a high concentration of solids, effectively drying the solids, and recirculating the solids at a high rate with precise control. This 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 2-4 lists the six variables used in the factorial tests and the levels at which they were applied. Inlet flue gas temperature was held constant at 320 °F. Factorial testing showed that lime stoichiometry had the greatest effect on SO_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 °F was achieved without plugging the system, the test was conducted at a very low chloride level (0.04%). Because water evaporation rates decrease as chloride levels increase, an 18 °F approach-to-saturation temperature was chosen for the higher 0.12% coal chloride level. Exhibit 2-5 summarizes key results from factorial testing.

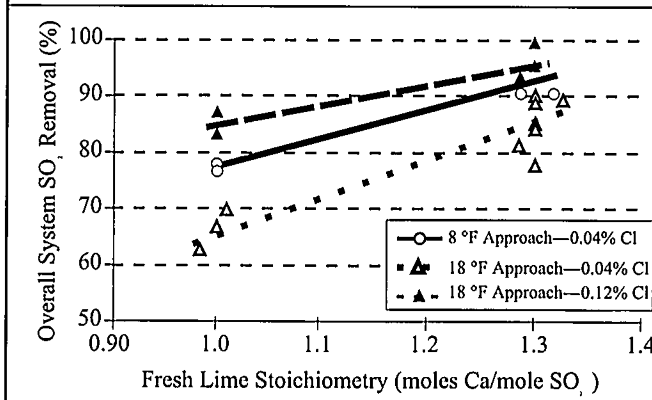
A 28-day continuous run to evaluate the GSA/ESP configuration was made with bituminous coals averaging 2.7% sulfur, 0.12% chloride levels, and 18 °F approach-to-saturation temperature. A subsequent 14-day continuous run to evaluate the GSA/PJBH configuration was performed under the same conditions as those of the 28-day run, except for adjustments in fly ash injection rate from 1.5–1.0 gr/ft³ (actual).

Exhibit 2-4
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
Fly ash loading (gr/ft³, actual)	0.50 and 2.0
Coal chloride level (%)	0.04 and 0.12
Flue gas flow rate (10³ scfm)	14 and 20
Recycle screw speed (rpm)	30 and 45

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

Exhibit 2-5
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 molar 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/10⁶ 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 molar 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 0.001–0.003 lb/10⁶ Btu.

All air toxics tests were conducted with 2.7% sulfur, low-chloride coal with a 12 °F approach-to-saturation temperature and a high fly ash loading of 2.0 gr/ft³ (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 are not required to achieve uniform, fine droplet size. Also, recycle of solids is direct and avoids recycling material in the feed slurry, which would necessitate expensive abrasion-resistant materials in the atomizer(s).

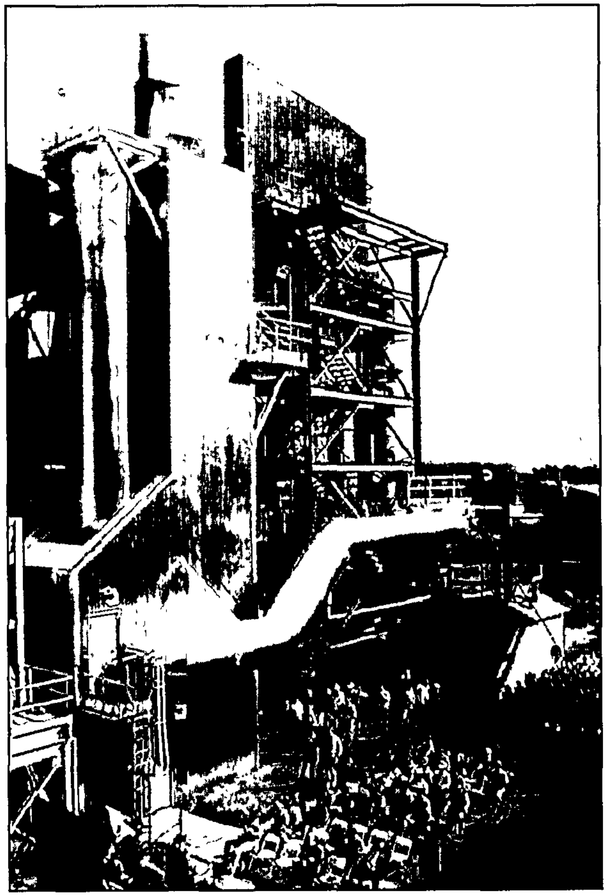
The high heat and mass transfer characteristics of the GSA enable the GSA system to be significantly smaller than a conventional spray dryer for the same capacity—one-quarter to one-third the size. This makes retrofit feasible for space-confined plants and reduces installation cost. The GSA system slurry 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 dust loading than a conventional spray dryer, 2–5 gr/ft^3 for GSA versus 6–10 gr/ft^3 for a spray dryer, thereby easing the burden on particulate controls. 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 pozzuolanic reaction, essentially providing the characteristics of a low-grade cement.

Economic Performance

Using EPRI costing methods, which have been applied to 30 to 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 estimated that (1) the capital cost was $149/kW (1990$) with three units at 50% capacity, and (2) the levelized cost (15-year constant 1990$) 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, Inc. successfully demonstrated the GSA system at TVA's Center for Emissions Research, located at TVA's Shawnee Plant.



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- to 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, Ohio, 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. Another GSA system has been sold to a Swedish iron ore sinter plant. Sales to Taiwan, Indonesia, and India have a combined value of $20 million. Furthermore, Taiwan contracted for technical assistance and proprietary equipment valued at $1.0 million.

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- *10-MWe Demonstration of Gas Suspension Absorption Final Project Performance and Economics Report.* Report No. DOE/PC/90542-T9. AirPol, Inc. June 1995. (Available from NTIS as DE95016681.)
- *10-MW Demonstration of Gas Suspension Absorption Final Public Design Report.* Report No. DOE/PC/90542-T10. AirPol, Inc. June 1995. (Available from NTIS as DE960003270.)
- *SO_2 Removal Using Gas Suspension Absorption Technology.* Topical Report No. 4. U.S. Department of Energy and AirPol, Inc. April 1995.
- *10-MWe Demonstration of the Gas Suspension Absorption Process at TVA's Center for Emissions Research: Final Report.* Report No. DOE/PC/90542-T10. Tennessee Valley Authority. March 1995. (Available from NTIS as DE96000327.)

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 equivalent

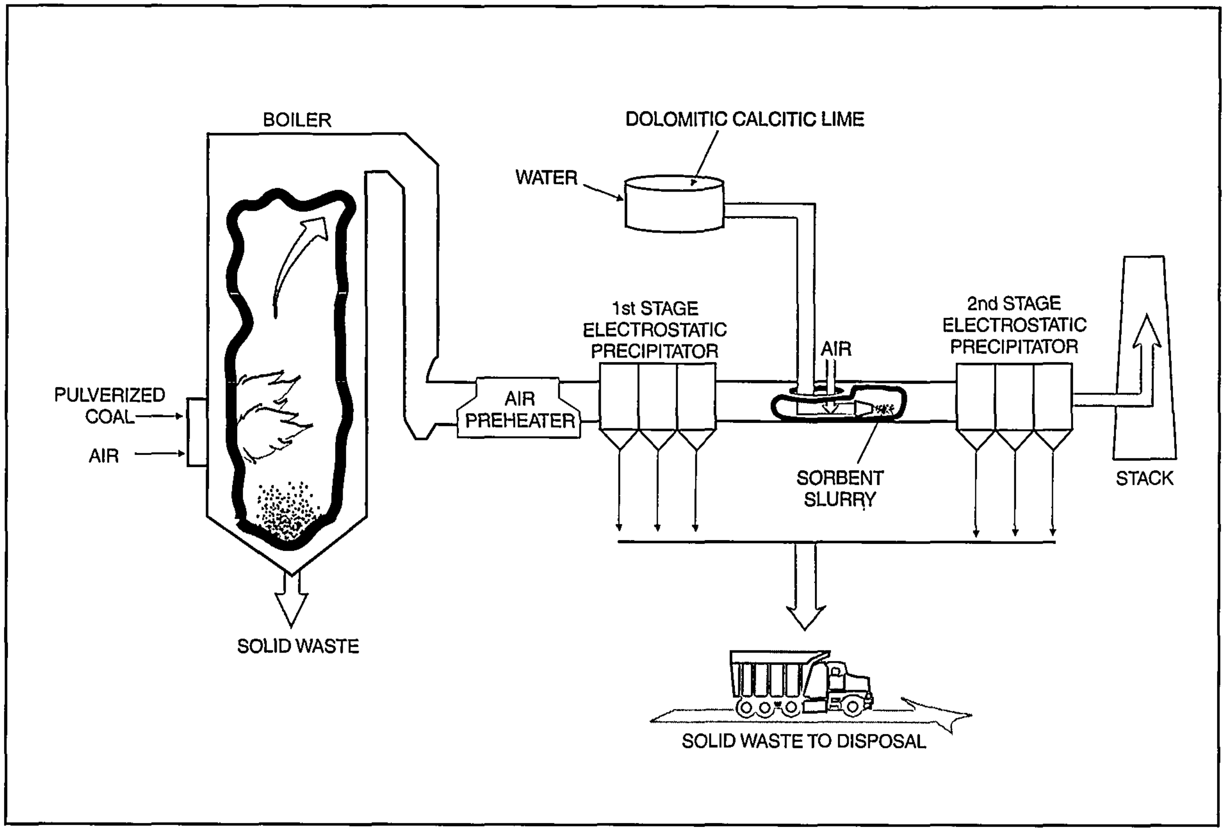
Coal
Pennsylvania bituminous, 1.2–2.5% sulfur

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

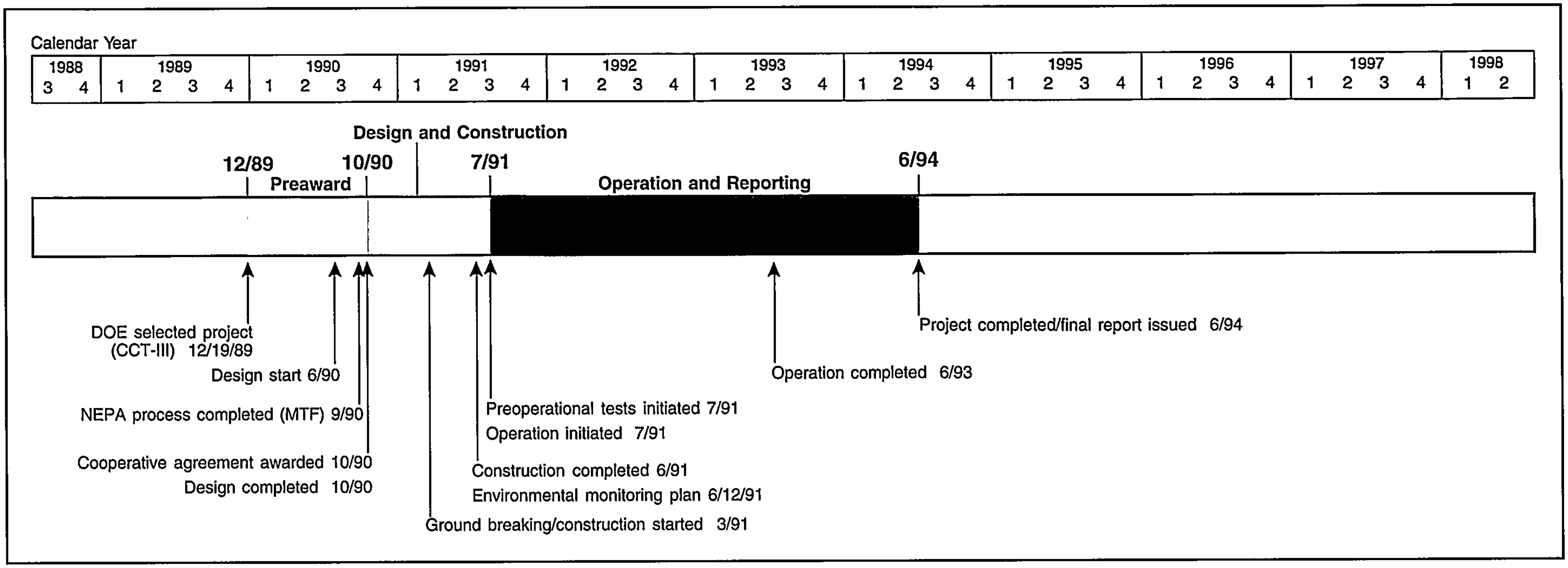
*Additional project overrun costs were funded 100% by the participant for a final total project cost of $12,173,000.



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

Technology/Project Description
In Bechtel's CZD/FGD process, a finely atomized slurry of reactive lime is sprayed into the flue gas stream between the boiler air heater and the electrostatic precipitator (ESP). The lime slurry is injected into the center of the duct by spray nozzles designed to produce a cone of fine spray. As the spray moves downstream and expands, the gas within the cone cools and the SO_2 is quickly absorbed on 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 evaluate the effects on SO_2 removal and ESP performance. 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, extended straight section of duct between the first- and second-stage ESPs.



Results Summary

Environmental

- Pressure-hydrated dolomitic lime proved to be a more effective sorbent than either dry hydrated calcitic lime or freshly slaked calcitic lime.
- Sorbent injection rate was the most influential parameter on SO_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 °F 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 °F (full load), sorbent injection rate of 52–57 gal/min, residence time of 2 seconds, and a pressure-hydrated dolomitic-lime concentration of about 9%.
- For operating conditions at Seward Station, data indicated that for 40–50% SO_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.

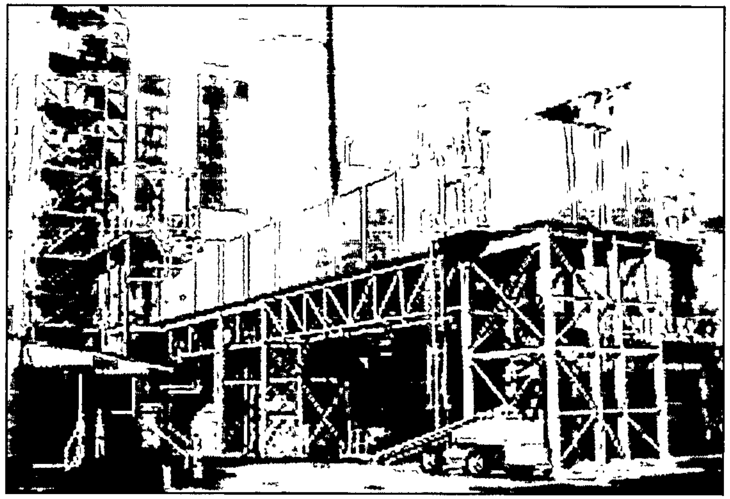
Economic

- 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 (1994\$).

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 duct walls. 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'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.

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; and
- Eliminate negative effects on normal boiler operations without increasing particulate emissions and opacity.

The parametric tests included duct injection of atomized lime slurry made of dry hydrated calcitic lime, 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 operation were achieved 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 °F to 260–280 °F. At 300–310 °F, injection rates of 52–57 gal/min were possible and SO_2 reductions greater than 50% were achieved. At 260–280 °F, injection rates had to be dropped to 30–40 gal/min, resulting in a 15–30% drop in SO_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 °F; boiler load of 145–147 MWe; residence time in the duct of 2 seconds; and lime slurry injection rate of 52–57 gal/min.

Operational Performance

The percentage of lime utilization in the CZD/FGD significantly affected the total cost of SO_2 removal. An analysis of the continuous operational data indicated that the percentage of lime utilization was directly dependent on two key factors: (1) percentage of SO_2 removed, and (2) 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

Estimates show that the CZD/FGD process can achieve costs of \$300/ton of SO_2 removed (1994\$) 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 (1994\$).

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 retrofiting 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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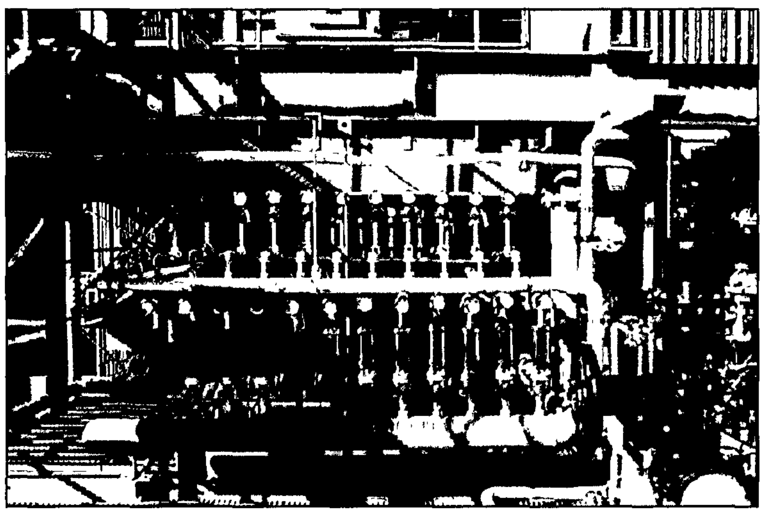


▲ This photo shows the CZD/FGD lime slurry injector control system.

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)

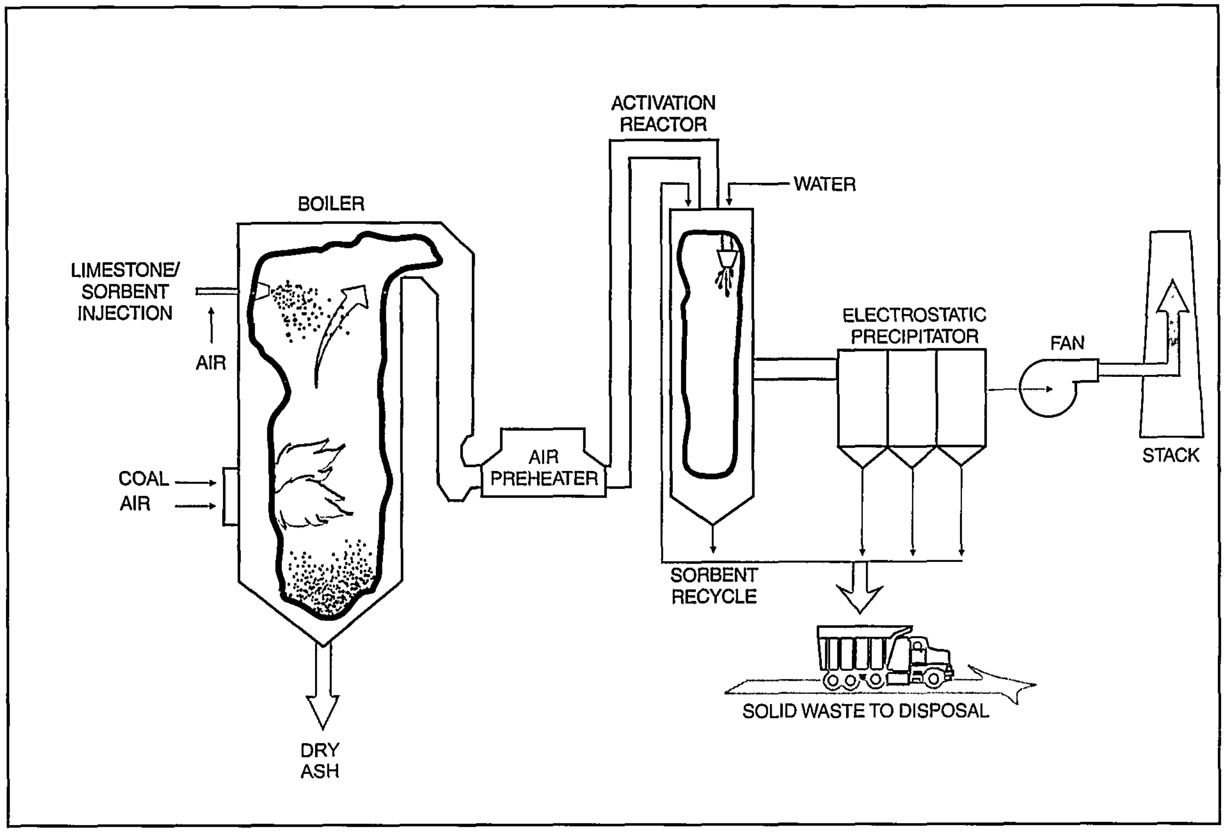
Technology
LIFAC's sorbent injection process with sulfur capture in a unique, patented vertical activation reactor

Plant Capacity/Production
60 MWe

Coal
Bituminous, 2.0–2.8% sulfur

Project Funding

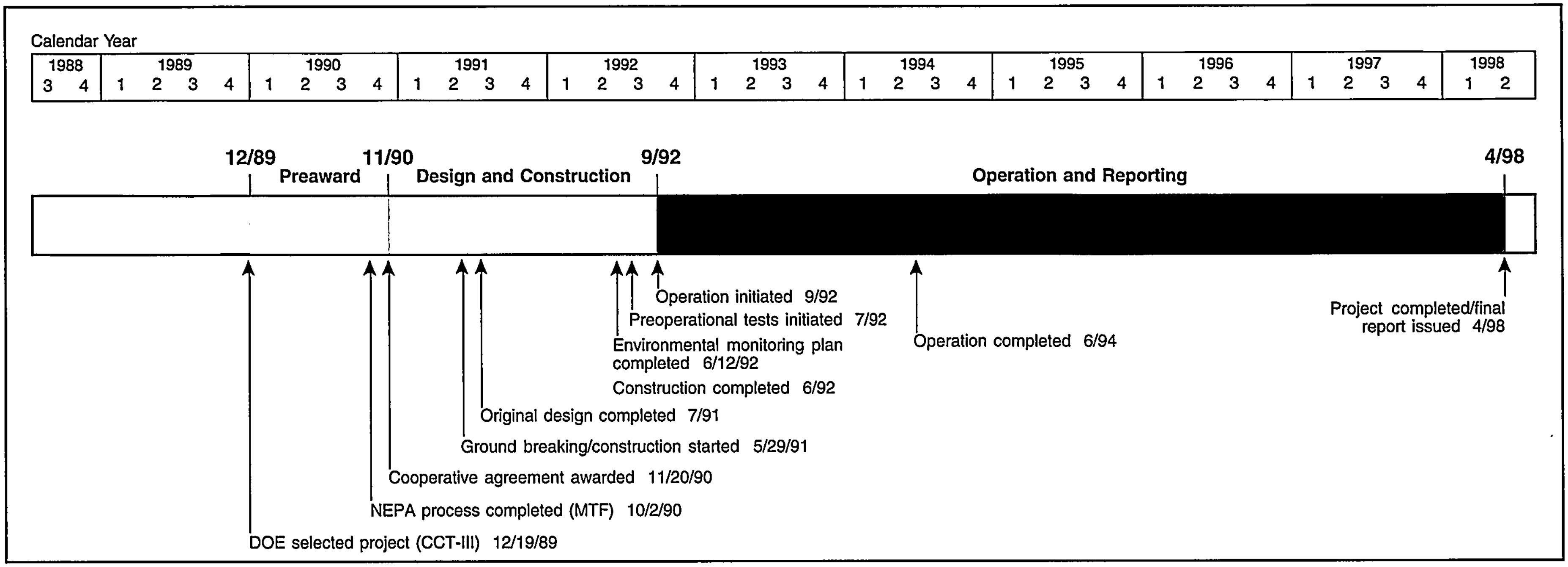
Total project cost	$21,393,772	100%
DOE	10,636,864	50
Participants	10,756,908	50



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 °F, 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 molar ratio of 2.0 and 7–12 °F approach-to-saturation temperature.
- The four parameters having the greatest influence on sulfur removal efficiency were limestone fineness, Ca/S molar ratio, approach-to-saturation temperature, and ESP ash recycle rate.
- ESP ash recycle rate was limited in the demonstration system configuration. Increasing the recycle rate and sustaining a 5 °F approach-to-saturation temperature were projected to increase SO_2 removal efficiency to 85% at a Ca/S molar ratio of 2.0 and limestone fineness of 80% minus 325 mesh.
- 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 startup, 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 (1994$)—$66/kW for two LIFAC reactors
(300 MWe); $76/kW for one LIFAC reactor
(150 MWe); $99/kW for one LIFAC reactor
(65 MWe).
- Operating cost (1994$)—$65/ton of SO_2 removal, assuming 75% SO_2 capture, Ca/S molar ratio of 2.0, limestone composed of 95% $CaCO_3$, and costing $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:

- 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 1.4–2.8%. However, most of the testing was conducted with the higher sulfur coals (2.0–2.8% sulfur).

Environmental Performance

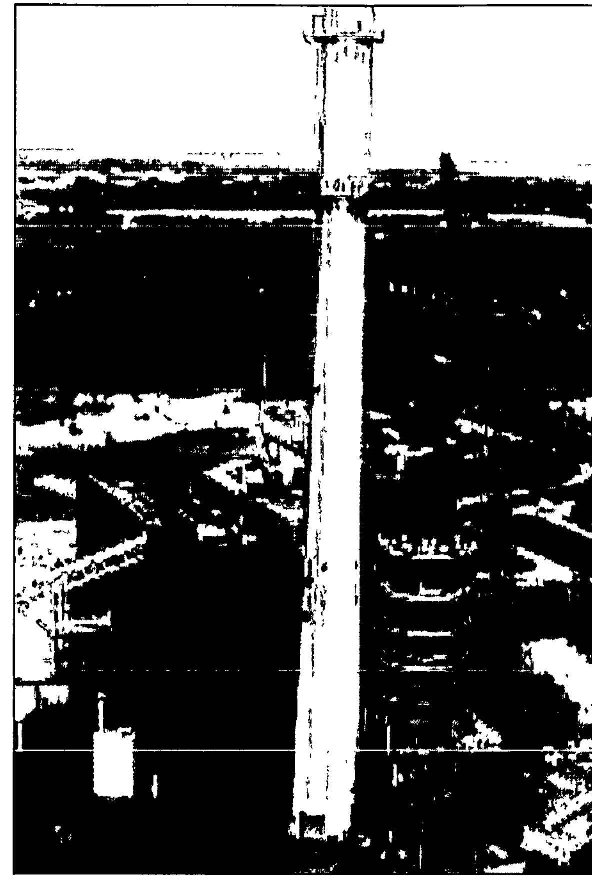
During the parametric testing phase, the numerous LIFAC process values and their effects on sulfur removal efficiency were evaluated. The four major parameters having the greatest influence on sulfur removal efficiency were limestone fineness, Ca/S molar ratio, reactor bottom temperature (approach-to-saturation), 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-hour to 4.5-hour cycles. 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 was found to be essential for efficient SO_2 capture. However, 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, but even 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 °F above saturation temperature, an SO_2 reduction of 85% could be maintained.

Operational Performance

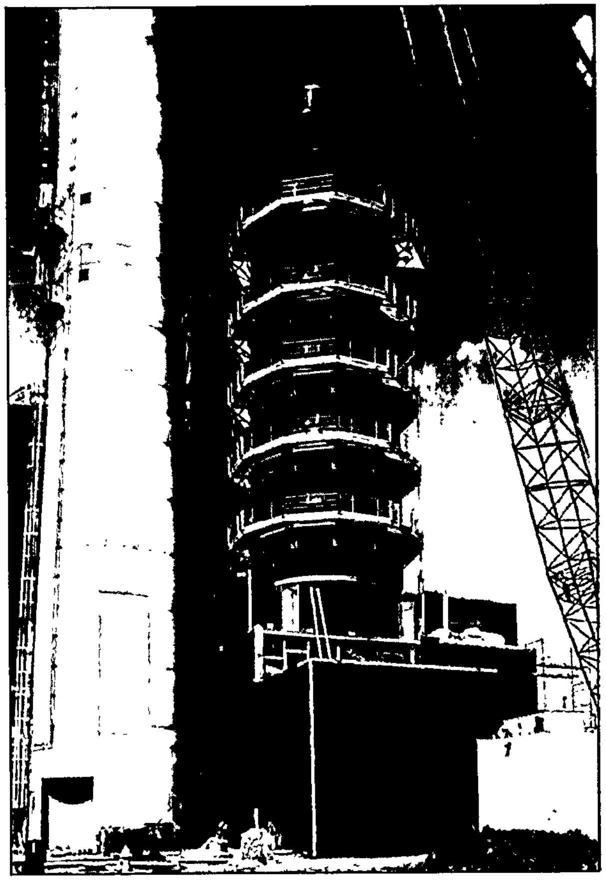
Optimization testing began in March 1994 and was followed by long-term testing in June 1994. The boiler was operated at an average load of 60 MWe during long-term testing, although it fluctuated according to power demand. The LIFAC process automatically adjusted to boiler load changes. A Ca/S molar ratio of 2.0 was selected to attain SO_2 reductions above 70%. Reactor bottom temperature was about 5 °F higher than optimum to avoid ash buildup on the steam reheaters. Atomized water droplet size was smaller than optimum for the same



▲ 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.

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.

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



▲ 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.

boiler bottom ash increased slightly during testing, but there was no negative impact on the power plant's bottom and fly ash 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 that regulates process control loops, interlocking, startup, 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:

- $99/kW for one LIFAC reactor at Whitewater Valley Station (65 MWe) (1994$),
- $76/kW for one LIFAC reactor at Shand Station (150 MWe), and
- $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 1.0 ton of SO_2, assuming 75% SO_2 capture, a Ca/S molar 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 subsidiary 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

Stearns-Roger Division of United Engineers and Constructors—facility designer

Air Products and Chemicals, Inc.—constructor and operator

Location

Chesterton, Porter County, IN (Northern Indiana Public Service Company's Bailly Generating Station, Unit Nos. 7 and 8)

Technology

Pure Air's advanced flue gas desulfurization (AFGD) process and PowerChip® agglomeration process

Plant Capacity/Production

528 MWe

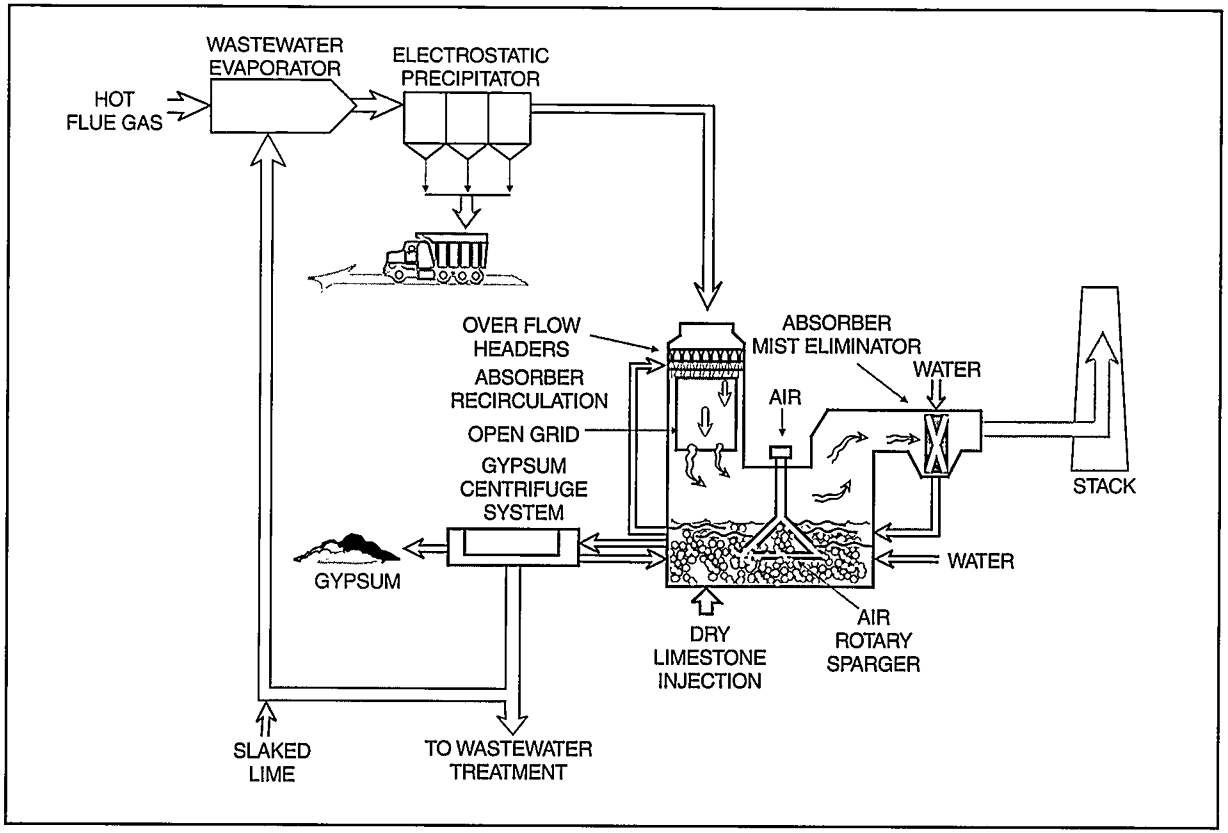
Coal

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

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



Project Objective

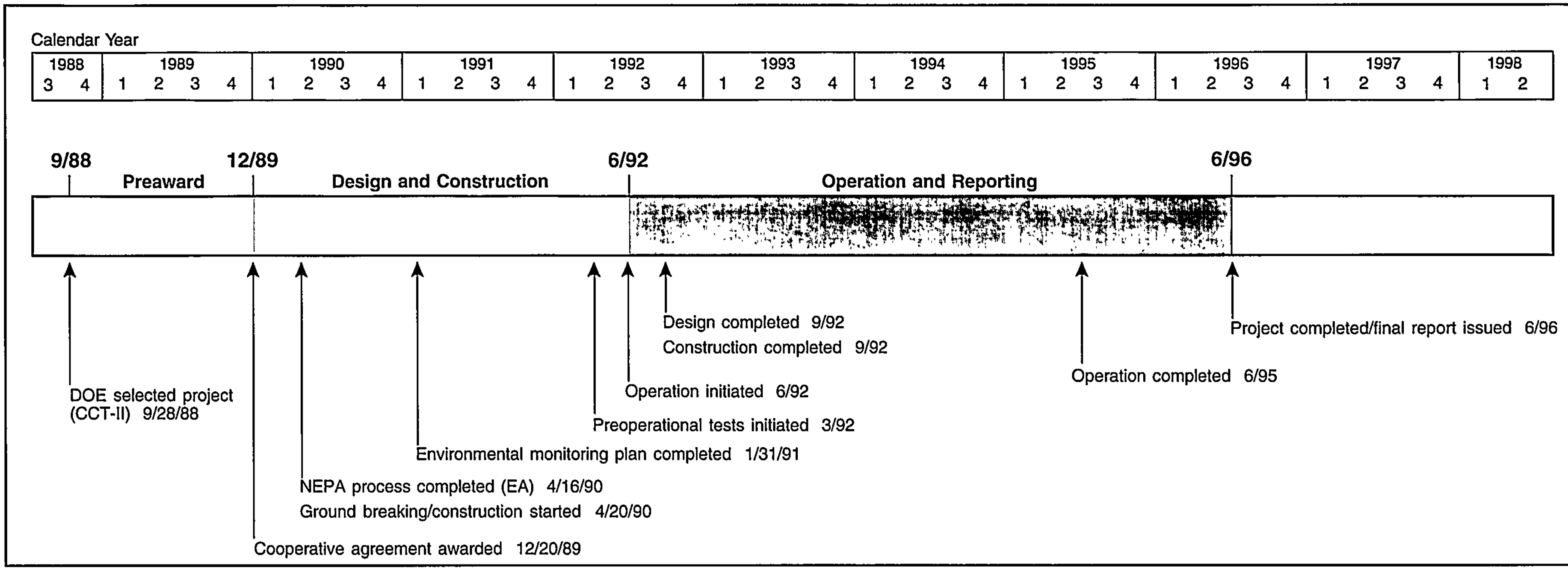
To reduce SO_2 emissions by 95% or more at approximately one-half the cost of conventional scrubbing technology, significantly reduce space requirements, and create no new waste streams.

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, absorbing, 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.



Results Summary

Environmental

- The 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, and 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—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 conventional 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 spare absorber modules. The major performance objectives were met.

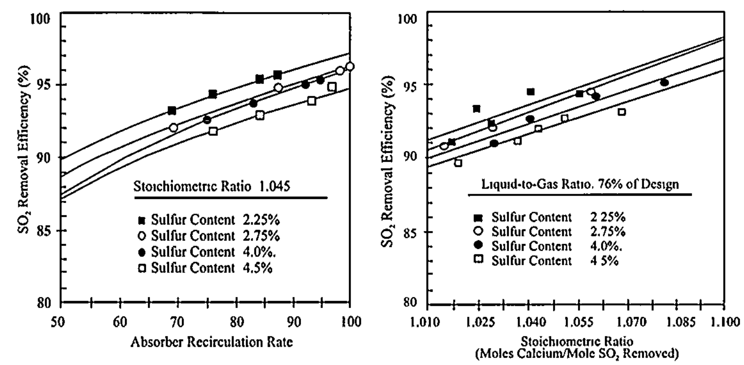
Over the 3-year demonstration, the AFGD unit accumulated 26,280 hours of operation with an availability of 99.5%. Approximately 237,000 tons of SO_2 were removed, with capture efficiencies of 95% or more, and over 210,000 tons of salable gypsum were produced. The AFGD continues in commercial service, which includes sale of all by-product gypsum to U.S. Gypsum's East Chicago, Indiana 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, which is 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/1,000 ft³. The lower end of the L/G ratio was determined by solids settling rates in the slurry and the requirement for full wetting of the grid packing. The high end of the L/G ratio 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%, were possible at loads of 33% and 67% with low to moderate stoichiometric ratio and L/G settings, even for 4.5% sulfur coal. Exhibit 2-6 summarizes the results of parametric testing at full load.

Exhibit 2-6
Pure Air SO_2 Removal Performance
(100% Boiler Load)



In the AFGD process, chlorides that would have been released to the air are captured, but 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 evaporates the water and the dissolved solids are 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. Marketability of the gypsum is dependent upon whether users are in range of economic transport and whether they can handle the gypsum by-product. For these reasons, PowerChip® technology was demonstrated as part of the project. This technology uses a compression mill to convert the highly cohesive AFGD gypsum cake into a flaked product with handling characteristics equivalent to natural rock gypsum. The process avoids use of binders, pre-drying, or pre-calcining normally associated with briquetting, and is 30–55% cheaper at \$2.50–\$4.10/ton.

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

Operational Performance

Availability over the 3-year operating period averaged 99.5% while maintaining an average SO_2 removal efficiency of 94%. This was attributable to the simple, effective design and an effective operating/maintenance philosophy. Modifications contributed to the high availability. 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. The 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. The AFGD SO_2 capture efficiency with limestone was comparable to that in wet scrubbers using lime, which is far more expensive. The 24-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 2-7 summarizes capital and levelized 1995 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 EPRI's Technical Assessment Guide™.

The incremental benefits of the own-and-operate arrangement, by-product utilization, and emission allowances were also evaluated. Exhibit 2-8 depicts the relative costs of a hypothetical 500-MWe generating unit in the Midwest burning 4.3% sulfur coal with a base case conventional FGD system and four incremental cases. The horizontal lines in Exhibit 2-8 show the range of costs for a fuel-switching option. The lower bar is the cost of fuel delivered to the hypothetical midwest unit and the upper bar allows for some plant modifications to accommodate the compliance fuel.

Exhibit 2-7
Estimated Costs for an AFGD System
(1995 Current Dollars)

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

Commercial Applications

The AFGD technology is positioned well to compete in the pollution control arena of 2000 and beyond. The AFGD technology 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 lower 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 to trade allowances or apply credits to other units within the utility. WES and PowerChip® mitigate or eliminate otherwise serious environmental concerns. AFGD effectively deals with hazardous air pollutants.

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

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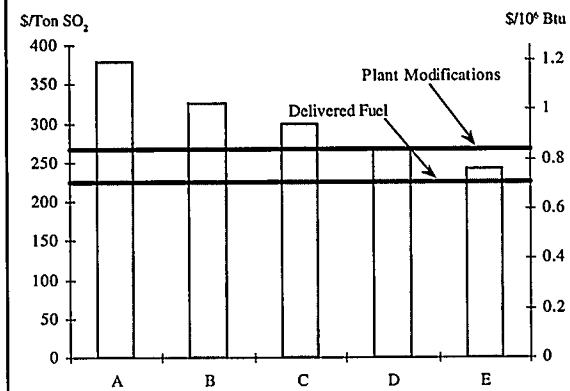
Exhibit 2-8
Flue Gas Desulfurization Economics



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

Incremental cases:

A—Conventional FGD (EPRI model)

B—AFGD, own-and-operate arrangement

C—Adds gypsum sales

D—Adds emission allowance credits at $300/ton, for 90% SO_2 removal

E—Increases SO_2 removal to 95%

References

- *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.
- *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.

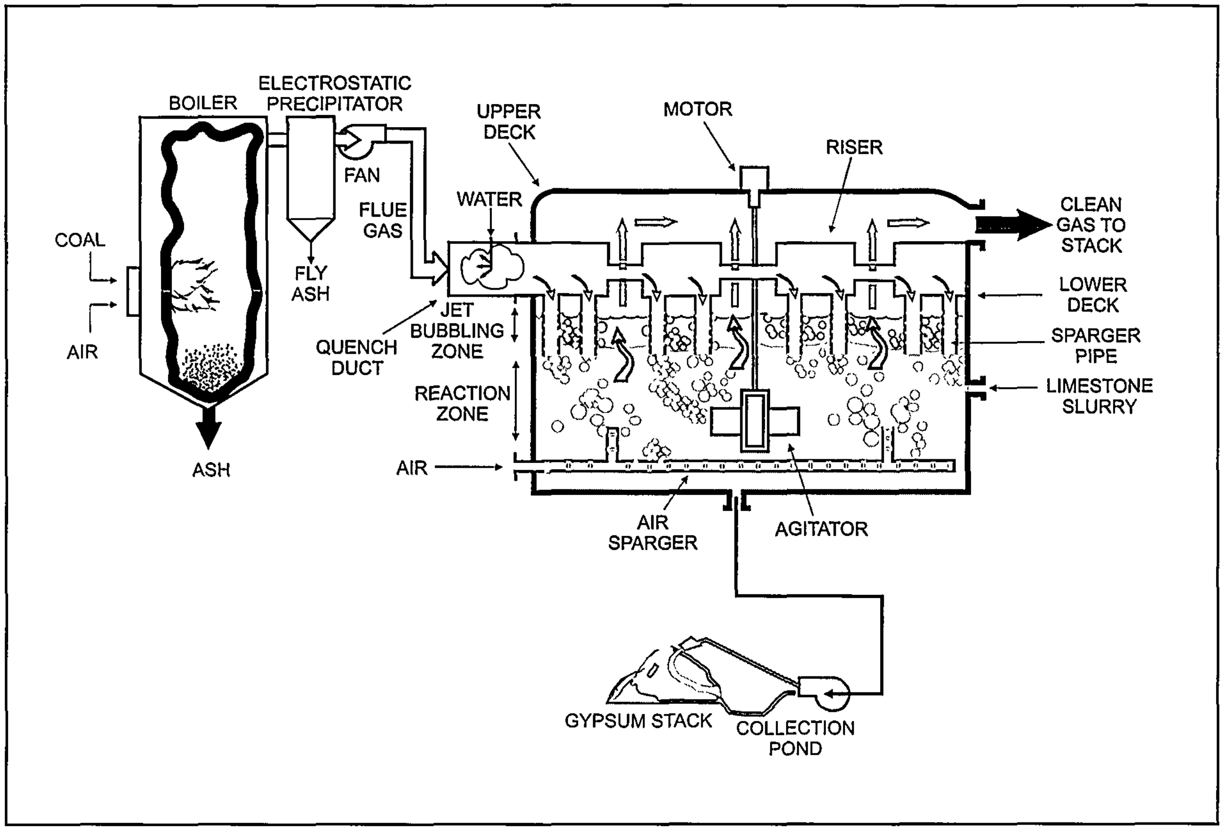
Additional Team Members
Georgia Power Company—host
Electric Power Research Institute—cofunder
Radian Corporation—environmental and analytical consultant
Ershigs, Inc.—fiberglass fabricator
Composite Construction and Equipment—fiberglass sustainment consultant
Acentech—flow modeling consultant
Ardaman—gypsum 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 (AFGD) process using the Jet Bubbling Reactor®

Plant Capacity/Production
100 MWe

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



Project Funding

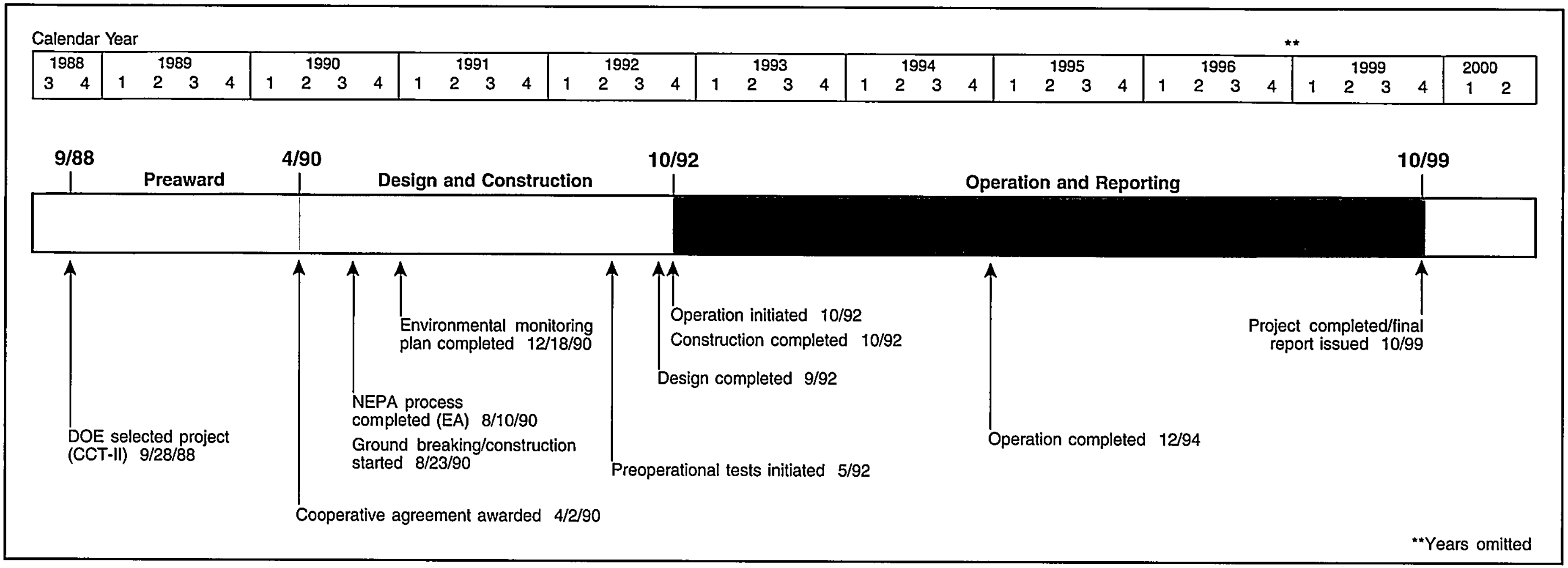
Total project cost	$43,074,996	100%
DOE	21,085,211	49
Participant	21,989,785	51

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

Technology/Project Description
The project demonstrated the CT-121 AFGD process, which uses a unique absorber design known as the Jet Bubbling Reactor® (JBR). The process combines limestone AFGD reaction, forced oxidation, and gypsum crystallization in one process vessel. The process is mechanically and chemically simpler than conventional AFGD processes and can be expected to exhibit lower cost characteristics.

The flue gas enters underneath the scrubbing solution in the JBR. 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 diked area with gypsum slurry. Gypsum solids settle in the diked 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 Corp.



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 hydrogen 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 fly ash loadings similar to an electrostatic precipitator (ESP) with marginal performance.

Economic

- Capital costs for project equipment, process, and startup were $29 million, or $293/kW at Plant Yates.
- Fixed O&M costs were $357,000/yr (1994$), and variable operating costs were $34–64/ton of SO_2 removed, depending on specific test conditions.
- Generic plant costs were not estimated; however, elimination of the need for flue gas prescrubbing, reheat, and a spare module should result in capital requirements far below those of contemporary conventional flue gas desulfurization (FGD) systems.

Project Summary

The CT-121 AFGD 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 startup and shakedown, during which approximately 19,000 hours were logged. Exhibit 2-9 summarizes operating statistics. Elevated particulate loading included a short test with the electrostatic precipitator (ESP) completely deenergized, but the long-term testing was conducted with the ESP partially deenergized to simulate a more realistic scenario, *i.e.*, a CT-121 retrofit to a boiler with a marginally performing particulate collection device. The SO_2 removal efficiency was measured under five different inlet concentrations with coals averaging 2.4% sulfur and ranging from 1.2–4.3% sulfur (as burned).

Exhibit 2-9
Operation of CT-121 Scrubber

	Low Ash Phase	Elevated Ash Phase	Cumulative for Project
Total test period (hr)	11,750	7,250	19,000
Scrubber available (hr)	11,430	6,310	18,340
Scrubber operating (hr)	8,600	5,210	13,810
Scrubber called upon (hr)	8,800	5,490	14,290
Reliability[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

Operating Performance

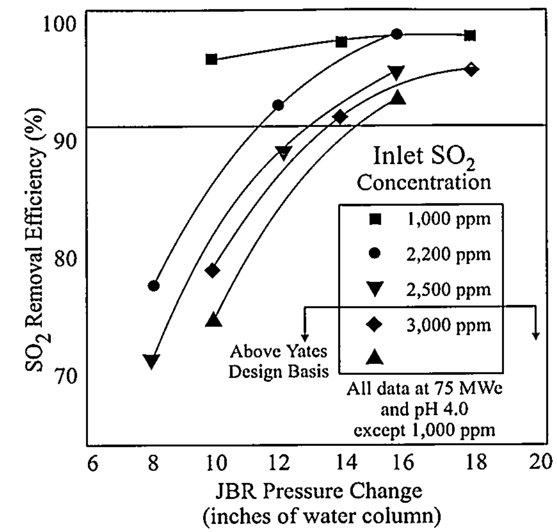
Use of FRP construction proved very successful. Because their large size precluded shipment, the JBR and limestone slurry storage tanks were constructed on site. Except for some erosion experienced at the JBR inlet transition duct, the FRP-fabricated equipment proved to be durable both structurally and 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%. Availability dropped to 95% under the elevated ash loading conditions due largely to sparger tube plugging problems, precipitated by fly ash 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 2-10 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.

Exhibit 2-10
SO_2 Removal Efficiency



Long-term particulate capture performance was tested with a partially deenergized ESP (approximately 90% efficiency), and is summarized in Exhibit 2-11.

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

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%.

Exhibit 2-11
CT-121 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.

Calculated air toxics removals across the CT-121 JBR, based on the measurements taken during the demonstration, are shown in Exhibit 2-12.

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

Economic Performance

The capital costs of the Plant Yates CT-121 project was $29,335,979, or $293/kW, which includes equipment, process, and start-up costs. The annual fixed O&M costs were $354,000/yr. (1994$). Variable operating costs were $34–64/ton of SO_2 removed (1994$), depending on specific test conditions.

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 strict 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.

Plant Yates continues to operate with the CT-121 scrubber as an integral part of the site's CAAA compliance strategy. Since the CCT Program demonstration, over 8,200 MWe equivalent of CT-121 AFGD capacity has been sold to 16 customers in seven countries.

The project received *Power* magazine's 1994 Powerplant Award. Other awards include the Georgia Chapter of the Air and Waste Management Association's 1994 Outstanding Achievement Award, the Georgia Chamber of Commerce's 1993 Air Quality Citizen of the Year award, and the Composites Institute (Society of Plastics Industries) 1996 Design Award of Excellence.

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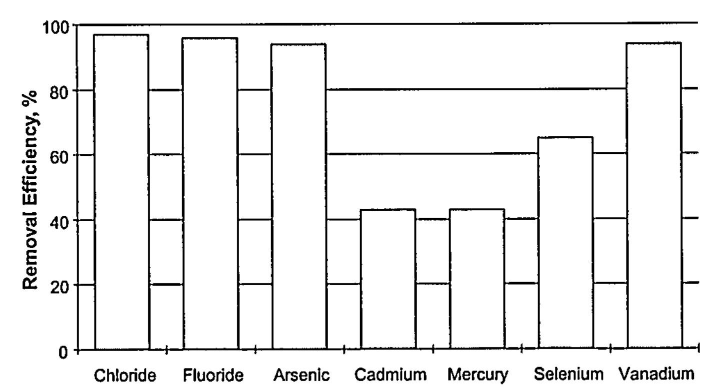
James U. Watts, DOE/NETL, (412) 386-5991

References

- Southern Company Services, Inc. *Demonstration of Innovative Applications of Technology for Cost Reductions to the CT-121 FGD Process. Final Report. Volumes 1-6.* January 1997.
- *Comprehensive Report to Congress on the Clean Coal Technology Program: Demonstration of Innovative Applications of Technology for the CT-121 FGD Process.* Southern Company Services, Inc. Report No. DOE/FE-0158. U.S. Department of Energy. February 1990. (Available from NTIS as DE9008110.)

Exhibit 2-12
CT-121 Air Toxics Removal
(JBR Components Only)



Environmental Control Devices
NO_x Control Technologies

Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler

Project extended.

Participant
Southern Company Services, Inc. (SCS)

Additional Team Members
Electric Power Research Institute (EPRI)—cofunder
Foster Wheeler Energy Corporation (Foster Wheeler)—technology supplier
Georgia Power Company—host
PowerGen—cofunder
U.K. Department of Trade and Industry—cofunder
EnTEC—technology supplier
Radian—technology supplier
Tennessee Technological University—technology supplier
Southern Company—cofunder

Location
Coosa, Floyd County, GA (Georgia Power Company's Plant Hammond, Unit No. 4)

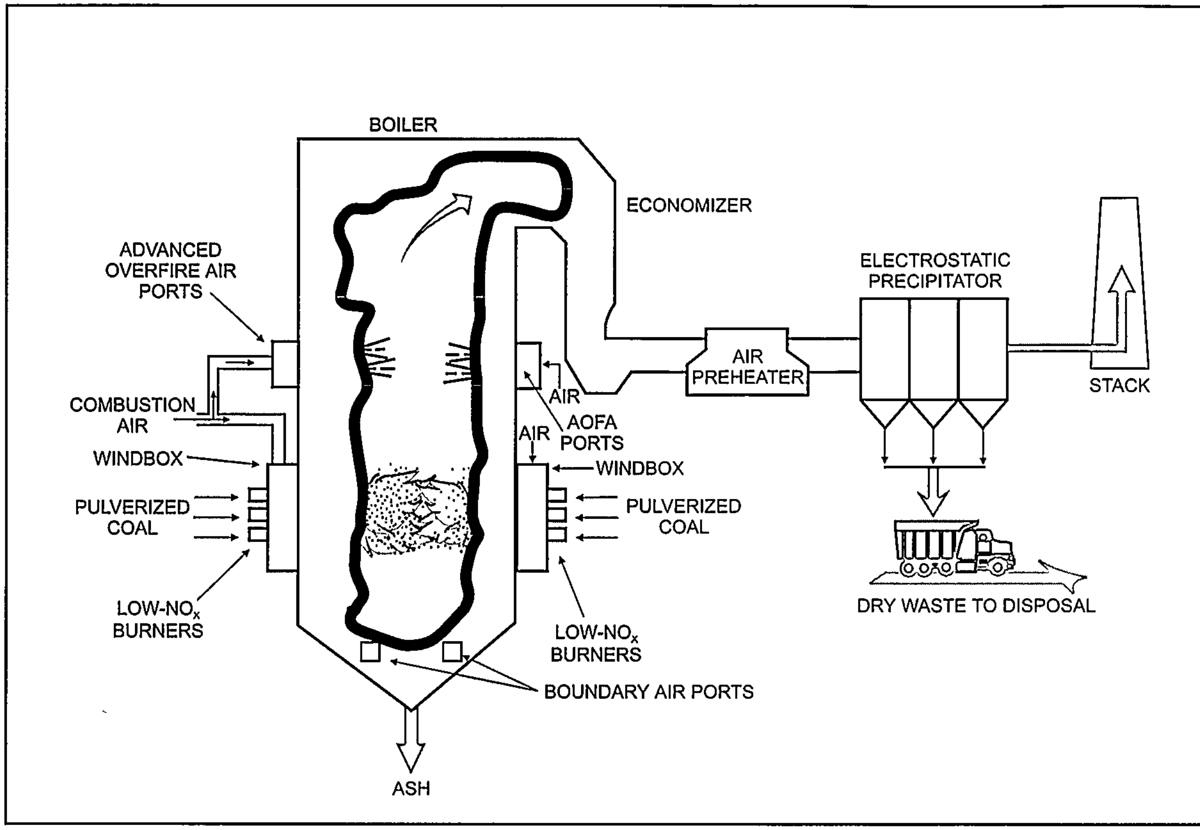
Technology
Foster Wheeler's low-NO_x burner (LNB) with advanced overfire air (AOFA) and EPRI's Generic NO_x Control Intelligent System (GNOCIS) computer software.

Plant Capacity/Production
500 MWe

Coal
Eastern bituminous coals, 1.7% sulfur

Project Funding

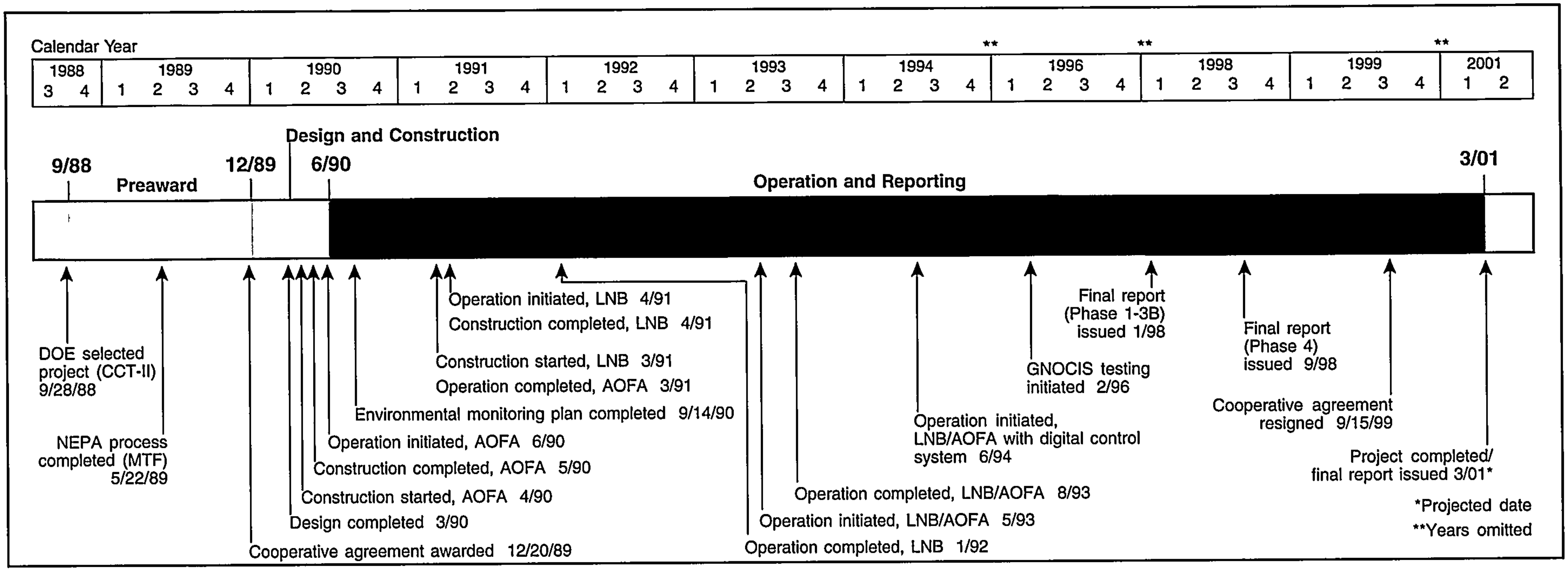
Total project cost	$15,853,900	100%
DOE	6,553,526	41
Participant	9,300,374	59



Project Objective
To achieve 50% NO_x reduction with the LNB/AOFA system; to determine the contributions of AOFA and LNB to NO_x reduction and the parameters for optimal LNB/AOFA performance; and to assess the long-term effects of LNB, AOFA, combined LNB/AOFA, and the GNOCIS advanced digital controls on NO_x reduction, boiler performance, and peripheral equipment performance. The project has been reopened and extended to demonstrate an overall unit optimization system.

Technology/Project Description
AOFA involves: (1) improving OFA mixing to enable operation of the burners below the air/fuel ratio theoretically required to complete combustion (sub-stoichiometric), without increasing combustible losses; and (2) introducing "boundary air" at the boiler walls to prevent corrosion caused by the reducing atmosphere.

In the Foster Wheeler Controlled Flow/Split Flame (CFSF) LNB, fuel and air mixing is staged by regulating the primary air/fuel mixture, velocities, and turbulence to create a fuel-rich core with sufficient air to sustain combustion at a severely sub-stoichiometric air/fuel ratio. The burner also controls the rate at which additional air, necessary to complete combustion, is mixed with the flame solids and gases so as to maintain a deficiency of oxygen until the remaining combustibles fall below the peak NO_x producing temperature (around 2,800 °F). The final excess air then can be allowed to mix with the unburned products so that combustion is completed at a relatively low temperature. The CFSF LNB splits the coal/air mixture into four streams, which minimizes coal and air mixing and combustion staging.



Results Summary

Environmental

- Using LNB alone, long-term NO_x emissions were 0.65 lb/10^6 Btu, representing a 48% reduction from baseline conditions (1.24 lb/10^6 Btu).
- Using AOFA only, long-term NO_x emissions were 0.94 lb/10^6 Btu, representing a 24% reduction from baseline conditions.
- Using LNB/AOFA, long-term NO_x emissions were 0.40 lb/10^6 Btu, representing a 68% reduction from baseline conditions.
- Chemical emissions testing showed no evidence of organic compound emissions resulting from the combustion modifications installed for NO_x control. Trace element control, except for mercury and selenium, proved to be a function of electrostatic precipitator (ESP) performance.

Operational

- AOFA accounted for an incremental NO_x reduction beyond the use of LNB of approximately 17%, with additional reductions resulting from other operational changes.
- GNOCIS achieved a boiler efficiency gain of 0.5 percentage points, a reduction in fly ash loss-on-ignition (LOI) levels of 1–3 percentage points, and a reduction in NO_x emissions of 10–15% at full load.
- Fly ash LOI increased from a baseline of 7% (corrected to representative excess oxygen conditions) to 10% with AOFA and 8% with LNB and LNB/AOFA, despite significant improvements in coal fineness.

Economic

- Capital cost for a 500-MWe wall-fired unit is \$8.8/kW for AOFA alone, \$10.0/kW for LNB alone, \$18.8/kW for LNB/AOFA, and \$0.5/kW for GNOCIS.
- Estimated cost of NO_x removal is \$79/ton using LNB/AOFA in a base load dispatch scenario experienced at Plant Hammond.

Project Summary

SCS conducted baseline characterization of the unit in an "as-found" condition from August 1989 to April 1990. The AOFA system was tested from August 1990 to March 1991. Following installation of the LNBs in the second quarter of 1991, the LNBs were tested from July 1991 to January 1992, excluding a three-month delay when the plant ran at reduced capacity. Post-LNB increases in fly ash LOI, along with increases in combustion air requirements and fly ash loading to the electrostatic precipitator (ESP), adversely affected the unit's stack particulate emissions. The LNB/AOFA testing was conducted from January 1992 to August 1993, excluding downtime for a scheduled outage and for portions of the test period due to excessive particulate emissions. However, an ammonia flue gas conditioning system was added to improve ESP performance, which enabled the unit to operate at full load, and allowed testing to continue.

Operational Performance

LOI increased for the AOFA, LNB, and LNB/AOFA phases, as shown in Exhibit 2-13, despite improved mill performance due to the replacement of the mills. Increased LOI was a concern not only because of the associated efficiency loss, but also due to a potential loss of fly ash sales. The increased carbon in the fly ash renders the material unsuitable for use in making concrete.

During October 1992, SCS conducted parametric testing to determine the relationship between NO_x and LOI emissions. The parameters tested were: excess oxygen, mill coal flow bias, burner sliding tip position, burner outer register position, and burner inner register position. Nitrogen oxide emissions and LOI levels varied from 0.44–0.57 lb/10^6 Btu and 3–10%, respectively. As expected, excess oxygen levels had considerable effect on both NO_x and LOI. The results showed that there is some flexibility in selecting the optimum operating point and making trade-offs between NO_x emissions and fly ash LOI; however, much of the variation was the result of changes in excess oxygen. This can be more clearly seen in Exhibit 2-14 in which all sensitivities are plotted. This exhibit shows that, for excess oxygen, mill bias, inner register, and sliding tip, any adjustments to reduce NO_x emissions are at the expense of increased fly ash LOI. In contrast, the slope of the outer register adjustment suggests that improvement in both NO_x emissions and LOI can be achieved by adjustment of this damper. However, due to the relatively small impact of the outer register adjustment on both NO_x and LOI, it is likely the positive NO_x/LOI slope is an artifact of process noise.

Exhibit 2-13
LOI Performance Test Results

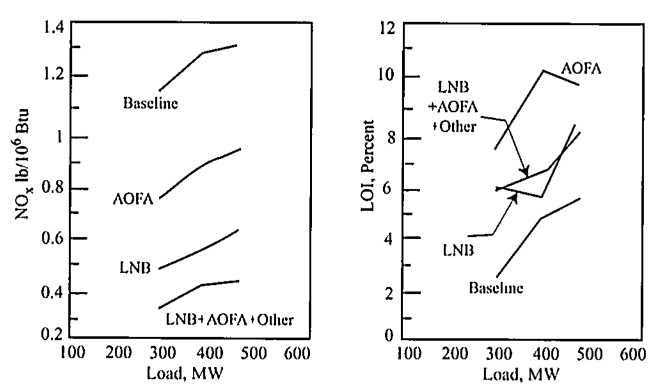
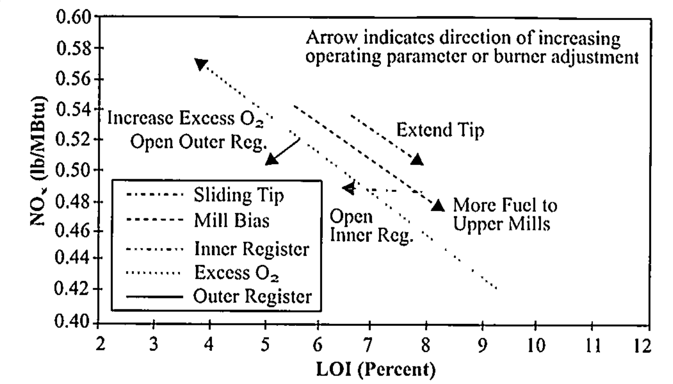


Exhibit 2-14
NO_x vs. LOI Tests—All Sensitivities



A subsidiary goal of the project was to evaluate advanced instrumentation and controls (I&C) as applied to combustion control. The need for more sophisticated I&C equipment is illustrated in Exhibit 2-15. There are trade-offs in boiler operation, *e.g.*, as excess air increases, NO_x increases, LOI decreases, and boiler losses increase. The goal is to find and maintain an optimal operating condition. The I&C systems tested included GNOCIS and carbon-in-ash analyzers.

The GNOCIS software applies an optimizing procedure to identify the best set points for the plant, which are

Exhibit 2-15
Typical Trade-Offs in Boiler Optimization

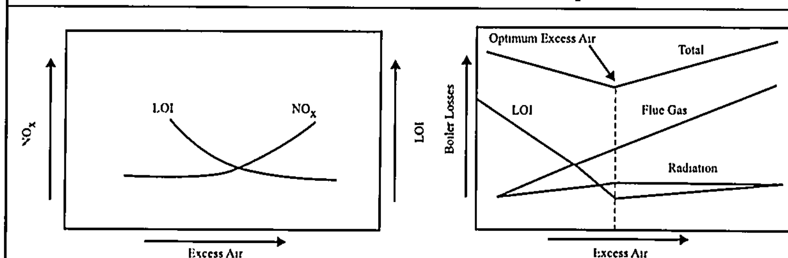
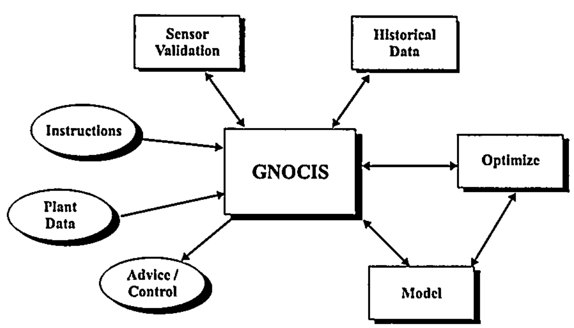


Exhibit 2-16
Major Elements of GNOCIS



implemented automatically without operator intervention (closed-loop), or conveyed to the plant operators for implementation (open-loop). The major elements of GNOCIS are shown in Exhibit 2-16. The GNOCIS system provided advice that reduced NO_x emissions by 10–15% at full load, while improving the heat rate or reducing a fly ash LOI by 1–3 percentage points.

Environmental Performance

Long-term testing showed that the AOFA, LNBs, and LNB/AOFA provide full load NO_x reductions of 24, 48, and 68%, respectively. Although the long-term LNB/AOFA NO_x level represents a 68% reduction from baseline levels, a substantial portion of the incremental change in NO_x emissions between the LNB and the LNB/AOFA configurations is the result of operational changes and is not the result of adding AOFA.

During the LNB/AOFA test phase a total of 63 days of valid long-term NO_x emissions data was collected. Based on this data set, the full-load, long-term NO_x emissions were 0.40 lb/10^6 Btu, which was consistent with earlier short-term test data. Earlier long-term testing had resulted in NO_x emissions of 0.94 lb/10^6 Btu for AOFA only and 0.65 lb/10^6 Btu for LNB only, respectively.

Chemical emissions testing showed no evidence of organic compound emissions resulting from the combustion modifications installed for NO_x control. Trace element control, except for mercury and selenium, proved to be a function of electrostatic precipitator (ESP) performance. Only a small portion of the mercury and selenium, which adopt a vapor phase, and none of the vapor phase chlorine (as hydrochloric acid) and fluorine (as hydrofluoric acid) were captured.

Economic Performance

Estimated capital costs for a commercial 500-MWe wall-fired installation are: AOFA—$8.8/kW, LNB—$10.0/kW, LNB/AOFA—$18.8/kW, and GNOCIS—$0.5/kW. Annual O&M costs and NO_x reductions depend on the assumed load profile. Based on the actual load profile observed in the testing, the estimated annual O&M cost increase for LNB/AOFA is $333,351. Efficiency is decreased by 1.3 percent, and the NO_x reduction is 68 percent of baseline, or 11,615 tons/year at full load. The capital cost is $8,300,000 and the calculated cost of NO_x removed is $79/ton for the Hammond base load dispatch scenario.

The addition of GNOCIS to the LNB/AOFA, using the actual load profile observed in the testing, results in a range of costs depending on whether the unit is operated to maximize NO_x removal efficiency, or LOI. For the maximum NO_x removal case, the efficiency is improved by 0.6 percent, the annual O&M cost is decreased by $228,058, the incremental NO_x reduction is 11 percent (696 tons/year), and the capital cost is $250,000. The calculated cost per ton of NO_x removed is -$299 (net gain due to increased efficiency).

Project Extension

On September 15, 1999, the cooperative agreement was extended and work began on the design and installation of an overall unit optimization system. The work will be carried out as part of Phase 4 of the project. The overall goal of Phase 4 is to demonstrate on-line optimization techniques for power plant processes and for the unit as a whole. The major tasks include unit optimization, boiler optimization, automated sootblowing, and precipitator modeling/optimization. To date, the total plant optimization study is complete and the designs for the optimization packages are in progress. The real-time heat rate monitor is being tested by the participant.

Commercial Applications

The technology is applicable to the 411 existing pre-NSPS dry-bottom wall-fired boilers in the United States, 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 cofiring coal and natural gas.

The host has retained the technologies for commercial use. Foster Wheeler has equipped 86 boilers with low-NO_x burner technology (51 domestic and 35 international)—1,800 burners for over 30,000 MWe capacity.

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James R. Longanbach, NETL, (304) 285-4659

References

- *500-MW Demonstration of Advanced Wall-Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers. Phase 4—Digital Control System and Optimization.* Southern Company Services, Inc. September 1998.
- *500-MW Demonstration of Advanced Wall-Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers. Phases 1-3B, Final Report.* Southern Company Services, Inc. January 1998.

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 handling
Electric Power Research Institute—cofunder
State of Illinois, Department of Energy and Natural Resources—cofunder
Utility companies (14 cyclone boiler operators)—cofunders

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

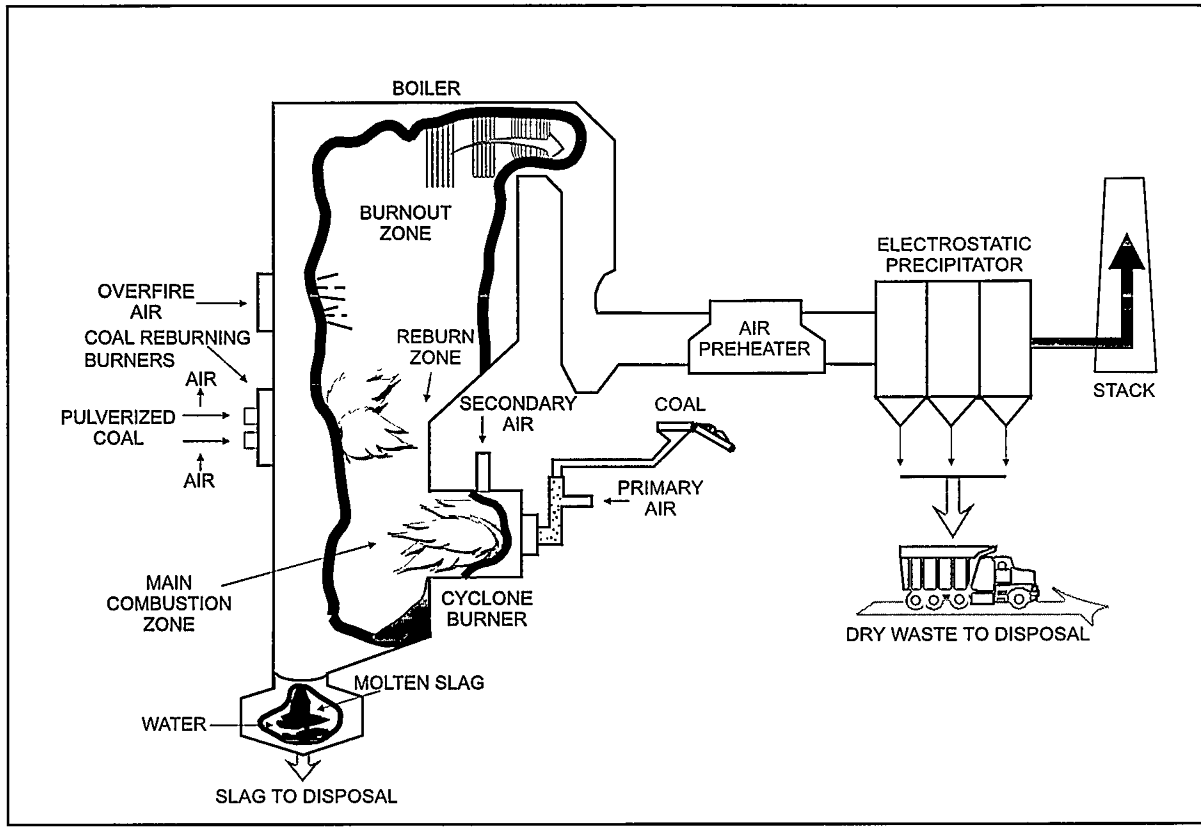
Technology
The Babcock & Wilcox Company's Coal Reburning System (Coal Reburning)

Plant Capacity/Production
100 MWe

Coal
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

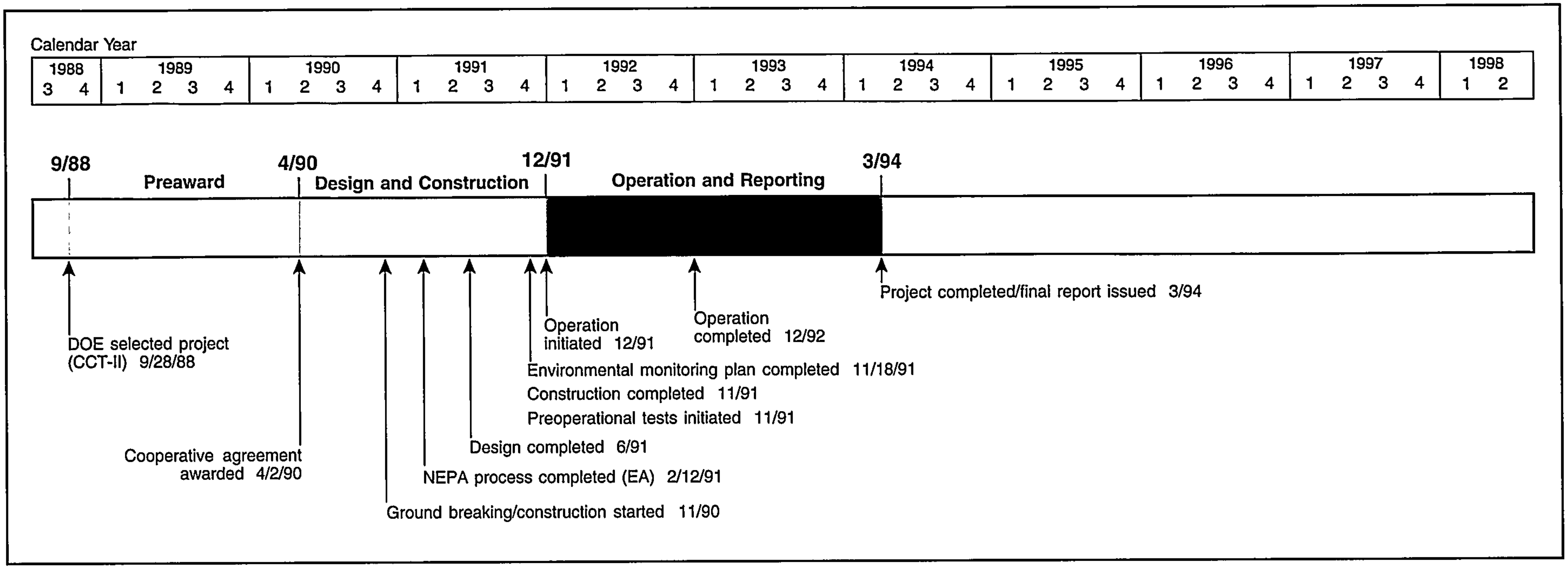


Project Objective
To demonstrate the technical and economic feasibility of Coal Reburning to achieve greater than 50% reduction in NO_x emissions with no serious impact on cyclone combustor operation, boiler performance, or other emission streams.

Technology/Project Description
Babcock & Wilcox Coal Reburning 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. Completion of the combustion process occurs in the third zone, called the burnout zone, where the balance of the combustion air is introduced.

Coal Reburning can be applied with the cyclone burners operating within their normal, noncorrosive, oxidizing conditions, thereby minimizing any adverse effects of reburning 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 Reburning achieved greater than 50% NO_x reduction at full load with Lamar bituminous and PRB subbituminous coals.
- Reburning-zone stoichiometry had the greatest effect on NO_x control.
- Gas recirculation was vital to maintaining reburning-zone stoichiometry while providing necessary burner cooling, flame penetration, and mixing.
- Opacity levels and electrostatic precipitator (ESP) performance were not affected by Coal Reburning with either coal tested.
- Optimal Coal Reburning 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 Reburning 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 percentage points 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 percentage points 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 reburning 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 (1990\$).
- Levelized 10- and 30-year busbar power costs for a 110-MWe plant were 2.4 and 2.3 mills/kWh, respectively (constant 1990\$).
- Levelized 10- and 30-year busbar power costs for a 605-MWe plant were 1.6 and 1.5 mills/kWh, respectively (constant 1990\$).

Project Summary

Although cyclone boilers represent only 8.5% of the pre-NSPS coal-fired generating capacity, they contribute 12% 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. However, at the time of this demonstration, there was no cost-effective combustion modification available for cyclone boiler NO_x control.

Babcock & Wilcox Coal Reburning offers an economic and operationally sound response to the environmental requirements. This technology avoids cyclone combustor modification and associated performance complications, and provides an alternative to postcombustion NO_x control options, such as SCR, which have relatively high capital and/or operating costs.

The majority of the testing was performed firing Illinois Basin bituminous coal (Lamar), because 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 reburning 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.

Exhibit 2-17
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

Environmental Performance

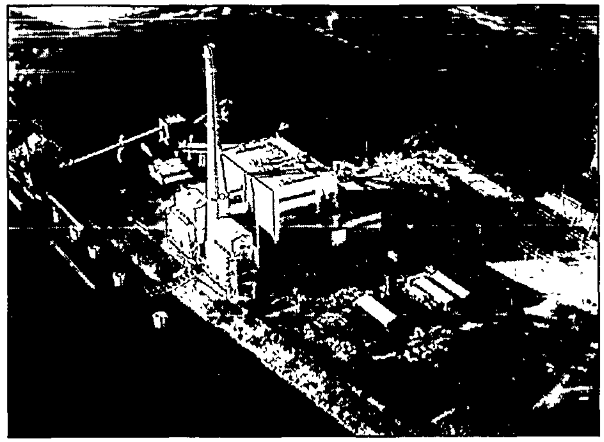
Three sequential tests of Coal Reburning used Lamar coal. Parametric optimization testing set up the automatic controls. Performance testing evaluated the unit in full automatic control at set load points. Long-term testing assessed performance in a load-following mode. PRB coal was used for parametric optimization and performance modes. Exhibit 2-17 shows changes in NO_x emissions and boiler efficiency using the reburning system for various load conditions and coal types.

Coal Reburning tests on both the Lamar and PRB coals indicated that variation of reburning-zone stoichiometry was the most critical factor in changing NO_x emissions levels. The reburning-zone stoichiometry can be varied by alternating the air flow quantities (oxygen availability) to the reburning burners, the percent reburning 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 Reburning were comparable to baseline operation. No major effect of reburning on trace-metals partitioning was discernible. None of the 16 targeted polynuclear aromatic semi-volatile organics (controlled under Title III of CAAA) were 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 efficiency losses due to unburned carbon were higher than the baseline by 0.1, 0.25, and 1.5 percent-



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

age points, respectively. Full-, medium-, and low-load efficiency losses with PRB coal were 0.0, 0.2, and 0.3 percentage points, respectively. Coal Reburning burner flame stability improved with PRB coal.

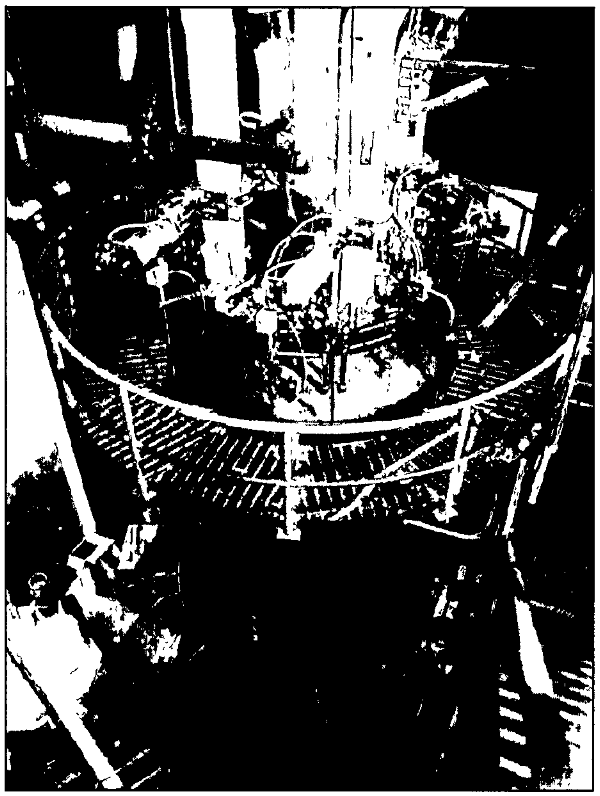
During Coal Reburning operation with Lamar coal, the operators continually monitored boiler internals for increased ash deposition and the on-line performance monitoring system for heat transfer changes. At no time throughout the system optimization or long-term operation period were any slagging or 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 Reburning minimizes and possibly eliminates a 0–25% derating normally associated with switching to subbituminous coal in a cyclone unit. This derating results from using a lower Btu fuel in a cyclone combustor, which has a limited coal feed capacity. Coal Reburning transferred about 30% of the coal feed out of the cyclone to the reburning 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 2-18. 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.

▼ The coal pulverizer is part of Babcock & Wilcox Coal Reburning. This system has been retained by Wisconsin Power and Light for NO_x emission control at the Nelson Dewey Station.



Commercial Applications

Coal Reburning is a retrofit technology applicable to a wide range of utility and industrial cyclone boilers. The current U.S. coal reburning market is estimated to be approximately 27,000 MWe and consists of about 89 units ranging from 100–1,150-MWe with most in the 100- to 300-MWe range.

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

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John C. McDowell, NETL, (412) 386-6175

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- *Public Design Report: Coal Reburning for Cyclone Boiler NO_x Control.* The Babcock & Wilcox Company. August 1991. (Available from NTIS as DE92012554.)
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Exhibit 2-18
Coal Reburn Economics
(1990 Constant Dollars)

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

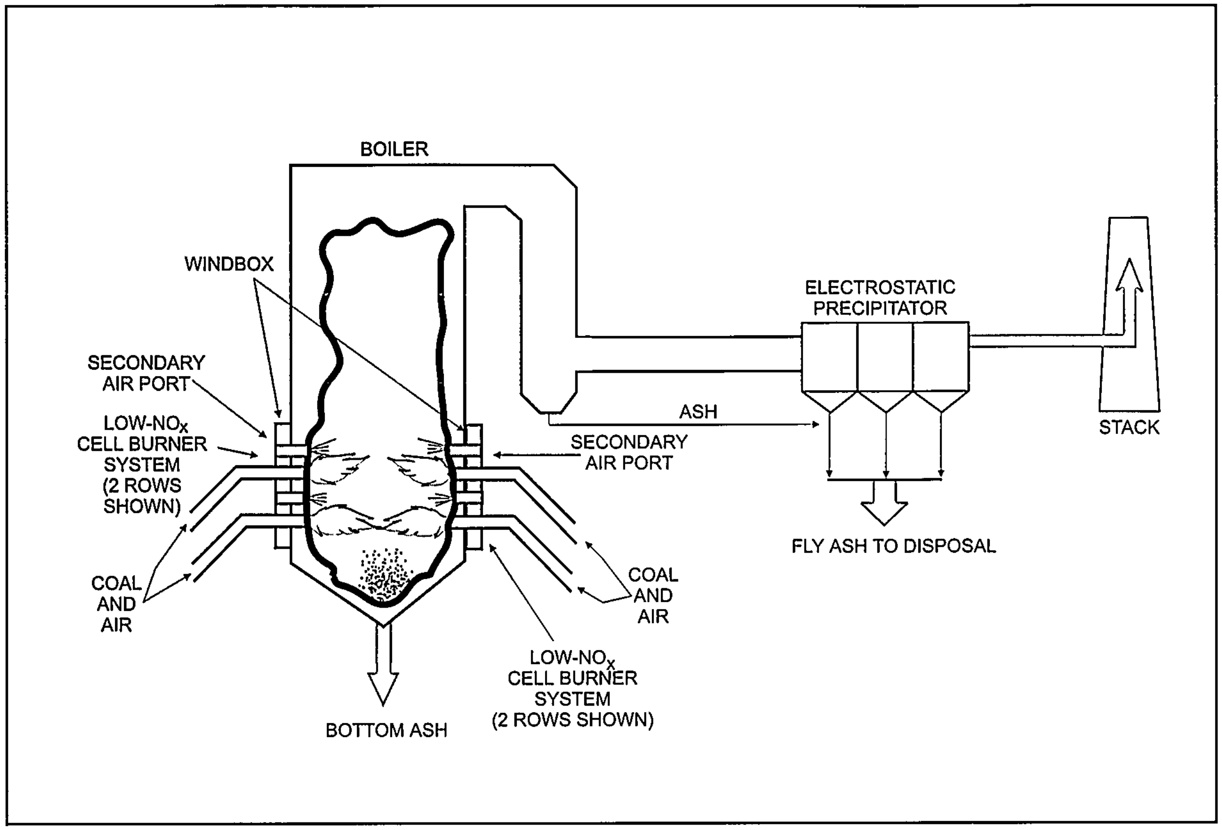
Coal

Bituminous, medium sulfur

Project Funding

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

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



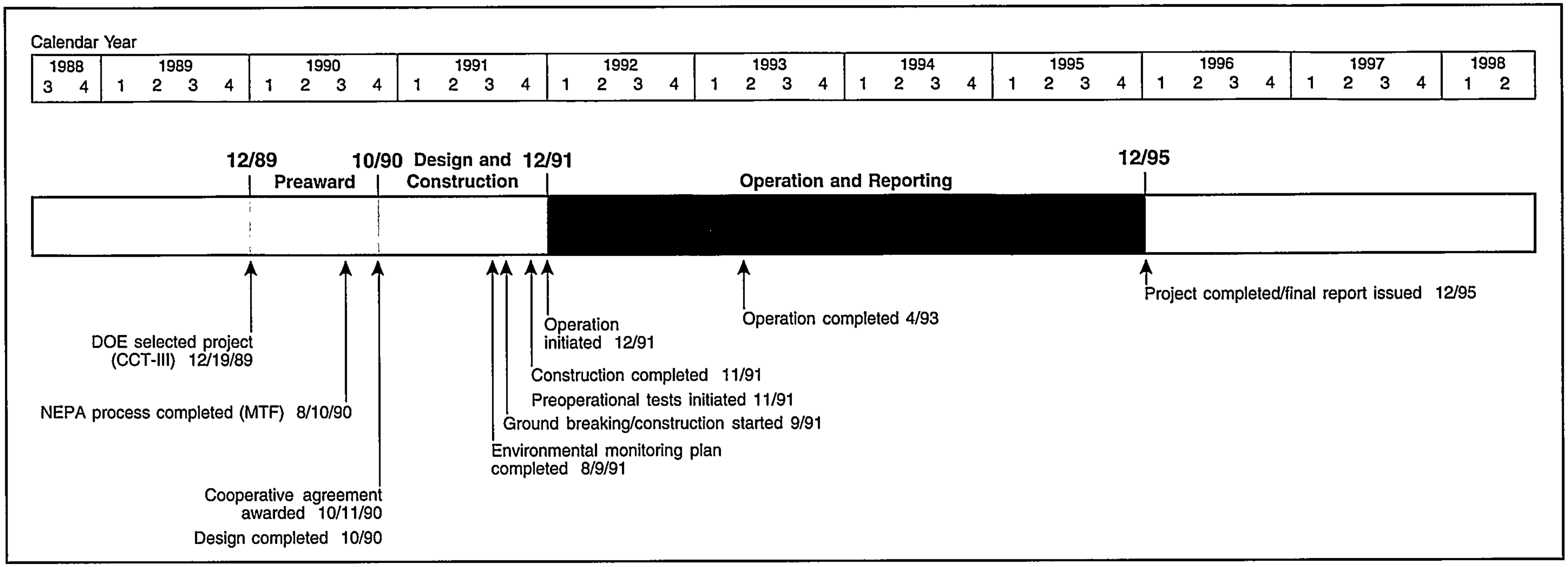
Project Objective

To demonstrate, through the first commercial-scale full burner retrofit, the cost-effective reduction of NO_x from a large 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. Combustion is staged by providing only about 58% of the air theoretically required for complete combustion through the lower burner and the balance of the air through the secondary air port (NO_x port).

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 LNCBs® were installed. Alternate LNCBs® on the bottom rows were inverted, with the air port then being on the bottom to ensure complete combustion in the lower furnace.



Results Summary

Environmental

- Short-term optimization testing (all mills in service) showed NO_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).
- Carbon monoxide (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 in the midwest, with a 1.2 lb/10^6 Btu initial NOx emission rate and 65% capacity factor, was $9/kW (1994$).
- Levelized cost (15-year) for the same 600-MWe plant was estimated at 0.284 mills/kWh and $96.48/ton of NO_x removed (constant 1994$).

Project Summary

Utility boilers equipped with cell burners currently represent 7.4% or approximately 24,000-MWe of pre-NSPS coal-fired generating capacity. Cell burners are designed for rapid mixing of fuel and air. The tight burner spacing and rapid mixing minimize 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 fuel and combustion air. A key design criterion was accomplishing delayed fuel-air mixing with no modifications to boiler walls. The plug-in LNCB® design reduces material costs and outage time required to complete the retrofit, compared to installing conventional, internally staged low-NO_x burners, thereby providing a lower cost alternative to address NO_x reduction requirements for cell burners.

Environmental Performance

The initial LNCB® configuration resulted in excessive CO and H_2S emissions. Through modeling, a revised configuration was developed (inverting alternate burners on the lower rows), which addressed the problem without compromising boiler performance. The modification served to validate 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 53.0–55.5%. With one mill out of service at full load, the average NO_x reduction ranged from 53.3–54.5%. Average NO_x reduction at intermediate load (about 460 MWe) ranged from 52.5–54.7%. At low loads (about 350 MWe), average NO_x reduction ranged from 46.9–47.9%. 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. The NO_x emission reductions realized were 58% for all mills in service and about 60% for one mill out of service.

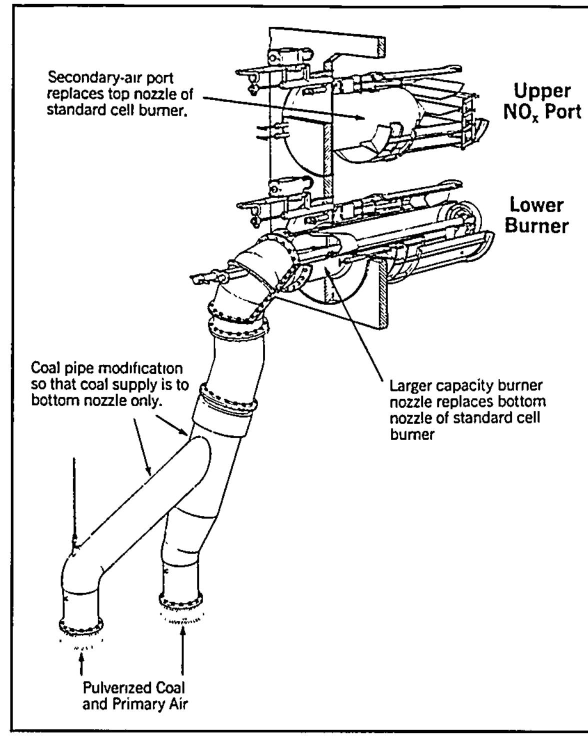
Complications arose in assessing CO emissions relative to baseline because baseline calibration was not sufficiently refined. However, accurate measurements were made with LNCB® in service. Carbon monoxide emissions were corrected for 3.0% O_2 and measured at full, intermediate, and low loads. The range 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 fly ash 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 99.50%, 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.

Operational Performance

Furnace exit gas temperature, initially decreased by 100 °F, but eventually rose to within 10 °F of baseline conditions. The UBCL increased by approximately 28% for all tests. The most significant increase from baseline data occurred for a test with one mill out of service. A 52% increase in UBCL resulted in an efficiency loss of 0.69%.

Boiler efficiency showed very little change from baseline. The average for all mills in service increased by 0.16%. The higher post-retrofit efficiency was attributed



▲ Single LNCB® Retrofit.

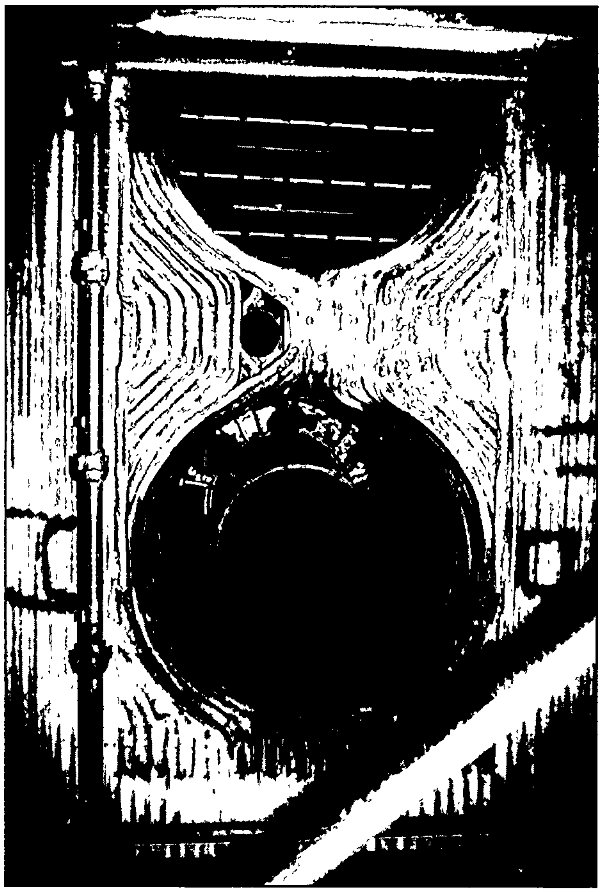
to a decrease in dry gas loss with lower economizer gas outlet temperature (and subsequent lower air heater gas outlet temperature), offsetting UBCL and CO emission losses. Also, increased coal fineness mitigated UBCL.

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 differed little from baseline ash. Furthermore, the small variations observed in furnace exit gas temperature between baseline and LNCB® indicated little change in furnace slagging. Startup and turndown of the unit were unaffected by conversion to LNCB®.

Economic Performance

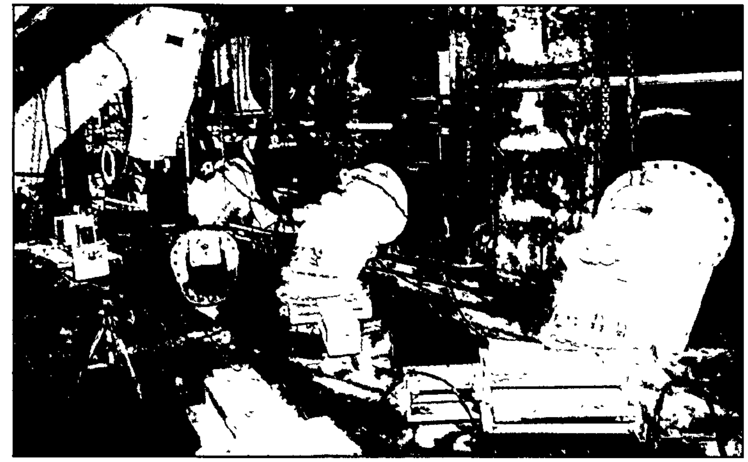
The economic analyses were performed for a 600-MWe nominal unit size and typical location in the midwest United States. A medium-sulfur, medium-volatile bituminous coal was chosen as the typical fuel. For a baseline NO_x emission level of 1.2 lb/10^6 Btu, 65% capacity factor, and a 50% reduction target, the estimated capital cost was \$9/kW (1994\$). The 15-year levelized cost of electricity was estimated at 0.284 mills/kWh, or \$96.48/ton of NO_x removed in constant 1994 dollars.



▲ The LNCB® is viewed from within the boiler.

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.



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

Dayton Power & Light has retained the LNCB® for use in commercial service. Seven commercial contracts have been awarded for 172 burners, valued at \$24 million. LNCBs® have already been installed on more than 4,900 MWe of capacity.

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

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James U. Watts, NETL, (412) 386-5991

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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 and Foster Wheeler Energy Corp.'s low-NO_x burners (LNB)

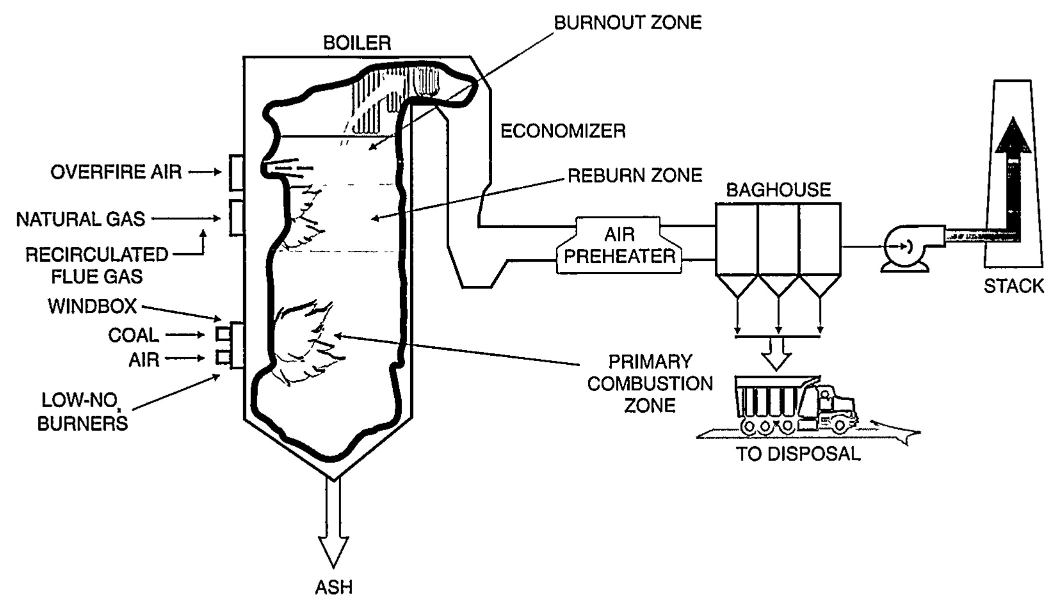
Plant Capacity/Production
172 MWe (gross), 158 MWe (net)

Coal
Colorado bituminous, 0.40% sulfur, 10% ash

Project Funding

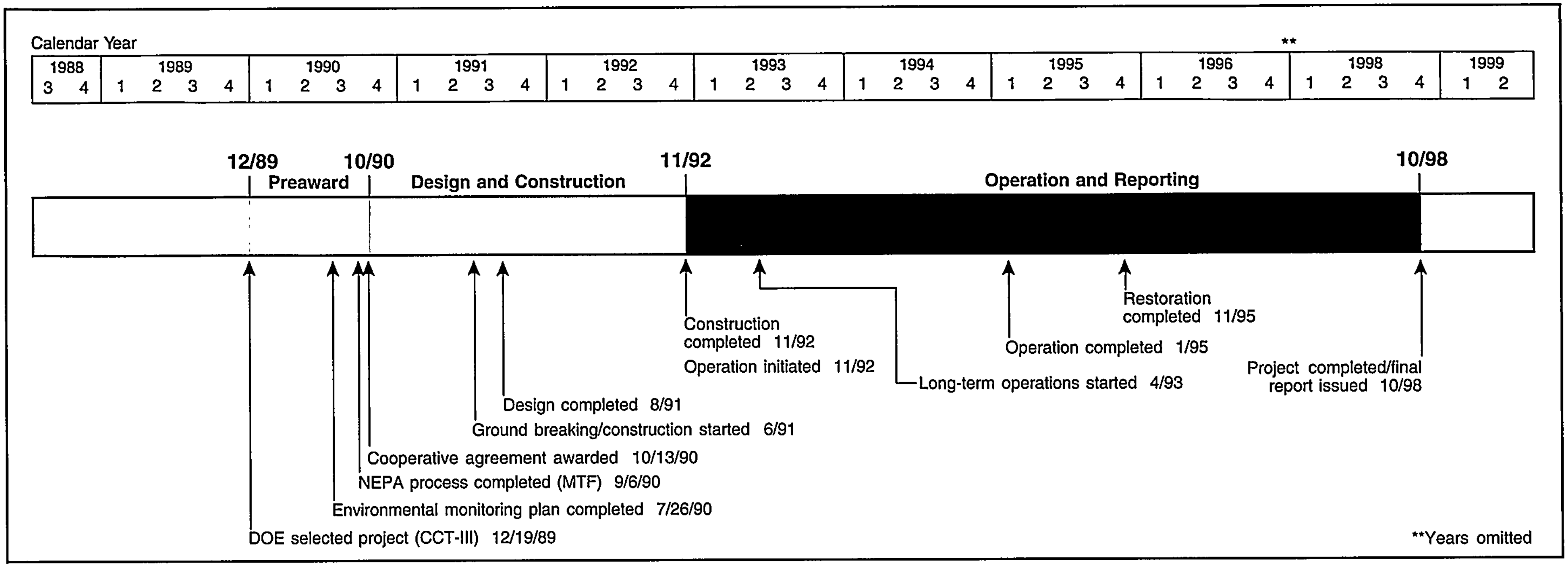
Total project cost	$17,807,258	100%
DOE	8,895,790	50
Participant	8,911,468	50

Project Objective
To attain up to a 70% decrease in NO_x emissions 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 injecting natural gas (up to 25% of total heat input) above the main coal combustion zone in a boiler. This upper-level injection and partial combustion by limiting available oxygen creates a fuel-rich zone. NO_x moving upward from coal combustion in the lower furnace is stripped of oxygen as the reburn fuel is partially combusted in the reburn zone and converted to molecular nitrogen. Overfire air ports above the reburn zone provide for complete combustion in a relatively cooler region of the boiler. Reburning allows the low-NO_x burners to operate at excess air levels far below that needed for complete combustion, thus enhancing their effectiveness. 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.

A series of parametric tests was performed on the gas reburning system, varying operational control parameters and assessing the effect on boiler emissions, completeness of combustion (carbon-in-ash or loss-on-ignition), thermal efficiency, and heat rate. A one-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 reduced NO_x emissions from a pre-construction baseline of 0.73 lb/10^6 Btu to 0.46 lb/10^6 Btu (at 3.5% O_2), a 37% NO_x reduction.
- First-generation GR, which incorporated flue gas recirculation in combination with LNB, reduced NO_x emissions to an average 0.25 lb/10^6 Btu (at 3.25% O_2), a 66% NO_x reduction at an 18% gas heat input rate.
- Second-generation GR, without flue gas recirculation and in combination with LNB, reduced NO_x emissions to an average 0.26 lb/10^6 Btu, a 64% NO_x reduction with only 12.5% gas heat input.
- Both first- and second-generation GR with LNB were capable of reducing NO_x emissions by up to 70% for short periods of time; the average was approximately 65%.
- 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.
- SO_2 emissions and particulate loadings were reduced by the percentage heat input supplied by GR.

Operational

- Boiler efficiency decreased $\leq$ 1.0%.
- There was no measurable boiler tube wear and only a small amount of slagging.
- Carbon-in-ash and CO levels were acceptable for first- and second-generation GR with LNB, but not with LNB alone.

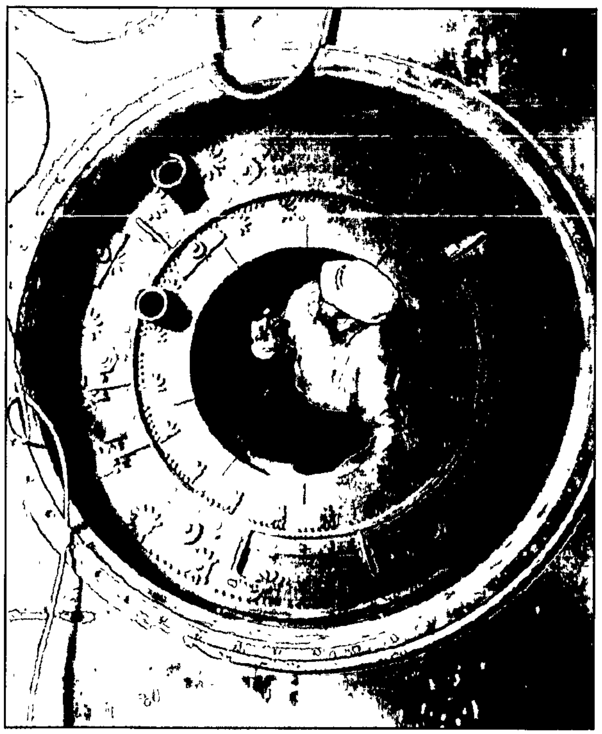
Economic

- Capital cost for a GR-LNB retrofit of a 300-MWe plant is $26.01/kW (1996$) plus the gas pipeline cost, if not already existing ($12.14/kW for GR only and $13.87/kW for LNB only).
- 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 reductions on wall-fired boilers. GR-LNB NO_x control performance approached that of selective catalytic reduction (SCR), but at significantly lower cost. The importance of cost-effective technology for deep NO_x reductions is that it meets 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.

The GR-LNB was installed and evaluated on a 172-MWe (gross) wall-fired boiler—a Babcock & Wilcox balanced-draft pulverized coal-fired unit. 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.



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

Parametric testing began in October 1992 and was completed in April 1993. The parametric tests examined the effect of process variables (such as zone stoichiometric ratio, percent gas heat input, percent overfire air, and load) on NO_x reduction, SO_2 reduction, CO emissions, carbon-in-ash, and heat rates. The baseline performance of the LNB was also established.

Environmental Performance

At a constant load (150 MWe) and a constant oxygen level at the boiler exit, 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 the Cherokee Station, low-sulfur (0.40%) coal is used, and typical SO_2 emissions are 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. 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 was added to the demonstration to evaluate a modified or second-generation system. Modifications included the following:

- 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%. 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, particularly at low total flows.

Over 4,000 hours of operation were achieved, with the results shown in Exhibit 2-19. Although the 37% NO_x reduction performance of LNB 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. However, with LNB alone, carbon-in-ash and CO could not be maintained at acceptable levels.

Exhibit 2-19
NO_x Data from Cherokee Station, Unit No. 3

	GR Generation	
	First	Second
Baseline (lb/10^6 Btu)	0.73	0.73
Avg NO_x reduction (%)		
LNB	37	44
GR-LNB	66	64
Avg gas heat input (%)	18	12.5

Economic Performance

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

- Gas availability at the site,
- Gas/coal cost differential,
- Boiler efficiency,
- SO_2 removal requirements, and
- Value of SO_2 emission credits.

Based on the demonstration, GR-LNB is expected to achieve at least a 64% NO_x reduction with a gas heat input of 12.5%. The capital cost estimate for a 300-MWe wall-fired installation is $26.01/kW (1996$), plus gas pipeline costs, if required. This cost includes both equipment and installation costs and a 15% contingency. The GR and LNB system capital costs can be easily separated from one another because they are independent systems. The capital cost for the GR system only is estimated at $12.14/kW. The LNB system capital cost is $13.87/kW.

Operating costs are almost entirely related to the differential cost of natural gas and coal and reduced by the value of the SO_2 emission credits received due to absence of sulfur in the gas. A fuel differential of $1.00/$10^6$ Btu was used because gas costs more than coal on a heating value basis. Boiler efficiency was estimated to decline by 0.80%; the cost of this decline was calculated using a composite fuel cost of $1.67/$10^6$ Btu. Overfire air booster and cooling fan auxiliary loads will be partially offset by lower loads on the pulverizers. No additional operating labor is required, but there is an increase in maintenance costs. Allowances also were made for overhead, taxes, and insurance. Based on these assumptions and assuming an SO_2 credit allowance of $95/ton (Feb. 1996$), the net operating cost is $2.14 million per year and the NO_x removal cost is $786/ton (constant 1996$).

Commercial Applications

The technology can be used in retrofit, repowering, or greenfield installations of wall-fired boilers. 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 selective catalytic reduction. 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 No. 1, with options for Unit Nos. 2 and 3 (identical 330 MWe units); and Baltimore Gas & Electric's C.P. Crane, Unit No. 2, with an option for Unit No. 1 (similar 200 MWe units). Use of the technology also extends to overseas markets. One of the first installations of the technology took place at the Ladyzkin State Power Station in Ladyzkin, Ukraine.

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

Contacts

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- *Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler: Performance and Economics Report, Gas Reburning—Low-NO_x Burner System, Cherokee Station Unit No. 3, Public Service Company of Colorado.* Final Report. July 1998.
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- *Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler (Long-Term Testing, April 1993–January 1995).* Report No. DOE/PC/90547-T20. Energy and Environmental Research Corporation. June 1995. (Available from NTIS as DE95017755.)
- *Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler (Optimization Testing, November 1992–April 1993).* Report No. DOE/PC/90547-T19. Energy and Environmental Research Corporation. June 1995. (Available from NTIS as DE95017754.)

Micronized Coal Reburning Demonstration for NO_x Control

Project completed.

Participant

New York State Electric & Gas Corporation

Additional Team Members

Eastman Kodak Company—host and cofunder
CONSOL (formerly Consolidation Coal Company)—coal sample tester
D.B. Riley—technology supplier
Fuller Company—technology supplier
Energy and Environmental Research Corporation (EER)—reburn system designer
New York State Energy Research and Development Authority—cofunder
Empire State Electric Energy Research Corporation—cofunder

Locations

Lansing, Tompkins County, NY (New York State Electric & Gas Corporation's Milliken Station, Unit No. 1)
Rochester, Monroe County, NY (Eastman Kodak Company's Kodak Park Power Plant, Unit No. 15)

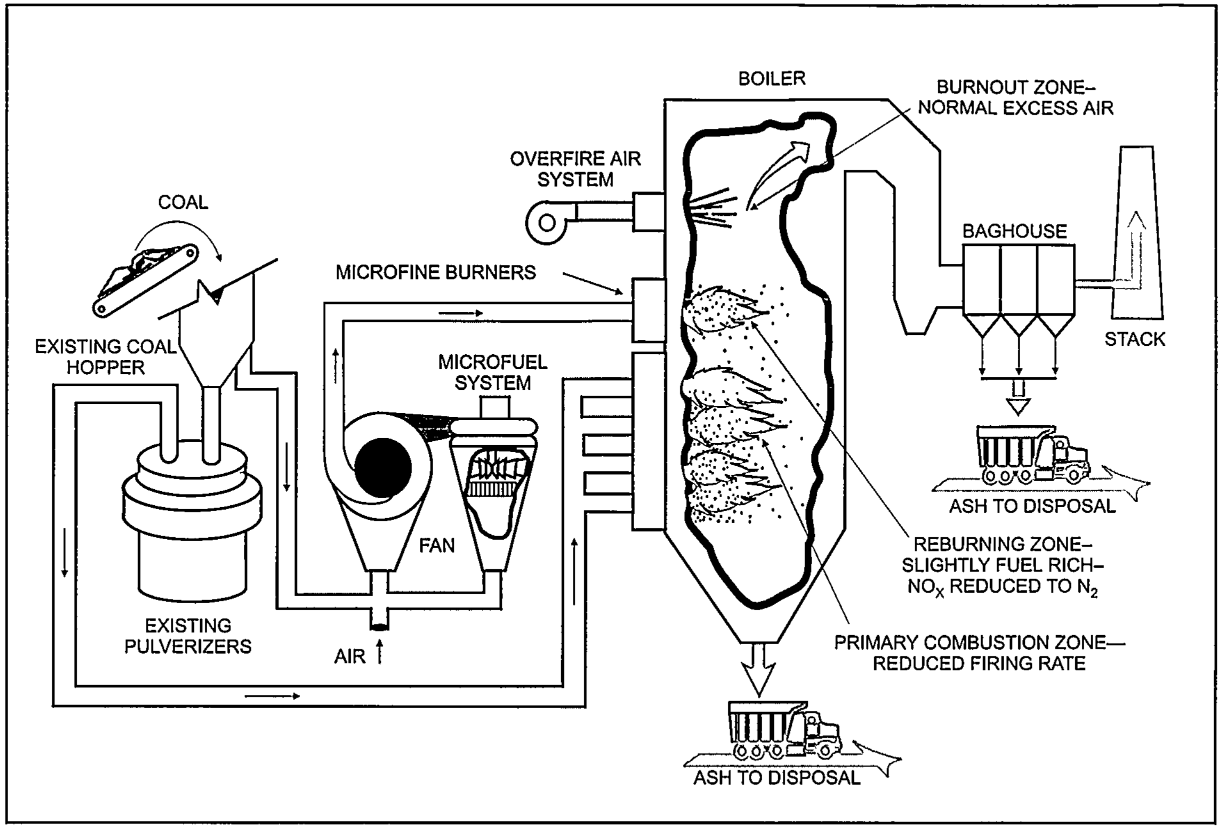
Technology

D.B. Riley's MPS mill (at Milliken Station) and Fuller's MicroMill™ (at Eastman Kodak) technologies for producing micronized coal

Plant Capacity/Production

Milliken Station: 148-MWe tangentially fired boiler
Kodak Park: 50-MWe cyclone boiler

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



Coal

Pittsburgh seam bituminous, medium- to high-sulfur (3.2% sulfur and 1.5% nitrogen at Milliken and 2.2% sulfur and 1.6% nitrogen at Kodak Park)

Project Funding

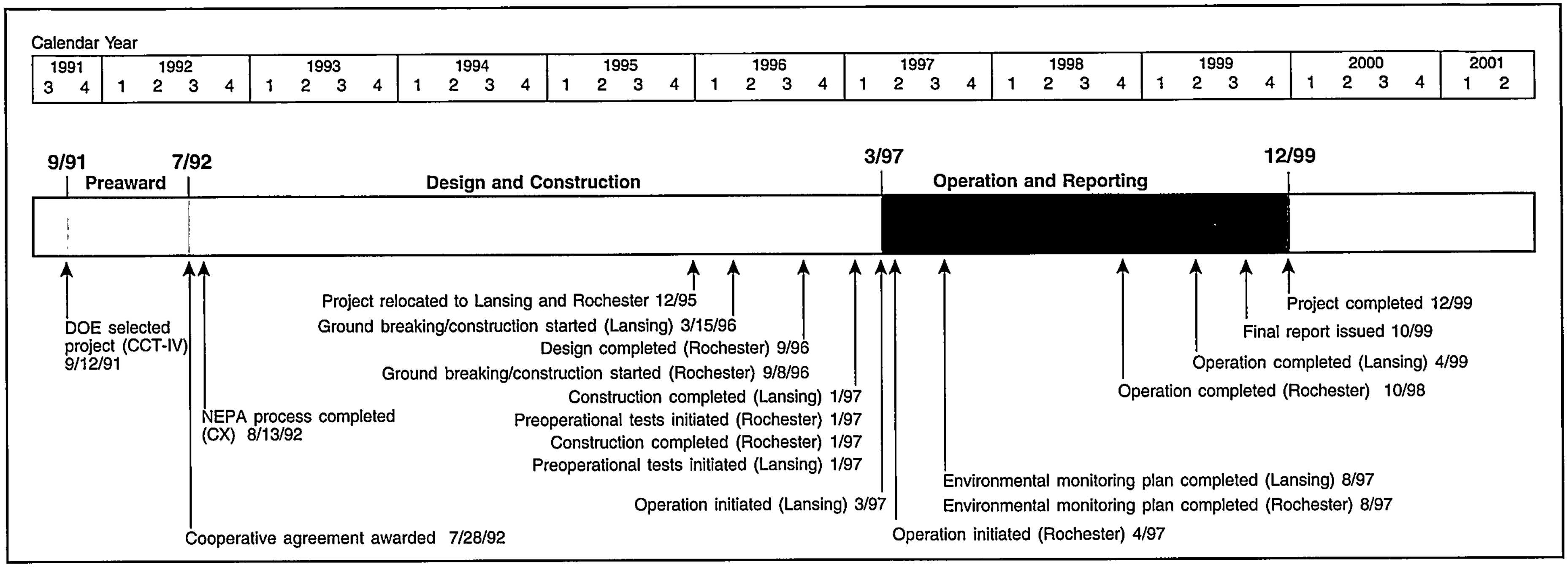
Total project cost	$9,096,486	100%
DOE	2,701,011	30
Participant	6,395,475	70

Project Objective

To achieve at least 50% NO_x reduction with micronized coal reburning technology on a cyclone boiler; to achieve 25–35% NO_x reduction with micronized coal reburning technology in conjunction with low-NO_x burners on a tangentially fired boiler; and to determine the effects of coal micronization on electrostatic precipitator (EPS) performance.

Technology/Project Description

The reburn coal, which can constitute up to 30% of the total fuel, is micronized (pulverized to achieve 85% below 325 mesh) and injected into a pulverized coal-fired furnace above the primary combustion zone. At the Milliken tangentially fired boiler site, NO_x control is achieved by: (1) close-coupled overfire air (CCOFA) reburning in which the top coal injector of the LNCFS III™ burner is used for injecting the micronized coal, and the separated overfire air system completes combustion; and (2) the remaining burners and air ports are adjusted for deep stage combustion by re-aiming them to create a fuel-rich inner zone and fuel-lean outer zone providing combustion air. At the Kodak Park cyclone boiler site, the Fuller MicroMill™ is used to produce the micronized coal, reburn fuel is introduced above the cyclone combustor, and overfire air is employed to complete the combustion.



Results Summary

Environmental

- Using a 14% reburn fuel heat input on the Milliken Station tangentially fired (T-fired) boiler resulted in a NO_x emission rate of 0.25 lb/10^6 Btu, which represents a 28% NO_x reduction over and above the 39% NO_x reduction achieved with the LNCFS III™ burner.
- Using a 17% reburn fuel heat input on the Kodak Park cyclone boiler resulted in a NO_x emission rate of 0.60 lb/10^6 Btu, which represents a 59% NO_x reduction.

Operational

- Testing on the T-fired boiler at Milliken Station showed:
  - Unburned carbon-in-ash, also referred to as loss-on-ignition (LOI), was maintained under 4%, which is below the 4.5% maximum LOI for marketable fly ash;
  - Excess air is the single most important parameter that affects NO_x emissions;
  - Increasing coal fineness only marginally improved NO_x emissions; and
  - Increasing the percent of reburn fuel slightly decreased NO_x, but increased LOI.
- Testing on the cyclone boiler at Kodak Park showed:
  - Increasing reburn fuel rates resulted in lower NO_x emissions;
  - NO_x emission reductions on micronized coal were comparable to NO_x reductions achieved with gas reburning;
  - LOI increased with the reburn system in operation—LOI was 35–45% during full load (compared to a baseline of 10–12% without reburning); and
  - Stoichiometric ratios needed in the primary combustion zone and the reburn zone were 1.05–1.15 and 0.9, respectively.

Economic

- The estimated capital cost for retrofitting micronized coal reburning on a generic 300-MWe tangentially fired boiler is \$4.3 million, or approximately \$14/kW (1999\$).
- The estimated O&M costs are \$0.30 million per year (1999\$) for a 300 MWe unit.
- The total 15-year levelized cost of micronized coal reburning is \$1,329/ton of NO_x removed (current 1999\$) or \$1,023 (constant 1999\$).

Project Summary

NYSEG demonstrated the micronized coal reburning technology in both tangentially fired and cyclone-fired boilers. The T-fired boiler was NYSEG's Milliken Station (also the host for another CCT Program demonstration), 148-MWe Unit No. 1. The cyclone-fired boiler was Eastman Kodak Company's Kodak Park Power Plant, 50-MWe Unit No. 15.

The challenge with this coal reburning demonstration was to achieve adequate combustion of the reburn coal in the oxygen-deficient, short-residence-time reburn zone to reduce NO_x emissions without detrimentally increasing the unburned carbon in the ash, *i.e.*, loss-on-ignition. The primary objective of this two-site project was to demonstrate improvements in coal reburning for NO_x emission control by reducing the particle size of the reburn coal. In this demonstration, the coal was finely ground to 85% below 325 mesh and injected into the boilers above the primary combustion zone. The resulting typical particle size is 20 microns compared to 60 microns for normal pulverized coal particles. This smaller size increases surface area ninefold. With this increased surface area and coal fineness (micronized coal has the combustion characteristics of atomized oil) which allows carbon combustion in milliseconds and release of volatiles at an even rate.

Operating Performance

At the Milliken Station, the existing ABB Low-NO_x Concentric Firing System™ (LNCFS-III), which includes both close coupled and separated overfire air (OFA) ports, was used for the reburn demonstration. Four D.B. Riley MPS 150 mills with dynamic classifiers provided the pulverized coal. With LNCFS-III, there are four levels of burners. To simulate and test the reburning application, the top-level coal injection nozzles fed micronized coal to the upper part of the furnace for this demonstration. The lower three coal injection nozzles were biased to carry approximately 80% of the fuel required for full load, with the top injector supplying the remaining fuel. The speed of the dynamic classifier serving the mill feeding the top burners was increased to produce the micronized coal.

At Kodak Park, EER designed the micronized coal reburn system using a combination of analytical and empirical techniques. The reburn fuel and OFA injection components were designed with a high degree of flexibility to allow for field optimization to accommodate the complex furnace flow patterns in the cyclone boiler. A Fuller MicroMill™ produced the micronized coal reburn fuel with a particle size of about 20 microns. To maximize NO_x reduction, the reburn fuel was injected with flue gas rather than air. The flue gas was extracted downstream of the electrostatic precipitator and was boosted by a single fan.

Two Fuller MicroMills™ were installed in parallel on Kodak Park Unit 15 to provide the capacity necessary for high reburn rates, the second mill serving as a spare at lower reburn rates. Eight injectors, six on the rear wall and one on each of the side walls, introduced the micronized coal into the reburn zone. The optimization variables included the number of injectors, swirl, and velocity. Four injectors on the front wall provided OFA using EER's second-generation, dual-concentric OFA air design, which has variable injection velocity and swirl. A new boiler control system was also installed on Unit No. 15.

Some mechanical problems were encountered during the demonstration, including plugging of the coal handling system that feeds the MicroMill™, vibration and blade wear on the mills, erosion of the classifiers, and corrosion due to low-temperature flue gas when the reburn system was out of service. These problems were corrected and successful operation was achieved.

Environmental Performance

At the Milliken Station, micronized coal reburning with 14% reburn fuel reduced NO_x from 0.35 lb/10^6 Btu baseline level to 0.25 lb/10^6 Btu, a 28% reduction, which is within the target range of 25–35% reduction. This reduction represents an addition to the 39% reduction achieved with the LNCFS III™ low-NO_x burner.

A primary objective at Milliken was to determine the minimum NO_x level attainable while maintaining marketable fly ash (fly ash having less than 4.5% carbon). Variables studied at Milliken included boiler load, reburn coal fineness, oxygen level at the economizer, percent reburn fuel, main burner tilt, and OFA tilt. During the testing, NYSEG found that excess air was the single most important parameter that affects NO_x emissions. As shown in Exhibit 2-20, higher excess air results in higher NO_x emissions, but lower LOI. In the case of the top mill (feeding reburning level) adjusted for regular grind (80% through 200 mesh), an increase in measured O_2 at the economizer inlet from 2.5% to 3.75% yields an increase in NO_x emissions from 0.36 lb/10^6 Btu to 0.43 lb/10^6 Btu, or about a 20% increase. When the top mill is adjusted for fine grind (micronized), the NO_x emissions are only marginally better with the same O_2 increase. Exhibit 2-20 also shows the dramatic impact of excess air on LOI. When the economizer O_2 is varied from 2.5% to 3.5%, the LOI will drop from 6.2% to 3.8% (39% reduction) for the case of the top mill adjusted for regular grind. When the same measurements are made while the top mill is micronizing, the reduction in LOI is less significant.

Results from other parametric testing at Milliken revealed that increasing coal fineness improved NO_x emissions only marginally, but lowered LOI. Other results showed that increasing the percent reburn fuel slightly decreased NO_x, but substantially increased LOI.

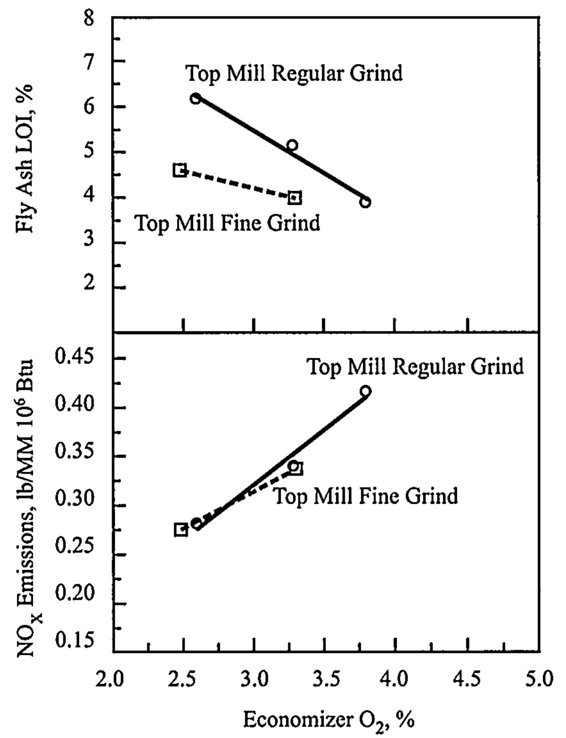
At Kodak Park, micronized coal reburning with 17% reburn fuel reduced NO_x emissions to 0.60 lb/10^6 Btu from a baseline of 1.45 lb/10^6 Btu, a 59% reduction. At greater reburn rates, further NO_x reduction was achieved to a degree comparable with gas reburning systems. As expected, LOI increased with the reburn system in operation. At full load LOI was 35–45%, compared to a baseline level of 10–12%.

Economic Performance

With gas reburning, the differential cost of gas over coal is the largest component of the cost of NO_x reduction. This differential is zero when micronized coal is used as the reburn fuel. However, the capital cost of coal reburning is higher than that of gas reburning due to the capital and operating costs of the coal milling system and other coal-handling equipment.

Estimates were prepared for retrofitting micronized coal reburning on a generic 300-MWe tangentially fired boiler. The capital costs were estimated at $4.3 million (1999$), or approximately $14/kW. The operating costs were estimated at $0.30 million per year (1999$). Costs were levelized both on a current dollar and constant dollar basis. The 15-year levelized costs for the 300-MWe unit is $1,329/ton of NO_x removed on a current dollar basis, and $1,023/ton of NO_x removed on a constant dollar basis.

Exhibit 2-20
Parametric Testing Results



Commercial Applications

Micronized coal reburning technology can be applied to existing and greenfield cyclone-fired, wall-fired, and tangentially fired pulverized coal units. The technology reduces NO_x emissions by 20–59% with minimal furnace modifications for existing units.

The availability of a coal-reburning fuel, as an additional fuel to the furnace, enables switching to lower heating-value coals without boiler derating. 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.

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- New York State Electric & Gas Corporation and CONSOL, Inc. *Micronized Coal Reburning Demonstration for NO_x Control.* Final Report. October 1999.
- *Reburning Technologies for the Control of Nitrogen Oxides from Coal-Fired Boilers.* (U.S. Department of Energy, Babcock & Wilcox, EER Corp., and NYSEG) Topical Report No. 14. May 1999.
- Savichky *et al.* *"Micronized Coal Reburning Demonstration of NO_x Control."* Sixth Clean Coal Technology Conference: Technical Papers. April-May 1998.

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 No. 4)

Technology
Selective catalytic reduction (SCR)

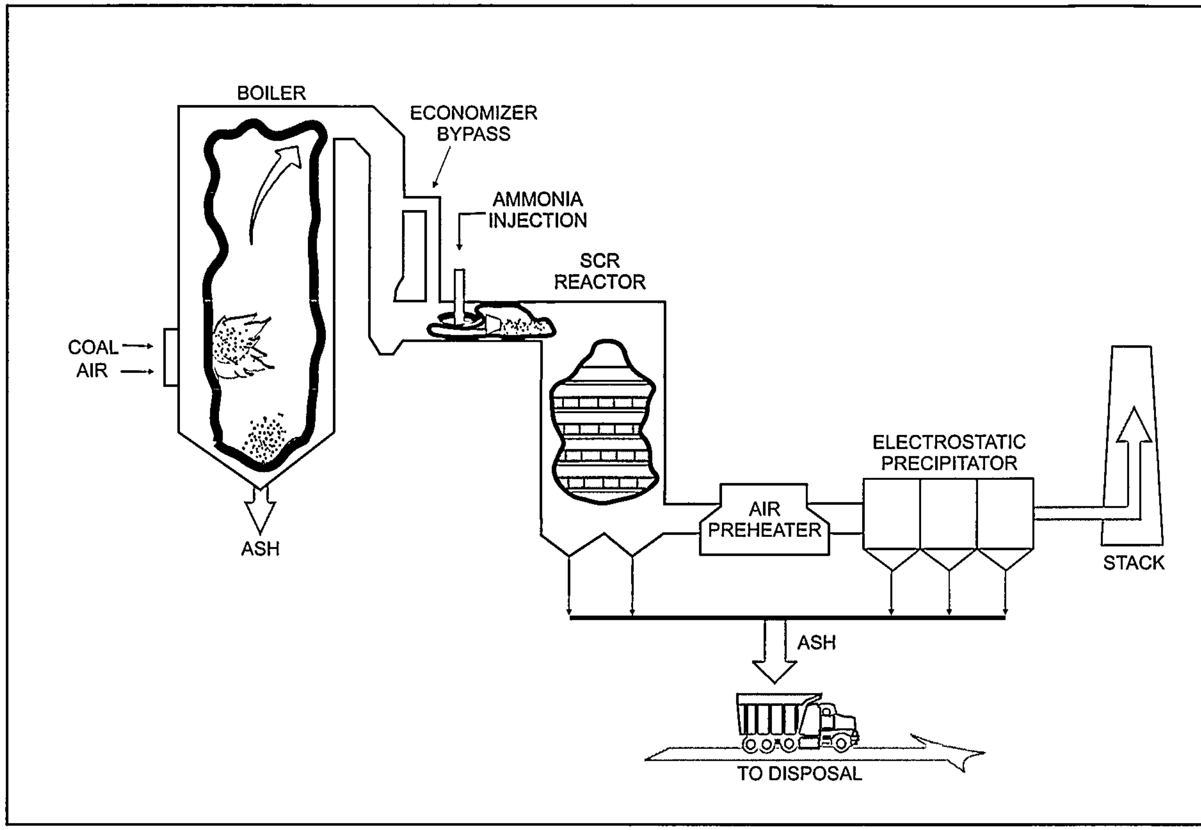
Plant Capacity/Production
8.7-MWe equivalent (three 2.5-MWe and six 0.2-MWe equivalent SCR reactor plants)

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.

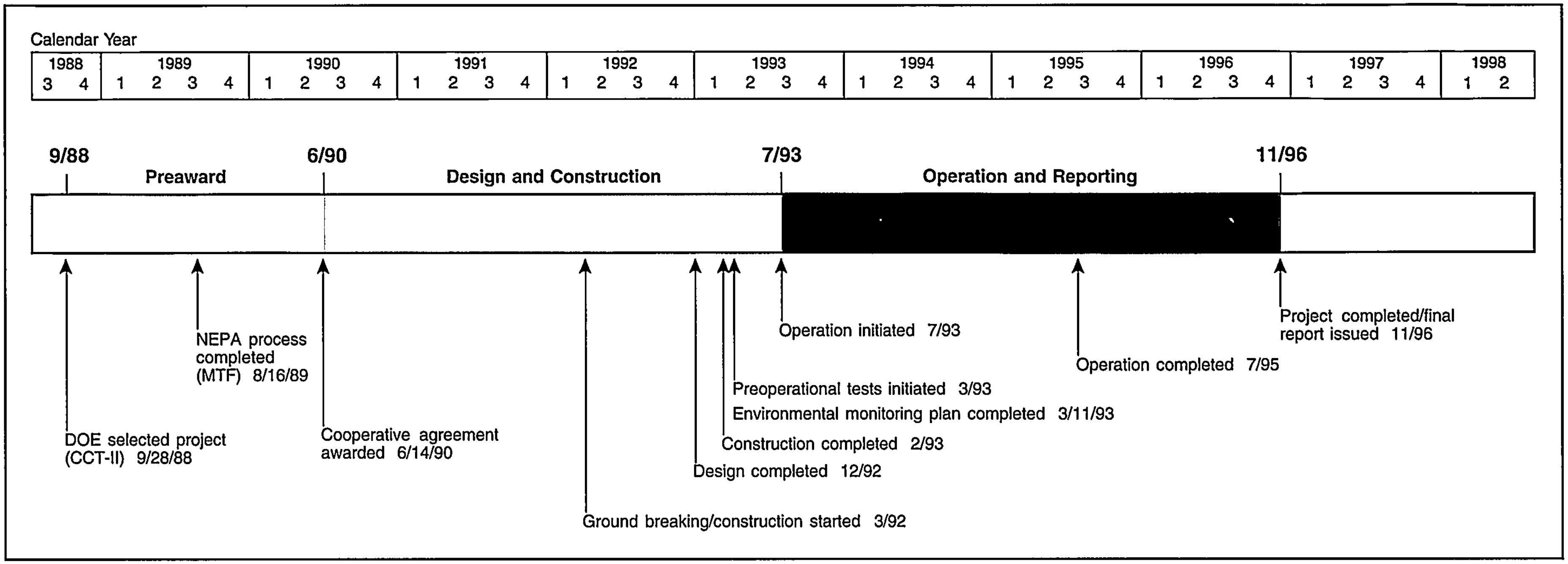


Technology/Project Description
The SCR technology consists of injecting ammonia into boiler flue gas and passing it through a catalyst bed where the NO_x and ammonia react to form nitrogen and water vapor.

In this demonstration project, the SCR facility consisted of three 2.5-MWe equivalent SCR reactors, supplied by separate 5,000-scfm 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, Florida, used flue gas from the burning of 2.7% sulfur coal.



Results Summary

Environmental

- NO_x reductions of over 80% were achieved at an ammonia slip well under the 5 ppm deemed 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 °F, the benefit did not outweigh the heat rate penalties.
- Increases in ammonia slip, a sign of catalyst deactivation, went from less than 1 ppm to approximately 3 ppm over the nearly 12,000 hours of operation, thus demonstrating deactivation in coal-fired units was in line with worldwide experience.
- Long-term testing showed that SO_2 oxidation was within or below the design limits necessary to protect downstream equipment.

Operational

- Fouling of catalysts was controlled by adequate soot-blowing procedures.
- Long-term testing showed that catalyst erosion was not a problem.
- Air preheater performance was degraded because of ammonia slip and subsequent by-product formation; however, solutions were identified.
- The SCR process did not significantly affect the results of Toxicity Characteristic Leaching Procedure analysis of the fly ash.

Economic

- Levelized costs on a 30-year basis for various NO_x removal levels for a 250-MWe unit at a 0.35 lb/10^6 Btu NO_x emission rate follow:

	40%	60%	80%
Constant 1996$ levelized cost (mills/kWh)	2.39	2.57	2.79
Constant 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 (°F)	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 (scfm)			
Large reactor	3,000	5,000	7,500
Small reactor	240	400	600

The catalysts tested are listed in Exhibit 2-21. Catalyst suppliers were given great latitude in providing the amount of catalyst for this demonstration.

Exhibit 2-21
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 scfm Small = 0.2 MWe; 400 scfm

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 at the 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.

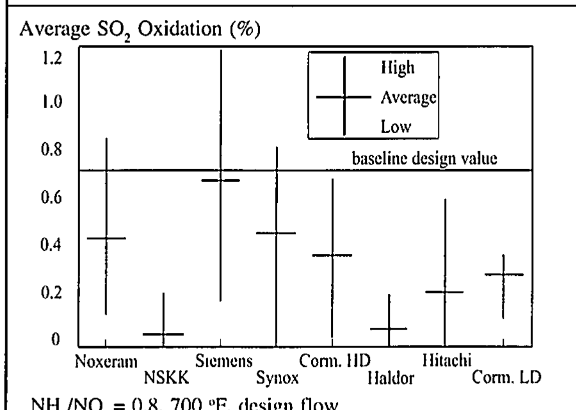
Catalyst deactivation was generally observed by an increase in ammonia slip over time, assuming the NO_x reduction efficiency was held constant. Over the 12,000 hours of the demonstration tests, the ammonia slip did increase from less than 1 ppm to approximately 3 ppm. These results demonstrated the maturity of catalyst design and that deactivation was in line with prior worldwide experience.

Experience has shown that the catalytic active species that result 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 2-22. 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 were flow rate and temperature. 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. 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 °F and 700 °F. On the other hand, between 700 °F and 750 °F, the SO_2 oxidation increased more significantly.

Other findings from the demonstration deal with pressure drop, fouling, erosion, air preheater perfor-

Exhibit 2-22
Average SO_2 Oxidation Rate
(Baseline)



mance, ammonia volatilization, and toxicity characteristic leaching procedure (TCLP) analysis. Overall reactor pressure drop was a function of the catalyst geometry and volume, but tests were inconclusive in determining which parameter was controlling. The fouling characteristics of the catalyst were important to long-term operation. During the demonstration, measurements showed a 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. Catalyst erosion was not considered to be a significant problem because most of the erosion was attributed to aggressive sootblowing. With regard to 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. The ammonia volatilized from the SCR fly ash when a significant amount of water was absorbed by the ash. This was caused by formation of a moist layer on the ash with a pH high enough to convert ammonia compounds in the ash to gas-phase ammonia. TCLP analyses were performed on fly ash 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 2-23.

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% showed:

	125 MWe	**250 MWe**	**700 MWe**
Capital cost ($/kW)	61	54	45
Operating cost ($)	580,000	1,045,000	2,667,000
Constant 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/10^6 Btu of inlet NO_x are:

	40%	**60%**	**80%**
Capital cost ($/kW)	52	54	57
Operating costs ($)	926,000	1,045,000	1,181,000
Constant 1996$ levelized cost			
mills/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 $1,850–5,100/ton (1996$).

Exhibit 2-23
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 over 1,000 coal-fired utility boilers in active commercial service in the United States; these boilers represent a total generating capacity of approximately 300,000 MWe.

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References

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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

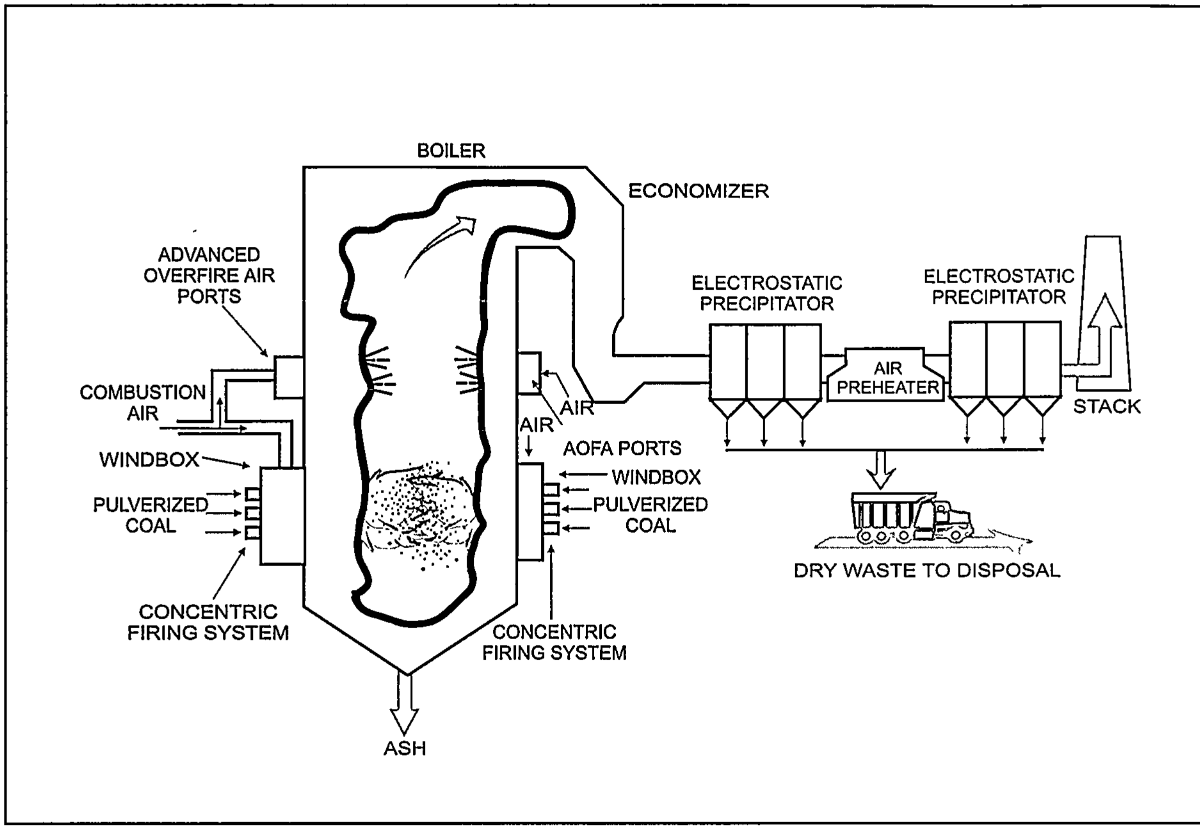
Plant Capacity/Production
180 MWe

Coal
Eastern bituminous, high reactivity

Project Funding

Total project cost	$8,553,665	100%
DOE	4,149,382	49
Participant	4,404,283	51

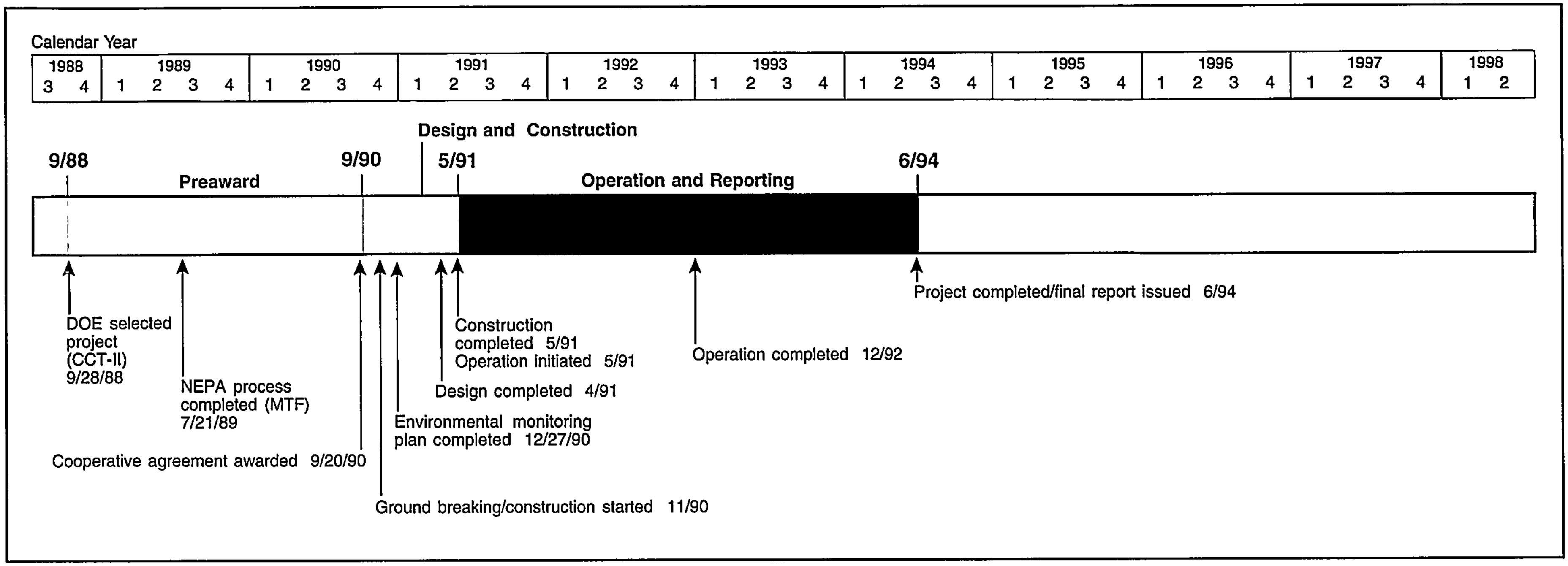
LNCFS is a trademark of ABB Combustion Engineering, Inc.



Project Objective
To demonstrate in a stepwise fashion the short- and long-term NO_x reduction capabilities of LNCFS™ levels I, II, and III on a single reference boiler.

Technology/Project Description
Technologies demonstrated included 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.



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 MWe 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 backpass 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 (1993\$).
- The cost effectiveness for LNCFS™ I was \$103/ton of NO_x removed; LNCFS™ II, \$444/ton; and LNCFS™ III, \$400/ton (1993\$).

Project Summary

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 vertically staging combustion in the boiler with separate 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 under normal dispatch and operating conditions over the long-term. 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.

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.

Exhibit 2-24 shows the various LNCFS™ configurations used to achieve staged combustion. In addition to overfire air, the LNCFS™ incorporates other NO_x-reducing techniques into the combustion process as shown in Exhibit 2-25. 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.

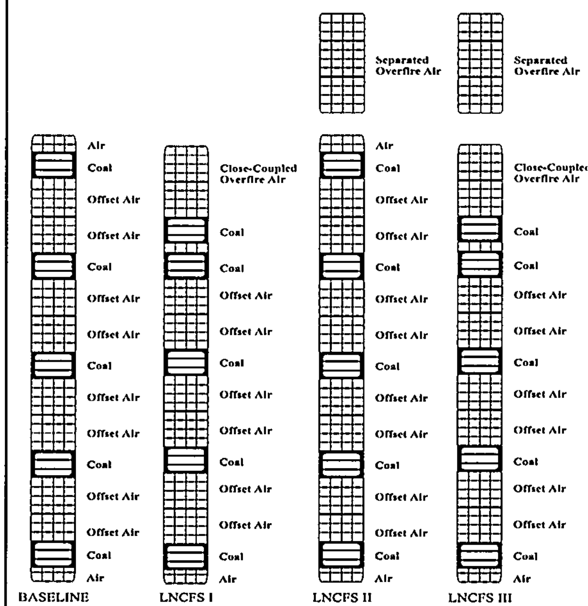
Operational Performance

Exhibit 2-26 summarizes the impacts of LNCFS™ on unit performance.

Environmental Performance

At full load, LNCFS™ I, II, and III reduced NO_x emissions by 37, 37, and 45%, respectively. Exhibit 2-27 presents the NO_x emission estimates obtained in the assessment of the average annual NO_x emissions for three dispatch scenarios.

Exhibit 2-24
LNCFS™ Configurations

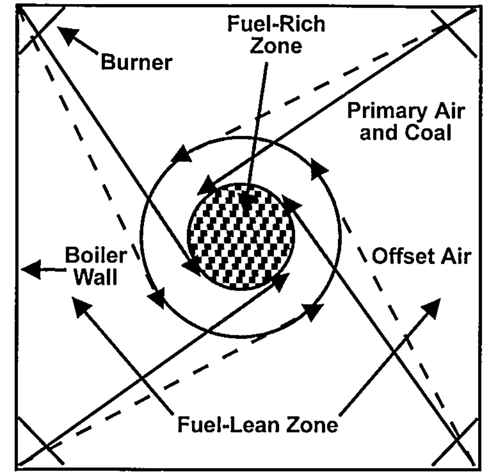


Air toxics testing found LNCFS™ to have no clear-cut effect on the emission of trace metals or acid gases. The data provided marginal evidence for a decreased emission of chromium. The effect on aldehydes/ketones could not be assessed because baseline data were compromised. VOCs appeared to be reduced 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 in 1993 dollars follow:

Exhibit 2-25
Concentric Firing Concept



- 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 actual 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 follows (based on a levelization factor of 0.144 in 1993 constant dollars):

- 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 potential commercial application to all the nearly 423 U.S. pulverized coal, tangentially fired utility units. These units range from 25 MWe to 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. ABB Combustion Engineering has modified 116 tangentially fired boilers with LNCFS™ and derivative TFS 2000™ burners, representing over 25,000 MWe.

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- *180-MWe Demonstration of Advanced Tangentially fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers: Final Report and Key Project Findings*. Report No. DOE/PC/89653-T14. Southern Company Services, Inc. February 1994. (Available from NTIS as DE94011174.)
- *180-MWe Demonstration of Advanced Tangentially fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers—Plant Lansing Smith—Phase III and Final Environmental Monitoring Program Report.* Southern Company Services, Inc. December 1993.

Exhibit 2-26
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 temperatures at low loads	Full load: 5–10 °F lower than baseline Low loads: 10–30 °F lower than baseline	Same as baseline	160–200 MWe: satisfactory 80 MWe: 15–35 °F lower than baseline
Furnace slagging and backpass fouling	Medium	Medium	Reduced slagging, but increased fouling	Reduced slagging, but increased fouling
Operating flexibility	Normal	Same as baseline	More care required at low loads	More difficult to operate than other systems
Boiler efficiency (%) Efficiency change (points)	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 2-27
Average Annual NO_x Emissions and Percent 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

Environmental Control Devices
Combined SO_2/NO_x Control Technologies

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 Condenser
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

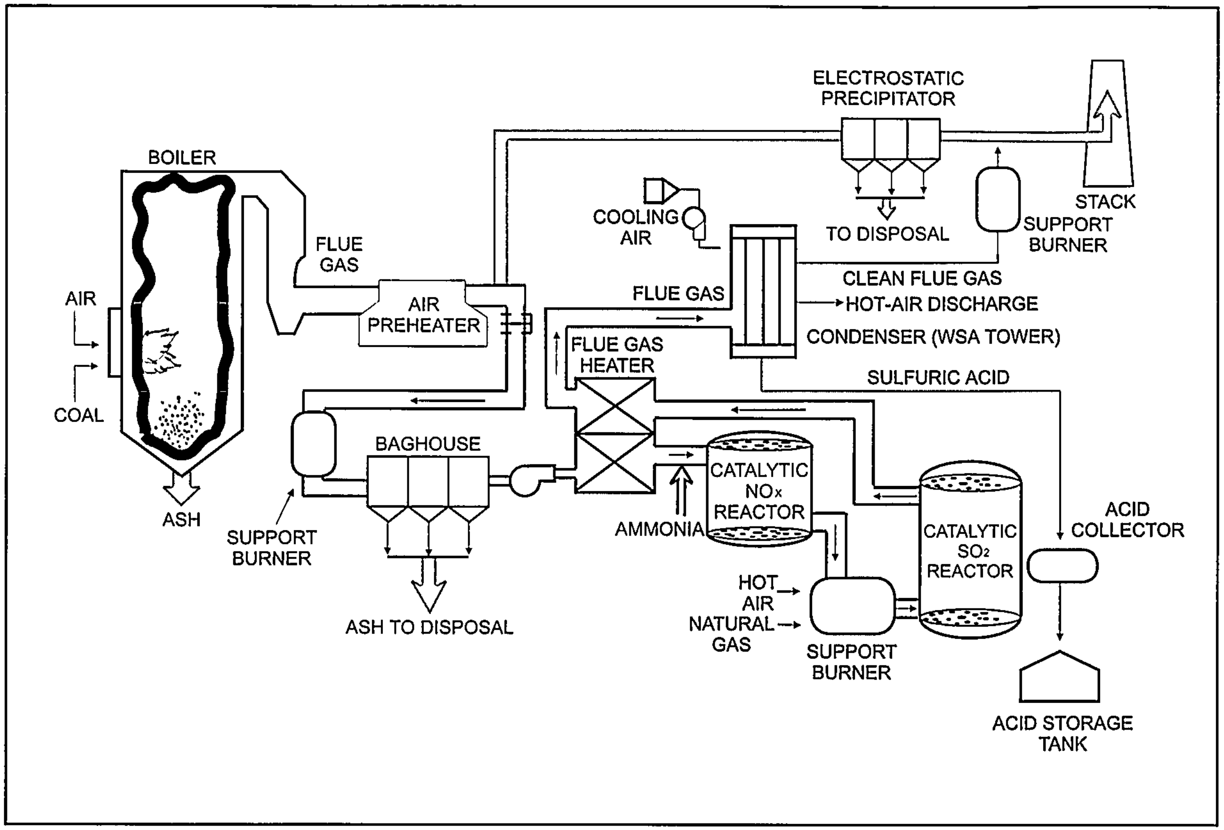
Plant Capacity/Production
35-MWe equivalent slipstream from a 108-MWe boiler

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 SNOX™ technology at an electric power plant using U.S. high-sulfur coals in which it 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.



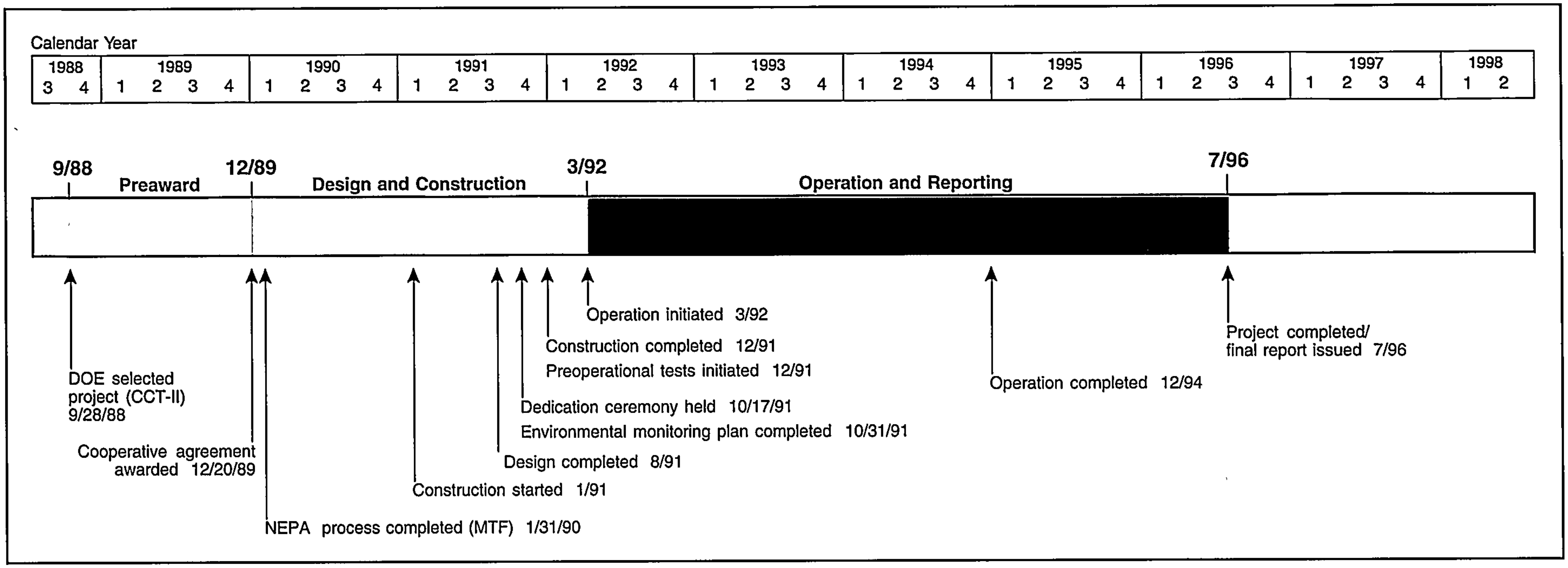
Technology/Project Description
In the SNOX™ process, the stack gas leaving the boiler is cleaned of fly ash in a high-efficiency fabric filter baghouse to minimize the cleaning frequency of the sulfuric acid catalyst in the downstream SO_2 converter. The ash-free gas is reheated, and NO_x is reacted 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.

Because the SO_2 catalyst follows the NO_x catalyst, any unreacted ammonia (slip) is oxidized in the SO_2 catalyst largely to nitrogen and water vapor. Downstream fouling by ammonia compounds is eliminated, permitting operation at higher than normal stoichiometries. These higher stoichiometries allow smaller catalyst volumes and high reduction efficiencies.

The technology 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 using U.S. coals. This was accomplished without using sorbents and without creating waste streams.

The demonstration was conducted at Ohio Edison's Niles Station in Niles, Ohio. 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 full-scale commercial 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 ranging from 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 elimination of secondary pollution streams and increases in CO_2 emissions.
- Presence of the SO_2 catalyst virtually eliminated CO and hydrocarbon emissions.

Operational

- Having the 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 15-year levelized incremental cost was estimated at 6.1 mills/kWh, $219/ton of SO_2 removed, and $198/ton of SO_2 and NO_x removed on a constant 1995 dollar basis.

Project Summary

No reagent was required for the SO_2 removal step because the SNOX™ process utilized an oxidation catalyst to convert SO_2 to SO_3 and ultimately to sulfuric acid. 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 operated for approximately 8,000 hours and produced more than 5,600 tons of commercial-grade sulfuric acid. Many of the 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/Nm³) due to the characteristics of the SO_2 catalyst and the sulfuric acid condenser (WSA Condenser). 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 rather was needed to maintain an acceptable cleaning frequency for the SO_2 catalyst. At operating temperature, the SO_2 catalyst retained about 90% of the dust that entered the catalyst vessel because of its sticky surface. 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 resulted from 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. Under most design conditions this heat recovery results in the net heat rate of the boiler remaining the same or increasing after addition of the SNOX™ process, and consequently no increase occurs in CO_2 generation.

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. 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.

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 passed 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.

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 production of diammonium phosphate fertilizer and to the steel industry for pickling. Ohio Edison also has used a significant amount in boiler water demineralizer systems throughout its plants.

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

▲ The bottom portion of the SO_2 converter catalyst, with the catalyst dust collector hopper mounted on steel rails (center), is shown.

- 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; and
- Aldehydes.

Most trace elements were captured in the baghouse along with the particulates. 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.

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 °F, compared to approximately 300 °F for a typical power plant, additional thermal energy was recovered along with that from the heats of reaction.

Economic Performance

The economic evaluation of the SNOX™ process showed a capital cost of approximately $305/kW for a 500-MWe unit firing 3.2% sulfur coal. The 15-year levelized incremental cost was 6.1 mills/kWh on a constant dollar basis (1995$). The equivalent costs per ton of pollutant removed were $219/ton of SO_2, and $198/ton of SO_2 and NO_x.

▲ 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.

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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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 No. 4)

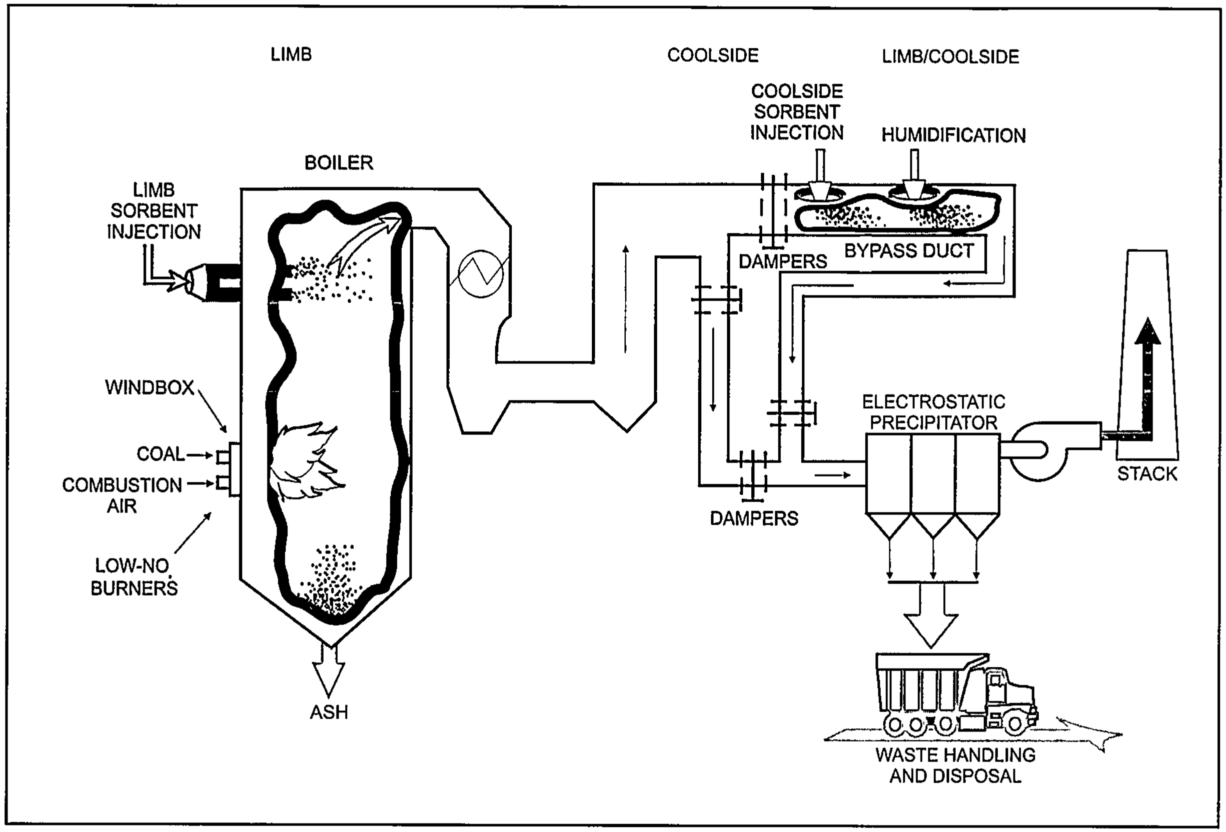
Technology
The Babcock & Wilcox Company's (B&W) limestone injection multistage burner (LIMB) system; Babcock & Wilcox DRB-XCL® low-NO_x burners; Consolidation Coal Company's Coolside duct injection of lime sorbents

Plant Capacity/Production
105 MWe

Coal
Ohio bituminous, 1.6, 3.0, and 3.8% sulfur

Project Funding

Total project cost	$19,311,033	100%
DOE	7,591,655	39
Participant	11,719,378	61

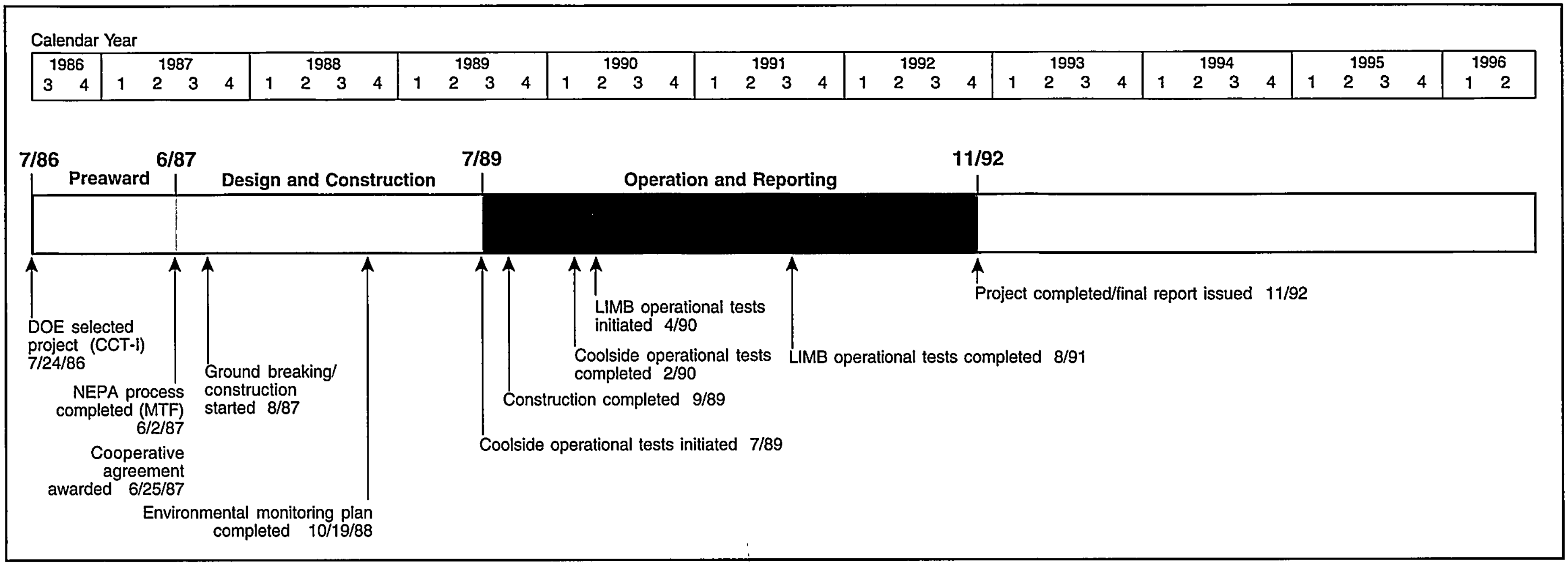


Project Objective
To demonstrate, with a variety of coals and sorbents, that the LIMB process can achieve up to 50% NO_x and SO_2 reductions, and to demonstrate that the Coolside process can achieve SO_2 removal of up to 70%.

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 elevation level in the boiler.

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 sodium hydroxide (NaOH) or sodium carbonate (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.



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 °F 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 °F approach-to-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.

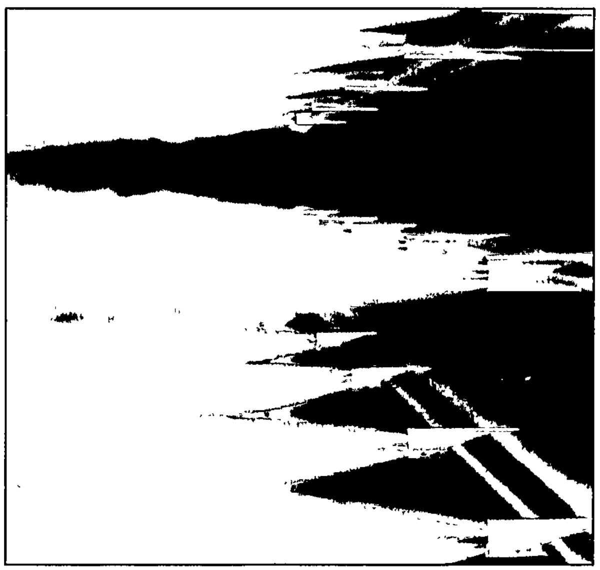
Economic

- LIMB capital costs were $31–102/kW for plants ranging from 100–500 MWe and coals with 1.5–3.5% sulfur, with a target SO_2 reduction of 60% (1992$). Annual levelized costs (15-year) for this range of conditions were $392–791/ton of SO_2 removed.
- Coolside capital costs were $69–160/kW for plants ranging from 100–500 MWe and coals with 1.5–3.5% sulfur, with a target SO_2 reduction of 70% (1992$). Annualized levelized costs (15-year) for this range of conditions were $482–943/ton of SO_2 removed.

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 was 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 the 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.



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

Environmental Performance (LIMB)

LIMB tests were conducted over a range of Ca/S molar ratios 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 elevation level in the boiler. Exhibit 2-28 summarizes SO_2 removal efficiencies for the range of sorbents and coals tested.

While injecting commercial limestone with 80% of the particles less than 44 microns in size, removal efficiencies of about 22% were obtained at a stoichiometry of 2.0 while burning 1.6% sulfur coal. However, removal efficiencies of about 32% were achieved at a stoichiometry of 2.0 when using a limestone with a smaller particle size (*i.e.*, all particles were less than 44 microns). A third limestone with essentially all particles less than 10 microns was used to determine the removal efficiency limit. The removal efficiency for this very fine limestone was approximately 5–7% higher than that obtained under similar conditions for limestone with particles all sized less than 44 microns.

During the design phase, it was expected that injection at the 181-foot plant elevation level inside the boiler would permit the introduction of the limestone at close to the optimum furnace temperature of 2,300 °F. Testing confirmed that injection at this level, just above the nose of the boiler, yielded the highest SO_2 removal. Injection was also performed at the 187-foot level and similar removals were observed. Removal efficiencies while injecting at these levels were about 5% higher than while injecting sorbent at the 191-foot level.

Removal efficiencies were enhanced by approximately 10% over the range of stoichiometries tested when using humidification down to a 20 °F approach-to-saturation temperature. 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.

Exhibit 2-28
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 molar ratio of 2.0, minimal humidification.

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 (limit was 20%).

Environmental Performance (Coolside)

The Coolside process was tested while burning compliance (1.2–1.6% sulfur) and noncompliance (2.8–3.2% sulfur) coals. Objectives of the full-scale test program were to verify short-term process operability and to develop a design performance database to establish process economics for Coolside. Key process variables—Ca/S molar ratio, Na/Ca molar ratio, and approach-to-saturation temperatures—were evaluated in short-term (6–8 hour) parametric tests and longer term (1–11 day) process operability tests.

Exhibit 2-29
LIMB Capital Cost Comparison
(1992 $/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 2-30
LIMB Annual Levelized Cost Comparison
(1992 $/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

The test program demonstrated that the Coolside process routinely achieved 70% SO_2 removal at design conditions of 2.0 Ca/S molar ratio, 0.2 Na/Ca molar ratio, and 20 °F approach-to-saturation temperature using commercially available hydrated lime. Coolside SO_2 removal depended on Ca/S molar ratio, Na/Ca molar ratio, approach-to-adiabatic-saturation, and the physical properties of the hydrated lime. Sorbent recycle showed significant potential to improve sorbent utilization. The observed SO_2 removal with recycled sorbent alone was 22% at 0.5 available Ca/S molar ratio 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 molar ratio, 0.2 fresh Na/Ca molar ratio, 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. The EPRI TAG™ methods were used for the economics, which are summarized in Exhibits 2-29 and 2-30.

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 desulfurization processes.

LIMB has been sold to an independent power plant in Canada. Babcock & Wilcox has signed 124 contracts for DLB-XCL® low-NO_x burners, representing 2,428 burners for 31,467 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)

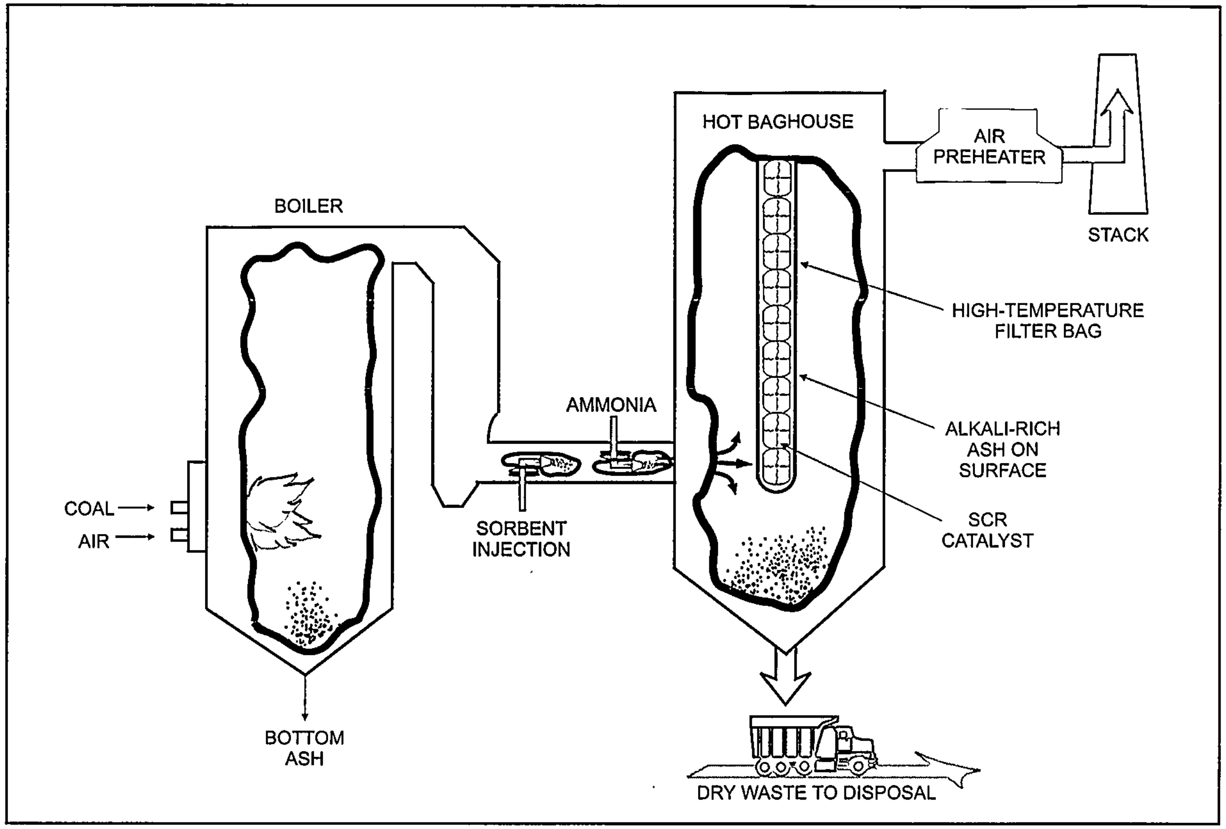
Technology
The Babcock & Wilcox Company's SO_x-NO_x-Rox Box™ (SNRB™) process

Plant Capacity/Production
5-MWe equivalent slipstream from a 156-MWe boiler

Coal
Bituminous coal blend, 3.7% sulfur average

Project Funding

Total project cost	$13,271,620	100%
DOE	6,078,402	46
Participant	7,193,218	54

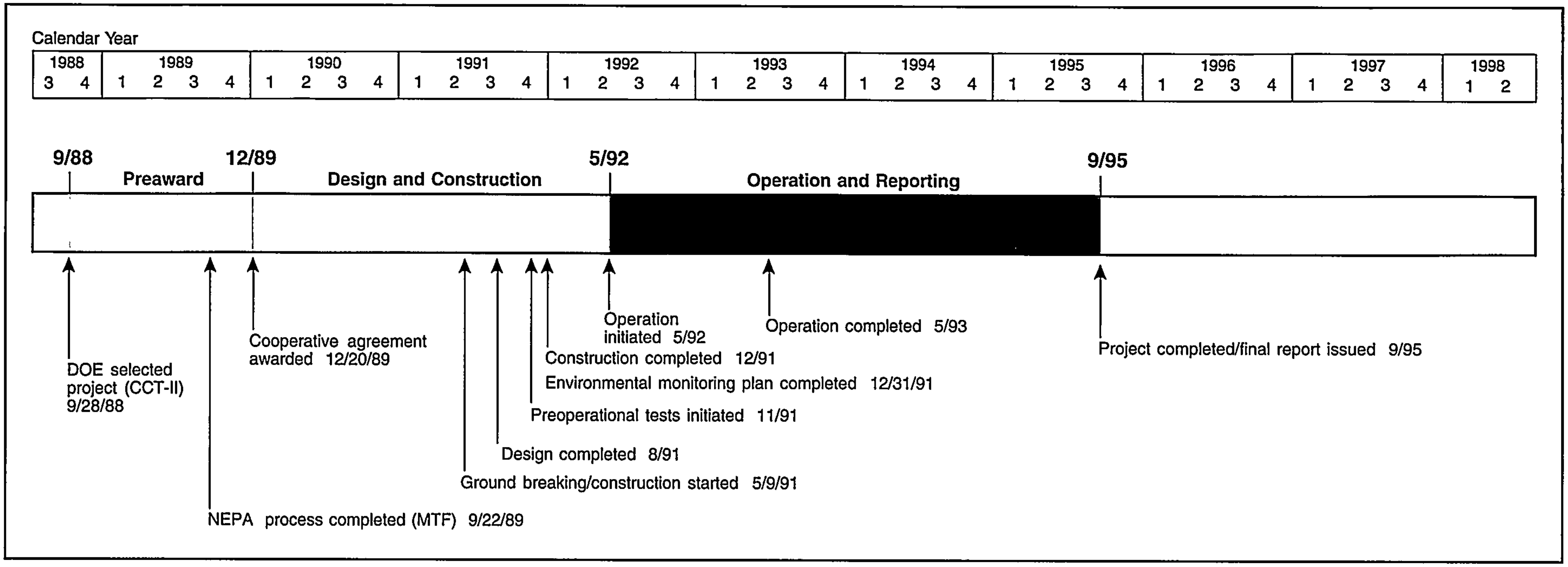


Project Objective
To achieve greater than 70% SO_2 removal and 90% or higher reduction in NO_x emissions while maintaining particulate emissions below 0.03 lb/10^6 Btu.

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 (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.

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 °F.
- SO_2 removal efficiency of 90% was achieved with sugar hydrated and lignosulfonate hydrated lime at a Ca/S molar ratio of 2.0 and temperature of 800–850 °F.
- 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 °F.
- 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 molar ratio of 1.0.
- Injection of calcium-based sorbents directly upstream of the baghouse at 825–900 °F resulted in higher overall SO_2 removal than injection further upstream at temperatures up to 1,200 °F.
- NO_x reduction of 90% was achieved with an NH_3/NO_x molar ratio of 0.9 and temperature of 800–850 °F.
- Air toxics 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-Glass filter bag.

Economic

- Capital cost in 1994 dollars for a 150-MWe retrofit was \$253/kW, assuming 3.5% sulfur coal, baseline NO_x emissions of 1.2 lb/10^6 Btu, 65% capacity factor, and 85% SO_2 and 90% NO_x removal.
- Levelized cost over 15 years in constant 1994 dollars was \$553/ton of SO_2 and NO_x removed.

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 controls in a single component with a low plan-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).

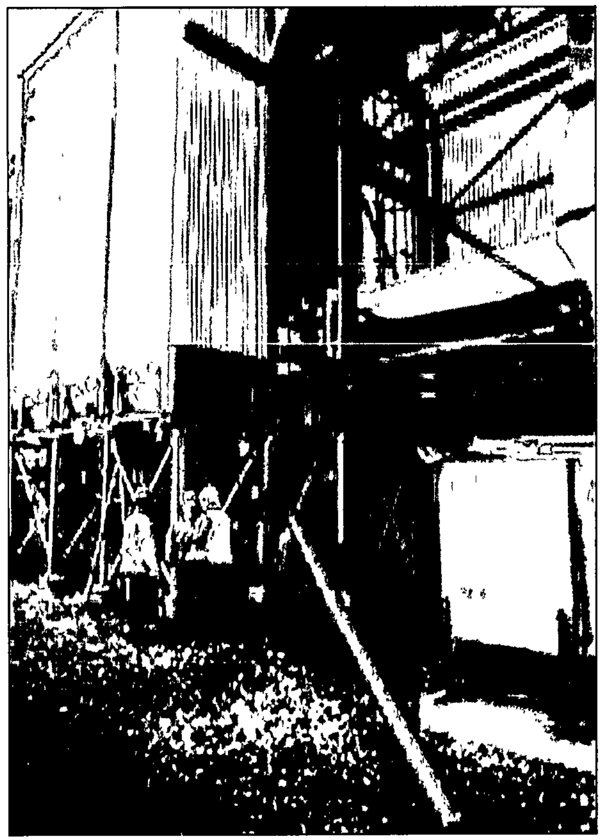
Environmental Performance

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. Essentially, 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 °F, injection of commercial-grade hydrated lime at Ca/S molar ratios of 1.8 and above resulted in SO_2 removals of over 80%. At a Ca/S 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 in the range of 40–45%. Injection of the calcium-based sorbents directly upstream of the baghouse at 825–900 °F resulted in higher overall SO_2 removal than injection further upstream at temperatures up to 1,200 °F.

The SO_2 removal using sodium bicarbonate was 80% at an Na_2/S molar ratio of 1.0 and 98% at an Na_2/S molar ratio of 2.0, at a significantly reduced baghouse temperature of 450–460 °F. 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 molar 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.

A NO_x emission 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 °F. Catalyst space velocity (volumetric gas flow/catalyst volume) had a minimal effect on NO_x removal over the range evaluated.

Turndown capability for tailoring the degree of NO_x reduction by varying the rate of ammonia injection was demonstrated for a range of 50–95% 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 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 hazardous 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, Colorado 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 150-MWe boiler fired with 3.5% sulfur coal and NO_x emissions of 1.2 lb/10^6 Btu, 65% capacity factor, and 85% SO_2 and 90% NO_x removal, the projected capital cost of a SNRB™ system is approximately \$253/kW (1994\$), 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. Levelized costs over 15 years in constant 1994 dollars are estimated at \$553/ton of SO_2 and NO_x removed.

Commercial Applications

Commercialization of the technology is expected to develop with an initial 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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- *5-MWe SNRB™ Demonstration Facility: Detailed Design Report.* The Babcock & Wilcox Company. November 1992.
- *Comprehensive Report to Congress on the Clean Coal Technology Program: SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project.* The Babcock & Wilcox Company. Report No. DOE/FE-0145. U.S. Department of Energy. November 1989. (Available from NTIS as DE90004458.)

▲ Workers lower one of the catalyst holder tubes into a mounting plate in the penthouse of the high-temperature baghouse.

Enhancing the Use of Coals by Gas Reburning and Sorbent Injection

Project completed.

Participant
Energy and Environmental Research Corporation

Additional Team Members
Gas Research Institute—cofunder
State of Illinois, Department of Commerce & Community Affairs—cofunder
Illinois Power Company—host
City Water, Light and Power—host

Locations
Hennepin, Putnam County, IL (Illinois Power Company's Hennepin Plant, Unit No. 1)
Springfield, Sangamon County, IL (City Water, Light and Power's Lakeside Station, Unit No. 7)

Technology
Energy and Environmental Research Corporation's gas reburning and sorbent injection (GR-SI) process

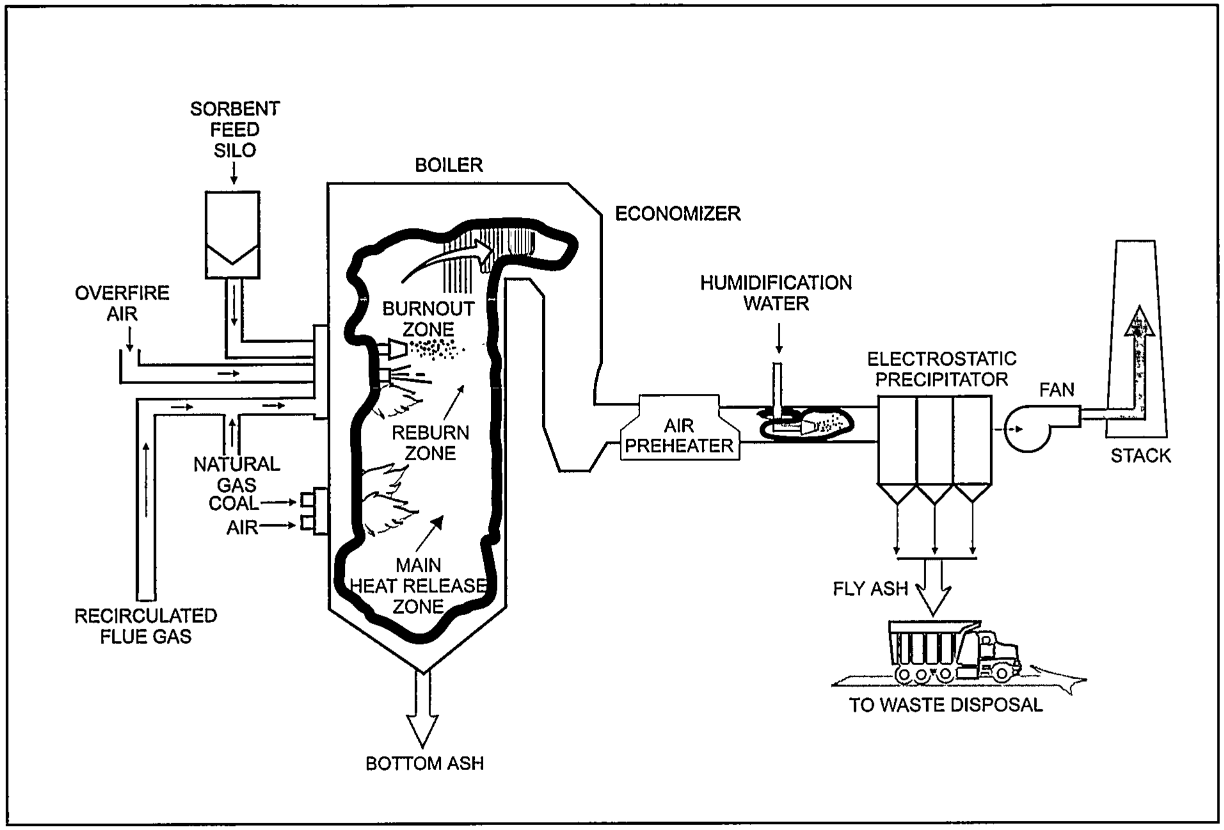
Plant Capacity/Production
Hennepin: tangentially fired 80 MWe (gross), 71 MWe (net)
Lakeside: cyclone-fired 40 MWe (gross), 33 MWe (net)

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

PromiSORB is a trademark of Energy and Environmental Research Corporation.

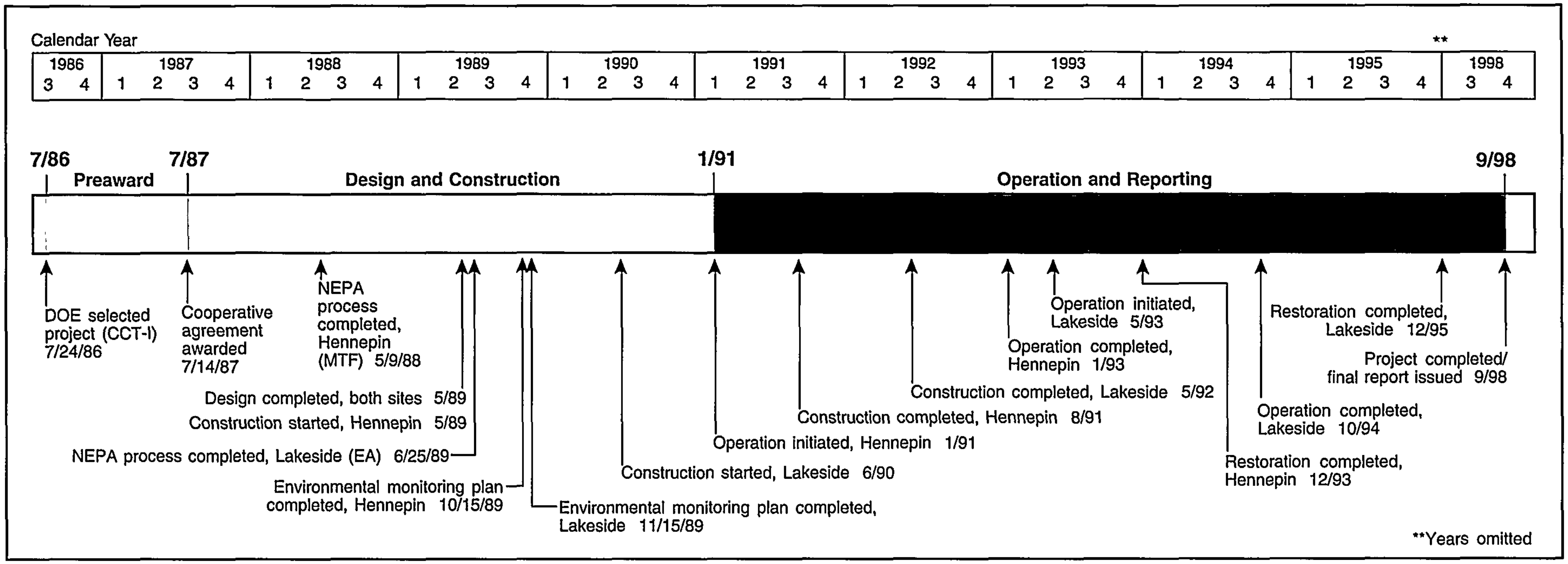


Project Objective
To demonstrate 60% NO_x reduction with gas reburning and at least 50% SO_2 removal with sorbent injection on two different boiler configurations—tangentially fired and cyclone-fired—while burning high-sulfur midwestern coal.

Technology/Project Description
In this process, 80–85% of the fuel as coal is supplied to the main combustion zone. The remaining 15–20% of the fuel, provided by natural gas, bypasses the main combustion zone and is injected above the main burners to form a reducing (reburning) zone in which NO_x is converted to nitrogen. A calcium compound (sorbent) is injected in the form of dry, fine particulates above the reburning zone in the boiler. Hydrated lime ($Ca(OH)_2$) serves as the baseline sorbent.

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, Illinois, and a cyclone-fired, 40-MWe (gross) boiler at City Water, Light and Power's Lakeside Station in Springfield, Illinois. 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.



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 (1996\$).
- 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 enabling effective design for any site-specific utility or industrial application.

Environmental Performance (Hennepin)

Following optimization testing throughout 1991, the GR-SI long-term demonstration tests spanned 1992. The unit was operated at constant loads and with the system under dispatch load following. 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 realized. This was due to partial replacement of coal with natural gas having a lower carbon-to-hydrogen 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 compared favorably to baseline emissions of 0.035 lb/10^6 Btu and a collection efficiency greater than 99.5%.

Following 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 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.

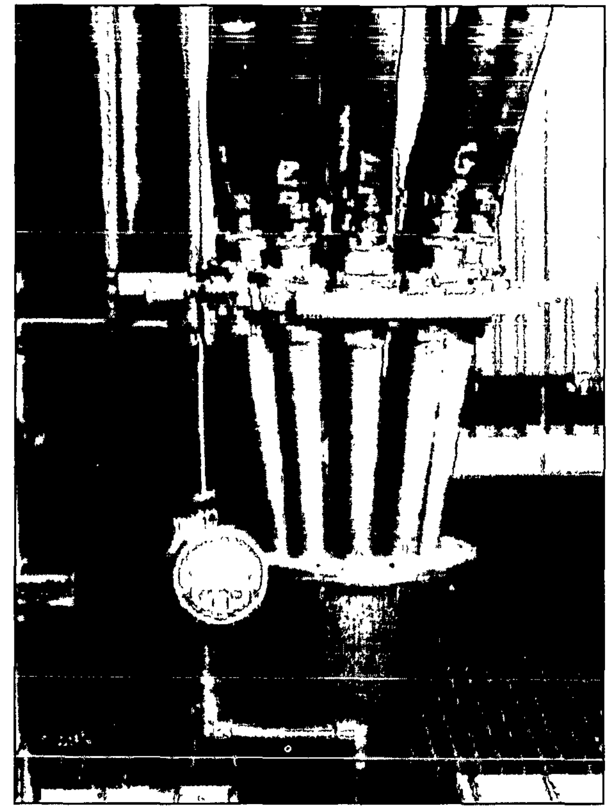
The SO_2 capture without GR, at a nominal 1.75 Ca/S molar ratio, was 53% for PromiSORB™ A, 66% for PromiSORB™ B, 60% for high-surface-area hydrated lime, and 42% for Linwood lime. At a 2.6 Ca/S molar ratio, the PromiSORB™ B yielded 81% SO_2 removal efficiency.

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 5–26%. 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 levels varied with load because of the effect of temperature on the sulfation reaction. At a Ca/S molar ratio 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 was 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 $15/kW for 100 MWe and larger plants plus the cost of the gas pipeline (if required) (1996$). 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

Project completed.

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 (S-H-U)—technology supplier

The Stebbins Engineering and Manufacturing Company—technology supplier

ABB Air Preheater, Inc.—technology supplier

DHR Technologies, Inc. (DHR)—operator of advisor control system

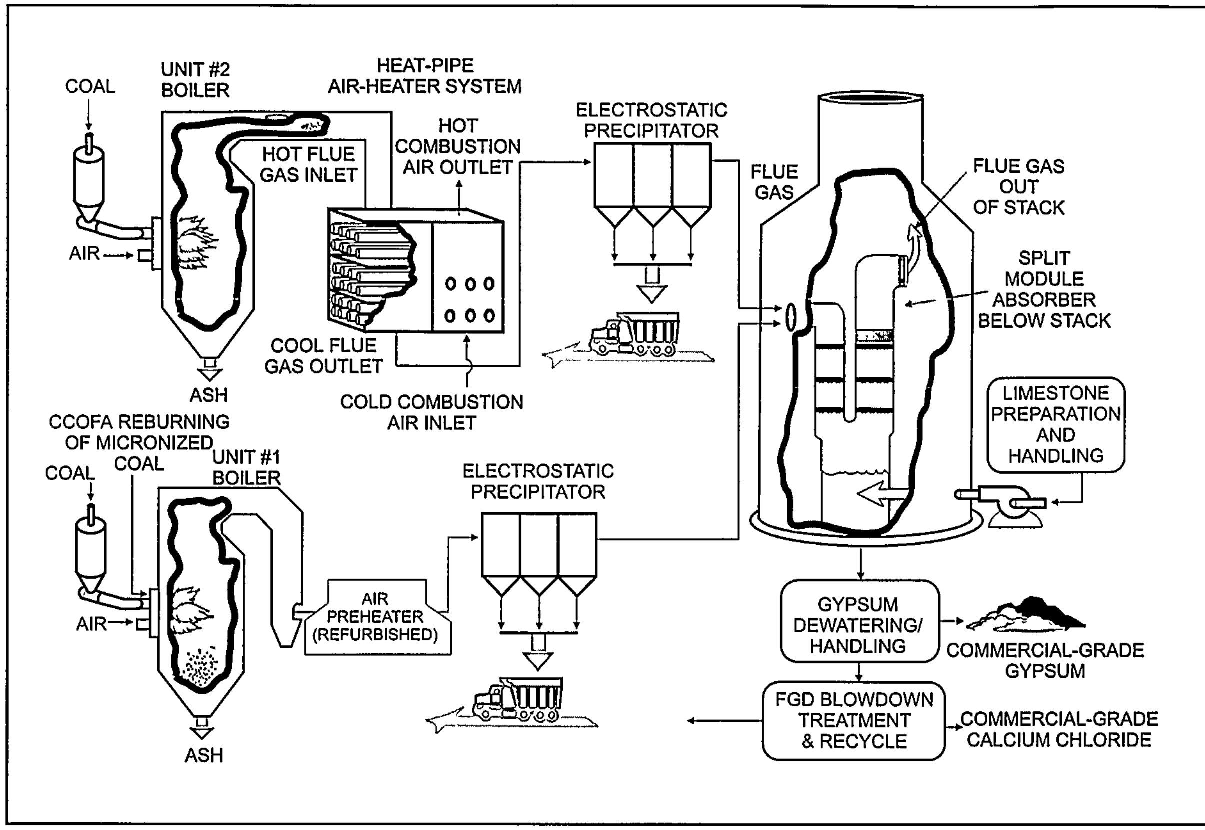
Location

Lansing, Tompkins County, NY (New York State Electric & Gas Corporation's Milliken Station, Unit Nos. 1 and 2)

Technology

Flue gas cleanup using S-H-U formic-acid-enhanced, wet limestone scrubber technology; ABB Combustion Engineering's Low-NO_x Concentric Firing System (LNCFS™) Level III; Stebbins' tile-lined split-module absorber; ABB Air Preheater's heat-pipe air preheater; and DHR's PEOA™ Control System.

LNCFS is a trademark of ABB Combustion Engineering, Inc.
PEOA is a trademark of DHR Technologies, Inc.



Plant Capacity/Production

300 MWe

Coal

Pittsburgh, Freeport, and Kittanning Coals; 1.5, 2.9 and 4.0% sulfur, respectively.

Project Funding

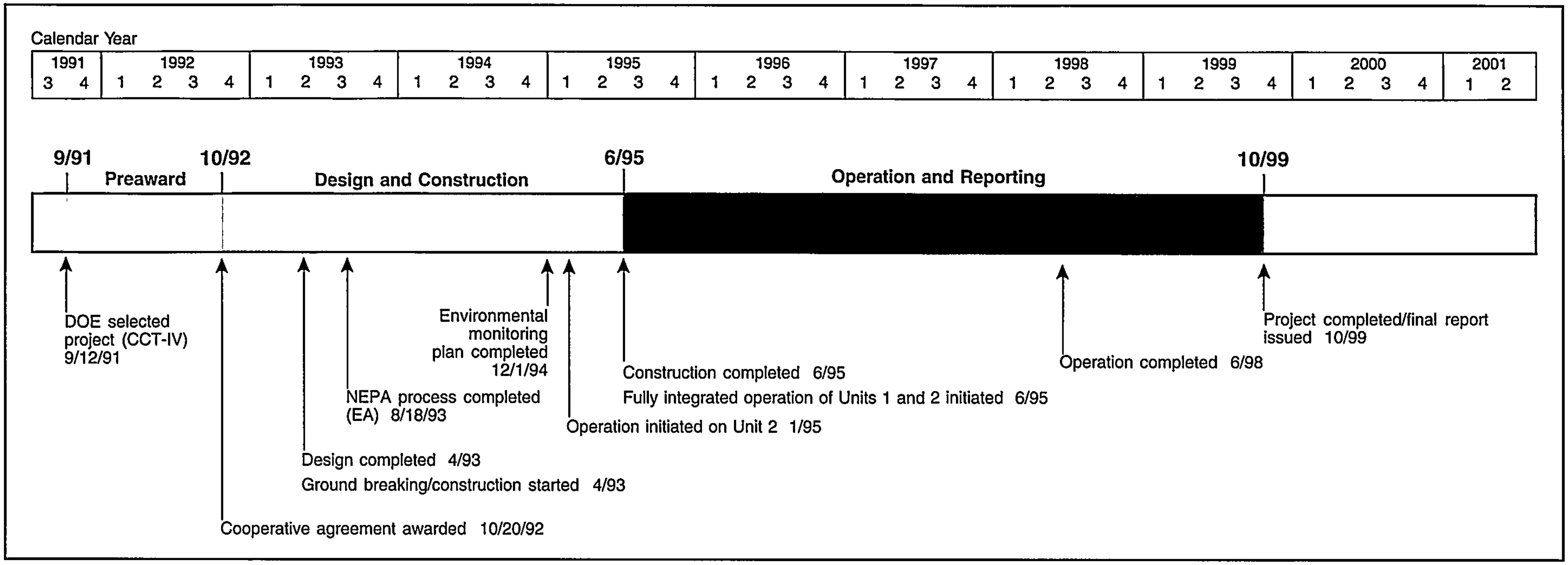
Total project cost	$158,607,807	100%
DOE	45,000,000	28
Participant	113,607,807	72

Project Objective

To demonstrate high sulfur capture efficiency and NO_x and particulate control at minimum power requirements, zero waste water discharge, and the production of by-products in lieu of wastes.

Technology/Project Description

The formic acid enhanced S-H-U process is designed to remove up to 98% SO_2 at high sorbent utilization rates. The Stebbins tile-lined, split-module reinforced concrete absorber vessel provides superior corrosion and abrasion resistance. Placement below the stack saves space and provides operational flexibility. NO_x emissions are controlled by LNCFS III™ low-NO_x burners and by micronized coal reburning. A heat-pipe air preheater is integrated to increase boiler efficiency by reducing both air leakage and the air preheater's flue gas exit temperature. To enhance boiler efficiency and emissions reductions, DHR's Plant Emission Optimization Advisor (PEOA™) provides state-of-the-art artificial-intelligence-based control of key boiler and plant operating parameters.



Results Summary

Environmental

- The maximum SO_2 removal demonstrated was 98% with all seven recycle pumps operating and using formic acid. The maximum SO_2 removal without formic acid was 95%.
- The difference in SO_2 removal between the two limestone grind sizes tested (90%–325 mesh and 90%–170 mesh) while using low-sulfur coal was an average of 2.6 percentage points.
- The SO_2 removal efficiency was greater than the design efficiency during the high velocity test of the concurrent scrubber section up to a liquid-to-gas ratio (L/G) of 110 gallons per 1,000 actual cubic feet of gas.
- At full load, LNCFS™ III lowered NO_x emissions to 0.39 lb/10^6 Btu (compared to 0.64 lb/10^6 Btu for the original burners)—a 39% reduction.
- During diagnostic tests, LOI was above 4% at full boiler load. During the validation tests (when overfire air limitations were relaxed), the LOI dropped by 0.7 to 1.7 percentage points, with a minor effect on NO_x emissions.

Operational

- The co-current pumps had no measurable effect on pressure drop, whereas the countercurrent pumps significantly increased the scrubber pressure drop. The average effect of each countercurrent header was to increase pressure drop by 0.45 inches water column (WC) in the design flow tests and 0.64 inches WC in the high velocity tests.
- Performance of a modified ESP with wider plate spacing and reduced plate area exceeded that of the original ESPs at lower power consumption.
- Boiler efficiency was 88.3–88.5% for LNCFS™ III, compared to a baseline of 89.3–89.6%.
- Air infiltration was low for both heat pipes. Some unaccounted for air leakage occurred at full load, ranging between 2.0–2.4%.
- The flue gas side pressure loss for both heat pipes was less than the design maximum of 3.65 inches WC. The primary side pressure drops for both heat pipes were less than the design maximum of 3.6 inches WC. The secondary air side pressure drops for both heat pipes were less than the design maximum of 5.35 inches WC.

Economic

- The capital cost (1998$) of the FGD system is estimated at $300 /kW for a 300 MWe unit with a 65% capacity factor, 3.2% sulfur coal, and 95% sulfur removal.
- The annual operating cost is estimated at $4.62 million (1998$); and the 15-year levelized cost is estimated at $412/ton of SO_2 removed (constant 1998$).

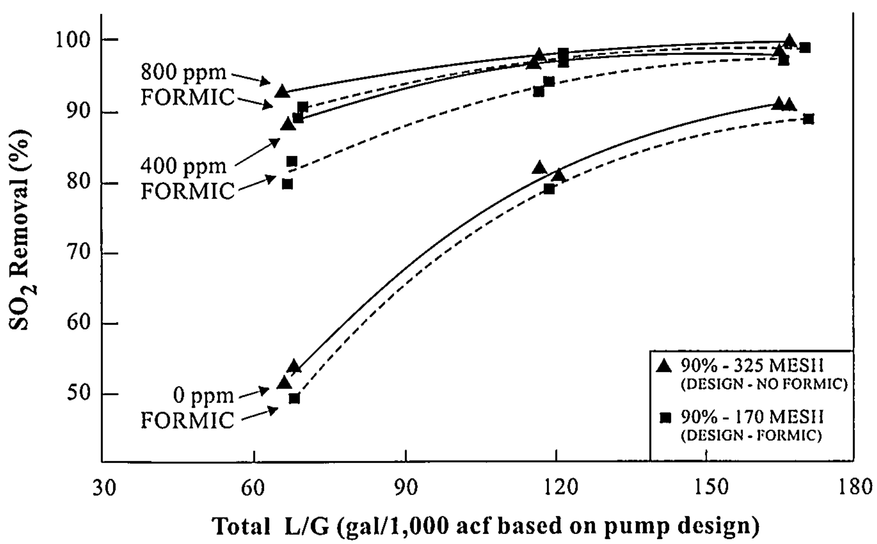
Project Summary

The test plan was developed to cover all of the new technologies used in the project. In addition to the technologies tested, the project demonstrated that existing technologies can be used in conjunction with new processes to produce salable by-products. Supplemental monitoring has provided operation and performance data illustrating the success of these processes under a variety of operating conditions. Generally, each test program was divided into four independent subtests: diagnostic, performance, long-term, and validation. (See Micronized Coal Reburning Demonstration for NO_x Control for another CCT Program project at this unit.)

Environmental Performance

The S-H-U FGD system was tested over a 36-month period. Typical evaluations included SO_2 removal efficiency, power consumption, process economics, load following capability, reagent utilization, by-product quality, and additive effects. Parametric testing included formic acid concentration, L/G ratio, mass transfer, coal sulfur content, and flue gas velocity. The maximum SO_2 removal demonstrated was 98% with all seven recycle pumps operating and using formic acid, and the maximum SO_2 removal without formic acid was 95%. The difference in SO_2 removal between the two limestone grind sizes tested (90%–325 mesh and 90%–170 mesh), while using low-sulfur coal was an average of 2.6 percentage points as shown in Exhibit 2-31. The SO_2 removal efficiency was greater than the design efficiency during the high velocity test of the cocurrent scrubber section up to a liquid-to-gas ratio of 110. The cocurrent pumps had no measurable effect on pressure drop, whereas the countercurrent pumps significantly increased the scrubber pressure drop. As seen in Exhibit 2-32, the average effect of each countercurrent header was to increase pressure drop by 0.45 inches water column (W.C.) in the design flow tests, and 0.64 inches W.C. in the high velocity tests.

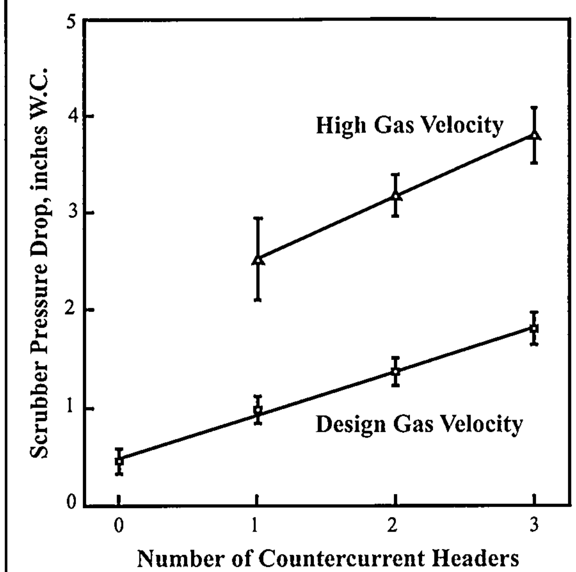
Exhibit 2-31
Effect of Limestone Grind



Performance of a modified ESP with wider plate spacing, reduced plate area, and reduced power consumption exceeded that of the original ESP. The average particulate matter penetration before the ESP modification was 0.22% and decreased to 0.12% after the modifications.

At full boiler load (145–150 MWe) and 3.0–3.5% economizer O_2, the LNCFS™ III lowered NO_x emissions from a baseline of 0.64 lb/10^6 Btu to 0.39 lb/10^6 Btu (39% reduction). At 80- to 90-MWe boiler load and 4.3–5.0% economizer O_2, the LNCFS™ III lowered NO_x emissions from a baseline of 0.58 lb/10^6 Btu to 0.41 lb/10^6 Btu (29% reduction). With LNCFS™ III, LOI was maintained below 4% and CO emissions did not increase.

Exhibit 2-32
Pressure Drop vs. Countercurrent Headers



Operational Performance

The S-H-U FGD system performance goal of 98% SO_2 removal efficiency was achieved. Similarly, the objective of producing a marketable gypsum by-product from the FGD system was achieved. The test results indicate that the gypsum produced can be maintained at a purity level exceeding 95% with a chloride level less than 100 ppm. However, the goal of producing a marketable calcium chloride solution from the FGD blowdown stream was not achieved. FGD availability for the test period was 99.9%.

The modified ESP has performed better than the original ESP at a lower power use. The total voltage current product (V•I) for ESPs is directly proportional to the total power requirement. The modified ESP required only 75% of the V•I demand of the original ESPs. The modified ESP has a smaller plant footprint with fewer internals and a smaller SCA. Total internal plate area is less than one-half that of the original ESPs, tending to lower capital costs.

Boiler efficiency was 88.3–88.5% for LNCFS™ III, compared to a baseline of 89.3–89.6%. The lower efficiency was attributed to higher post-retrofit flue gas excess O_2 requirement and higher stack temperatures which accompanied the air heater retrofit.

The heat pipe was tested in accordance with ASME Power Test Code for Air Heaters 4.3. Air infiltration was low for both heat pipes. Unaccounted for air leakage occurred at full load, ranging between 2.0–2.4%. The tests showed that the flue gas side pressure loss for both heat pipes was less than the design maximum of 3.65 inches WC. The primary side pressure drops for both heat pipes were less than the design maximum of 3.6 inches WC. The secondary air side pressure drops for both heat pipes were less than the design maximum of 5.35 inches WC.

Economic Performance

The capital cost of the total FGD system in 1998 dollars is estimated at $300/kW for a 300 MWe unit with a 65% capacity factor using 3.2% sulfur coal and achieving 95% sulfur removal. The annual operating cost is estimated at $4.62 million. The 15-year levelized cost is estimated at $412/ton of SO_2 removed in 1998 constant dollars.

Commercial Applications

The S-H-U process, Stebbins absorber module, and heat-pipe air preheater are applicable to virtually all power plants. The space-saving design features of the technologies, combined with the production of marketable byproducts, offer significant incentives to generating stations with limited space. Six modules of DHR Technologies' PEOA™ system have been sold, with an estimated value of $210,000.

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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—fly ash 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)

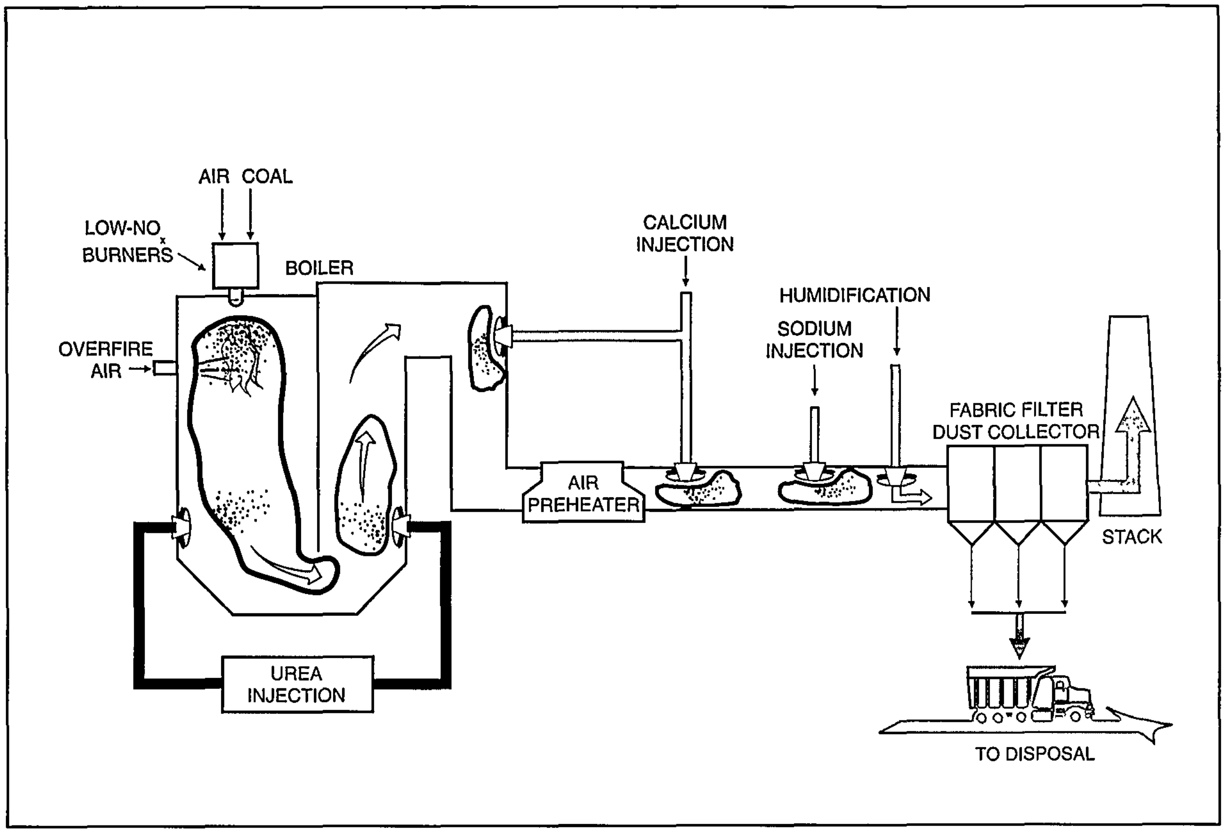
Technology
The Babcock & Wilcox Company's DRB-XCL® low-NO_x burners, in-duct sorbent injection, and furnace (urea) injection

Plant Capacity/Production
100 MWe

Coal
Colorado bituminous, 0.4% sulfur
Wyoming subbituminous (short test), 0.35% sulfur

Project Funding

Total project cost	$26,165,306	100%
DOE	13,082,653	50
Participant	13,082,653	50



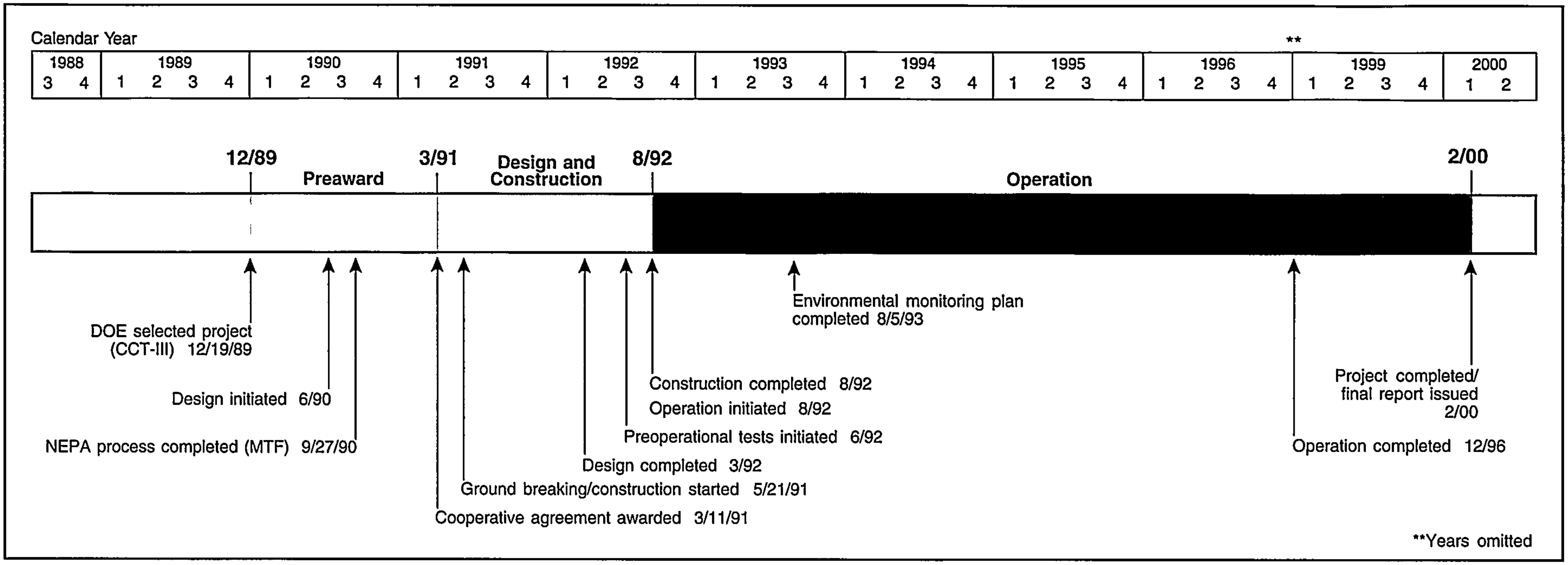
Project Objective
To demonstrate the integration of five technologies to achieve up to 70% reduction in NO_x and SO_2 emissions; more specifically, to assess the integration of a down-fired low-NO_x burner with in-furnace urea injection for additional NO_x removal and dry sorbent in-duct injection with 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 is 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-based sorbent was injected upstream of the boiler economizer, or sodium-based sorbent 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

- DRB-XCL® burners with minimum overfire air reduced NO_x emissions by more than 63% under steady state conditions.
- With maximum overfire air (24% of total combustion air), a NO_x reduction of 62–69% was achieved across the 50- to 110-MWe load range.
- 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 dry calcium hydroxide injection into the boiler economizer 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 calcium/sulfur (Ca/S) molar 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 bicarbonate than when using sodium sesquicarbonate.
- Integrated SNCR and dry sodium-based 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 Unit No. 4 operated more than 34,000 hours with the combustion modifications in place. Availability factor was over 91%.
- Control system modifications and additional operator training may be necessary to improve NO_x control under load-following conditions.
- Temperature differential between the top and bottom surfaces of the Advanced Retractable Injection Lances (ARIL) initially caused the lances to bend downward 12–18 inches. Alternative designs corrected the problem.

Economic

- When used on units burning low sulfur coal, the technology offers SO_2 and NO_x removals comparable to a wet scrubber and SCR, but at a lower cost.
- Total capital costs for the technology ranges from $125/kW to $281/kW for 300 MWe to 50 MWe plants, respectively. Levelized costs range from 12.43–7.03 mills/kWh or 1746–987 $/ton of SO_2 and NO_x removed for 300 MWe to 50 MWe plants, respectively.

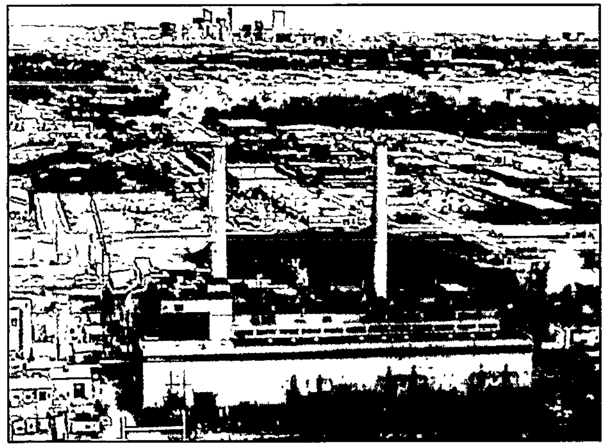
Project Summary

The Integrated Dry NO_x/SO_2 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 boiler roof. The low-NO_x combustion system also incorporates three Babcock & Wilcox dual-zone NO_x ports added to each side of the furnace approximately 20 feet below the boiler roof. These ports inject up to 24% of the total combustion air through the furnace sidewalls.

Additional NO_x control was achieved using the urea-based SNCR system. The SNCR when used with the low-NO_x combustion system, allowed 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. Levels were determined by 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 °F, thus moving one injector level out of the temperature regime needed for effective SNCR operation. With only one operational injector level, load-following performance was compromised.

In order to achieve the desirable NO_x reduction at low loads, two alternatives were explored. The first approach was to substitute ammonia for urea. 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 soot-



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

blower ports. Each lance was nominally 4 inches in diameter and approximately 20 feet 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 maldistributions 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.

The SO_2 control system was a direct sorbent injection system that could inject either calcium- or sodium-based reagents into the flue gas upstream of the fabric filter. Sorbent was injected into three locations: (1) air heater exit where the temperature was approximately 260 °F, (2) air heater entrance where the temperature was approximately 600 °F, or (3) the boiler economizer region where the flue gas temperature was approximately 1,000 °F. To improve SO_2 removal with calcium hydroxide, a humidification system capable of achieving 20 °F approach-to-saturation was installed approximately 100 feet 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 (24% of total combustion air), the low-NO_x combustion system reduced NO_x emissions by 62–69% across the load range (60- to 110-MWe). The results verified that the low-NO_x burners were responsible for most of the NO_x reduction.

The original design of two rows of SNCR 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 a 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 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 achieved NO_x removals in the range of 30–50% (at a NH_3 slip limited to 10 ppm at the fabric filter inlet), increasing total NO_x 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 within 20–30 °F approach-to-saturation. 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.

Operating Performance

The Arapahoe Unit No. 4 operated more than 34,000 hours with the combustion modifications in place. 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.

During the operation of the duct injection of calcium hydroxide and humidification under load-following conditions, the fabric filter pressure-drop significantly increased. This was caused by the buildup of a hard ash cake on the fabric filter bags that could not be cleaned under normal reverse-air cleaning. The heavy ash cake was caused by the humidification system, but it was not determined whether the problem was due to operation at 30 °F approach-to-saturation temperature or an excursion caused by a rapid decrease in load.

The performance of the ARIL lances in NO_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 downward 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 dropped relative to 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

The technology is an economical method of obtaining SO_2 and NO_x reduction on low sulfur coal units. Total estimated capital costs range from 125–281 \$/kW for capacities ranging from 300–50 MWe. Comparably, wet scrubber and SCR capital costs range from 270–474 \$/kW for the same unit size ranges. On a levelized cost basis, the demonstrated system costs vary from 12.43–7.03 mills/kWh (1,746–987 \$/ton of SO_2 and NO_x removed) compared to wet scrubber and SCR levelized costs of 23.34–12.67 mills/kWh (4,974–2,701 \$/ton of SO_2 and NO_x removed) based on 0.4% sulfur coal. The integrated system is most efficient on smaller low-sulfur coal units. As size and sulfur content increases, the cost advantages decrease.

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 Fluidized-Bed Combustion

McIntosh Unit 4A PCFB Demonstration Project

Participant
City of Lakeland, Lakeland Electric

Additional Team Members
Foster Wheeler Corporation—supplier of pressurized circulating fluidized-bed (PCFB) combustor and heat exchanger; engineer

Siemens Westinghouse Power Corporation—supplier of hot gas filter, gas turbine, and steam turbine

Location
Lakeland, Polk County, FL (Lakeland Electric's McIntosh Power Station, Unit No. 4)

Technology
Foster Wheeler's PCFB technology integrated with Siemens Westinghouse's hot gas particulate filter system (HGPFS) and power generation technologies

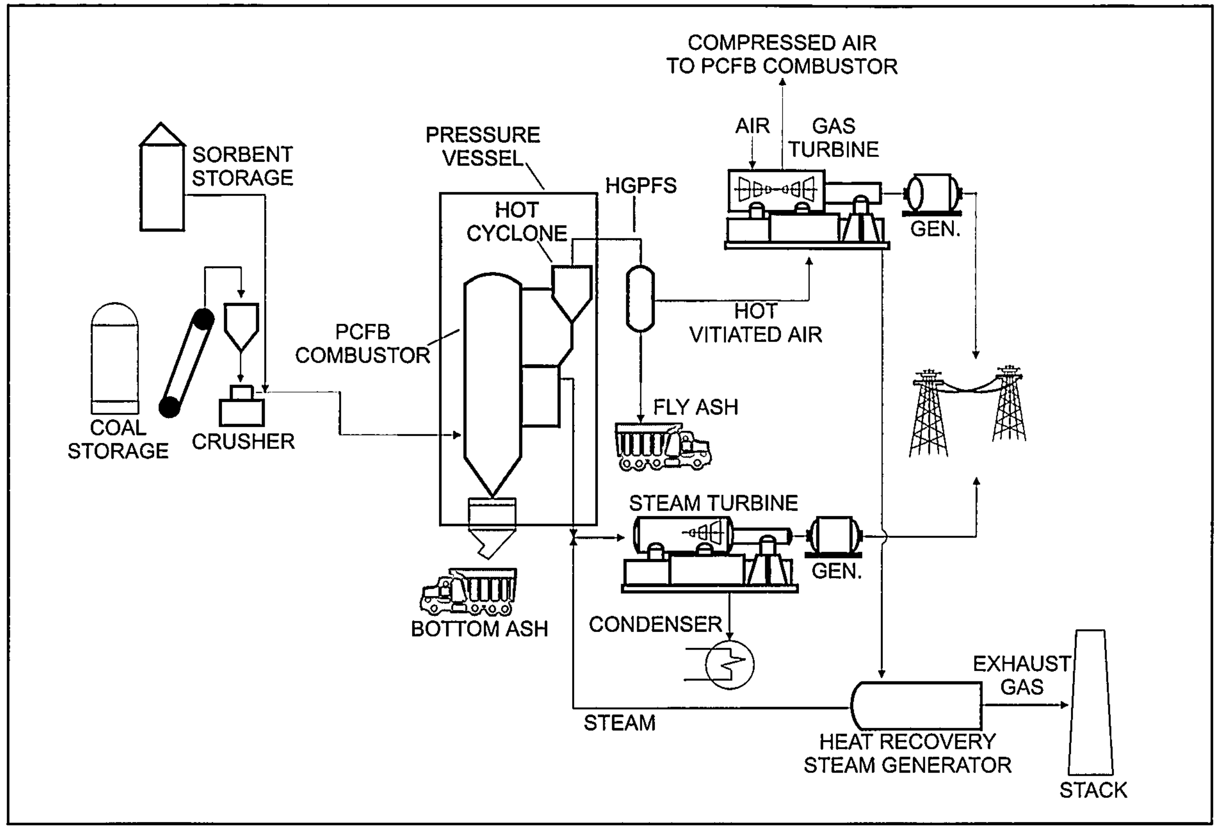
Plant Capacity/Production
137 MWe (net)

Coal
Eastern Kentucky and high-ash, high-sulfur bituminous coals

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 Siemens Westinghouse's ceramic candle type HGPFS 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.

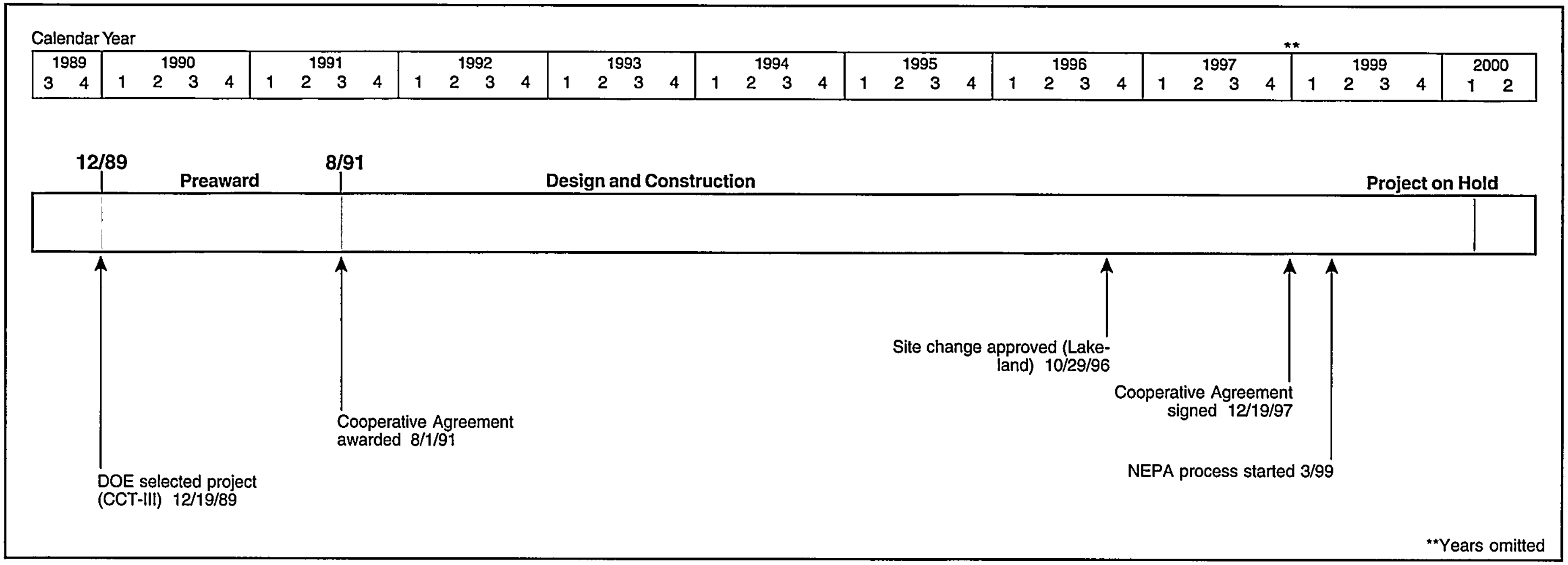


Technology/Project Description
In the first of the two Lakeland Electric projects, McIntosh Unit No. 4A will be constructed with a PCFB combustor adjacent to the existing Unit No. 3 (see also McIntosh Unit 4B Topped PCFB Demonstration Project).

Coal and limestone are mixed and fed into the combustion chamber. Combustion takes place at a temperature of approximately 1,560–1,600 °F and a pressure of about 200 psig. The resulting flue gas and fly ash leaving the combustor pass through a cyclone and ceramic candle type HGPFS where the particulates are removed. The hot gas leaving the HGPFS is expanded through a Siemens V64.3 gas turbine. 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 steam generator (HRSG).

Heat recovered from both the combustor and HRSG is used to generate steam to power a reheat steam turbine. Approximately 5–10% of the power is derived from the gas turbine, with the steam turbine contributing the balance. The project also includes an atmospheric fluidized-bed unit that can be fired on coal or char from the carbonizer and will replace the PCFB unit during times of PCFB unavailability, allowing various modes of operation.

The projected net heat rate for the system is approximately 9,480 Btu/kWh (HHV), which equates to an efficiency greater than 36%. 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.



Project Status/Accomplishments

The project resulted from a restructuring of the DMEC-1 PCFB Demonstration Project awarded under CCT-III. On December 19, 1997, a Cooperative Agreement modification was signed implementing the project restructuring from DMEC-1 to the City of Lakeland. The Lakeland City Council gave approval in April 1998 for the 10 year plan of Lakeland Electric (formerly Department of Electric & Water Utilities), which included this project. However, the project is on hold while technical and economic issues are resolved.

Efforts have been focused on testing the HGPFS, which is critical to system performance. Silicon carbide and alumina/mullite candle filters proved effective under conditions simulating those of the demonstration unit. At both 1,550 °F and 1,400 °F, the candle filters performed for over 1,000 hours at design levels without evidence of ash bridging or structural failure. Three new oxide-based candle filters showed promise as well and will undergo further testing because of the potential for reduced cost and operation at higher temperatures.

Commercial Applications

The project serves to demonstrate the PCFB technology for widespread commercial deployment and will include the first commercial application 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 pressurized bubbling-bed fluidized-bed system. The PCFB technology 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 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.

McIntosh Unit 4B Topped PCFB Demonstration Project

Participant
City of Lakeland, Lakeland Electric

Additional Team Members
Foster Wheeler Corporation—supplier of carbonizer; engineer

Siemens Westinghouse Power Corporation—supplier of topping combustor and high-temperature filter

Location
Lakeland, Polk County, FL (Lakeland Electric's McIntosh Power Station, Unit No. 4)

Technology
Fully integrated second-generation PCFB technology with the addition of a carbonizer island that includes Siemens Westinghouse's multi-annular swirl burner (MASB) topping combustor

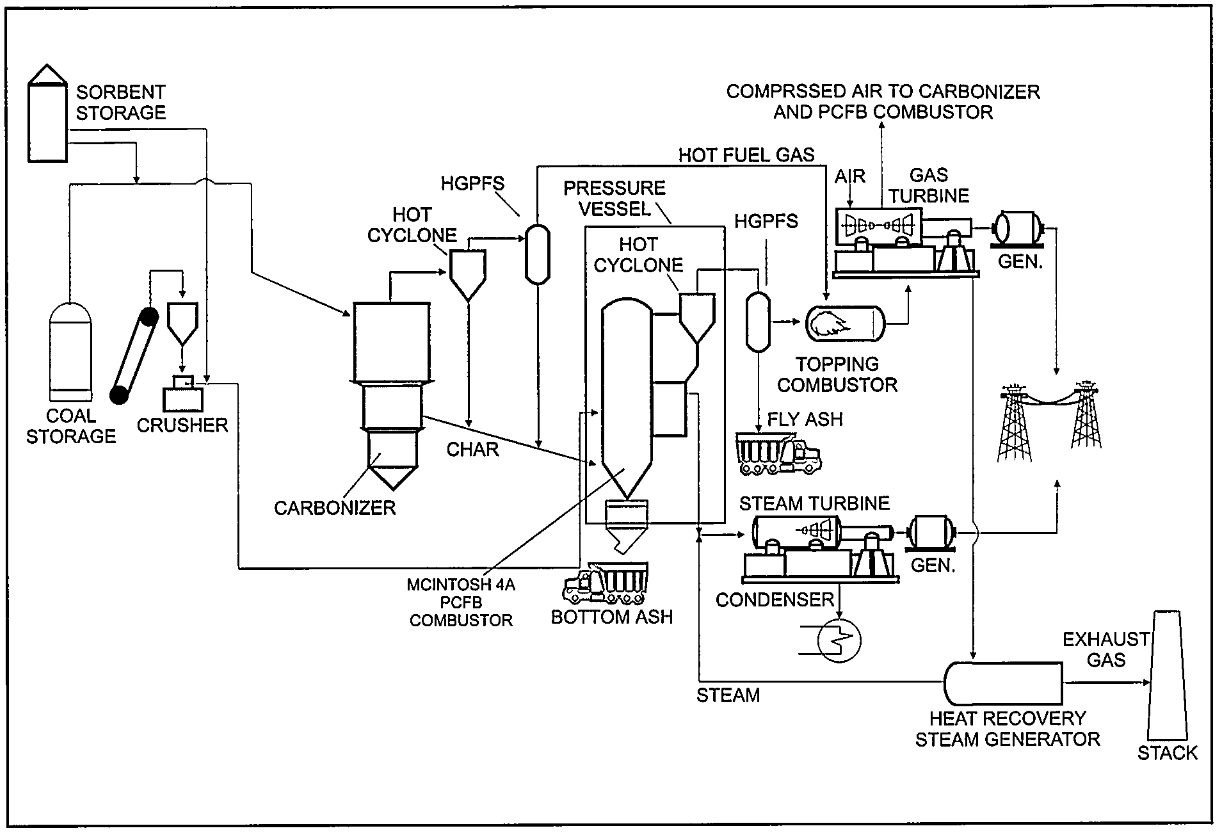
Plant Capacity/Production
103-MWe (net) addition to the 137-MWe (net) McIntosh 4A project

Coal
Eastern Kentucky and high-ash, high-sulfur bituminous coals

Project Funding

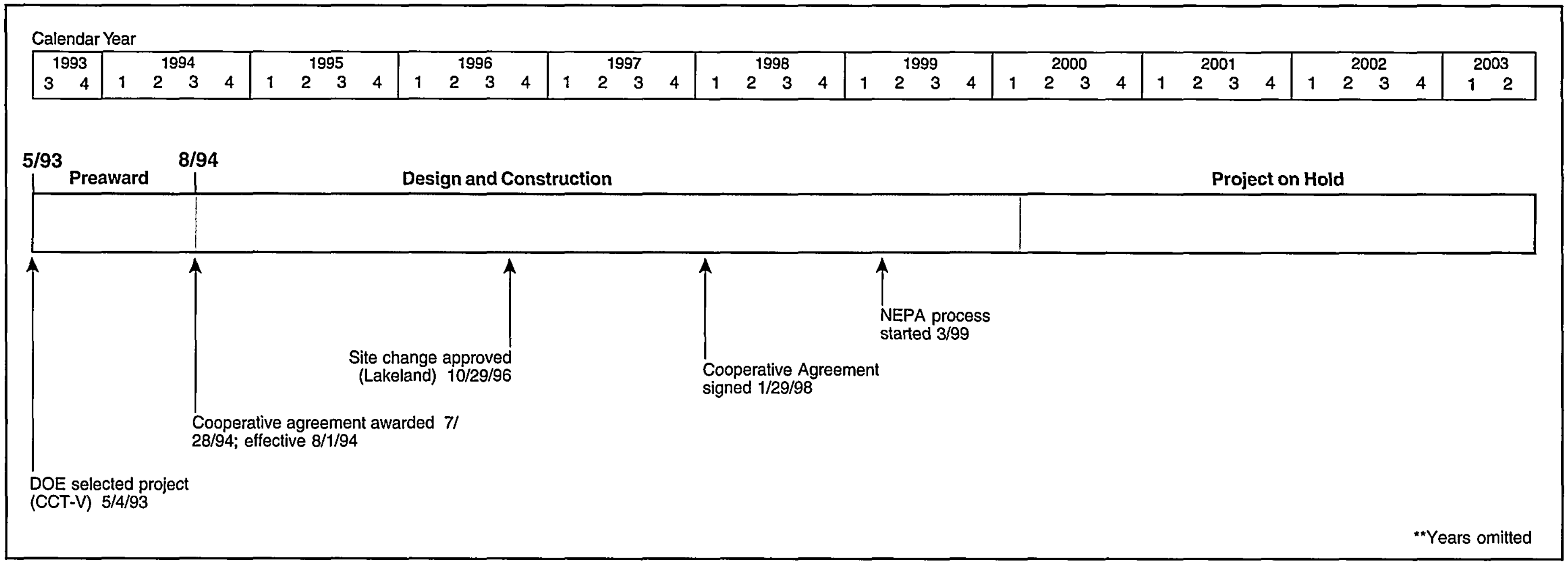
Total project cost	$219,635,546	100%
DOE	109,608,507	50
Participant	110,027,039	50

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



Technology/Project Description
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 with part of the gas turbine discharge air. The coal is partially gasified at about 1,750–1,800 °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 particulate filter system (HGPFS). 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 2,350 °F. The gas is expanded through the turbine, cooled in a heat recovery steam generator, and exhausted to the stack. The net impact of the addition of the topping cycle is an increase in both power output and efficiency. The coal and limestone used in McIntosh 4B are the same as those used in McIntosh 4A.

The 240-MWe (net) plant is expected to have a heat rate of 8,406 Btu/kWh (40.6% efficiency, HHV). The design SO_2 capture efficiency rate is 95%. Particulate and NO_x emissions are expected to be 0.02 lb/10^6 Btu and 0.17 lb/10^6 Btu, respectively. In the final configuration, the gas turbine will produce 58 MWe and the steam turbine will produce 207 MWe, while plant auxiliaries will consume about 25 MWe.



Project Status/Accomplishments

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 carbonizer (gasifier) and topping combustor (topping cycle) with the PCFB technology. By using a phased approach, Lakeland Electric will be able to demonstrate both PCFB (McIntosh 4A) and topped PCFB (McIntosh 4B) technologies at one plant site.

On January 29, 1998, a Cooperative Agreement modification was signed implementing the project restructuring from Four Rivers Energy Partners to the City of Lakeland. The Lakeland City Council gave approval in April 1998 for the 10 year plan of Lakeland Electric (formerly Department of Electric & Water Utilities), which included this project. However, the project is on hold while technical and economic issues are resolved.

Recent efforts focused on testing the HGPFS, which is critical to system performance. Silicon carbide and alumina/mullite candle filters proved effective under conditions simulating those of the demonstration unit. At both 1,550 °F and 1,400 °F, the candle filters performed for over 1,000 hours at design levels without evidence of ash bridging or structural failure. Three new oxide-based candle filters showed promise as well. These will undergo further testing because of the potential for reduced cost and operation at higher temperatures.

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, 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 allowed by New Source Performance Standard (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.

The commercial version of the topped PCFB technology has other environmental attributes, which include *in-situ* sulfur retention that can meet 95% removal requirements, NO_x emissions that will meet or exceed NSPS, and particulate matter discharge of approximately 0.03 lb/10^6 Btu. Although the system will generate a slight increase in solid waste compared to conventional systems, the material is a dry, readily disposable, and potentially usable material.

JEA Large-Scale CFB Combustion Demonstration Project

Participant
JEA (formerly Jacksonville Electric Authority)

Additional Team Member
Foster Wheeler Energy Corporation—technology supplier

Location
Jacksonville, Duval County, FL (JEA's Northside Station, Unit No. 2)

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

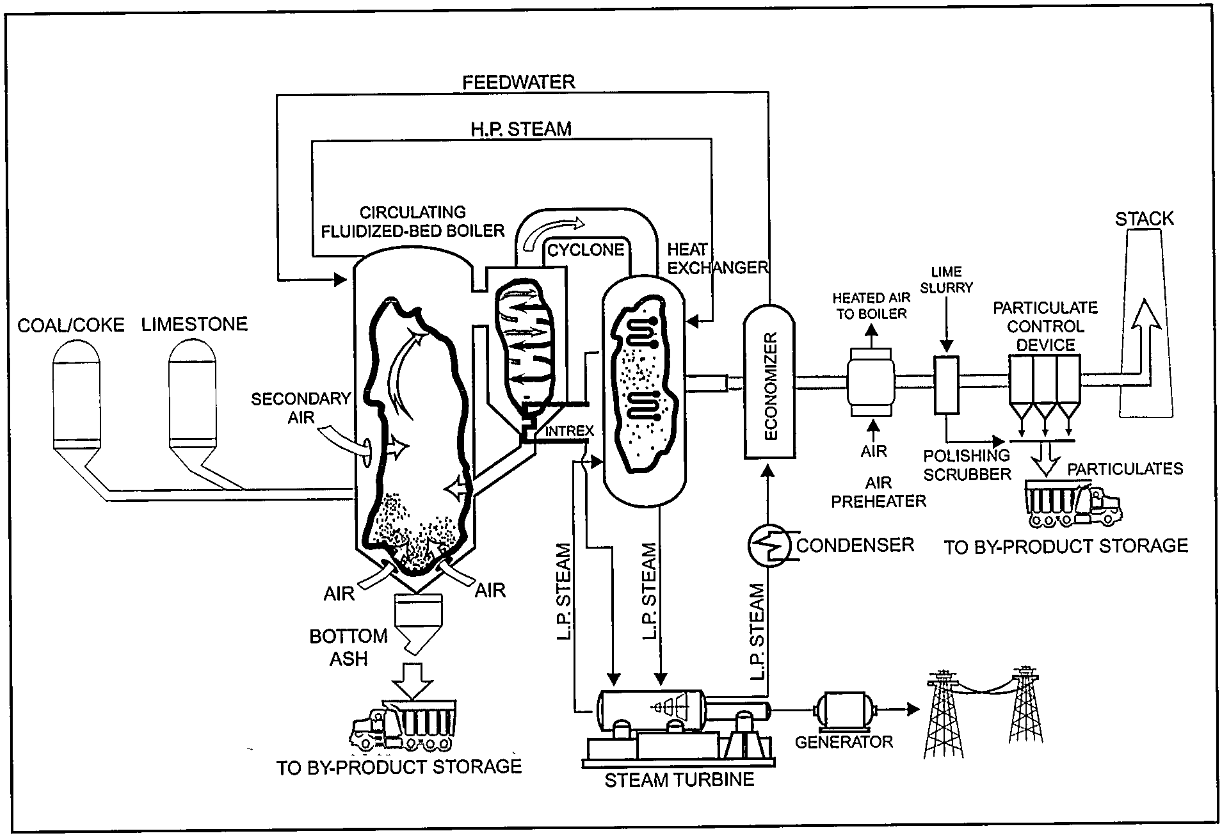
Plant Capacity/Production
297.5 MWe (gross), 265 MWe (net)

Coal
Eastern bituminous, 0.7% sulfur (design)

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 scaleup from previously constructed facilities; to verify expectations of the technology's economic, environmental, and technical performance to provide potential users 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.

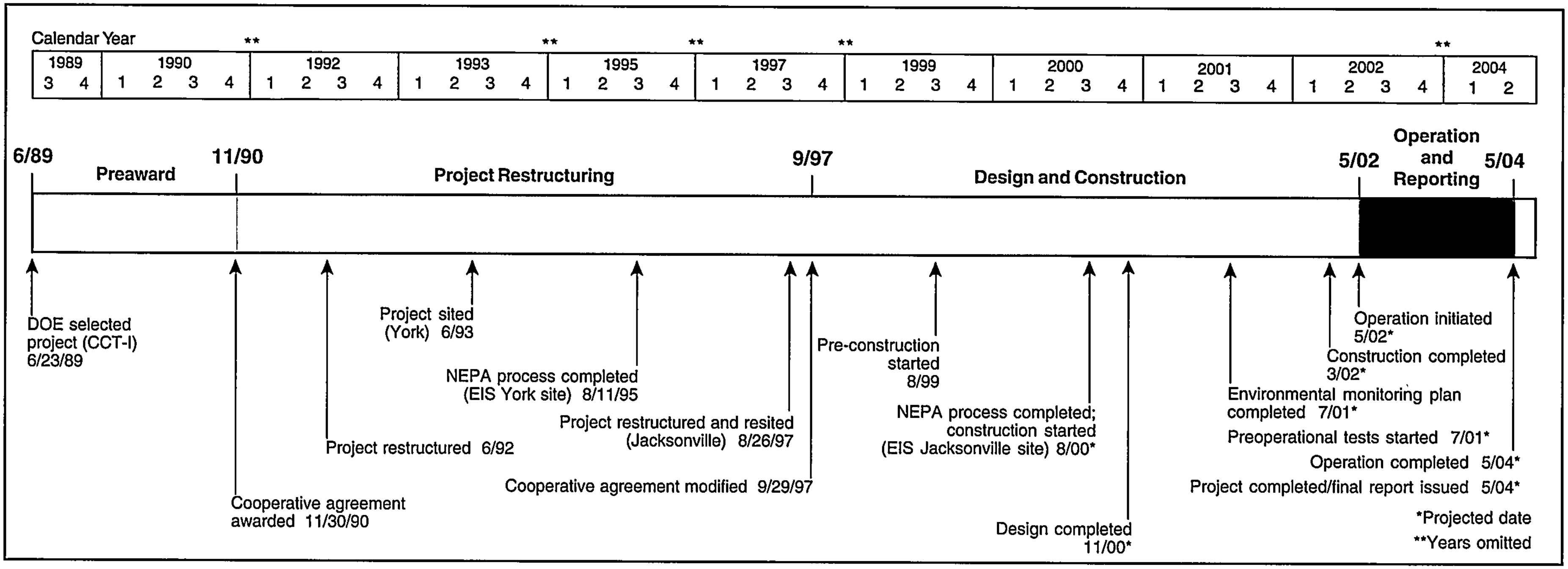


Technology/Project Description
A circulating fluidized-bed combustor, operating at atmospheric pressure, will be retrofitted into Unit No. 2 of the Northside Station. Coal or the secondary fuel (petroleum coke), primary air, and a solid sorbent (such as limestone), are introduced into the lower part 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 cyclone separator, and recycled to the lower portion of the combustor. Primary sulfur capture is achieved by the 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 x 10^6 lb/hr of main steam at about 2,400 psig and 1,005 °F, and 1.73 x 10^6 lb/hr of reheat steam at 600 psig and 1,005 °F. The steam will be used in an existing 297.5-MWe (nameplate) steam turbine.

The heat rate for the retrofit plant is expected to be approximately 9,950 Btu/kWh (34% efficiency; HHV). Expected environmental performance is 0.17 lb/10^6 Btu for SO_2 (98% reduction), 0.11 lb/10^6 Btu for NO_x, and 0.017 lb/10^6 Btu for total particulates (0.013 lb/10^6 Btu for PM_{10}).

INTREX is a trademark of Foster Wheeler Energy Corp.



Project Status/Accomplishments

The project was successfully resited to Jacksonville, Florida after York County Energy Partners and Metropolitan Edison Company terminated activities on the ACFB project in September 1996. On August 26, 1997, DOE approved the transfer of the ACFB Clean Coal Project from York, Pennsylvania to Jacksonville, Florida. On September 29, 1997, DOE signed a modified cooperative agreement with JEA to cost-share refurbishment of the first (Unit No. 2) of two units at Northside Generating Station.

The Environmental Impact Statement (EIS) process was initiated on December 3, 1997 with the Public Scoping Meeting. Following the NEPA process of public comment and review, the final draft EIS was prepared and approved by DOE. After incorporating comments and obtaining formal approval, the EIS was issued on June 30, 2000. After public comments are addressed, the Record of Decision will be issued.

The project, currently in design, moves atmospheric fluidized-bed combustion technology to the larger sizes of utility boilers typically considered in capacity additions and replacements. The nominal 300-MWe demonstration unit in the JEA project will be more than double the size of the Nucla unit (110-MWe). Features include an integrated recycle heat exchanger (INTREX™) in the furnace, steam-cooled cyclones, a parallel pass reheat control, an SO_2 polishing scrubber, and a fabric filter for particulate control.

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 unit 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; a high degree of fuel flexibility (including use of renewable fuels); and dry, granular solid material that is easily disposed of or potentially salable.

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 No. 1)

Technology

The Babcock & Wilcox Company's pressurized fluidized-bed combustion (PFBC) system (under license from ABB Carbon)

Plant Capacity/Production

70 MWe (net)

Coal

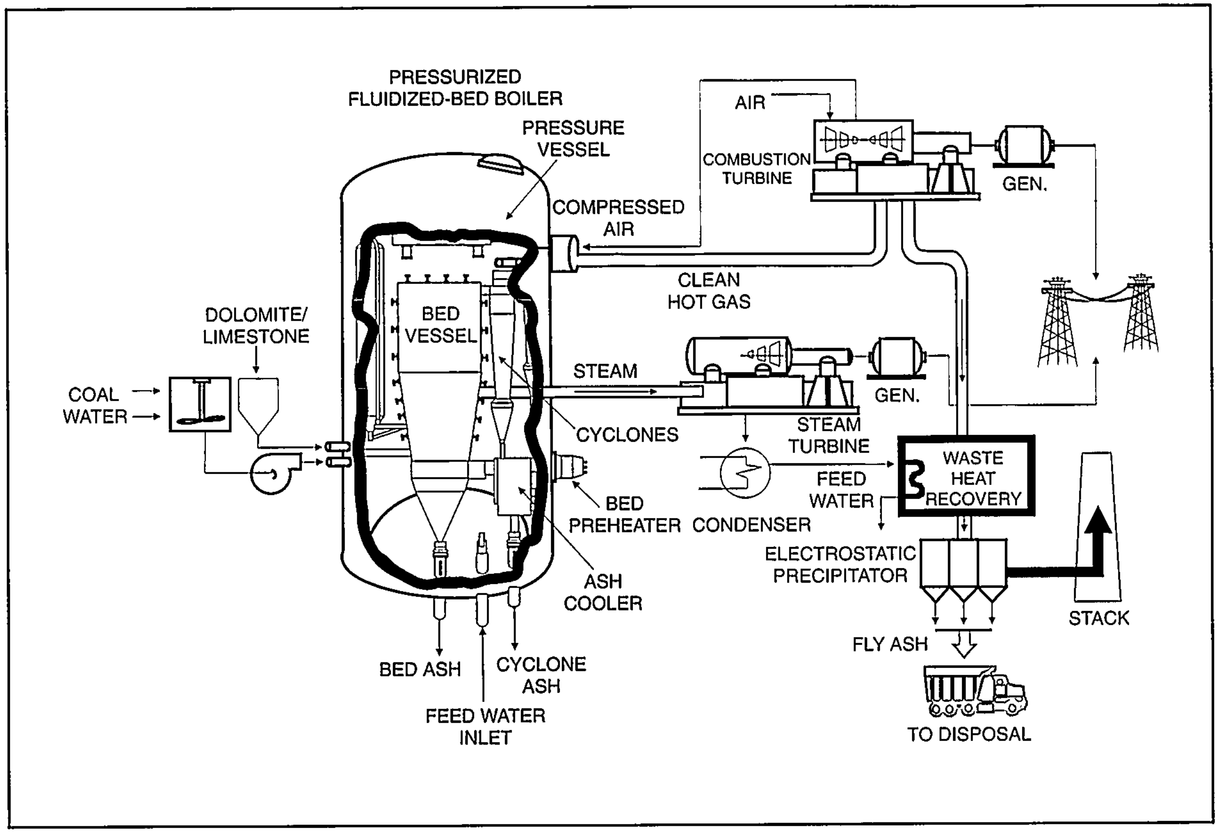
Ohio bituminous, 2–4% sulfur

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.



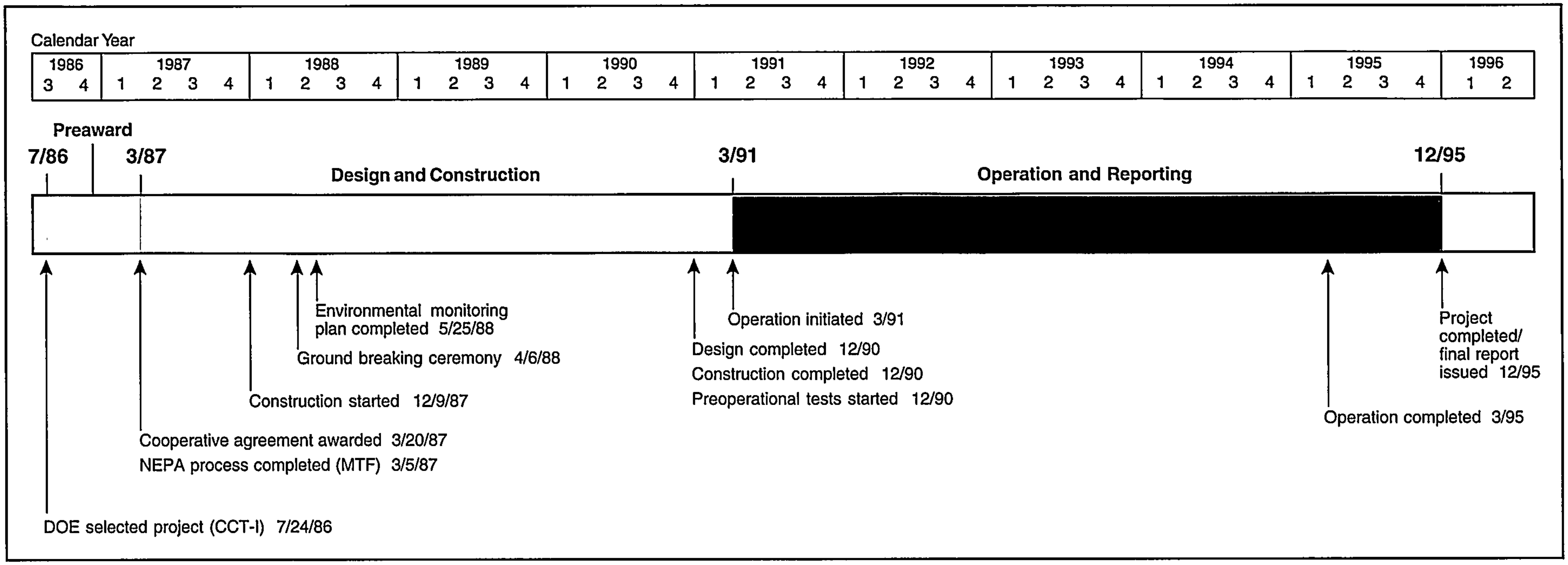
Technology/Project Description

Tidd was the first large-scale operational demonstration of PFBC in the United States. 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 feet in diameter and 70 feet high. The facility was designed so that one-seventh of the hot gases produced could be routed to an advanced particulate filter (APF).

The Tidd facility is a bubbling fluidized-bed combustion process operating at 12 atm (175 psi). Pressurized combustion air is supplied by the turbine compressor to fluidize the bed material, which consists of a coal-water fuel paste, coal ash, and a dolomite or limestone sorbent. Dolomite or limestone in the bed reacts with sulfur to form calcium sulfate, a dry, granular bed-ash material, which is easily disposed of or is usable as a by-product. A low bed temperature of about 1,600 °F limits NO_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

- Sorbent size had the greatest effect on SO_2 removal efficiency as well as stabilization and heat transfer characteristics of the fluidized-bed.
- SO_2 removal efficiency of 90% was achieved at full load with a calcium-to-sulfur (Ca/S) molar ratio of 1.14 and temperature of 1,580 °F.
- SO_2 removal efficiency of 95% was achieved at full load with a Ca/S molar ratio of 1.5 and temperature of 1,580 °F.
- 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 ranged from an average 99.3% at low bed levels to an average 99.5% at moderate to full bed levels.
- Heat rate was 10,280 Btu/kWh (HHV, gross output) (33.2% efficiency) because the unit was small and no attempt was made to optimize heat recovery.
- An advanced particulate filter (APF), using 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

- The Tidd plant was a relatively small-scale facility, and as such, detailed economics were not prepared as part of this project.
- A recent cost estimate performed on Japan's 360-MWe PFBC Karita Plant projected a capital cost of $1,263/kW (1997$).

Project Summary

The Tidd PFBC technology is a bubbling fluidized-bed combustion process operating at 12 atmospheres (175 psi). Fluidized-bed combustion is inherently efficient because the pressurized environment enhances combustion efficiency, allows very low temperatures that mitigate thermal NO_x generation, promotes flue gas/sorbent reactions that increase sorbent utilization, and produces flue gas energy that is used to drive a gas turbine. The latter contributed significantly to system efficiency because of the high efficiency of gas turbines and the availability of gas turbine exhaust heat that can be applied to the steam cycle. A bed design temperature of 1,580 °F was established because it was the maximum allowable temperature at the gas turbine inlet and was well below temperatures for coal ash fusion, thermal NO_x formation, and alkali vaporization.

Coal crushed to one-quarter 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. The sorbent feed system initially used two injector nozzles but was modified to add two more nozzles to enhance distribution.

In 1992, a 10-MWe equivalent APF was installed and commissioned as part of a research and development program and not part of the CCT Program 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 secondary cyclones.

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.

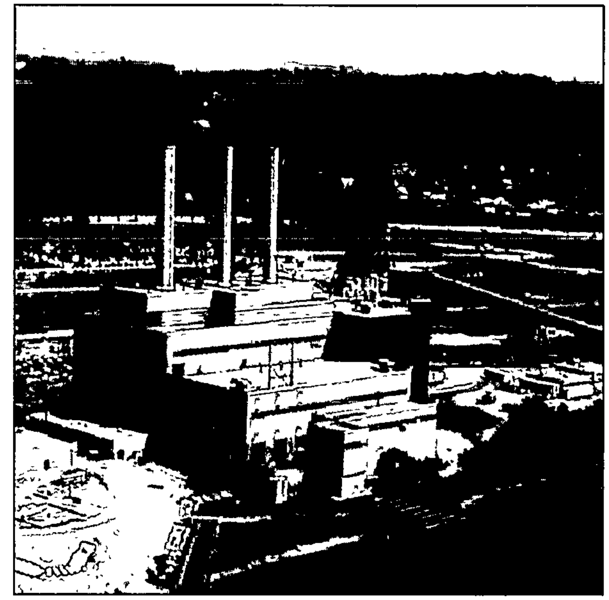
Environmental Performance

Testing showed that 90% SO_2 capture was achievable with a Ca/S molar ratio of 1.14 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 °F and full bed height. Limestone induced deterioration of the fluidized-bed, 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 was the design sorbent). 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. Furthermore, sintering was effectively eliminated.

NO_x emissions ranged from 0.15–0.33 lb/10^6 Btu, but were typically 0.2 lb/10^6 Btu during the demonstration. These emissions were inherent in the process, which was operating at approximately 1,580 °F. 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 maintenance. While the tube bundle experienced little wear, a significant amount of erosion on each of the four water walls was observed. This erosion posed no problem, however, because the area affected is not critical to heat transfer and could be protected by refractory.



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

The prototype gas turbine experienced structural 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 problem. The Tidd demonstration showed that a gas turbine could operate in a PFBC flue gas environment.

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.

Combustion efficiencies averaged 99.5% at moderate to full bed heights, surpassing the design or expected efficiency of 99.0%.

Using data for typical full-load operation, a heat rate of 10,280 Btu/kWh (HHV basis) was calculated. This corresponds to a cycle thermodynamic efficiency of 33.2% at a point where the cycle produced 70-MWe of gross electrical power while burning Pittsburgh No. 8 coal. Because the Tidd plant was a repowering application at a comparatively small scale, the measured efficiency does not represent what would be expected for a larger utility-scale plant using Tidd technology. Studies conducted under the PFBC Utility Demonstration Project showed that efficiencies of over 40% are likely for a larger, utility-scale PFBC plant.

In summary, the Tidd 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 design, sorbent utilization, sintering, post-bed combustion, ash removal, and boiler materials.

Testing of the APF for over 5,800 hours of coal-fired operation showed that the APF vessel was structurally adequate; the clay-bonded silicon carbide candle filters were structurally adequate unless subjected to side loads from ash bridging or buildup in the vessel; bridging was precluded with larger particulates included in the particulate matter; and filtration efficiency (mass basis) was 99.99%.

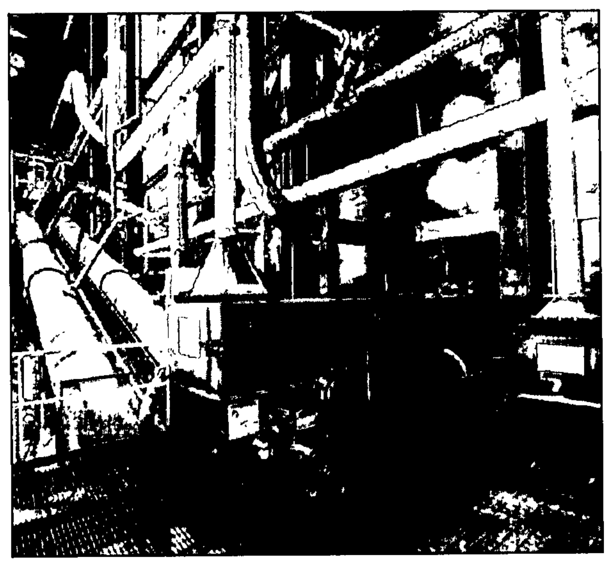
Economic Performance

The Tidd plant was a relatively small-scale demonstration facility, so detailed economics were not prepared as part of this project. However, a recent cost estimate performed on Japan's 360-MWe PFBC Karita Plant projected a capital cost of $1,263/kW (1997$).

Commercial Applications

Combined-cycle PFBC permits use of a wide range of coals, including high-sulfur coals. The compactness of bubbling-bed PFBC technology allows utilities to significantly increase capacity at existing sites. Compactness of the process due to pressurized operation reduces space requirements per unit of energy generated. 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.

The 360-MWe Karita Plant in Japan, which uses ABB Carbon P800 technology, represents a major move toward commercialization of PFBC bubbling-bed technology. A second generation P200 PFBC is under construction in Germany. Other PFBC projects are under consideration in China, South Korea, the United Kingdom, Italy, and Israel.



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

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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Donald W. Geiling, NETL, (304) 285-4784

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- *Tidd PFBC Demonstration Project Final Report, March 1, 1994–March 30, 1995.* Report No. DOE/MC/24132-T8. The Ohio Power Company. August 1995. (Available from NTIS as DE96004973.)
- *Tidd PFBC Demonstration Project—First Three Years of Operation.* Report No. DOE/MC/24132-5037-Vol. 1 and 2. The Ohio Power Company. April 1995. (Available from NTIS as DE96000559 for Vol. 1 and DE96003781 for Vol. 2.)

Nucla CFB Demonstration Project

Project completed.

Participant

Tri-State Generation and Transmission Association, Inc.

Additional Team Members

Foster Wheeler Energy Corporation*—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)

Coal

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

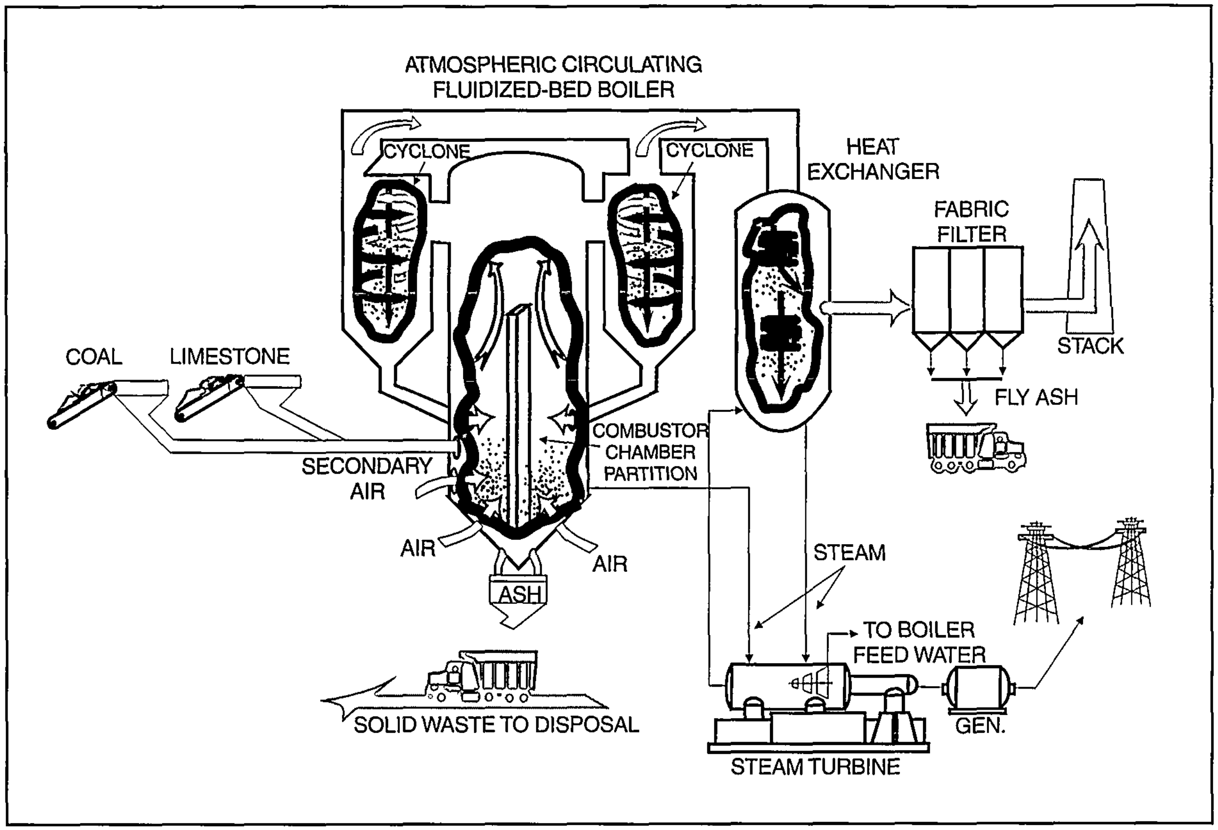
Project Funding

Total project cost	$160,049,949	100%
DOE	17,130,411	11
Participant	142,919,538	89

Project Objective

To demonstrate the feasibility of ACFB technology at utility scale and to evaluate the economic, environmental, and operational performance at that scale.

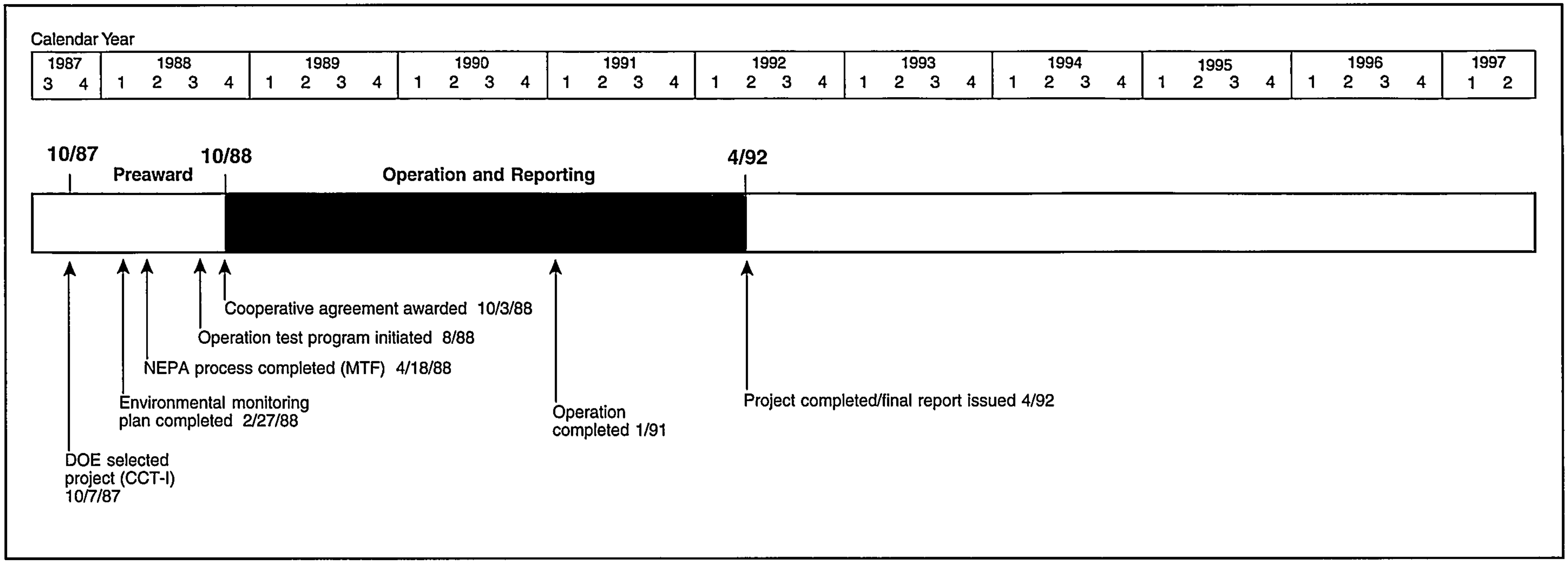
*Pyropower Corporation, the original technology developer and supplier, was acquired by Foster Wheeler Energy Corp.



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 gas 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).



Results Summary

Environmental

- Bed temperature had the greatest effect on pollutant emissions and boiler efficiency.
- At bed temperatures below 1,620 °F, sulfur capture efficiencies of 70 and 95% were achieved at calcium-to-sulfur (Ca/S) molar ratios of 1.5 and 4.0, respectively.
- During all tests, NO_x emissions averaged 0.18 lb/10^6 Btu and did not exceed 0.34 lb/10^6 Btu.
- CO emissions ranged from 70–140 ppmv.
- Particulate emissions ranged from 0.0072–0.0125 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/roadbed stabilizer, or landfill cap.

Operational

- Boiler efficiency ranged from 85.6–88.6% and combustion efficiency ranged from 96.9–98.9%.
- A 3:1 boiler turndown capability was demonstrated.
- Heat rate at full load was 11,600 Btu/kWh and was 12,400 Btu/kWh at half load.

Economic

- Capital cost for the Nucla retrofit was $1,123/kW and a normalized power production cost was 64 mills/kWh.

Project Summary

Fluidized-bed combustion evolved from efforts to find a combustion process conducive to controlling pollutant emissions without external controls. Fluidized-bed combustion enables efficient combustion at temperatures of 1,400–1,700 °F, well below the thermal NO_x formation temperature (2,500 °F), and enables 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, which entrains the bed material. 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.

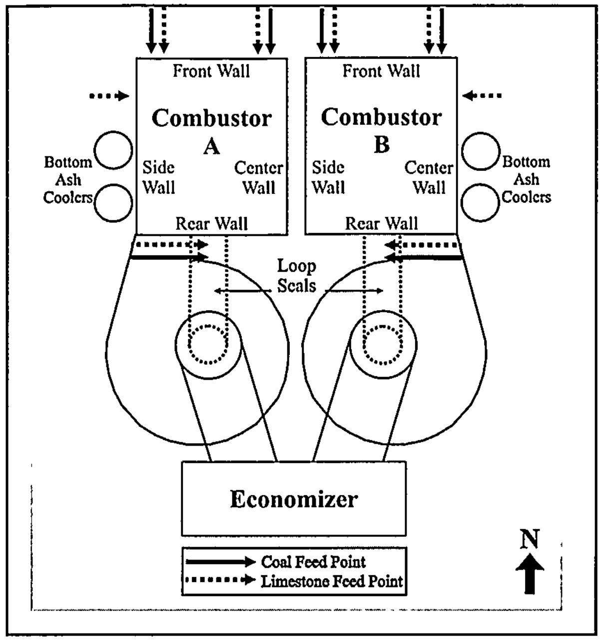
Interest and participation of DOE, EPRI, and the Technical Advisory Group (potential users) resulted in the evaluation of ACFB potential for broad utility application through a comprehensive test program. Over a two-and-a-half-year period, 72 steady-state performance tests were conducted and 15,700 hours 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 three months of the demonstration, average availability was 97% and the capacity factor was 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.

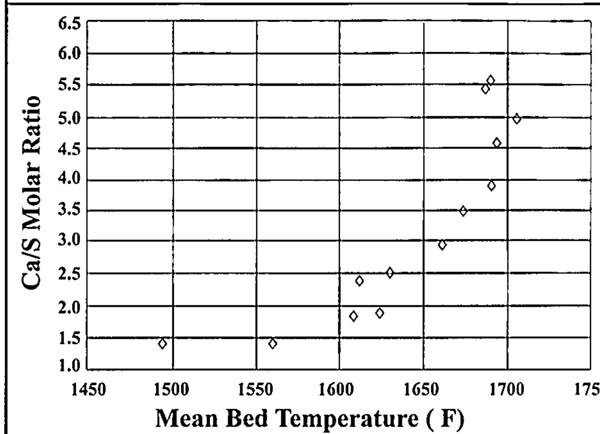
▼ Plant layout with coal and limestone feed locations.



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.

Exhibit 2-33
Effect of Bed Temperature on Ca/S Requirement

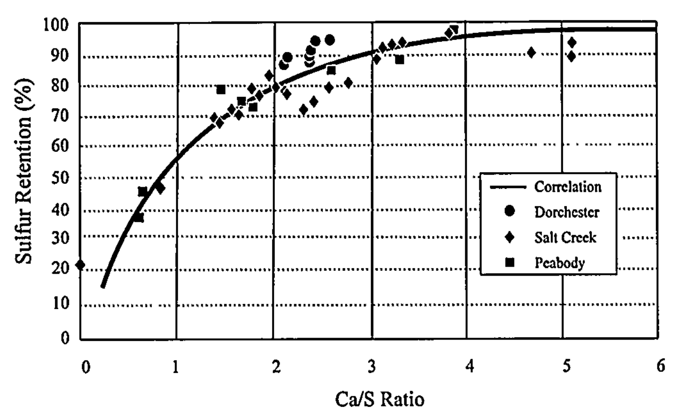


Environmental Performance

As indicated above, bed temperature had the greatest impact on ACFB performance, including pollutant emissions. Exhibit 2-33 shows the effect of bed temperatures on the Ca/S molar ratio requirement for 70% sulfur retention. The Ca/S molar 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 molar ratio of about 1.5 was sufficient to achieve 70% sulfur retention in the 1,500–1,620 °F range, the Ca/S molar ratio requirement jumped to 5.0 or more at 1,700 °F or greater.

Exhibit 2-34 shows the effect of Ca/S molar ratio on sulfur retention at average bed temperatures below 1,620 °F. Salt Creek and Peabody coals contain 0.5% and 0.7% sulfur, respectively. To achieve 70% SO_2

Exhibit 2-34
Calcium Requirements and Sulfur Retentions for Various Fuels



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 molar ratio for a given reduction.

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 °F 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) molar ratios. The mechanism was believed to be oxidation of volatile nitrogen in the form of ammonia (NH_3) catalyzed by calcium oxide. CO emissions decreased as temperature increased, from 140 ppmv at 1,425 °F to 70 ppmv at 1,700 °F.

At full load, the hot cyclones removed 99.8% of the particulates. With the addition of baghouses, removal efficiencies achieved on Peabody and Salt Creek coals were 99.905% and 99.959%, respectively. This equated to emission levels of 0.0125 lb/10^6 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 startup of the Nucla ACFB system were $112.3 million. This represents a cost of $1,123/kW (net). The total power cost associated with plant operations between September 1988 and January 1991 was approximately $54.7 million, resulting in a normalized cost of power production of 64 mills/kWh. The average monthly operating cost over this period was about $1,888,000. Fixed costs represent about 62% of the total and include interest (47%), taxes (4.8%), depreciation (6.9%), and insurance (2.7%). Variable costs represent more than 38% of the power production costs and include fuel expenses (26.2%), non-fuel expenses (6.8%), and maintenance expenses (5.5%).

Commercial Applications

The Nucla project represented the first repowering of a U.S. utility plant with ACFB technology and showed the technology's ability to burn a wide variety of coals cleanly and efficiently. The comprehensive database resulting from the Nucla project enabled the resultant technology to be replicated in numerous commercial plants throughout the world. Nucla continues in commercial service.

Today, every major boiler manufacturer offers an ACFB system in its product line. There are now more than 120 fluidized-bed combustion boilers of varying capacity operating in the U.S. and the technology has made significant market penetration abroad. The fuel flexibility and ease of operation make it a particularly attractive power generation option for the burgeoning power market in developing countries.

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Thomas Sarkus, NETL, (412) 386-5981

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- *Demonstration Program Performance Test: Summary Reports.* Report No. DOE/MC/25137-3104. Colorado-Ute Electric Association, Inc. March 1992. (Available from NTIS as DE92001299.)
- *Economic Evaluation Report: Topical Report.* Report No. DOE/MC/25137-3127. Colorado-Ute Electric Association, Inc., March 1992. (Available from NTIS as DE93000212.)
- *Nucla CFB Demonstration Project: Detailed Public Design Report.* Report No. DOE/MC/25137-2999. Colorado-Ute Electric Association, Inc., December 1990. (Available from NTIS as DE91002081.)

Advanced Electric Power Generation
Integrated Gasification Combined-Cycle

Kentucky Pioneer Energy IGCC Demonstration Project

Participant
Kentucky Pioneer Energy, LLC

Additional Team Members
Fuel Cell Energy, Inc. (formerly Energy Research Corporation)—molten carbonate fuel cell designer and supplier, and cofunder

Location
Trapp, Clark County, KY (East Kentucky Power Cooperative's Smith site)

Technology
Integrated gasification combined-cycle (IGCC) using a BGL (formerly British Gas/Lurgi) slagging fixed-bed gasification system coupled with Fuel Cell Energy's molten carbonate fuel cell (MCFC)

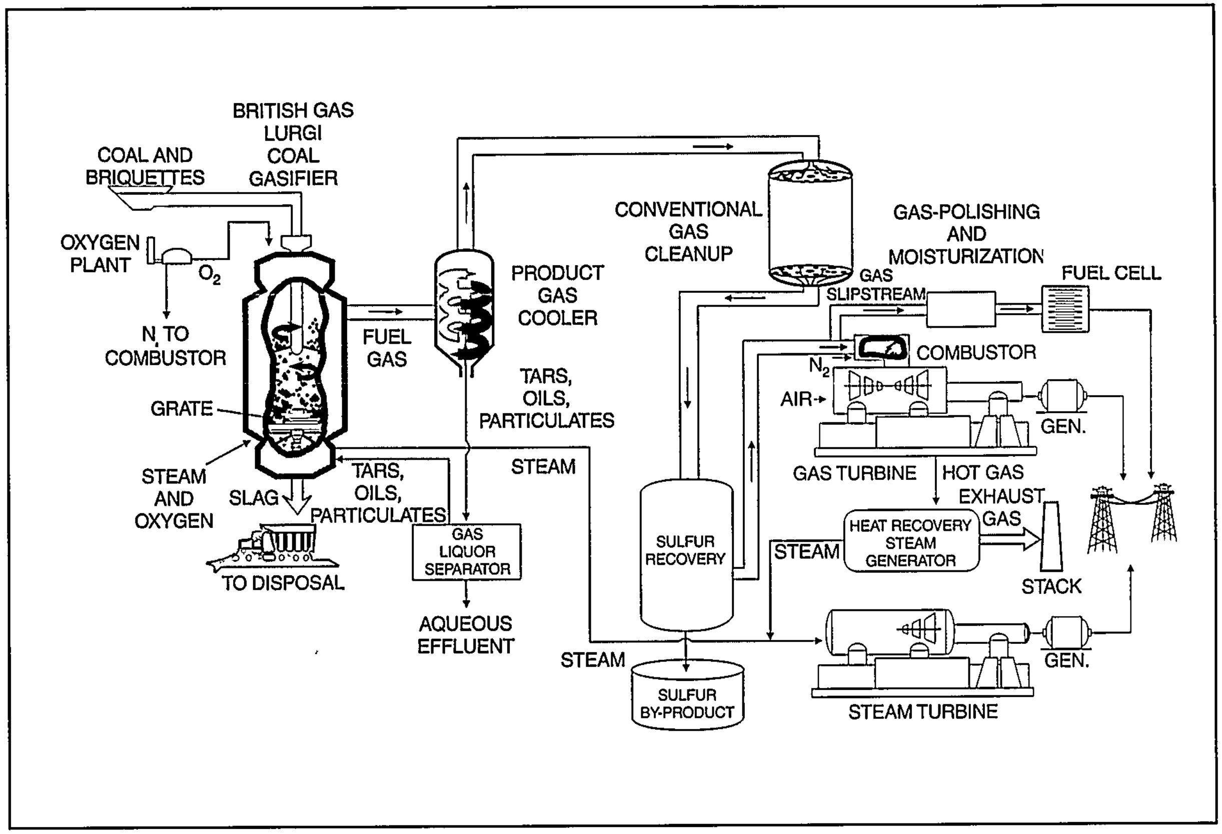
Plant Capacity/Production
400-MWe (net) IGCC; 2.0-MWe MCFC

Coal
High-sulfur Kentucky bituminous coal blended with municipal solid waste

Project Funding

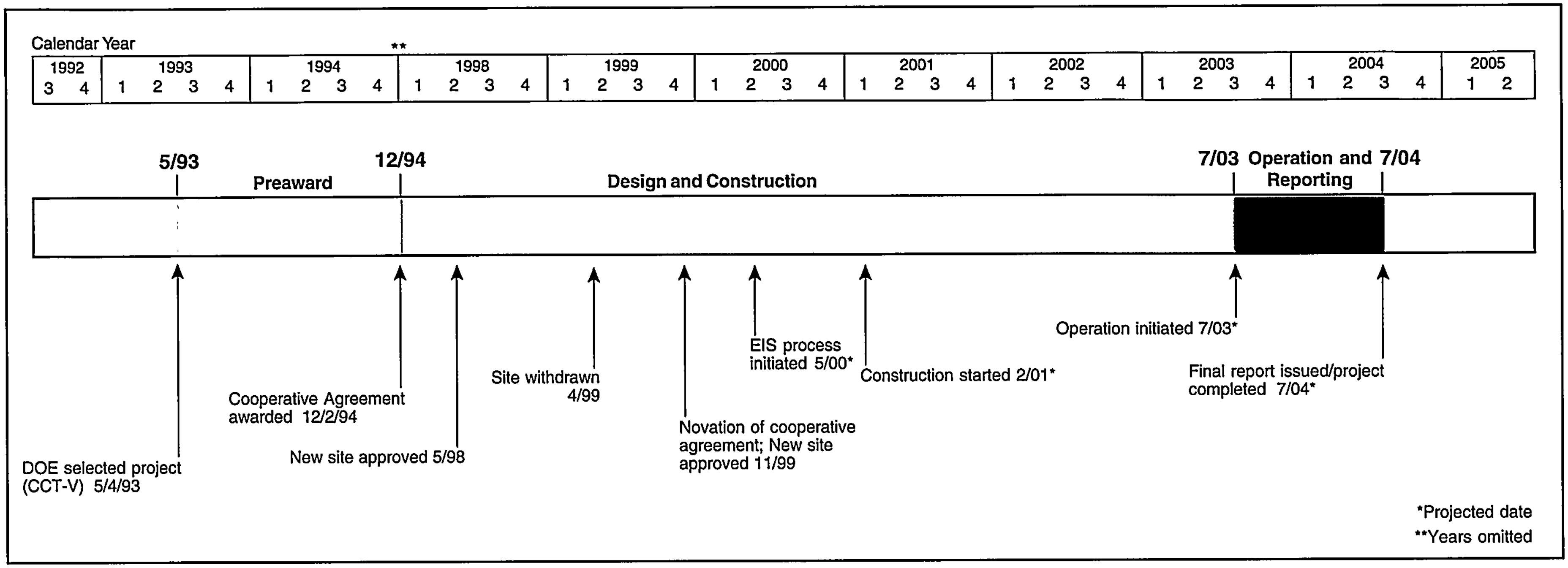
Total project cost	$431,932,714	100%
DOE	78,086,357	18
Participant	353,846,225	82

Project Objective
To demonstrate and assess the reliability, availability, and maintainability of a utility-scale IGCC system using a high-sulfur bituminous coal and municipal solid waste blend in an oxygen-blown, fixed-bed, slagging gasifier and the operability of a molten carbonate fuel cell fueled by coal gas.



Technology/Project Description
The BGL gasifier is supplied with steam, oxygen, limestone flux, and a coal and municipal waste blend. During gasification, the oxygen and steam react with the coal and limestone flux to produce a coal-derived fuel gas rich in hydrogen and carbon monoxide. Raw fuel gas exiting the gasifier is washed and cooled. Hydrogen sulfide and other sulfur compounds are removed. Elemental sulfur is reclaimed and sold as a by-product. Tars, oils, and dust are recycled to the gasifier. The resulting clean, medium-Btu fuel gas fires a gas turbine. A small portion of the clean fuel 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 fuel gas) and steam are fed continuously into the anode; CO_2-enriched air is fed into the cathode. Chemical reactions produce direct electric current, which is converted to alternating power with an inverter.



Project Status/Accomplishments

On May 8, 1998, the DOE conditionally approved Ameren Services Company (merger of Union Electric Co. and Central Illinois Public Service Co.) as an equity partner and host site provider subject to completing specific business and teaming milestones. The new project site to be provided by Ameren was at their Venice Station Plant in Venice, Illinois. On April 30, 1999, Ameren Services Company withdrew from the project for economic and business reasons.

In May 1999, Global Energy USA Limited (Global), sole owner of Kentucky Pioneer Energy, LLC (KPE), expressed interest in acquiring the project and providing a host site at East Kentucky Power Cooperative's Smith Site in Clark County, Kentucky. Subsequently, Global negotiated all the necessary documents with DOE and Clean Energy Partners, L.P. (CEP) to acquire the project. In November 1999, the cooperative agreement was novated and the new site was approved.

The NEPA process was initiated with the public scoping meeting on May 4, 2000. Comments from the meeting are being used in preparing the draft EIS, which should be released in late 2000.

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 BGL gasification technology has successfully used a wide variety of U.S. coals. Also, the highly modular approach to system design makes the BGL-based IGCC and MCFC 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 projected to be 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 BGL gasifier is anticipated to have a heat rate of 7,379 Btu/kWh (46.2% efficiency). These efficiencies represent a 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); and 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

Bechtel Corporation—start-up engineer

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

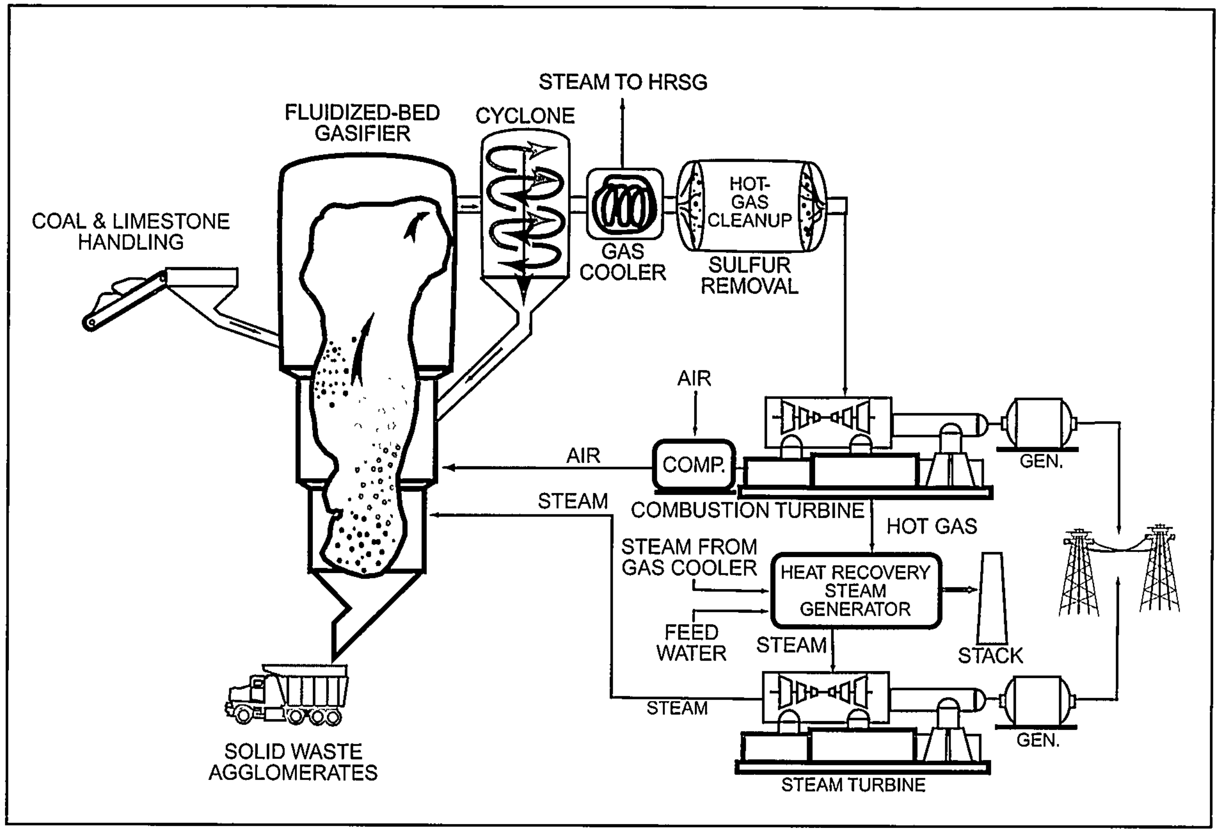
Plant Capacity/Production
107 MWe (gross), 99 MWe (net)

Coal
Southern Utah bituminous, 0.5–0.9% sulfur (design coal); Eastern bituminous, 2–3% sulfur (planned test)

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.

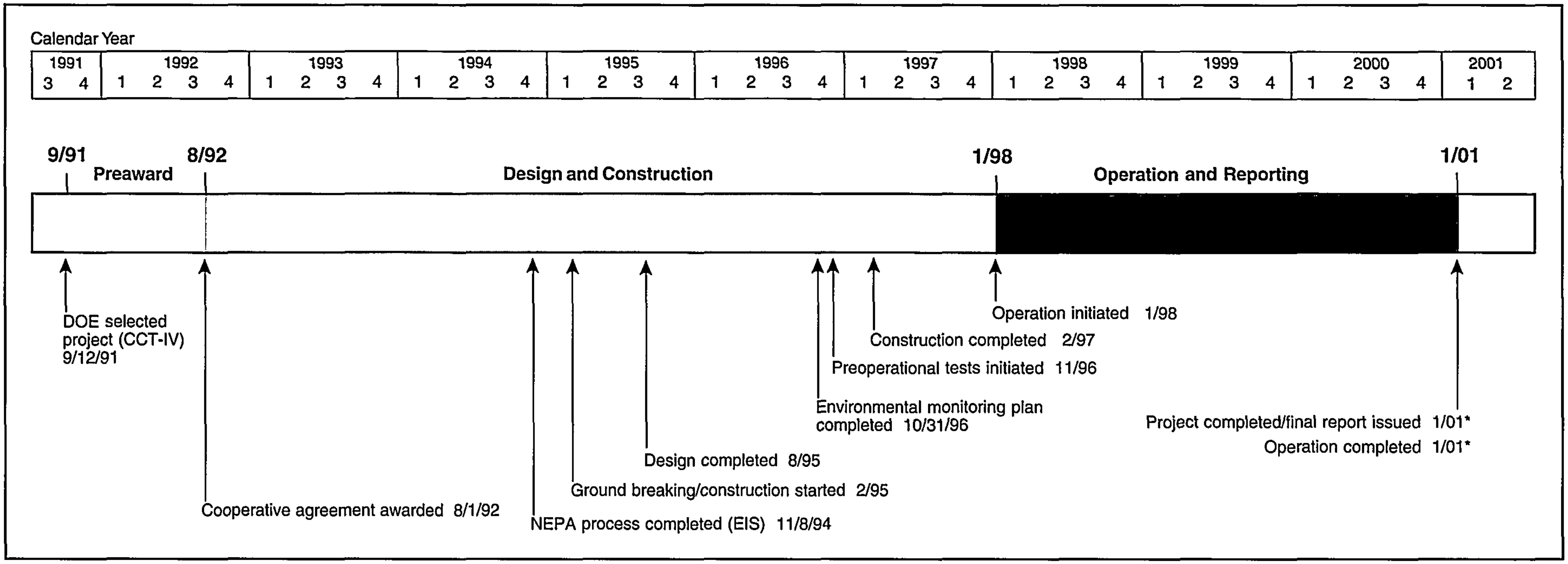


Technology/Project Description
Dried and crushed coal and limestone are introduced into a KRW air-blown pressurized fluidized-bed gasifier. Crushed limestone is used to capture a portion of the sulfur. The sulfur reacts with the limestone to form calcium sulfide which, after oxidation, exits as calcium sulfate along with the coal ash in the form of agglomerated particles suitable for landfill.

Low-Btu coal gas leaving the gasifier passes through cyclones, which return most of the entrained particulate matter to the gasifier. The gas, which leaves the gasifier at about 1,700 °F, is cooled to about 1,100 °F before entering the hot gas cleanup system. During cleanup, virtually all of the remaining particulates are removed by ceramic candle filters, and final traces of sulfur are removed by reaction with a metal oxide sorbent in a transport reactor.

The cleaned gas then enters the GE MS6001FA (Frame 6FA) combustion turbine, which is coupled to a 61-MWe (gross) generator. Exhaust gas from the combustion turbine is used to produce steam in a heat recovery steam generator (HRSG). Superheated high-pressure steam drives a condensing steam turbine-generator designed to produce about 46 MWe (gross).

The IGCC plant will remove 95+% of the sulfur in the coal. 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 expected to be 70% less than a conventional coal-fired plant. The IGCC will produce 20% less CO_2 than conventional plants.



Project Status/Accomplishments

The system has initiated demonstration operations but continues to experience operational difficulties. The station began operation on natural gas in November 1996. Preoperational testing and shakedown of the coal gasification combined-cycle system continued through 1997 with syngas produced in January 1998. The plant was dedicated in April 1998.

The project continues to suffer from a number of design issues, many of which have been solved, but others remain. Problems have been attributed to the high degree of new technology, high scale-up factors on auxiliary components, and some design and engineering deficiencies. Nevertheless, Sierra Pacific is confident that no fatal flaws exist that will preclude successful demonstration and subsequent commercialization of the KRW gasification technology.

In the first quarter of 2000, Sierra Pacific began to make additional repairs and improvements so that sustained operation of the gasifier can be achieved. Improvements include increasing the diameter to the annulus section of the gasifier to address the problem of high temperatures of the limestone and ash leaving the gasifier. Also, the refractory in the gasifier grid area and 18 feet into the fluid bed region will be replaced with a single castable layer on a revised anchoring pattern, to provide improved resistance to low cycle fatigue of the refractory lining. Sierra Pacific expects to restart the plant in August 2000.

Sierra Pacific's 2000 performance goals include: demonstrate a 90% combined-cycle availability; achieve stable, sustained production of syngas; demonstrate sustained operation on syngas; and successfully run the gas turbine on syngas.

Commercial Applications

The Piñon Pine IGCC system concept is suitable for new power generation, repowering needs, and cogeneration applications. The net 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 compared to a conventional pulverized coal plant with a scrubber and a comparable reduction in CO_2 emissions. The compactness of an IGCC system reduces space requirements per unit of energy generated relative to other coal-based power generation systems. The advantages provided by phased 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 biowaste or refuse-derived waste, with minimal environmental impact. 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 Corporation—combined-cycle technology supplier
Air Products and Chemicals, Inc.—air separation unit supplier
Monsanto Enviro-Chem Systems, Inc.—sulfuric acid plant supplier
TECO Power Services Corporation—project manager and marketer
Bechtel Power Corporation—architect and engineer

Location
Mulberry, Polk County, FL (Tampa Electric Company's Polk Power Station, Unit No. 1)

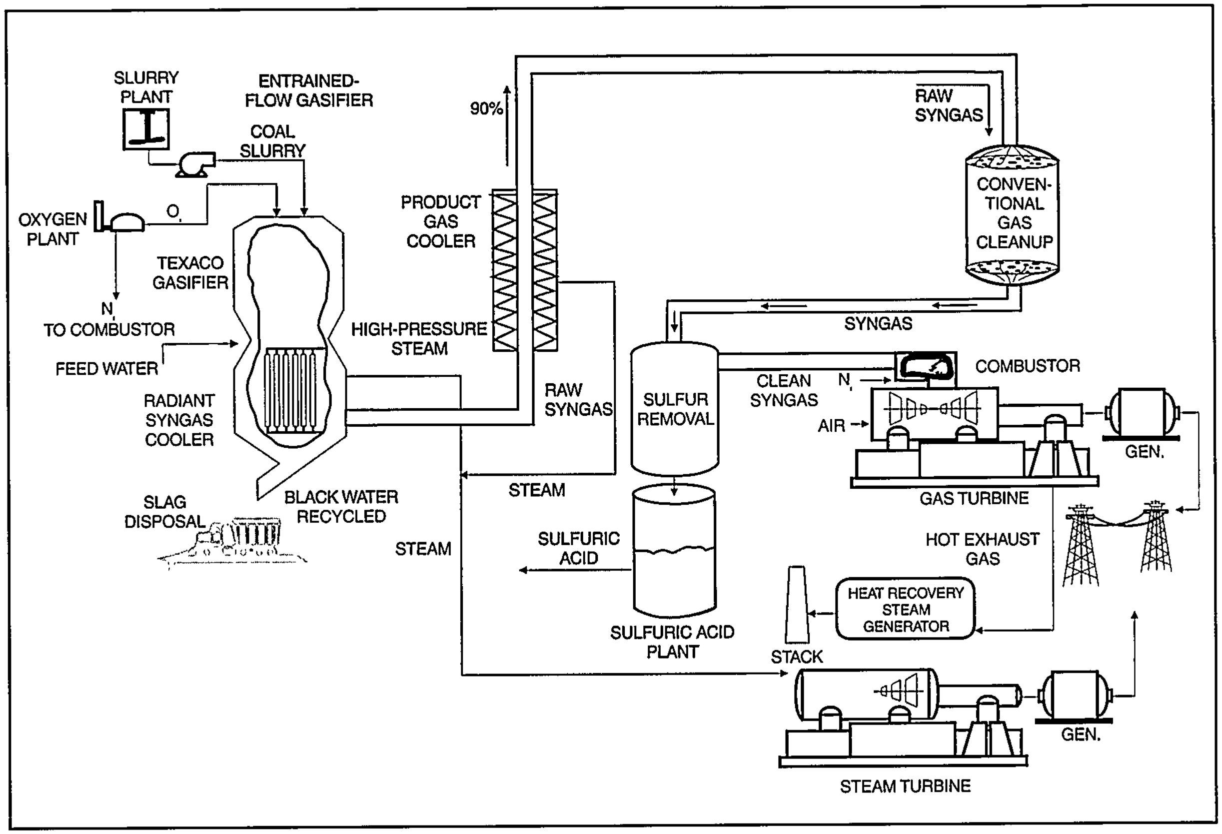
Technology
Advanced integrated gasification combined-cycle (IGCC) system using Texaco's pressurized, oxygen-blown entrained-flow gasifier technology

Plant Capacity/Production
316 MWe (gross), 250 MWe (net)

Coal
Illinois #6, Pittsburgh #8, Kentucky # 11, and Kentucky #9; 2.5-3.5% sulfur

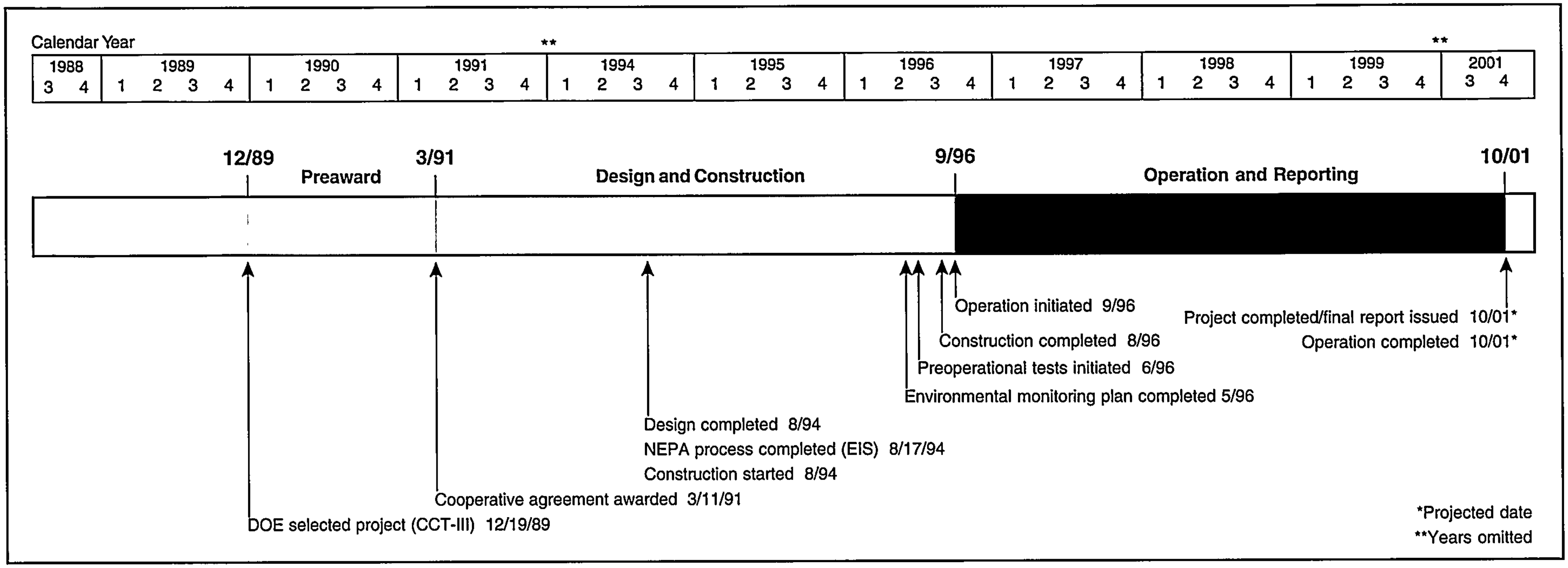
Project Funding

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 using an entrained-flow, oxygen-blown, gasifier with full heat recovery, conventional cold-gas cleanup, and an advanced gas turbine with nitrogen injection for power augmentation and NO_x control.

Technology/Project Description
Coal/water slurry and oxygen are reacted at high temperature and pressure to produce a medium-Btu syngas in a Texaco gasifier. Molten ash flows out of the bottom of the gasifier into a water-filled sump where it forms a solid slag. The syngas moves from the gasifier to a high temperature heat-recovery unit, which cools the syngas while generating high pressure steam. The cooled gases flow to a water wash for particulate removal. Next, a COS hydrolysis reactor converts one of the sulfur species in the gas to a form which is more easily removed. The syngas is then further cooled before entering a conventional amine sulfur removal system. The amine system keeps SO_2 emissions below 0.15 lb/10^6 Btu (97% capture). The cleaned gases are then reheated and routed to a combined-cycle system for power generation. A GE MS 7001FA gas turbine generates 192 MWe. Thermal NO_x is controlled to below 0.27 lb/ 10^6 Btu by injecting nitrogen. A steam turbine uses steam produced by cooling the syngas and superheated with the gas turbine exhaust gases in the HRSG to produce an additional 124-MWe. The plant heat rate is 9,350 Btu/kWh (HHV).



Project Status/Accomplishments

Since Polk Power Station's first gasifier run in July 1996, the gasifier has operated over 18,500 hours. The station generated more than 7 million MWh of electricity from syngas it produced through March 2000. During one six-month period, the gasifier had an 83.5% on-stream factor and the combined-cycle availability was 94%.

Several modifications to the original design and procedures were required to achieve the recent high availability, including: (1) removing or modifying some of the heat exchangers in the high temperature heat recovery system and making compensating adjustments in the balance of the system to resolve ash plugging problems, (2) additional solid particle erosion protection for the combustion turbine to protect the machine from ash, (3) implementing hot restart procedures to reduce gasifier restart time by 18 hours, (4) adding a duplicate fines handling system to deal with increased fines loading resulting from lower than expected carbon conversion, (5) revising operating procedures to deal with high shell temperatures in the dome of the radiant syngas cooler, and (6) making various piping changes to correct for erosion and corrosion in the process and coal/water slurry systems. A COS hydrolysis unit was installed in 1999 to further reduce SO_2 emissions, enabling the station to meet recent, more stringent emissions restrictions.

In March and April 2000, Tampa Electric tested several coal/petroleum coke blends. Preliminary test results from 60/40 and 40/60 blends of Pittsburgh #8 and petroleum coke (petcoke) looked promising. Both tests were successful and provide data that show continued operation on a blend of coal/petcoke is possible. One further test is planned using a 20/80 blend.

Commercial Applications

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.

As a result of the Polk Power Station demonstration, Texaco-based IGCC can be considered commercially and environmentally suitable for electric power generation utilizing a wide variety of feedstocks. Sulfur capture for the project is greater than 98%, while NO_x emissions reductions are 90% those of a conventional pulverized coal-fired power plant. The integration and control approaches utilized at Polk can also be applied in IGCC projects using different gasification technologies.

TECO Energy is not only actively working with Texaco to commercialize the technology in the United States, but has been contacted by European power producers to discuss possible technical assistance on using the gasifier technology.

Wabash River Coal Gasification Repowering Project

Project completed.

Participant

Wabash River Coal Gasification Repowering Project Joint Venture (a joint venture of Dynegy and PSI Energy, Inc.)

Additional Team Members

PSI Energy, Inc.—host

Dynegy (formerly Destec Energy, Inc., a subsidiary of Natural Gas Clearinghouse)—engineer and gas plant operator

Location

West Terre Haute, Vigo County, IN (PSI Energy's Wabash River Generating Station, Unit No. 1)

Technology

Integrated gasification combined-cycle (IGCC) using Global Energy's two-stage pressurized, oxygen-blown, entrained-flow gasification system—E-Gas Technology™

Plant Capacity/Production

296 MWe (gross), 262 MWe (net)

Coal

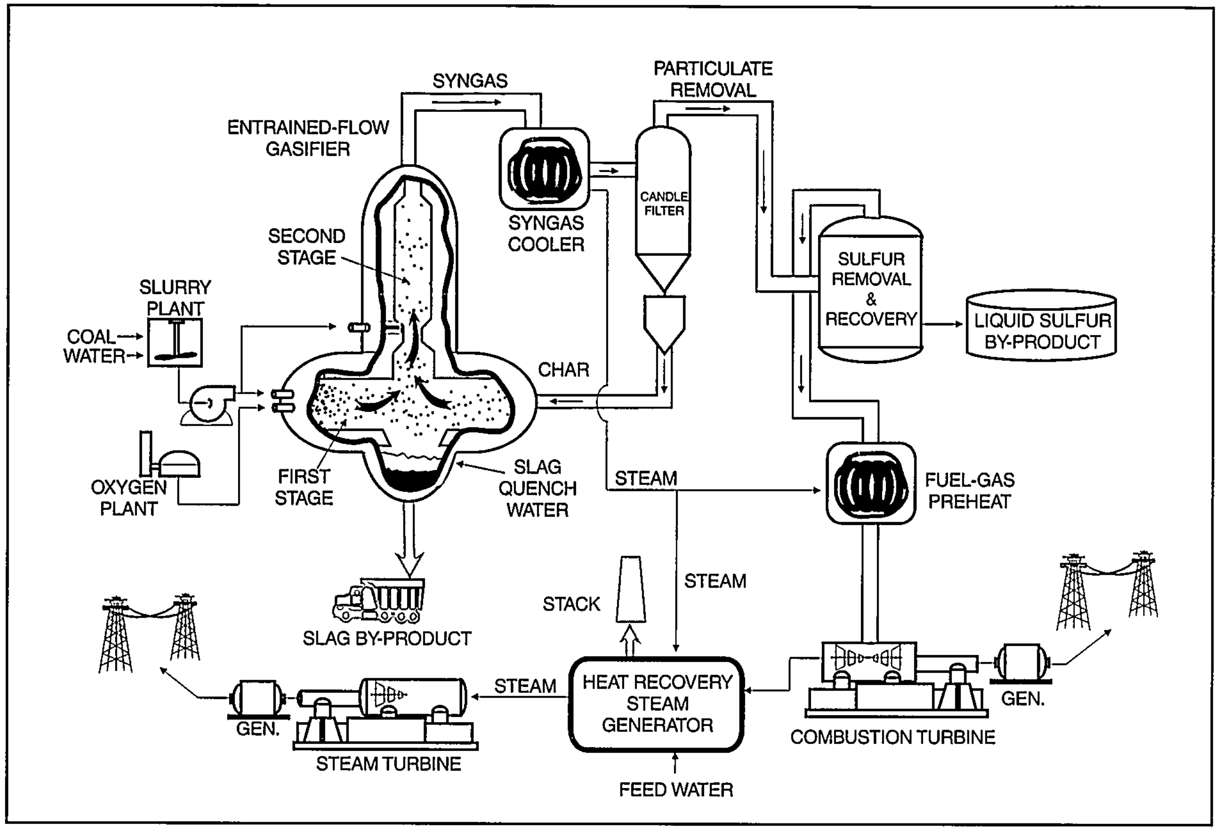
Illinois Basin bituminous

Project Funding

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

Project Objective

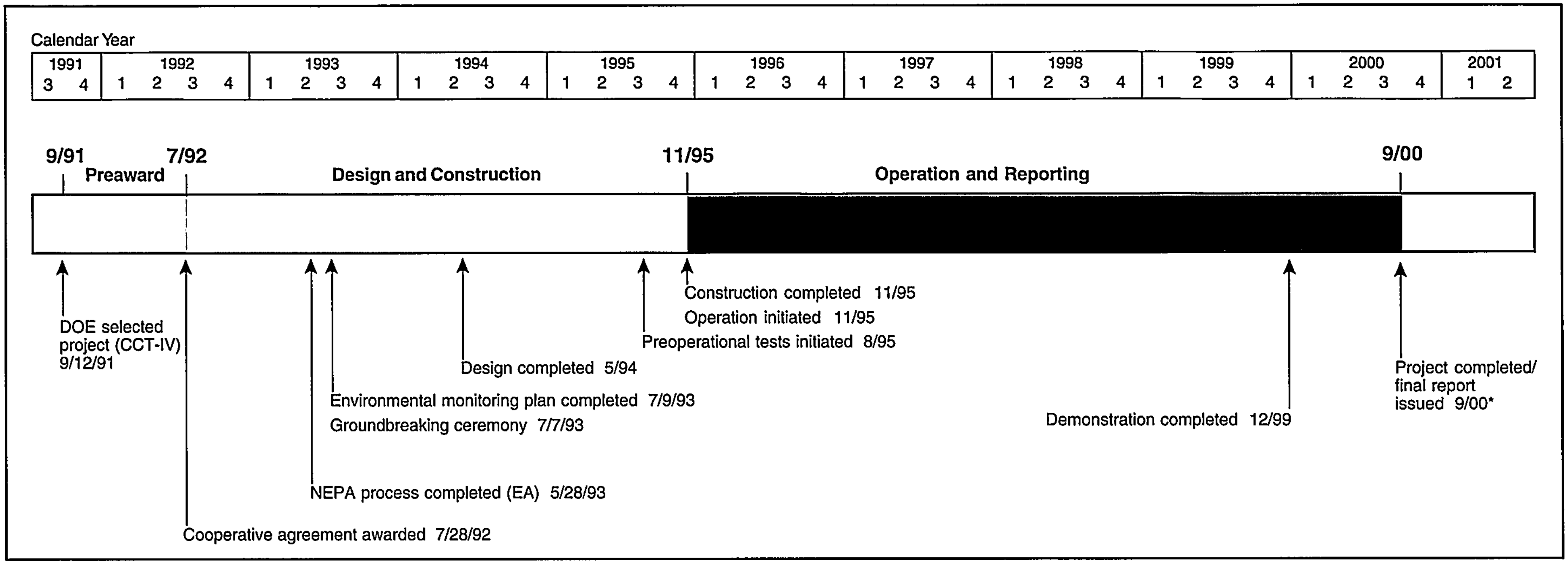
To demonstrate utility repowering with a two-stage pressurized, oxygen-blown, entrained-flow IGCC system, including advancements in the technology relevant to the use of high-sulfur bituminous coal; and to assess long-term reliability, availability, and maintainability of the system at a fully commercial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



Technology/Project Description

The Destec process features an oxygen-blown, continuous-slagging, two-stage, entrained flow gasifier. Coal is slurried, combined with 95% pure oxygen, and injected into the first stage of the gasifier, which operates at 2,600 °F/400 psig. In the first stage, the coal slurry undergoes a partial oxidation reaction at temperatures high enough to bring the coal's ash above its melting point. The fluid ash falls through a tap hole at the bottom of the first stage into a water quench, forming an inert vitreous slag. The syngas flows to the second stage, where additional coal slurry is injected. This coal is pyrolyzed in an endothermic reaction with the hot syngas to enhance syngas heating value and improve efficiency.

The syngas then flows to the syngas cooler, essentially a firetube steam generator, to produce high-pressure saturated steam. After cooling in the syngas cooler, particulates are removed in a hot/dry filter and recycled to the gasifier. The syngas is further cooled in a series of heat exchangers. The syngas is water-scrubbed to remove chlorides and passed through a catalyst that hydrolyzes carbonyl sulfide into hydrogen sulfide. Hydrogen sulfide is removed in the acid gas removal system using MDEA-based absorber/stripper columns. A Claus unit is used to produce elemental sulfur as a salable by-product. The "sweet" gas is then moisturized, preheated, and piped to the power block. The power block consists of a single 192-MWe GE MS 7001FA (Frame 7 FA) gas turbine, a Foster Wheeler single-drum heat recovery steam generator with reheat, and a 1952 vintage Westinghouse reheat steam turbine.



Results Summary

Environmental

- SO_2 capture efficiency was greater than 99%, keeping SO_2 emissions consistently below 0.1 lb/10^6 Btu and reaching as low as 0.03 lb/10^6 Btu; and SO_2 was transformed into 99.99% pure sulfur, a highly valued by-product.
- NO_x emissions were controlled by steam injection down to 0.15 lb/10^6 Btu.
- Coal ash was converted to a low-carbon vitreous slag, impervious to leaching and valued as an aggregate in construction or as grit for abrasives and roofing materials; and trace metals from petroleum coke were also encased in an inert vitreous slag.

Operational Performance

- First year problems encountered included:
  - Ash deposition at the fire tube boiler inlet, which was corrected by a change to the flow path geometry;
  - Particulate breakthrough in the hot gas filter, which was largely solved by changing to improved metallic candle filters.
  - Chloride and metals poisoning of the COS catalyst, which was eliminated by installation of a wet chloride scrubber and a COS catalyst less prone to poisoning.
- The second year identified cracking in the gas turbine combustion liners and tube leaks in the heat recovery steam generator (HRSG). Resolution involved replacement of the gas turbine fuel nozzles and liners and modifications to the HRSG to allow for more tube expansion.
- The third year was essentially trouble free and the IGCC unit underwent fuel flexibility tests, which showed that the unit operated trouble free, without modification, on a second coal feedstock, a blend of two different Illinois #6 coals, and petroleum coke.
- Overall thermal performance actually improved during petroleum coke operation.
- In the fourth year, the gas turbine incurred damage to rows 14 through 17 of the compressor causing a 3-month outage. But over the four years of operation, availability of the gasification plant steadily improved reaching 79.1% in 1999.

Economic Performance

- Overall cost of the gasification and power generation facilities was $417 million, including engineering and environmental studies, equipment procurement, construction, pre-operations management, and start-up.
- Preliminary estimates for a future dual-train facility are $1,200/kW. Costs could fall to under $1,000/kW for a greenfield plant with advances in turbine technology.

Project Summary

The Wabash River Coal Gasification Repowering Project repowered a 1950s vintage pulverized coal-fired plant, transforming the plant from a nominally 33% efficient 90-MWe unit into a nominally 40% efficient 262-MWe (net) unit. Cinergy, PSI's parent company, dispatches power from the project, with a demonstrated heat rate of 8,910 Btu/kWh (HHV), second only to their hydroelectric facilities on the basis of environmental emissions and efficiency.

Beyond the integration of an advanced gasification system, a number of other advanced features contributed to the high energy efficiency. These include: (1) hot/dry particulate removal to enable gas cleanup without heat loss, (2) integration of the gasifier high temperature heat recovery steam generator with the gas turbine-connected HRSG to ensure optimum steam conditions for the steam turbine, (3) use of a carbonyl sulfide (COS) hydrolysis process to enable high percentage sulfur removal, (4) recycle of slag fines for additional carbon recovery, (5) use of 95% pure oxygen to lower power requirements for the oxygen plant, and (6) fuel gas moisturization to reduce steam injection requirements for NO_x control.

Over the four year demonstration period starting in November 1995, the facility operated approximately 15,000 hours and processed approximately 1.5 million tons of coal to produce about 23 x 10^{12} Btu of syngas. For several of the months, syngas production exceeded one trillion Btus. By the beginning of the final year of operation under the demonstration, the 262-MWe IGCC unit had captured over 100 million pounds equivalent of SO_2.

Operational Performance

The first year of operation was plagued primarily by problems with: (1) ash deposition at the inlet to the fire-tube boiler, (2) particulate breakthrough in the hot gas filter system, and (3) chloride and metals poisoning of the COS catalyst. A modification to the hot gas path flow geometry corrected the ash deposition problem. Replacement of the ceramic candle filters with metallic candles proved to be largely successful. A follow-on metallic candle filter development effort ensued using a hot gas slipstream, which resulted in improved candle filter metallurgy, blinding rates, and cleaning techniques. The combined effort all but eliminated downtime associated with the filter system by the close of 1998. Installation of a wet chloride scrubber eliminated the chloride problem by September 1996 and use of an alternate COS catalyst less prone to trace metal poisoning provided the final cure for the COS system by October 1997.

The second year of operation identified cracking problems with the gas turbine combustion liners and tube leaks in the HRSG. Replacement of the fuel nozzles and liners solved the cracking problem. Resolution of the HRSG problem required modification to the tube support and HRSG roof/penthouse floor to allow for more expansion.

By the third year, downtime was reduced to nuisance items such as instrumentation induced trips in the oxygen plant and high maintenance items such as replacement of high pressure slurry burners every 40–50 days. In the third year, the IGCC unit underwent fuel flexibility tests. The unit operated effectively, without modification or incident, on a second coal feedstock, a blend of two different Illinois #6 coals, and petroleum coke (petcoke). These tests added to the fuel flexibility portfolio of the gasifier, which had previously processed both lignite and subbituminous coals during its earlier development. The overall thermal performance of the IGCC unit actually improved during petcoke operation. The unit processed over 18,000 tons of high sulfur petcoke and produced 350,000 x 10^6 Btu of syngas. There was a negligible amount of tar production and no problems were encountered in removing the dry char particulate despite a higher dust loading. Exhibit 2-35 provides a summary of the thermal performance of the unit on both coal and petcoke. Exhibit 2-36 compares the coal and petcoke fuel characteristics and Exhibit 2-37 compares the syngas product.

The fourth year of operation was marred by a 3-month outage due to damage incurred to rows 14 through 17 of the gas turbine air compressor. However, over the four years of operation, availability of the gasification plant steadily improved, reaching 79.1% in 1999.

Environmental Performance

The IGCC unit operates with an SO_2 capture efficiency greater than 99%. As a result, SO_2 emissions are consistently below 0.1 lb/10^6 Btu of coal input, reaching as low as 0.03 lb/10^6 Btu. Moreover, the process transforms the SO_2 pollutant into 99.99% pure sulfur, a highly valued by-product, rather than a solid waste.

Steam injection controls NO_x emissions down to 0.15 lb/10^6 Btu. This is the emission limit being sought under the EPA SIP call related to ozone nonattainment areas. Also, particulate emissions are below detection limits.

The ash component of the coal results in a low-carbon vitreous slag, impervious to leaching and valued as an aggregate in construction or as grit for abrasives and roofing materials. Also, the trace metal constituents in the petcoke were effectively captured in the slag produced.

Economic Performance

The economic performance of the IGCC unit will be forthcoming in the Final Technical Report currently in preparation. Some preliminary information presented here was drawn from technical papers prepared over the course of the demonstration.

The overall combined cost of the gasification and power generation facilities was $417 million at completion. This cost includes engineering and environmental studies, equipment procurement, construction, pre-operations management (including operator training), and start-up. Escalation during the project is included. Start-up includes the costs of construction and operations, excluding coal and power, up to the date of commercial operation in December 1995. Soft costs such as legal and financing fees and interest during construction are not included.

Project participants project future costs of $1,200/kW for dual-train repowered facilities, and greenfield costs under $1,000/kW, with advances in turbine technology.

Commercial Applications

At the end of the demonstration in December 1999, Global Energy, Inc. purchased Dynegy's gasification assets and technology. Global Energy plans to market the technology under the name "E-Gas Technology™."

The immediate future for E-Gas Technology™ appears to lie with both foreign and domestic applications where low-cost feedstocks such as petcoke can be used and co-production options are afforded such as bundled production of steam, fuels/chemicals, and electricity. Integration or association with refinery operations are examples.

In the longer term, the technology has application to the repowering of the 95,000 MWe of existing U.S. coal-fired boilers over 30 years old, and new foreign and domestic coal-fired capacity additions. Over time, the economics and performance of the technology will continue to improve, coal and gas price differentials will increase, and displacement of petroleum in chemicals and fuels production will increase in importance.

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References

- Steven L. Douglas. "Wabash River in Its Fourth Year of Commercial Operation." *7th Clean Coal Technology Conference: Volume II Technical Papers.* June 1999.

Exhibit 2-35
Wabash Thermal Performance Summary

	Design	Actual	
	Coal	Coal	Petcoke
Nominal Throughput, tons/day	2,550	2,450	2,000
Syngas Capacity, 10^6 Btu/hr	1,780	1,690	1,690
Combustion Turbine, MW	192	192	192
Steam Turbine, MW	105	96	96
Auxiliary Power, MW	35	36	36
Net Generation, MW	262	261	261
Plant Efficiency, % (HHV)	37.8	39.7	40.2
Sulfur Removal Efficiency, %	>98	>99	>99

Exhibit 2-36
Wabash Fuel Analysis

	Typical Coal	Petcoke
Moisture, %	15.2	7.0
Ash, %	12.0	0.3
Volatile, %	32.8	12.4
Fixed Carbon, %	39.9	80.4
Sulfur, %	1.9	5.2
Heating Value, as Rec'd, Btu/lb	10,536	14,282

Exhibit 2-37
Wabash Product Syngas Analysis

	Typical Coal	Petcoke
Nitrogen, vol %	1.9	1.9
Argon, vol %	0.6	0.6
Carbon Dioxide, vol %	15.8	15.4
Carbon Monoxide, vol %	45.3	48.6
Hydrogen, vol %	34.4	33.2
Methane, vol %	1.9	0.5
Total Sulfur, ppm_v	68	69
Higher Heating Value, Btu/scf	277	268

Advanced Electric Power Generation
Advanced Combustion/Heat Engines

Clean Coal Diesel Demonstration Project

Participant
Arthur D. Little, Inc. (ADL)

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 (EERC)—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

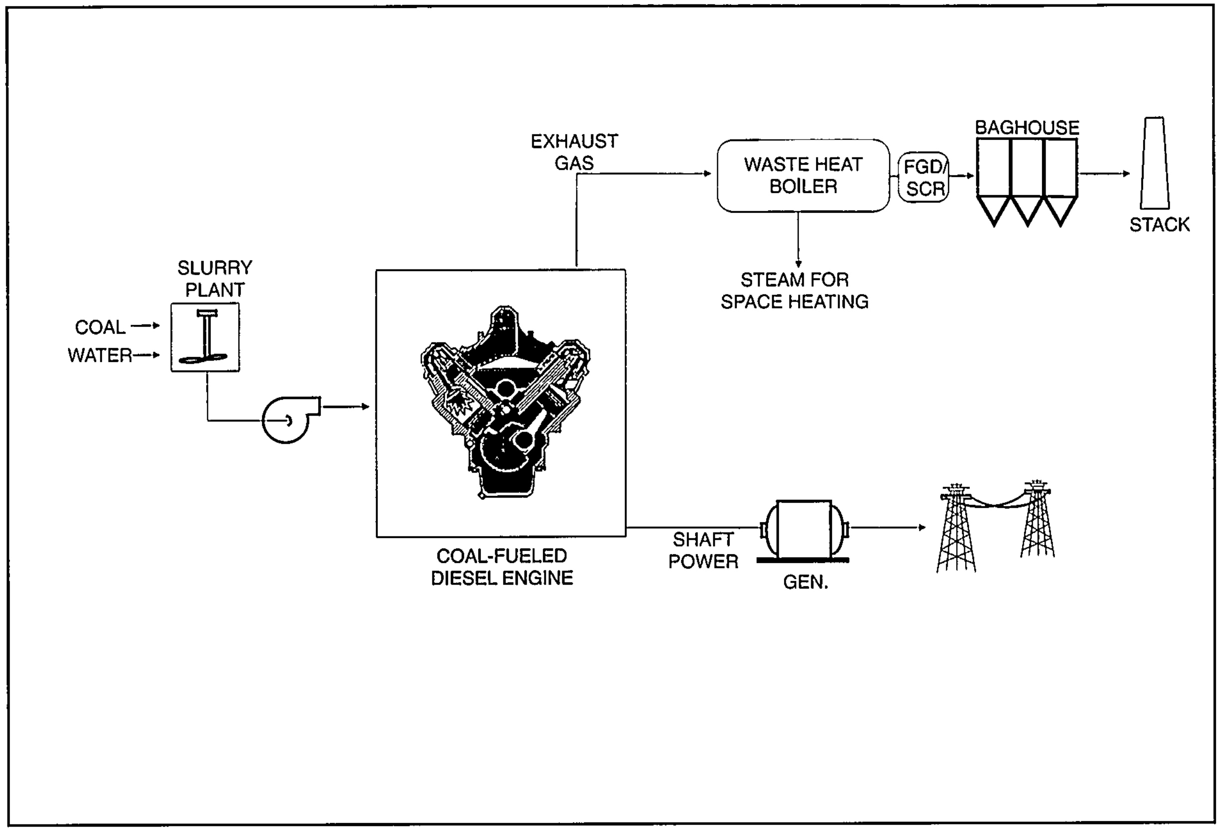
Plant Capacity/Production
6.4 MWe (net)

Coal
Usibelli Alaskan subbituminous

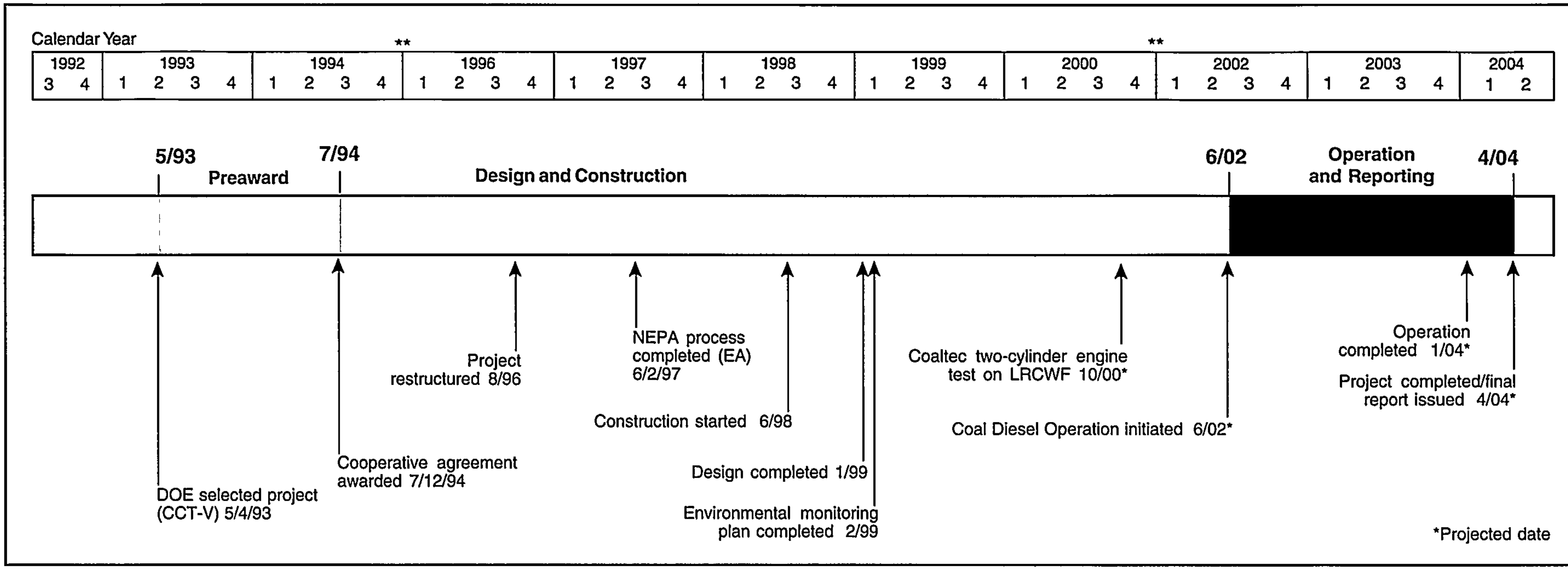
Project Funding

Total project cost	$47,636,000	100%
DOE	23,818,000	50
Participant	23,818,000	50

Project Objective
To prove the design, operability, and durability of the coal diesel engine during 6,000 hours of operation and test the coal slurry in the diesel.



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 coal. The clean coal diesel technology, which uses a low-rank coal-water-fuel (LRCWF), 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 and future plant designs are expected to reach 48% efficiency. This will result in a 25% reduction in CO_2 emissions compared to conventional coal-fired plants.



Project Status/Accomplishments

Overall project system design was completed in early 1999. The 18-cylinder diesel engine arrived on site at UAF in January 1999 and was mounted in the engine house in late February. In October 1999, the engine, after being connected to the generator, was operated on diesel fuel to ensure it would function coupled with the generator. In May 2000, total system startup was attempted on diesel fuel. Minor problems with system integration and tie-in with the existing electrical bus system were encountered. Those problems are being corrected and system startup on diesel fuel should commence Fall 2000. Upon completion of system checkout, the diesel engine will be modified to use the LRCWF. Design of the hardened engine parts, coal fuel preparation and testing, and completion of the baghouse and SNCR system are in progress.

With the change of site from Easton, Maryland to UAF, Alaskan subbituminous coal will now be used to manufacture the LRCWF. Usibelli Coal Mine, Inc. will supply the coal. Samples of the coal have been sent to CQ Inc. for analysis and washability tests. ADL and EERC will also perform various analyses on the coal. Upon completion of the tests, a design formula will be devised to produce the LRCWF. The LRCWF will first be tested in Coltec two-cylinder test engine. These tests are scheduled for the Fall 2000. The tests on the test engine will provide information and data on how to optimize the operational settings, verify the coal fuel performance, and finalize the requirements for hardened coatings for critical components.

Commercial Applications

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 distributed power generation in the 5- to 20-MWe range, using indigenous coal in 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.

Healy Clean Coal Project

Project completed.

Participant
Alaska Industrial Development and Export Authority

Additional Team Members
Golden Valley Electric Association—host and operator
Stone and Webster Engineering Corp.—engineer
TRW Inc., Space & Technology Division—combustor technology supplier
The Babcock & Wilcox Company (B&W) (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 No. 1)

Technology
TRW's Clean Coal Slagging Combustor; Babcock & Wilcox's spray dryer absorber (SDA) with sorbent recycle

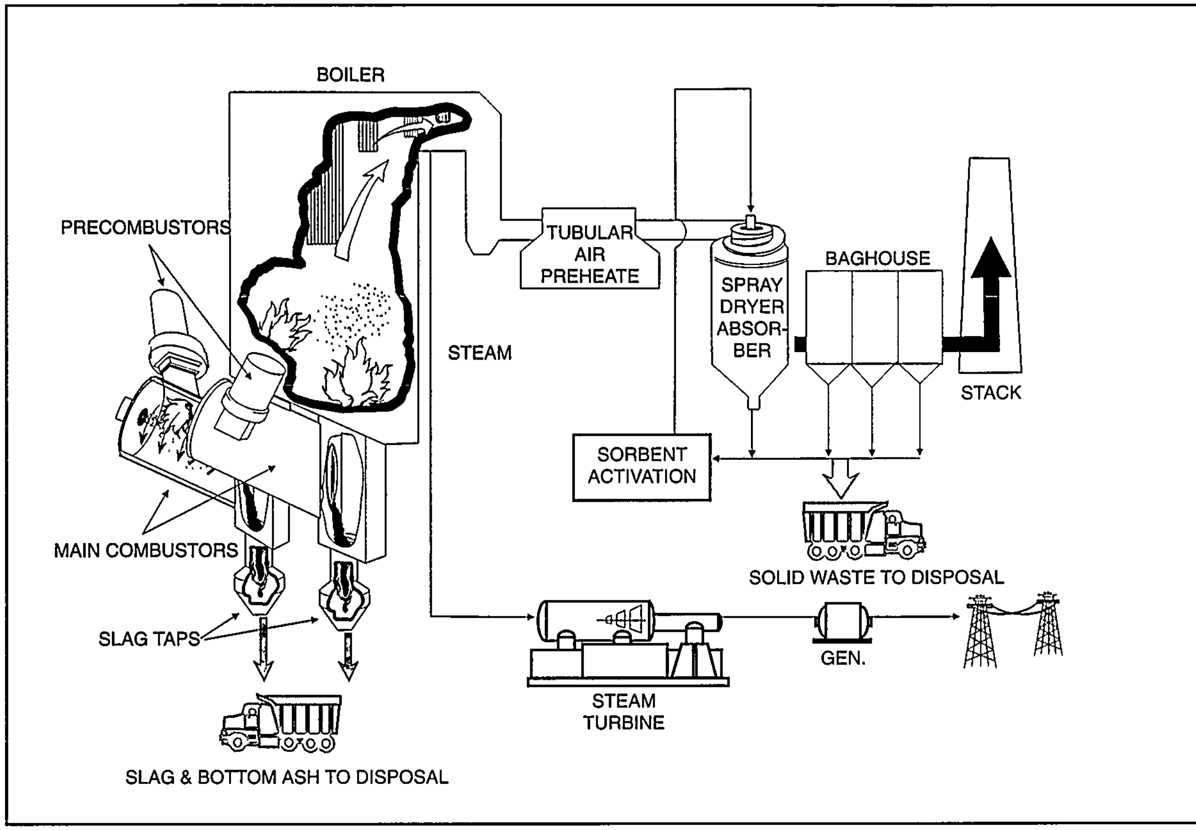
Plant Capacity/Production
50 MWe (nominal)

Coal
Usibelli subbituminous 50% run-of-mine (ROM) and 50% waste coal (performance coal)

Project Funding

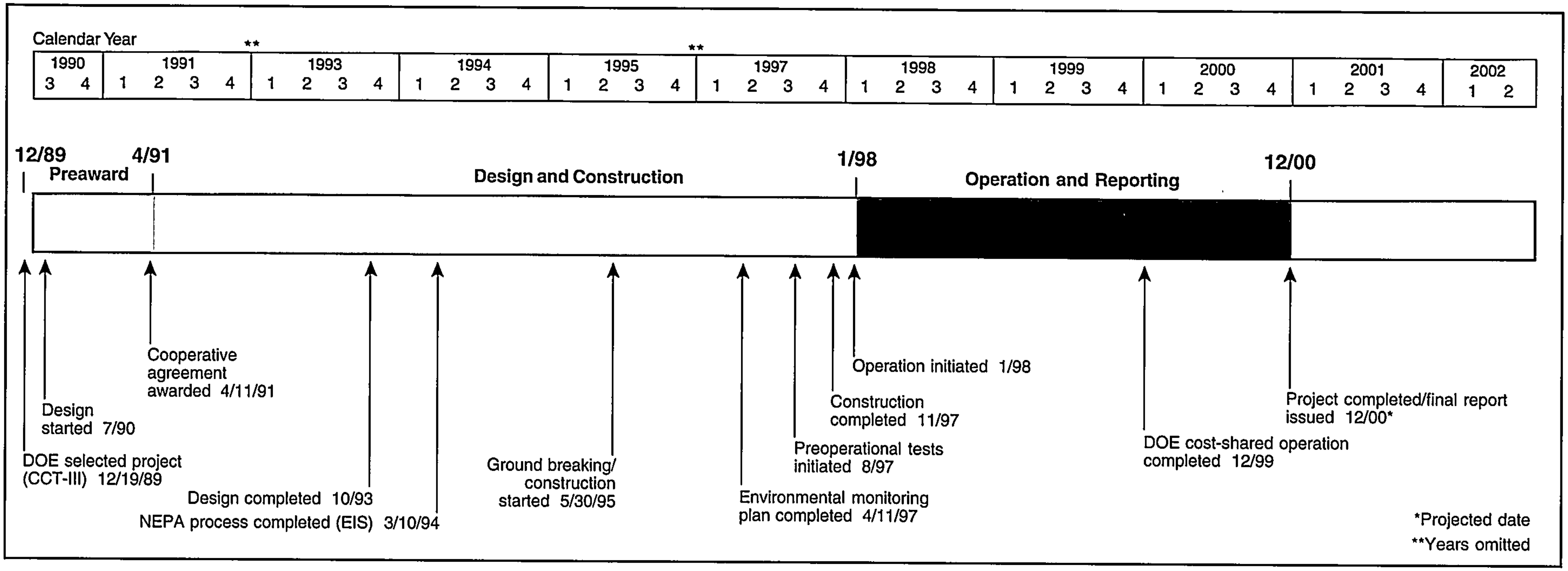
Total project cost	$242,058,000	100%
DOE	117,327,000	48
Participant	124,731,000	52

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 involves two unique slagging combustors. Emissions are controlled using TRW's slagging combustion systems through staged fuel and air injection for NO_x control and limestone injection for SO_2 control. Additional SO_2 is removed using B&W's activated recycle SDA.

A coal-fired precombustor increases the air inlet temperature for optimum slagging performance. The slagging combustors are bottom mounted, injecting the combustion products into the boiler. 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 conditions for NO_x control. The ash forms molten slag, which flows along 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 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 a tertiary air windbox to NO_x ports and to final over-fire air ports. Pulverized limestone ($CaCO_3$) for SO_2 control is fed into the combustors where it is flash calcined (converting $CaCO_3$ to lime (CaO)). The mixture of this CaO and ash that was not removed in the combustor, called flash-calcined material, is removed in the fabric filter system. Most of the flash-calcined material is used to form a 45% solids slurry, which is injected into the spray dryer. The SO_2 in the flue gas reacts with the slurry droplets as water is simultaneously evaporated. The SO_2 is further removed from the flue gas by reacting with the dry flash-calcined-material on the baghouse filter bags.



Results Summary

Environmental

- NO_x emissions ranged from 0.208–0.278 lb/10^6 Btu, with typical emissions of 0.245 lb/10^6 Btu on a 30-day rolling average, which is well below the permit limit of 0.350 lb/10^6 Btu on a rolling day average.
- SO_2 emissions were consistently less than 0.09 lb/10^6 Btu, with typical emissions of 0.038 lb/10^6 Btu, which are below the permit limit of 0.10 lb/10^6 Btu (3-hour average).
- High SO_2 removal efficiencies in excess of 90% were achieved with low-sulfur coal and Ca/S molar ratios of 1.4–1.8.
- Particulate matter (PM) emissions were 0.0047 lb/10^6 Btu, which is well below the permit limit of 0.02 lb/10^6 Btu.
- CO emissions were less than 130 ppm at 3.0% O_2, with typical emissions of 30–40 ppm at 3.0% O_2, which is well below the permit limit of 202 ppm at 3.0% O_2.
- Tests showed that the SDA system SO_2 emissions, PM emissions, and opacity were well within guarantees.

Operational

- Carbon burnout contract goals were achieved—greater than 99% carbon burnout at 100% maximum continuous rating (MCR) for the performance, ROM, and 55/45 blend of ROM/waste coal. The carbon burnout was typically 99.7%.
- The contract goal for slag recovery greater than 70% at 100% MCR for all coals was also achieved. Slag recovery ranged from 78–87%, with a typical recovery of 83%.
- During a 90-day test in the second half of 1999, the plant availability was 97% at a capacity factor of 95%.
- The SDA pressure drops and power consumption were well below guarantee levels.

Economic

- Economic data are not yet available.

Project Summary

The Healy Clean Coal Project is the first utility-scale demonstration of the TRW advanced entrained (slagging) combustor. The project site is adjacent to the existing Healy Unit No. 1 near Healy, Alaska and the Usibelli coal mine. Power is supplied to the Golden Valley Electric Association (GVEA).

Environmental Performance

The slagging combustor is designed to minimize NO_x emissions, achieve high carbon burnout, and remove the majority of fly ash from the flue gas prior to the boiler. The slagging combustor is also the first step of a three step process for controlling SO_2 by first converting limestone to flash calcined lime. Second, the flash calcined lime absorbs SO_2 within the boiler. Third, the majority of the SO_2 is removed with B&W's SDA system, which uses the flash calcined lime and fly ash captured in the baghouse. Because most of the coal ash is removed by the slagging combustors, the recycled material is rich enough in calcium content that the SDA can be operated solely on the recycled solids, eliminating the need to purchase or manufacture lime for the back end scrubbing system.

During a cumulative six-month combustion system characterization test, a series of tests were performed to establish baseline performance of the combustion system while burning ROM and ROM/waste coal blends, to map combustor performance characteristics over a broad range of operating conditions and hardware configurations, and to determine the best configuration and operating conditions for long-term operation. Throughout the testing period, the NO_x, SO_2, PM, opacity, and CO emission goals were met with the exception of short-term SO_2 and opacity exceedences during startup and repairs. The emissions, as well as permit and NSPS requirements, are presented in Exhibit 2-38.

Performance testing of the SDA system conducted in June 1999 showed that the technology performed well. Measurements of the SDA inlet, SDA outlet, stack, limestone feed, coal feed, air preheater hopper ash, surge bin ash, electrical power consumption, and stack opacity, as well as normal plant data from the plant distributed control system, showed that the technology exceeds the guarantees. The results of the tests and the performance guarantees are shown in Exhibit 2-39.

Operational Performance

The slagging stage of the combustor performed extremely well and continuously demonstrated the capability to burn both ROM and ROM/waste coal blends over a broad range of operating conditions. The precombustor performed very well with ROM coal, but exhibited more variable performance, in terms of slagging behavior, during the initial tests with ROM/waste coal blends.

Localized slag freezing was observed in the precombustor during early testing. A combination of hardware configuration and operational configuration changes were made that successfully minimized slag freezing. These changes included relocating the secondary air from the precombustor mix annulus to the head end of the slagging stage and completely transferring the precombustor mill air to the boiler NO_x ports following boiler warmup. These changes eliminated the mixing of excess air downstream of the precombustor chamber to minimize local slag freezing and increased the precombustor operating temperature in order to provide additional temperature margin. The mill air change had the added benefit of simplifying combustor operation by eliminating the need to monitor and control coal-laden mill air flow to the precombustor mill air ports during steady-state operation.

Testing of the slagging combustor also showed that the contract goals were achieved, which included greater than 99% carbon burnout at 100% MCR for the performance, ROM, and 55/45 blend of ROM/waste coal and greater than 98% carbon burnout at 100% MCR for waste coal. The carbon burnout was typically 99.7%. Slag recovery ranged from 78–87%, with a typical reading of 83%, easily meeting the contract goal for slag recovery of greater than 70% at 100% MCR for all coals.

The SDA system also performed well. During performance testing in June 1999, system pressure drops were well below the 13 in. W.G. guarantee. The range was 9.6–10.0 in. W.G. as can be seen in Exhibit 2-39. Power consumption was approximately 38–41% less than the guaranteed level. Based on these results, Stone & Webster concluded that the SDA system met all performance guarantees.

Economic Performance

Economic data are not yet available.

Commercial Applications

This technology is appropriate for any size utility or industrial boiler in new or 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 requirements.

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References

- TRW, Inc. *Healy Clean Coal Project (HCCP) Demonstration Program Topical Report: Combustion System Operation Final Report.* March 31, 2000.
- Stone & Webster Engineering Corporation. *Spray Dryer Absorber System Performance Test Report: June 7-11, 1999.* February 2000.

Exhibit 2-38
Healy Performance Goals and Combustion System Characterization Testing Results (June – December 1998)

Parameter	NSPS	Permit	Goal	Actual Range	Actual Typical
NO_x	0.5 lb/10^6 Btu (before 7/97) 0.15 lb/10^6 Btu (modified after 7/97) 0.5 lb/10^6 Btu (new plant after 7/97)	0.350 lb/10^6 Btu (30 day rolling avg)	<0.35 lb/10^6 Btu	0.208–0.278 lb/10^6 Btu (30 day rolling avg)	0.245 lb/10^6 Btu (30 day rolling avg)
SO_2	90% removal and less than 1.2 lb/10^6 Btu 70% removal when emissions < 0.60 lb/10^6 Btu	0.086 lb/10^6 Btu (annual avg) 0.10 lb/10^6 Btu (3-hour avg) 65.8 lb/hr max (3-hour avg)	70% removal (min) 79.6 lb/hr max	<0.09 lb/10^6 Btu (<35 ppm @ 3% O_2)	0.038 lb/10^6 Btu (15 ppm @ 3% O_2) 25 lb/hr
PM	0.03 lb/10^6 Btu	0.02 lb/10^6 Btu (hourly avg)	0.015 lb/10^6 Btu	NA	0.0047 lb/10^6 Btu[a]
Opacity	20% Opacity (6 minute avg)	20% Opacity (3 minute avg) 27% Opacity (one 6 minute period per hour)	20% Opacity (3 minute avg)	<10% Opacity (30 min avg.)	2.3% Opacity[a]
CO	Dependent on ambient CO levels in the local region	0.20 lb/10^6 Btu (hourly avg) (202 ppm CO @ 3.0% O_2)	<200 ppm (dry basis) at 3.5% O_2 (dry basis) (<206 ppm CO @ 3.0% O_2)	<130 ppm @ 3.0% O_2	30–40 ppm @ 3.0% O_2 0.036 lb/10^6 Btu

[a] After correction of problems with premature filter bag failures in the baghouse.

Exhibit 2-39
Healy SDA Performance Test Results and Performance Guarantees

Operating Parameter	Guarantee	Parameter Values Test 1	Test 3[a]	Test 4	Test 5	Test 6	Test 7	Test 8	Test 9
SO_2	79.6 lb/hr (max)	<2.01	<2.07	<2.13	<2.15	<2.10	<2.13	<2.13	<2.15
PM	0.015 lb/10^6 Btu	0.0023	0.0042	0.0052	0.0040	0.0027	0.0030	0.0014	0.0034
Opacity	20% Opacity (3 minute avg) 27% Opacity for 3 minutes per hour	1.3–1.5	1.3–1.7	1.5–1.7	1.5–1.7	1.1–1.4	1.0–2.0	1.3–1.5	1.3–1.5
System Pressure Drop	13 inches W.C.	10.0	10.5	9.6	9.7	9.8	9.9	9.8	9.9
System Power Consumption	550.5 kW	334	330	324	331	333	333	328	340

[a] Test 2 was terminated due to testing equipment failure.

Coal Processing for Clean Fuels

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

ARCADIS Geraghty & Miller—fuel methanol tester and cofunder

Electric Power Research Institute—utility advisor

Location
Kingsport, Sullivan County, TN (Eastman Chemical Company's Chemicals-from-Coal Complex)

Technology
Air Products and Chemicals, Inc.'s liquid phase methanol process

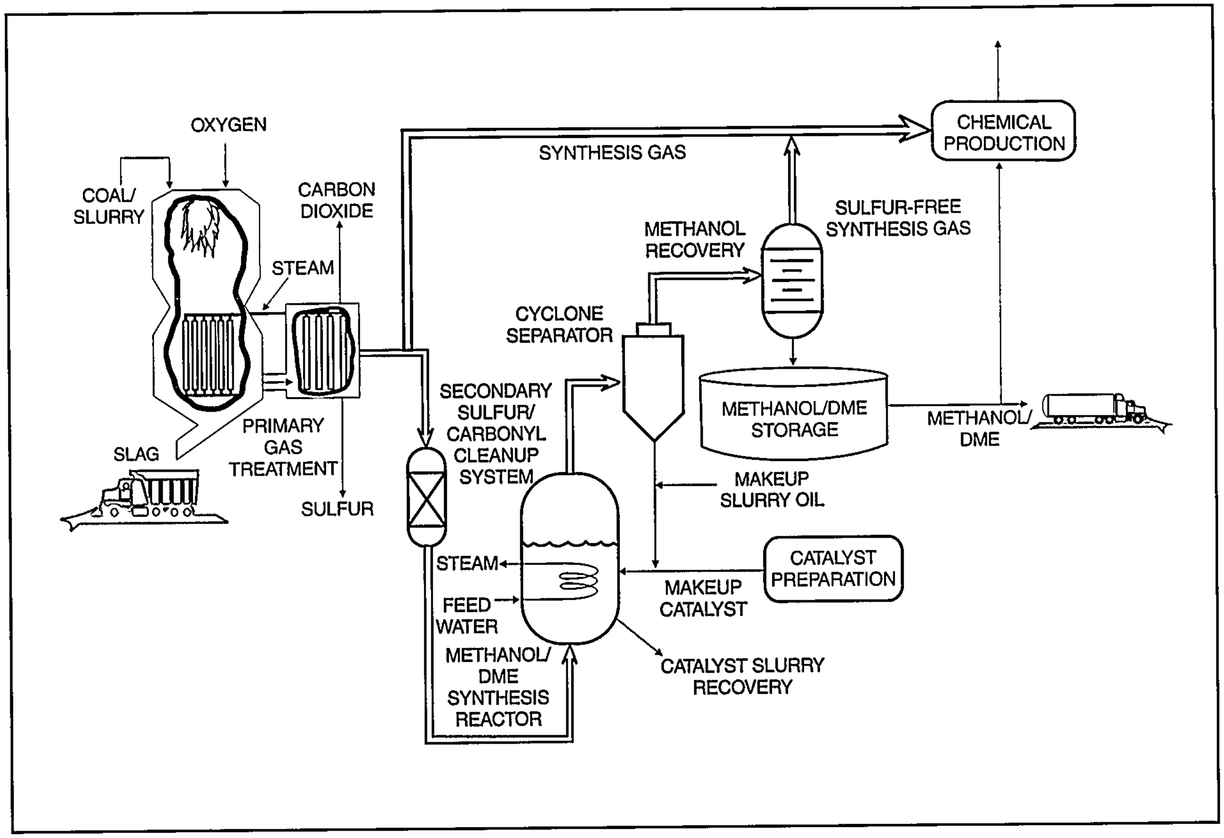
Plant Capacity/Production
80,000 gallons/day of methanol (nominal)

Coal
Eastern high-sulfur bituminous, 3–5% sulfur

Project Funding

Total project cost	$213,700,000	100%
DOE	92,708,370	43
Participant	120,991,630	57

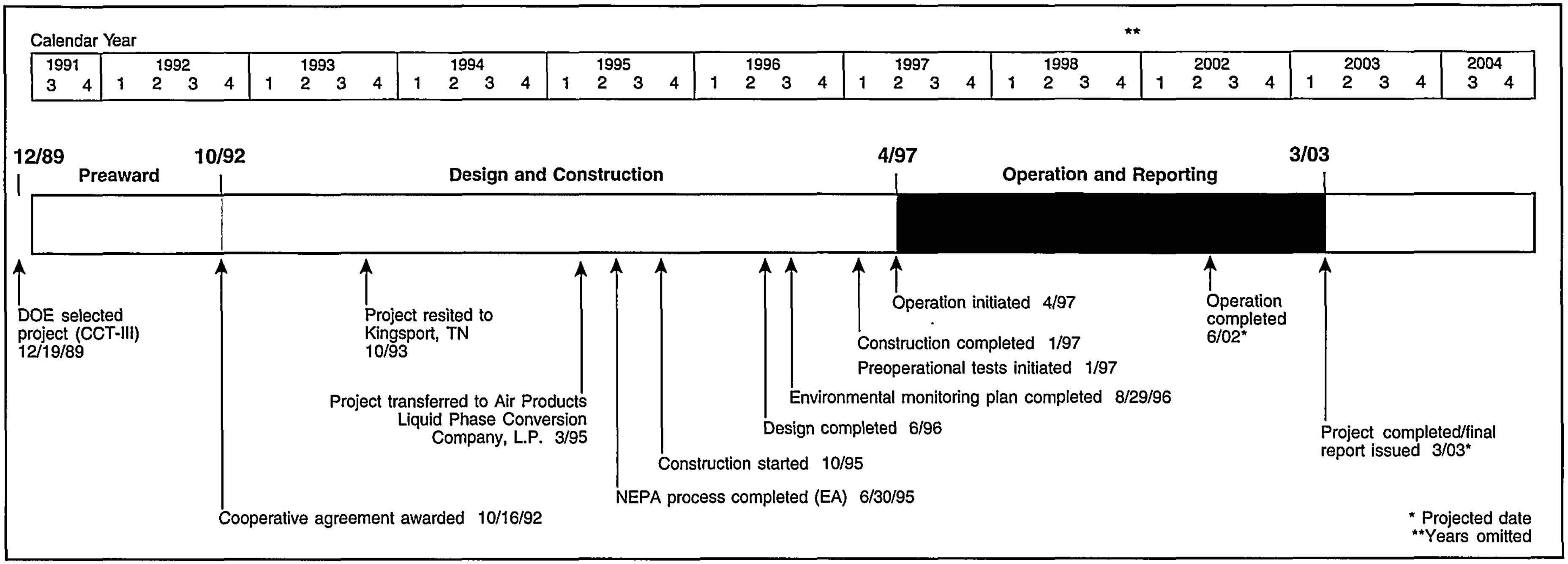
LPMEOH is a trademark of Air Products and Chemicals, Inc.



Project Objective
To demonstrate on a commercial scale the production of methanol from coal-derived synthesis gas using the LPMEOH™ process; to determine the suitability of methanol produced during this demonstration for use as a chemical feedstock or as a low-SO_x emitting, low-NO_x emitting alternative fuel in stationary and transportation applications; and 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 water-gas shift conversion.

Methanol fuel testing is being conducted in off-site stationary and mobile applications, such as fuel cells, buses, and distributed electric power generation. Stabilized methanol from the project is being made available to several test locations to study the feasibility of using the product as a feedstock in transportation and power generation applications. Eastern high-sulfur bituminous coal (Mason seam) containing 3% sulfur (5% maximum) and 10% ash is being used.



Project Status/Accomplishments

The first production of methanol from the 80,000 gal/day unit occurred on April 2, 1997 with the first stable operation at nameplate capacity occurring on April 6, 1997. A stable test period at over 92,000 gal/day revealed no system limitations.

The LPMEOH™ process demonstration unit continues to exceed expectations. Recent tests demonstrating the unique operability of the LPMEOH™ process demonstration unit have shown that catalyst deactivation with a CO-rich feed gas is statistically similar to the catalyst deactivation achieved with the balanced feed gas that is normally available. In addition, a test was also performed to demonstrate the ramping capabilities of the LPMEOH(tm) reactor. The results of these tests, together with the results of the previous tests, have given increased confidence in the use of the LPMEOH(tm) process for IGCC applications.

Since start-up in April 1997, about 60 million gallons of methanol have been produced and plant availability has exceeded 97%. Availability in 1998 and 1999 was in excess of 99.7%. As a result of the successes achieved, the demonstration operations were extended an additional 15 months (through June 30, 2002) to allow for the opportunity to perform new tests that are considered to be of significant commercial interest.

Stabilized methanol from the project has been made available to a number of test locations to study its feasibility as a feedstock in transportation and power generation applications. A total of five vehicles have been tested on fuel blends made from the stabilized methanol. In the tests, stabilized methanol was shown to provide the same environmental benefits as chemical-grade methanol with no penalty on performance or fuel economy. Four projects were selected to study the use of stabilized methanol in both central and distributed power generation systems. Initial results show that stabilized methanol can lower NO_x emissions in gas turbines and diesel engines. Testing in a fuel cell is currently underway.

Commercial Applications

The LPMEOH™ process has been developed to enhance IGCC power generation by producing a clean-burning, storable-liquid fuel (methanol) from clean coal-derived gas. Methanol also has a broad range of commercial applications; it can be substituted for conventional fuels in stationary and mobile combustion applications and is an excellent fuel for utility peaking units. Methanol contains no sulfur and has exceptionally low NO_x characteristics when burned.

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 also can 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 50,000–300,000 gal/day of methanol produced when associated with commercial IGCC power generation trains of 200–500 MWe.

Advanced Coal Conversion Process Demonstration

Participant

Western SynCoal LLC (formerly Rosebud SynCoal Partnership; a subsidiary of Montana Power Company's Energy Supply Division)

Additional Team Members

None

Location

Colstrip, Rosebud County, MT (adjacent to Western Energy Company's Rosebud Mine)

Technology

Western SynCoal LLC's Advanced Coal Conversion Process for upgrading low-rank subbituminous and lignite coals

Plant Capacity/Production

45 tons/hr of SynCoal® product

Coal

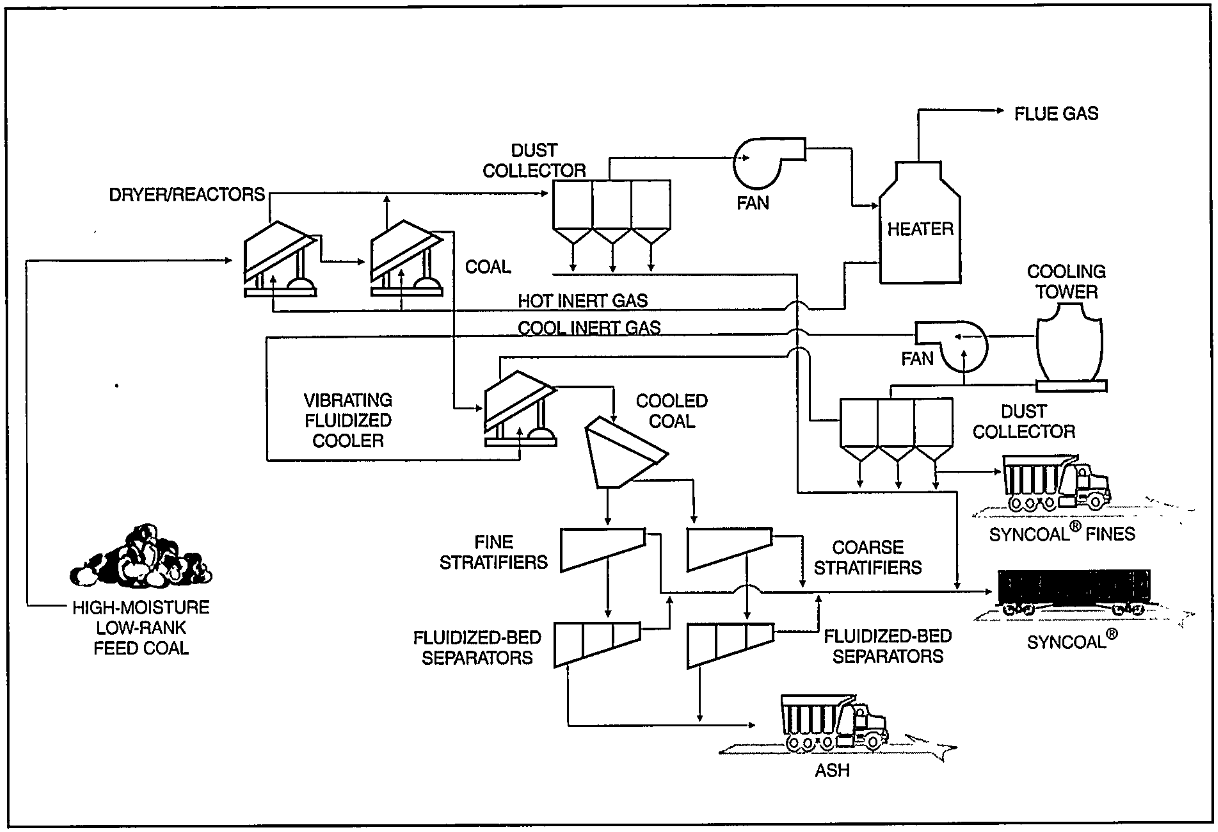
Powder River Basin subbituminous (Rosebud Mine), 0.5–1.5% sulfur, plus tests of other subbituminous coals and lignites

Project Funding

Total project cost	$105,700,000	100%
DOE	43,125,000	41
Participant	62,575,000	59

Project Objective

To demonstrate Western SynCoal LLC's Advanced Coal Conversion Process (ACCP) 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.



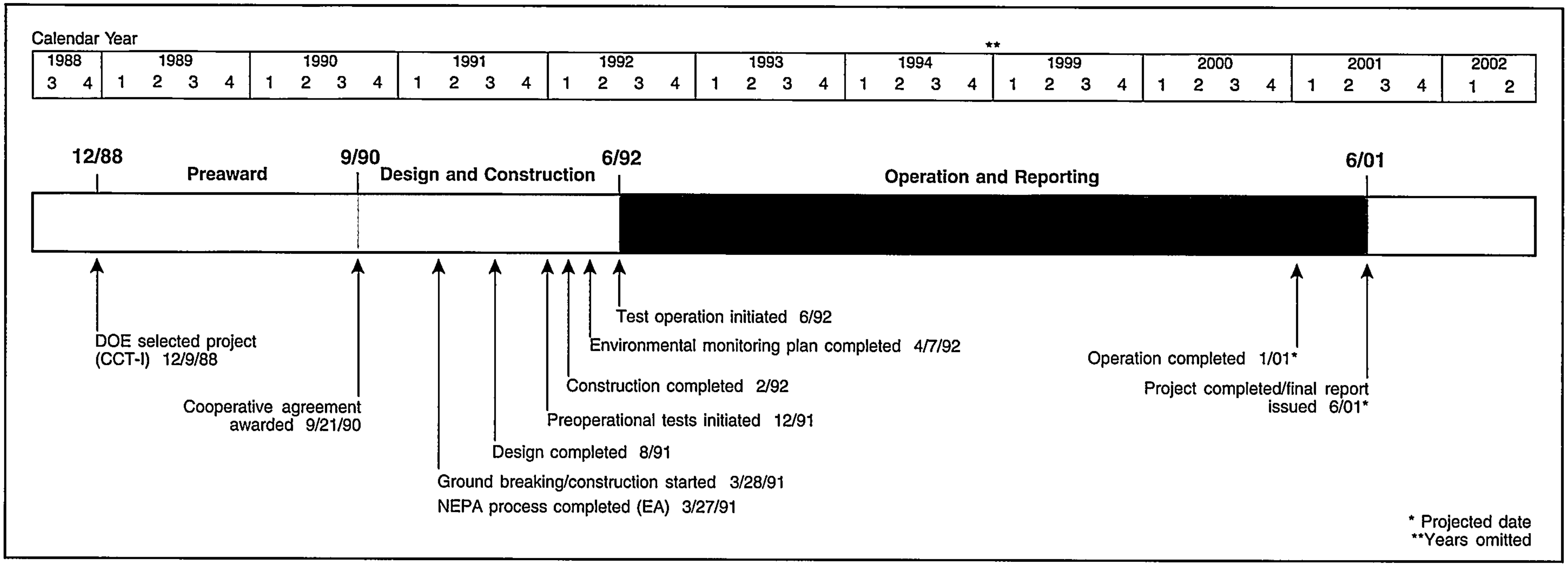
Technology/Project Description

The process 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 raw coal is screened and fed to a vibratory fluidized-bed reactor where surface moisture is removed by heating with hot combustion gas. Coal exits this reactor at a temperature slightly higher than that required to evaporate water and flows to a second vibratory reactor where the coal is heated to nearly 600 °F. This temperature is sufficient to remove chemically bound water, carboxyl groups, and volatile sulfur compounds. In addition, a small amount of tar is released, partially sealing the dried product. Particle shrinkage causes fracturing, destroys moisture reaction sites, and liberates the ash-forming mineral matter.

The coal is then cooled to less than 150 °F by contact with an inert gas in a vibrating fluidized-bed cooler. The cooled coal is sized and fed to deep bed stratifiers where air pressure and vibration separate mineral matter, including much of the pyrite, from the coal, thereby reducing the sulfur content of the product. The low specific gravity fractions are sent to a product conveyor while heavier fractions go to fluidized-bed separators for additional ash removal.

The fines handling system consolidates the coal fines that are produced throughout the ACCP facility. The fines are gathered by screw conveyors and transported by drag conveyors to a bulk cooling system. The cooled fines are blended with the coarse product, stored in a 250-ton capacity bin until loaded into pneumatic trucks for off-site sales, or returned to the mine pit.

SynCoal is a registered trademark of the Rosebud SynCoal Partnership.



Project Status/Accomplishments

The ACCP facility was scheduled to complete demonstration operations in January 1999 but was granted a two-year no-cost extension. The ACCP facility has processed over 2.6 million tons of raw coal to produce over 1.7 million tons of SynCoal. The SynCoal is used by electric utilities and industrial facilities (primarily cement and lime plants). The ACCP facility continues to supply six commercial customers including the 330-MWe Colstrip Unit No. 2. SynCoal is trucked to Colstrip Unit No. 2 and fed to three of the five pulverizers using a dedicated pneumatic feed system.

The demonstration of SynCoal as a supplemental fuel for Unit No. 2 started in February 1999. About 131,000 tons of SynCoal were used during 1999, or approximately 11.6% of the total thermal input on an annual basis. On days that SynCoal was used as a supplemental fuel, Unit No.2 produced an average of 3.7%, or 10.5 MWe (net), of additional generation. The gross unit heat rate for Unit No. 2 improved by 85 Btu/kWh when firing SynCoal (auxiliary power demand decreased about 1.9 MWe).

When the demonstration started, baseline testing indicated that Unit No. 2 was typically producing 2.9 MW (net) less than Unit No. 1, a sister unit of comparable capacity. In late Spring 1999, Unit No. 1 was overhauled, resulting in an increase in its average output of 7 MWe (net). With this increase in output, the overhauled Unit No. 1 would have produced 5.4 MWe more than Unit No. 2. However, for the days that SynCoal was used, Unit No. 2 out-produced the overhauled Unit No. 1 by an average of 7.3 MWe—285.7 MWe versus 278.4 MWe (net)—with 15.0% of the total heat input coming from SynCoal. Furthermore, SynCoal can be credited for actual 1999 SO_2 emissions reductions for Unit No. 2 of approximately 430 tons, or an 8% reduction, and NO_x emissions reductions of approximately 826 tons, or a 19% reduction, when compared to Unit No. 1 emissions.

Three different feedstocks were tested at the ACCP facility—North Dakota lignite, Knife River lignite, and Amax subbituminous coal. Approximately 190 tons of the SynCoal® product produced with the North Dakota lignite was burned at the 250-MWe cyclone-fired Milton R. Young Power Plant Unit No. 1. Testing showed dramatic improvement in cyclone combustion, improved slag tapping, and a 13% reduction in boiler air flow requirements. In addition, boiler efficiency increased from 82% to over 86% and the total gross heat rate improved by 123 Btu/kWh.

Commercial Applications

ACCP has the potential to enhance the use of low-rank western subbituminous and lignite coals. The SynCoal® is a viable compliance option for meeting SO_2 emission reduction requirements. SynCoal® is an ideal supplemental fuel for plants seeking to burn western low-rank coals because the ACCP allows a wider range of low-sulfur raw coals without derating the units. The participant has six long-term agreements in place to provide SynCoal® to industrial and utility customers.

The ACCP has the potential to convert inexpensive, low-sulfur low-rank coals into valuable carbon-based reducing agents for many metallurgical applications. Furthermore, SynCoal® enhances cement and lime production and provides a value-added bentonite product.

Development of the Coal Quality Expert™

Project completed.

Participants

ABB Combustion Engineering, Inc. and
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
Utility Companies—(5 hosts)

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)
Five utility host sites

Technology

CQ Inc.'s EPRI Coal Quality Expert™ (CQE™) computer software

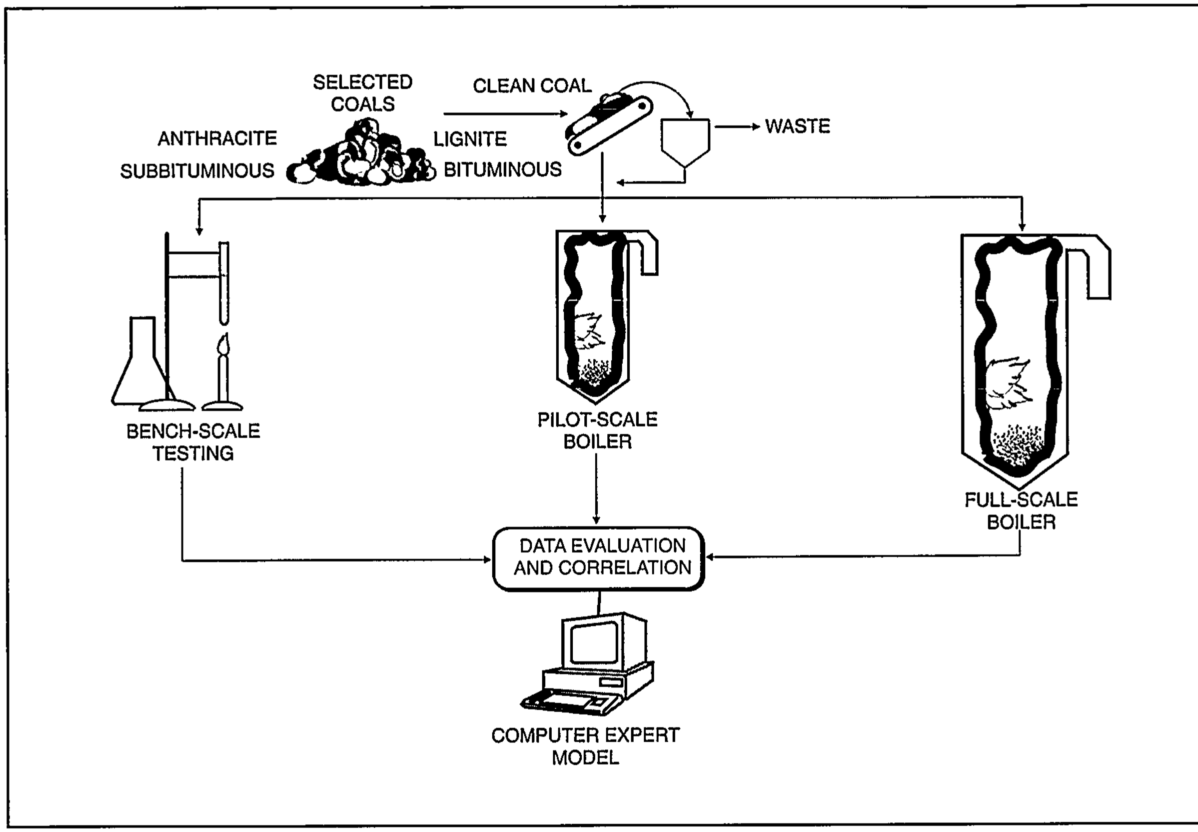
Plant Capacity/Production

Full-scale testing took place at six utility sites ranging in size from 250–880 MWe.

Coal

Wide variety of coals and blends

Coal Quality Expert, CQE, CQIS, and CQIM are trademarks of the Electric Power Research Institute.
Pentium is a registered trademark of Intel.
OS/2 is a registered trademark of IBM.
Windows is a registered trademark of Microsoft Corporation.



Project Funding

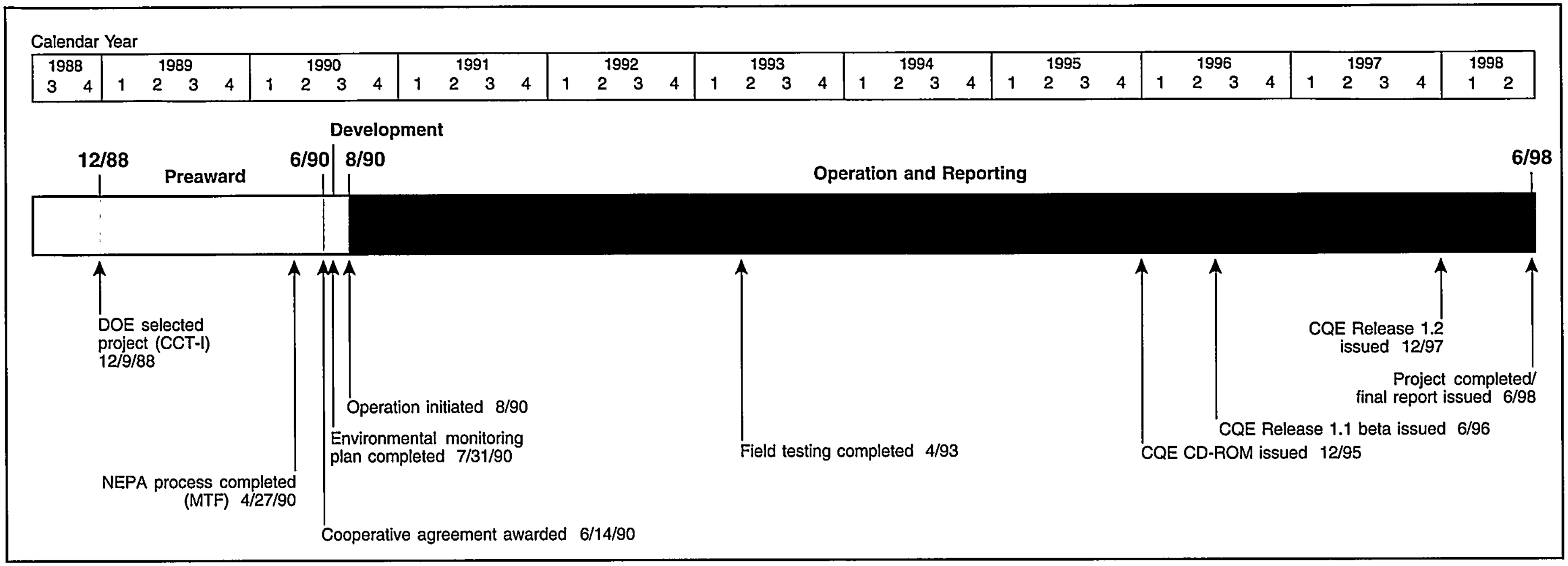
Total project cost	$21,746,004	100%
DOE	10,863,911	50
Participants	10,882,093	50

Project Objective

The objective of the project was to provide the utility industry with a PC software program it could use 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 model 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 fueling decisions by integrating the system-wide impact of fuel purchase decisions on coal-fired power plant performance, emissions, and power generation costs. The impacts of coal quality; capital improvements; operational changes; and environmental compliance alternatives on power plant emissions, performance, and production costs can be evaluated using CQE™. CQE™ can be used to systematically evaluate all such impacts, or it may be used in modules with some default data to perform more strategic or comparative studies.



Results Summary

Environmental

- CQE™ includes models to evaluate emission and regulatory issues.

Operational

- CQE™ can be used on a stand-alone computer or as a network application for utilities, coal producers, and equipment manufacturers to perform detailed coal impact analyses.
- Four features included in the CQE™ program are:
  - Fuel Evaluator,
  - Plant Engineer,
  - Environmental Planner, and
  - Coal-Cleaning Expert.
- CQE™ can be used to evaluate:
  - Coal quality,
  - Transportation system options,
  - Performance issues, and
  - Alternative emissions control strategies.
- Operates on an OS/2 Warp® (Version 3 or later) operating system with preferred hardware requirements of a Pentium®-equipped personal computer, 1 gigabyte hard disk space, 32 megabytes RAM, 1024x768 SVGA, and CD-ROM.

Economic

- CQE™ includes economic models to determine production cost components for coal-cleaning processes, power production equipment, and emissions control systems.

Project Summary

Background

CQE™ began with EPRI's 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 technical and 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: (1) new flexibility and application, (2) advanced technical models and performance correlations, and (3) 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, Connecticut and the University of North Dakota's Energy and Environmental Research Center in Grand Forks, North Dakota. Pilot-scale testing was performed at ABB Combustion Engineering's facilities in Windsor, Connecticut and Alliance, Ohio. The five field test sites were:

- Alabama Power's Gatson, Unit No. 5 (880 MWe), Wilsonville, Alabama;
- Mississippi Power's Watson, Unit No. 4 (250 MWe), Gulfport, Mississippi;
- New England Power's Brayton Point, Unit No. 2 (285 MWe) and Unit No. 3 (615 MWe), Somerset, Massachusetts;
- Northern States Power's King Station (560 MWe), Bayport, Minnesota; and
- Public Service Company of Oklahoma's Northeastern, Unit No. 4 (445 MWe), Oologah, Oklahoma.

The six large-scale field tests consisted of burning a baseline coal and an alternate coal over a two 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 OS/2®-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 operation and maintenance costs for coal-cleaning processes, power production equipment, and emissions control systems. CQE™ has four main features:

- Fuel Evaluator—Performs system-, plant-, 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

The CQE™ includes more than 100 algorithms based on the data generated in the six full-scale field test.

The CQE™ 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 of 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. 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 30 U.S. utilities and one U.K. utility have CQE™ through their EPRI membership. Over 100 utilities and coal companies are now using CQE™. 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.

CQE™ was recognized by the Secretary of Energy and the President of EPRI in 1996 as the best of nine DOE/EPRI cost-shared utility research and development projects under the "Sustainable Electric Partnership" program.

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Joseph B. Renk, NETL, (412) 386-6406

References

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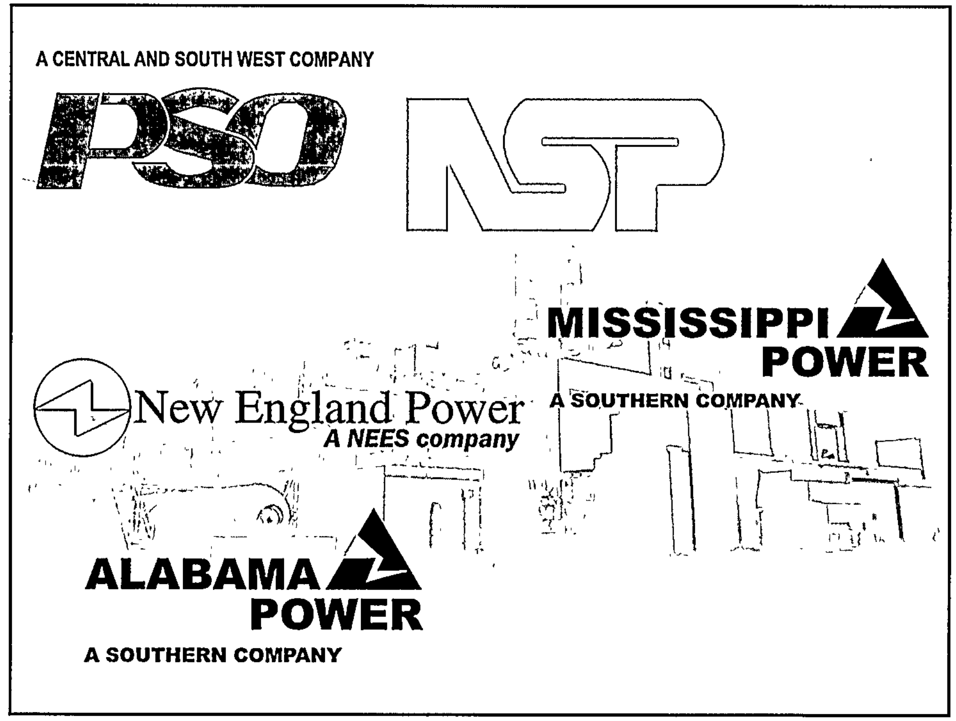
- Harrison, Clark D. *et al.* "Recent Experience with the CQE™." *Fifth Annual Clean Coal Technology Conference: Technical Papers.* January 1997.
- *CQE™ Users Manual,* CQE™ Home Page at http://www.fuels.bv.com:80/cqe/cqe.htm.
- *Comprehensive Report to Congress on the Clean Coal Technology Program: 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.)



▲ Five utilities acted as hosts for field tests of CQE™.

ENCOAL® Mild Coal Gasification Project

Project completed.

Participant

ENCOAL Corporation (a wholly owned subsidiary of Bluegrass Coal Development Company)

Additional Team Members

Bluegrass Coal Development Company (a wholly owned subsidiary of AEI Resources, Inc.)—cofunder

SGI International—technology developer, owner, licensor

Triton Coal Company (a wholly owned subsidiary of Vulcan Coal Company)— host

Location

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

Technology

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

Coal

Low-sulfur Powder River Basin (PRB) subbituminous coal, 0.45% sulfur

Plant Capacity/Production

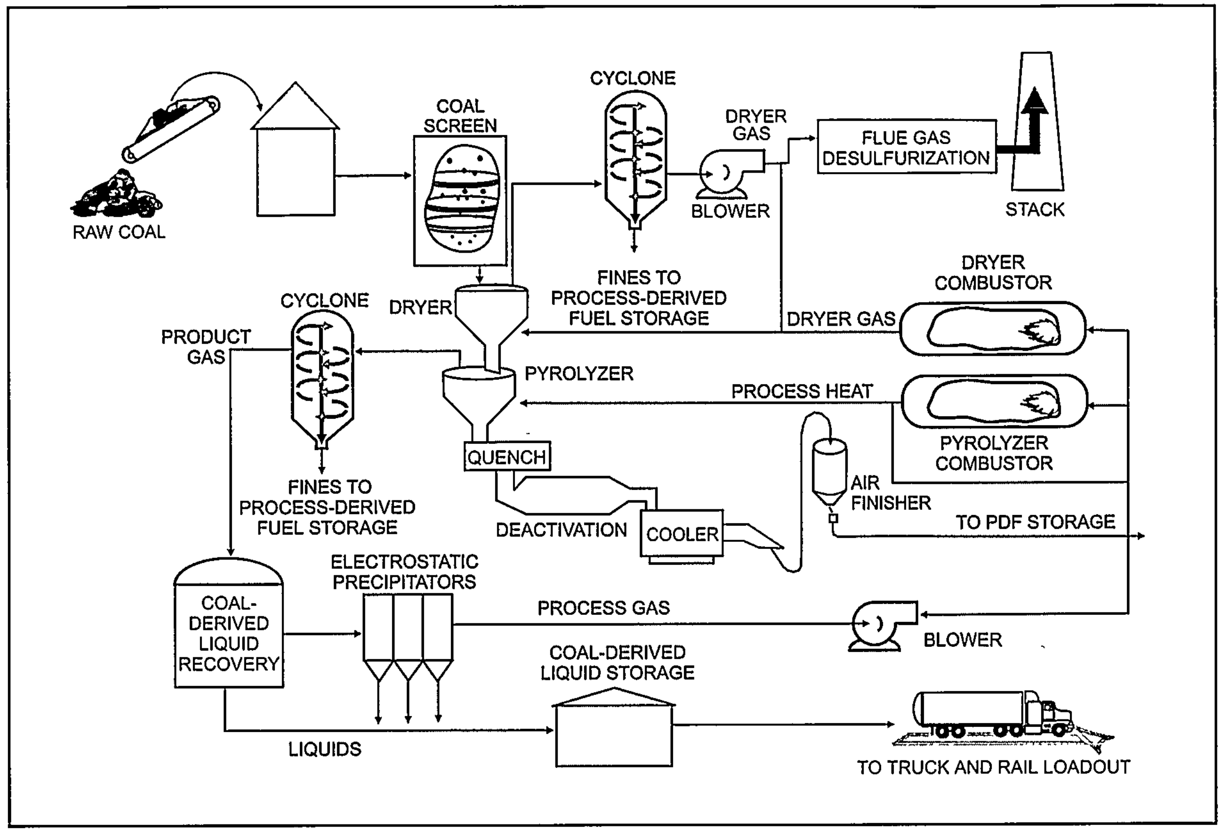
1,000 tons/day of subbituminous coal feed

Project Funding

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

Project Objective

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



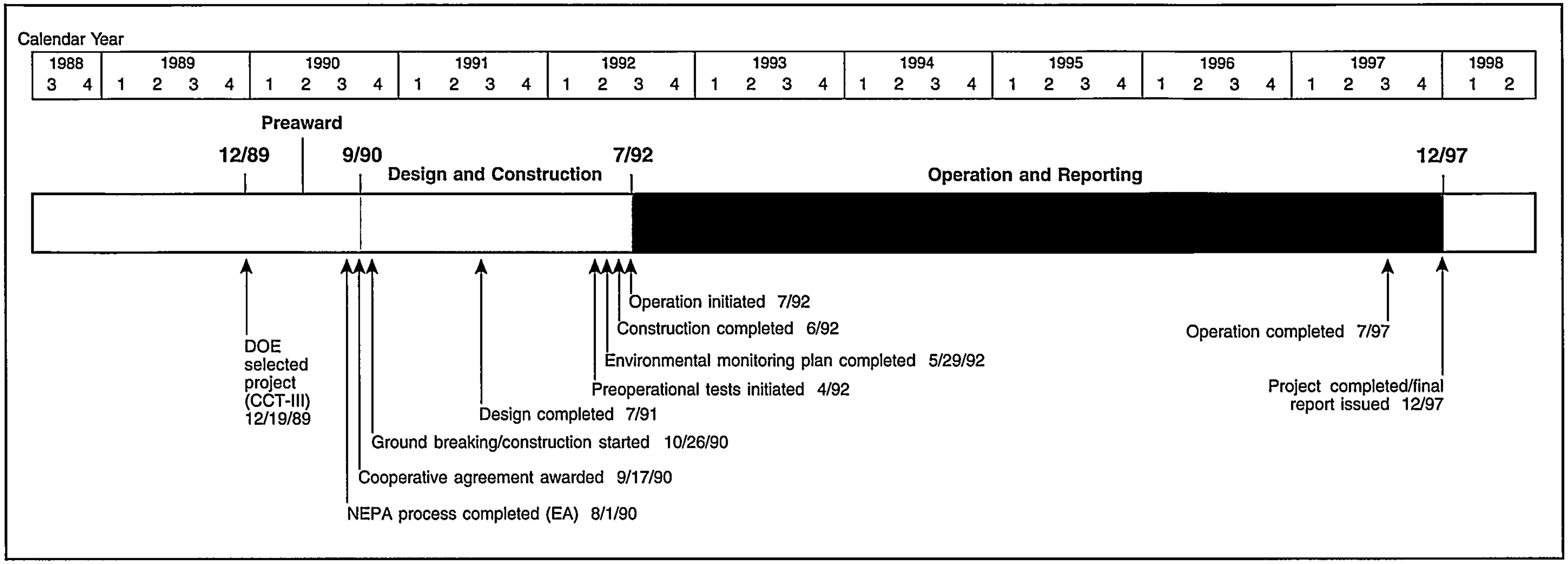
Technology/Project Description

Coal is fed into a rotary grate dryer where it is heated to reduce moisture. The temperature is controlled so that no significant amounts of methane, CO_2, or CO are released. The solids are then fed to the pyrolyzer where the temperature is about 1,000 °F, and all remaining water is removed. A chemical reaction releases the volatile gaseous material. Solids exiting the pyrolyzer are quenched to stop the pyrolysis reactions.

In the original process, the quench table solids were further cooled in a rotary cooler and transferred to a surge bin. A single 50% flow rate vibrating fluidized bed (VFB) was added to stabilize the Process-Derived Fuel (PDF®) with respect to oxygen and water. In the VFB, the partially-cooled, pyrolyzed solids contact a gas stream containing a controlled amount of oxygen. Termed "oxidative deactivation," a reaction occurs at active surface sites on the particles, reducing the tendency for spontaneous ignition.

Following the VFB, the solids are cooled to near atmospheric temperature in an indirect rotary cooler where water is added to rehydrate the PDF®. A patented dust suppressant is added as the PDF® leaves the surge bin. The hot gas produced in the pyrolyzer is sent through a cyclone for removal of the particulates, and then cooled in a quench column to stop any additional pyrolysis reactions and to condense the Coal-Derived Liquid (CDL®).

ENCOAL, LFC, CDL, and PDF are registered trademarks of SGI International and Bluegrass Coal Development Company.



Results Summary

Environmental

- The PDF® contains 0.36% sulfur with a heat content of 11,100 Btu/lb (compared to 0.45% sulfur and 8,300 Btu/lb for the feed coal).
- The CDL® contains 0.6% sulfur and 140,000 Btu/gal (compared to 0.8% sulfur and 150,000 Btu/gal for No. 6 fuel oil).
- In utility applications, PDF® enabled reduction in SO_2 emissions, reduction in NO_x emissions (through flame stabilization), and maintenance of boiler rated capacity with fewer mills in service.
- LFC® products contained no toxins in concentrations anywhere close to federal limits.

Operational

- Steady state operation exceeding 90% availability was achieved for extended periods for the entire plant (numerous runs exceeded 120 days duration).
- The LFC® process consistently produced 250 tons/day of PDF® and 250 barrels/day of CDL® from 500 tons/day of run-of-mine PRB coal.
- Integrated operation of the LFC® process components over five years has provided a comprehensive database for evaluation and design of a commercial unit.
- Over 83,500 tons of PDF® were shipped via 17 unit trains and one truck shipment to seven customers in six states. Shipments included 100% PDF® and blends from 14–94% PDF®.
- PDF®, alone and in blends, demonstrated excellent combustion characteristics in utility applications, providing heating values comparable to bituminous coal, more reactivity than bituminous coal, and a stable flame.
- The low-volatile PDF® also showed promise as a reductant in direct iron reducing testing and also as a blast furnace injectant in place of coke.
- Nearly 5 million gallons of CDL® were produced and shipped to eight customers in seven states.
- CDL® demonstrated fuel properties similar to a low-sulfur No. 6 fuel oil but with the added benefit of lower sulfur content. High aromatic hydrocarbon content, however, may make CDL® more valuable as a chemical feedstock.

Economic

- A commercial plant designed to process 15,000 metric tons per day would cost an estimated $475 million (2,001$) to construct, with annual operating and maintenance costs of $52 million per year.

Project Summary

Operational Performance

The LFC® facility operated for more than 15,000 hours over a five-year period. Steady-state operation was maintained for much of the demonstration with availabilities of 90% for extended periods. The length of operation and volume of production proved the soundness and durability of the process.

Exhibit 2-40 summarizes ENCOAL's production history. By the end of the demonstration, over 83,500 tons of PDF® were shipped via 17 unit trains and one truck shipment to seven customers in six states. Shipments included 100% PDF® and blends from 14–94% PDF®. Over 5 million gallons of CDL® were produced and shipped to eight customers in seven states.

PDF® Product. As with most demonstrations, however, success required overcoming many challenges. The most difficult challenge was achieving stability of the PDF® product, which had to be resolved in order to achieve market acceptance.

In June 1993, efforts ceased in trying to correct persistent PDF® stability problems within the bounds of the original plant design. The rotary cooler failed to provide the deactivation necessary to quell spontaneous ignition of PDF®. ENCOAL concluded that a separate, sealed vessel was needed for product deactivation. A search for a suitable design led to adoption of a VFB. A 500-ton/day VFB was installed between the quench table and rotary cooler. (Installation of a second 500 ton/day VFB was planned but never implemented.)

Although the VFB enhanced deactivation, the PDF still required "finishing" to achieve stabilization. Extensive study revealed that more oxygen was needed for deactivation. Two courses of action were pursued: (1) development of interim measures to finish deactivation external to the plant, enabling immediate PDF® shipment for test burns; and (2) development of an in-plant process for finishing, eliminating product quality and labor penalties for external finishing.

"Pile layering" was the primary external PDF® finishing measure adopted. However, PDF® quality becomes somewhat impaired by impacting size, moisture, and ash content.

Pursuit of a finishing process step resulted in establishment of a stabilization task force composed of private sector and government engineers and scientists. The outcome was construction and testing of a Pilot Air Stabilization System (PASS) to complete the oxidative deactivation of PDF®. The PASS controls temperature and humidity during forced oxidation. The data obtained were used to develop specifications and design requirements for a full-scale, in-plant PDF® finishing unit based upon a commercial (Aeroglide) tower dryer design.

CDL® Product. The first shipment of ENCOAL's liquid product experienced unloading problems. The use of heat tracing and tank heating coils solved the unloading problems for subsequent customers. The CDL® also contained more solids and water than had been hoped for, but was considered usable as a lower grade oil.

Following VFB installation, CDL® quality improved. The pour point ranged from 75–95 °F, and the flash point averaged 230 °F, both within the design range. Water content was down to 1–2%, and solids content was 2–4%. Improvements resulted from more consistent operation and lower pyrolysis temperatures and higher pyrolysis flow rates enabled by a new pyrolyzer water seal.

Environmental Performance

PDF® Product. PDF® offers the advantages of low-sulfur Powder River Basin coal without a heating value penalty. In fact, the LFC® process removes organically-bound sulfur, making the PDF® product lower in sulfur than the parent coal on a Btu basis. Because the ROM coal is low in ash, PDF® ash levels remain reasonable after processing, even though the ash level is essentially doubled (ash from one ton of ROM coal goes into one-half ton of PDF®).

Dust emissions were not a problem with PDF®. A dust suppressant (MK) was sprayed on the PDF® to coat the surface as it leaves the storage bin. Also, PDF® has a narrower particle size distribution than ROM coal, having a larger fines content but fewer particles in the fugitive dust range than ROM coal.

Exhibit 2-40
ENCOAL Production

	Pre-VFB 1992	Pre-VFB 1993	Post-VFB 1994	Post-VFB 1995	Post-VFB 1996	Post-VFB 1997[1]	Sum
Raw Coal Feed (tons)	5,200	12,400	67,500	65,800	68,000	39,340	**258,300**
PDF® Produced (tons)	2,200	4,900	31,700	28,600	33,300	19,300	**120,500**
PDF® Sold (tons)	0	0	23,700	19,100	32,700	7,400	**82,900**
CDL® Produced (bbl)	2,600	6,600	28,000	31,700	32,500	20,300	**121,700**
Hours on Line	314	980	4,300	3,400	3,600	2,603	**15,197**
Average Length of Runs (Days)	2	8	26	38	44	75	**N/A**

[1]Through June 1997.

ENCOAL's test burn shipments became international when Japan's Electric Power Development Company (EPDC) evaluated six metric tons of PDF® in 1994. The EPDC, which must approve all fuels being considered for electric power generation in Japan, found PDF® acceptable for use in Japanese utility boilers.

In October 1996, instrumented combustion testing was conducted at the Indiana-Kentucky Electric Cooperative's (IKEC) Clifty Creek Station, Unit #3. Important findings included the following:

- Full generating capacity using PDF® was possible with one mill out of service, which was not possible on the baseline fuel. Operation on PDF® afforded time to perform mill maintenance and calibration without losing capacity or revenues, increasing capacity factor and availability, and decreasing operation and maintenance costs.
- NO_x emissions were reduced by 20% due to high PDF® reactivity, resulting in almost immediate ignition upon leaving the burner coal nozzle. Furthermore, PDF® sustained effective combustion (maintaining low loss on ignition) with very low excess oxygen, which is conducive to low NO_x emissions.
- PDF® use precipitated increased ash deposits in the convective pass that were wetter than those resulting from baseline coal use, requiring increased sootblowing to control build-up.

CDL® Product. The CDL® liquid product is a low-sulfur, highly aromatic, heavy liquid hydrocarbon. CDL® fuel characteristics are similar to a low-sulfur No. 6 fuel oil, except that the sulfur content is significantly lower. CDL®'s market potential as a straight industrial residual fuel, however, appears limited. The market for CDL® as a fuel never materialized and CDL® has limited application as a blend for high-sulfur residual fuels due to incompatibility of the aromatic CDL® with many straight-chain hydrocarbon distillates.

ENCOAL determined that a centrifuge was needed to reduce solids retention and improve marketability of CDL® (tests validated a 90% removal capability); and an optimum slate of upgraded products was identified. The upgraded products were: (1) crude cresylic acid, (2) pitch, (3) refinery feedstock (low-oxygen middle distillate), and (4) oxygenated middle distillate (industrial fuel).

Economic

The "base case" for economics of a commercial plant is the 15,000-metric-ton/day, three-unit North Rochelle LFC® plant, the commercial-scale plant proposed by ENCOAL, with an independent 80-MWe cogeneration unit, and no synthetic fuel tax credit (29c tax credit). It is assumed that the cogeneration unit is owned and operated by an independent third party. The capital cost for a full-scale three module LFC® plant is $475 million.

Economic benefits from an LFC® commercial plant are derived from the margin in value between a raw, unprocessed coal and the upgraded products, making an LFC® plant dependent on the cost of feed coal. In fact, this is the largest single operating cost item. The total estimated operating cost is $9.00/ton of feed coal including the cost of feed coal, chemical supplies, maintenance, and labor.

Commercial Applications

In a commercial application, CDL® would be upgraded to cresylic acid, pitch, refinery feedstock, and oxygenated middle distillate. Oxygenated middle distillate, the lowest value by-product, would be used in lieu of natural gas as a make-up fuel for the process (30% of the process heat input). PDF® would be marketed not only as a boiler fuel but as a supplement or substitute for coke in the steel industry. PDF® characteristics make it attractive to the metallurgical market as a coke supplement in pulverized coal injection and granular coal injection methods, and as a reductant in direct reduced iron processes.

Partners in the ENCOAL® project completed five detailed commercial feasibility studies over the course of the demonstration and shortly thereafter—two Indonesian, one Russian, and two U.S. projects. A U.S. project has received an Industrial Siting Permit and an Air Quality Construction Permit, but the project is on hold due to lack of funding.

Contacts

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Industrial Applications

Clean Power from Integrated Coal/Ore Reduction (CPICOR™)

Participant
CPICOR™ Management Company LLC (a limited liability company composed of subsidiaries of the Geneva Steel Company)

Additional Team Members
Geneva Steel Company—cofunder, constructor, host, and operator of unit

Location
Vineyard, Utah County, UT (Geneva Steel Co.'s mill)

Technology
HIsmelt® direct iron making process

Plant Capacity/Production
3,300 ton/day liquid iron production

Coal
Bituminous, 0.5% sulfur

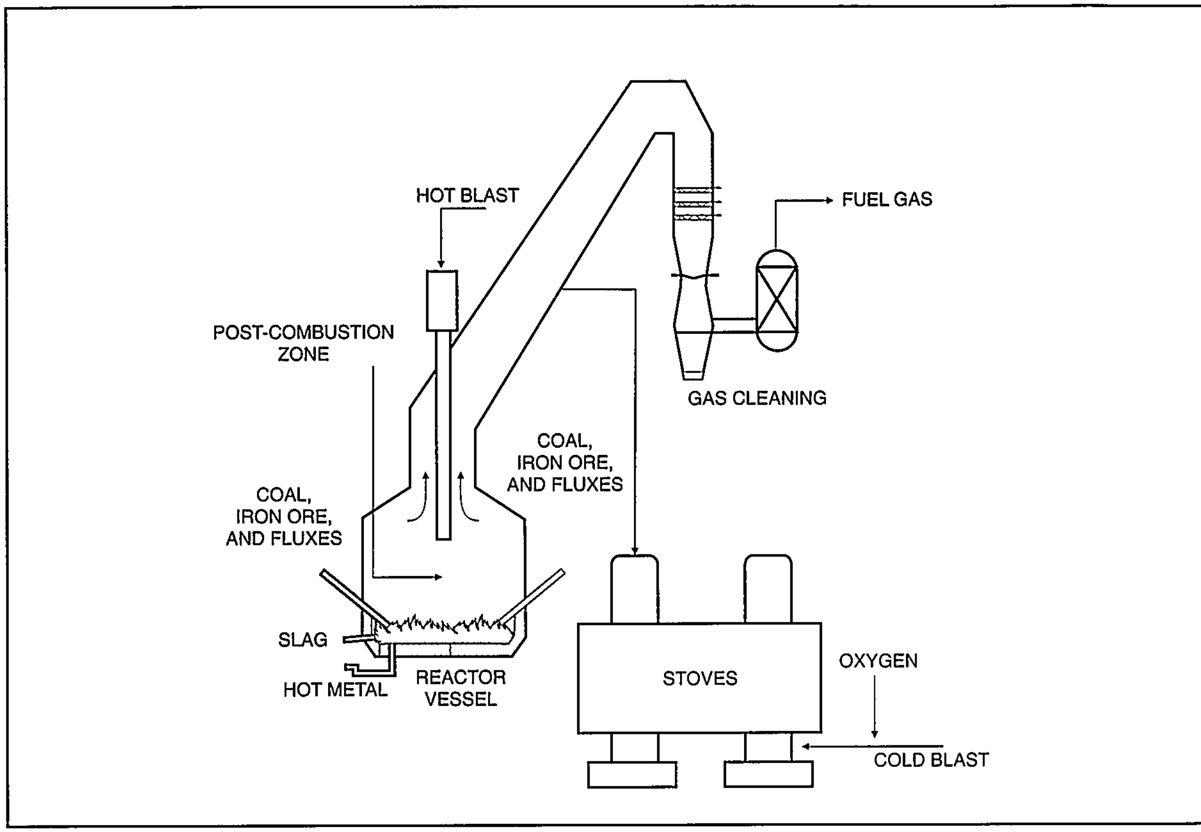
Project Funding

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

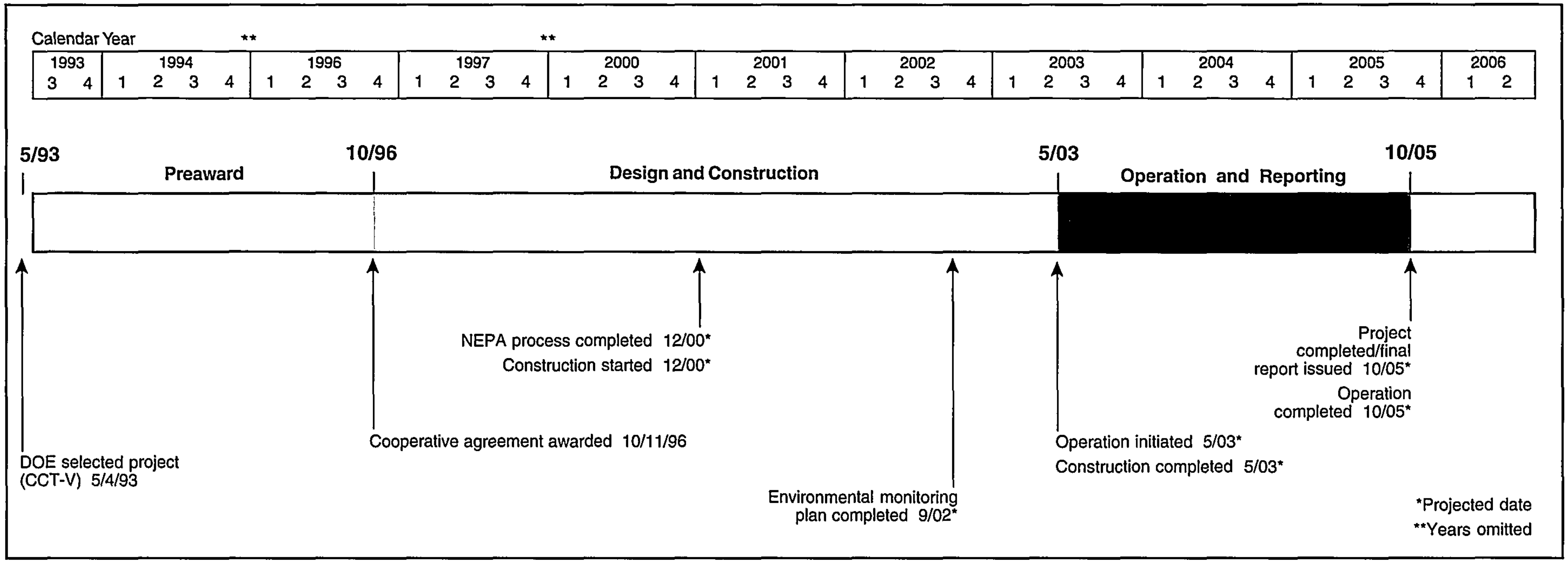
Project Objective
To demonstrate the integration of direct iron making with the coproduction of electricity using various U.S. coals in an efficient and environmentally responsible manner.

Technology/Project Description
The HIsmelt® process is based on producing hot metal and slag from iron ore fines and non-coking coals. The heart of the process is producing sufficient heat and maintaining high heat transfer efficiency in the post-combustion zone above the reaction zone, to reduce and smelt iron oxides. The HIsmelt® process uses a vertical smelt reduction reactor, which is a closed molten bath vessel, into which iron ore fines, coal, and fluxes are injected. The coal is injected into the bath where carbon is dissolved rapidly. The carbon reacts with oxygen (from the iron ore) to form CO and metallic iron. Injection gases and evolved CO entrain and propel droplets of slag and molten iron upward into the post-combustion zone.

The iron reduction reaction in the molten bath is endothermic; therefore, additional heat is needed to sustain the process and maintain hot metal temperature. This heat is generated by post-combusting the CO and hydrogen from the bath with an O_2-enriched hot air blast from the central top lance. The heat is absorbed by the slag and molten iron droplets and are returned to the bath by gravity. Droplets in contact with the gas in the post-combustion zone absorb heat, but are shrouded during the descent by ascending reducing gases (CO), which, together with bath carbon, prevent unacceptable levels of FeO in the slag. The molten iron collects in the bottom of the bath and is continuously tapped from the reactor through a fore-hearth, which maintains a constant level of iron in the reactor. Slag, which is periodically tapped through a conventional blast furnace-type tap hole, is used to coat and control the internal cooling system and reduce the heat loss. Reacted gases, mainly N_2, CO_2, CO, H_2, and H_2O, exit the vessel. After scrubbing the reacted gases, the cleaned gases will be combusted to produce 170 MWe of power. The cleaned gases can also be used to pre-heat and partially reduce the incoming iron ore.



HIsmelt is a registered trademark of HIsmelt Corporation Pty Limited.
CPICOR is a trademark of the CPICOR™ Management Company, L.L.C.



Project Status/Accomplishments

The cooperative agreement was awarded on October 11, 1996. CPICOR™ analyzed the global assortment of new direct ironmaking technologies to determine which technology would be most adaptable to western U.S. coals and raw materials. Originally, the COREX® process appeared suitable for using Geneva's local raw materials; however, lack of COREX® plant data on 100% raw coals and ores prevented its application in this demonstration. Thus, CPICOR™ chose to examine alternatives. The processes evaluated included: AISI direct ironmaking, DIOS, Romelt, Tecnored, Cyclonic Smelter, and HIsmelt®. The HIsmelt® process appears to offer good economic and operational potential, as well as the prospect of rapid commercialization. CPICOR™ has completed testing of two U.S. coals at the HIsmelt® pilot plant near Perth, Australia.

Project definition, preliminary design, and environmental permitting are on-going. On July 28, 1999, DOE issued a Notice of Intent to prepare an Environmental Impact Statement for the project. A NEPA public scoping meeting was held in Provo, Utah on July 15, 1999.

On February 1, 1999, Geneva Steel Company (CPICOR™ Management Company's parent corporation) filed a voluntary petition for bankruptcy under Chapter 11 of the United States Bankruptcy Code in the U.S. Bankruptcy Court for the District of Utah. Geneva Steel intends to emerge from Chapter 11 with a restructured balance sheet that will enable full participation in this demonstration project.

Commercial Applications

The HIsmelt® technology is a direct replacement for existing blast furnace and coke-making facilities with additional potential to produce steam for power production. Of the existing 79 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. HIsmelt® represents a viable option as a substitute for conventional iron making technology.

The HIsmelt® process is ready for demonstration. Two pilot plants have been built, one in Germany in 1984 and one in Kwinana, Western Australia in 1991. Through test work in Australia, the process has been proven—operational control parameters have been identified and complete computer models have been successfully developed and proven.

Pulse Combustor Design Qualification Test

Participant
ThermoChem, Inc.

Additional Team Member
Manufacturing and Technology Conversion International, Inc. (MTCI)—technology supplier

Location
Baltimore, MD (MTCI Test Facility)

Technology
MTCI's Pulsed Enhanced™ Steam Reforming process using a multiple resonance tube pulse combustor.

Plant Capacity/Production
30 million Btu/hr (steam reformer)

Coal
Black Thunder (Powder River Basin) subbituminous

Project Funding

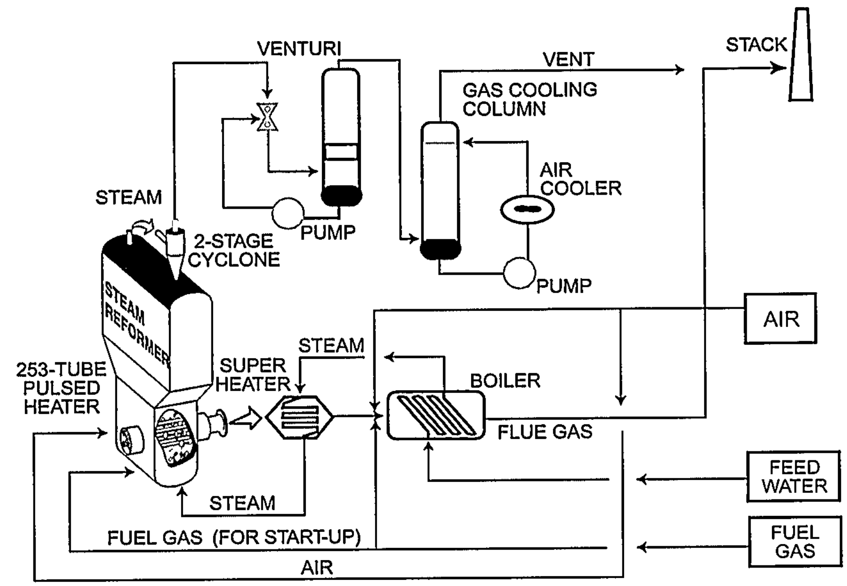
Total project cost	$8,612,054	100%
DOE	4,306,027	50
Participants	4,306,027	50

Project Objective
To demonstrate the operational/commercial viability of a single 253-resonance-tube pulse combustor unit and evaluate characteristics of coal-derived fuel gas generated by an existing Process Data Unit.

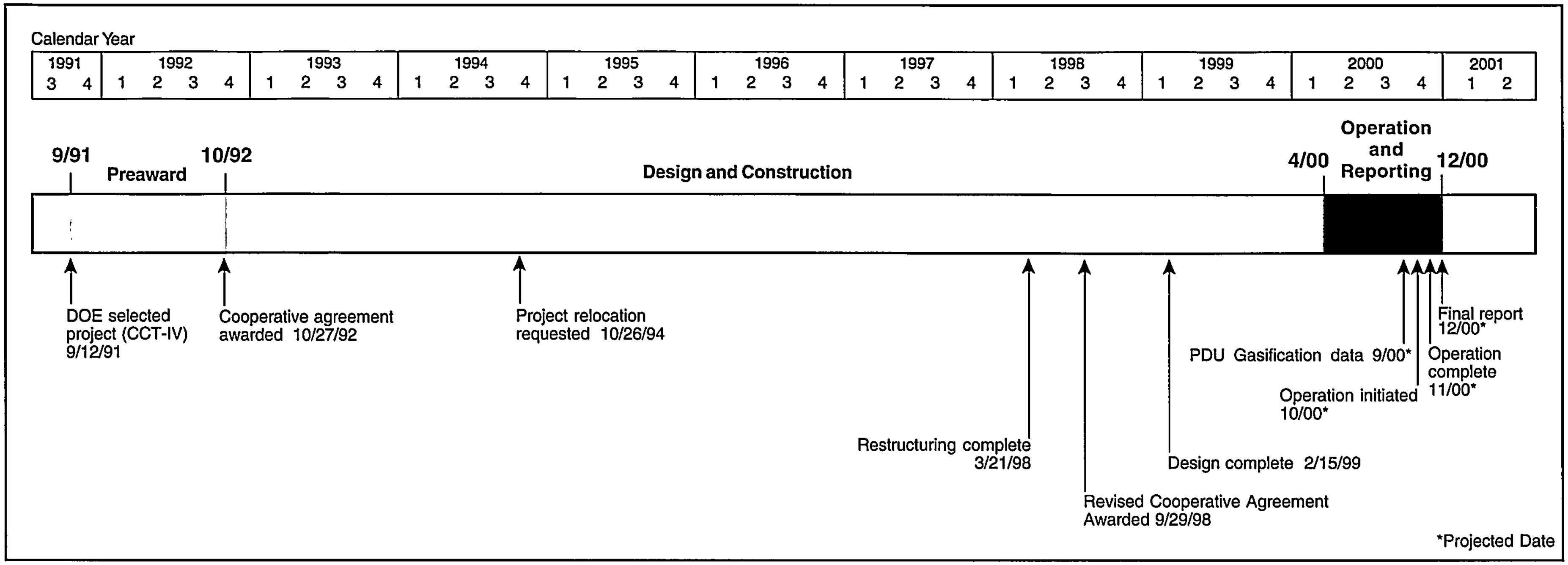
Technology/Project Description
MTCI's Pulsed Enhanced™ Steam Reforming process incorporates an indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean, medium-Btu content fuel gas without the need for an oxygen plant. Indirect heat transfer is provided by immersing multiple resonance-tube pulse combustors in a fluidized-bed steam gasification reactor. Pulse combustion increases the heat transfer rate by a factor of 3 to 5, thus greatly reducing the heat transfer area required in the gasifier.

The pulse combustor represents the core of the Pulsed Enhanced™ Steam Reforming process because it provides a highly efficient and cost-effective heat source. Demonstration of the combustor at the 253-resonance-tube commercial-scale is critical to market entry. The 253-resonance-tube unit represents a 3.5:1 scale-up from previous tests. Testing will seek to verify scale-up criteria and appropriateness of controls and instrumentation. Also, an existing process data unit will be used to gasify coal feedstock to provide fuel gas data, including energy content, species concentration, and yield. Char from the process data unit will be evaluated as well.

The facility will also have a product gas cleanup train that includes two stages of cyclones, a venturi scrubber with a scrubber tank, and a gas quench column. An air-cooled heat exchanger will be used to reject heat from the condensation of excess steam (unreacted fluidization steam) quenched in the venturi scrubber and gas quench column. All project testing will be performed at the MTCI test facility in Baltimore, Maryland.



Pulsed Enhanced is a trademark of MTCI.



Project Status/Accomplishments

On September 10, 1998, DOE approved revision of ThermoChem, Inc.'s Cooperative Agreement for a scaled-down project. The original project, awarded in October 1992, was a commercial demonstration facility that would employ 10 identical 253-resonance-tube pulse combustor units. After fabrication of the first combustor unit, the project went through restructuring. The revised project will demonstrate a single 253-resonance-tube pulse combustor. NEPA requirements were satisfied on November 30, 1998, with a Categorical Exclusion. The first major milestone was completion of the design on February 15, 1999.

Construction of the 253-resonance-tube combustor unit is continuing. Operation is expected to begin in October 2000. Shakedown tests of the process data unit was conducted in April 2000. Following modifications to improve operability, PDU tests with Black Thunder subbituminous coal are expected to be completed in September 2000.

Commercial Applications

PulsedEnhanced™ Steam Reforming has application in many different processes. Coal, with the world production on the order of four billion tons per year, constitutes the largest potential feedstock for steam reforming. Other potential feedstocks include spent liquor from pulp and paper mills, refuse-derived fuel, municipal solid waste, sewage sludge, biomass, and other wastes.

Although the project will demonstrate mild gasification only, the following coal-based applications are envisioned:

- Coal processing for combined-cycle power generation,
- Coal processing for fuel cell power generation,
- Coal pond waste and coal rejects processing to produce a hydrogen-rich gas from the steam reformer for use in overfiring or reburning to reduce NO_x emissions,
- Coal processing for production of gas or liquid fuel, and char for the steel industry for use in direct reduction of iron ore,
- Coal processing for producing compliance fuels,
- Mild gasification of coal,
- Coprocessing of coal and wastes, and
- Coal drying.

In addition, the technology has application for black liquor processing and chemical recovery and for hazardous, low-level radioactive, and low-level mixed waste volume reduction and destruction.

Blast Furnace Granular-Coal Injection System Demonstration Project

Project completed.

Participant
Bethlehem Steel Corporation

Additional Team Members
British Steel Consultants Overseas Services, Inc. (marketing arm of British Steel Corporation)—technology owner

CPC-Macawber, Ltd. (formerly named Simon-Macawber, Ltd.)—equipment supplier

Fluor Daniel, Inc.—architect and engineer

ATSI, Inc.—injection equipment engineer (North America technology 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

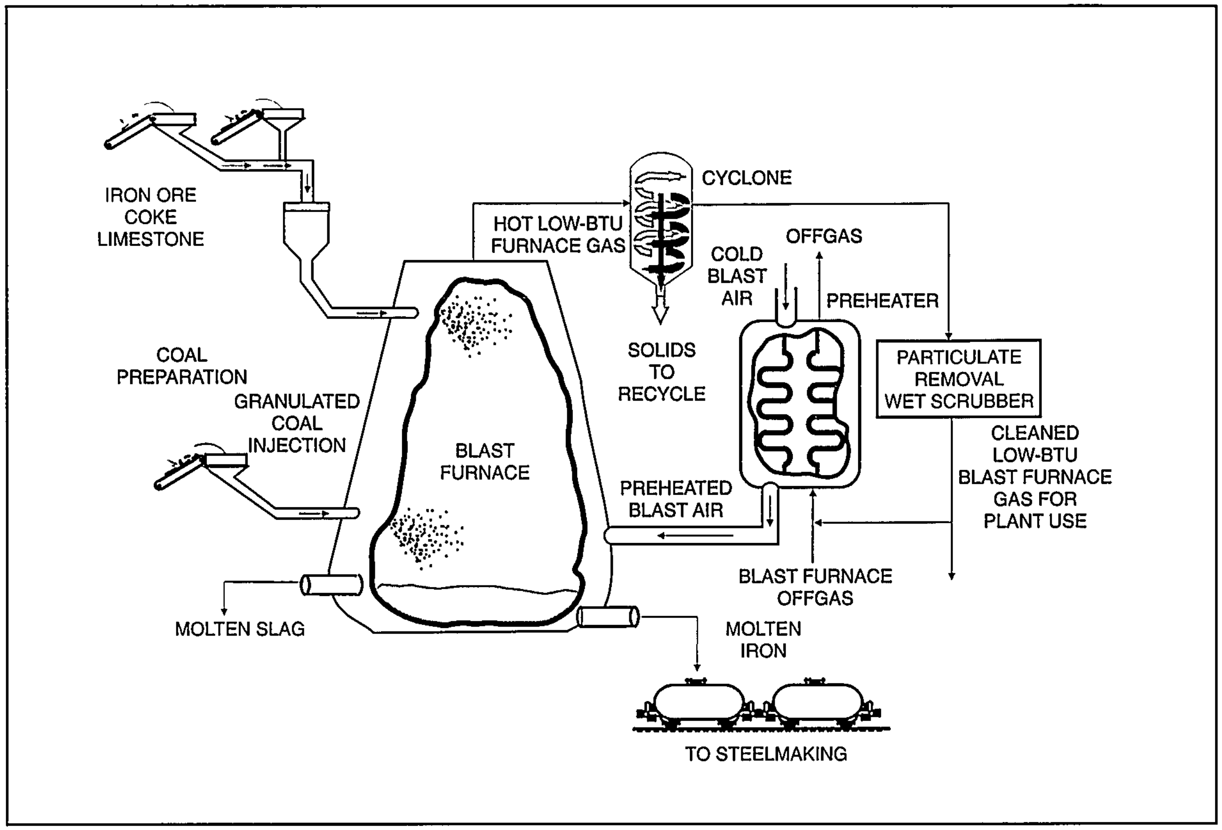
Plant Capacity/Production
7,000 net tons of hot metal (NTHM)/day (each blast furnace)

Coal
Eastern bituminous, 0.8–2.8% sulfur

Western subbituminous, 0.4–0.9% sulfur

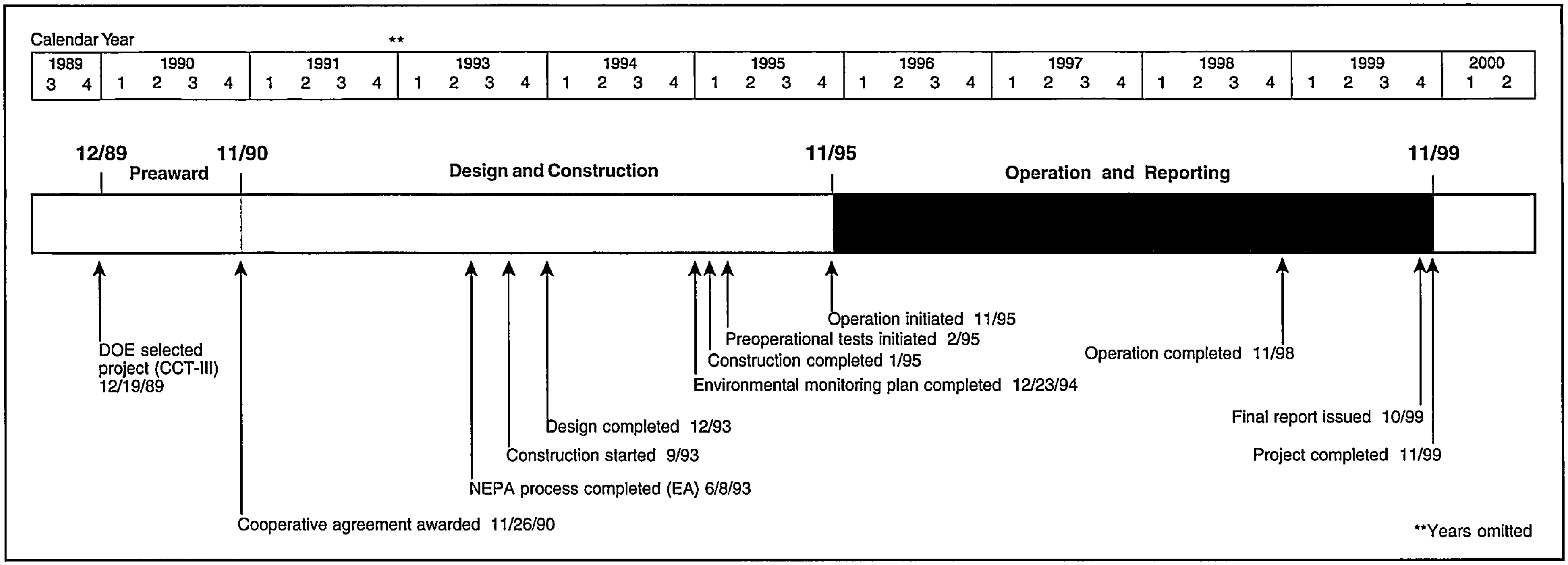
Project Funding

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; to demonstrate sustained operation with a variety of coal types, particle sizes, and injection rates; 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 natural gas injection, reduces blast furnace production rates. Coal, with a lower hydrogen content than either natural gas or oil, does not cause as severe a reduction in raceway temperatures. In addition to displacing 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 up to 40% of total requirements. Emissions generated by the blast furnace itself remain virtually unchanged by the injected coal; the gas exiting the blast furnace is cleaned and used in the mill. Sulfur from the coal is removed by the limestone flux and bound up in the slag, which is a salable by-product. Two high-capacity blast furnaces, Units C and D at Bethlehem Steel's Burns Harbor Plant, were retrofitted with BFGCI technology.



Results Summary

Environmental

- The BFGCI technology has the potential to reduce pollutant emissions substantially by displacing coke, the production of which results in significant emissions of air toxics.

Operational

- The low-ash, low-volatile, high-carbon coal provided a high coke replacement value.
- Reliability of the coal system enabled the operators to reduce furnace coke to a low rate of 661 lb/NTHM (pre-demonstration rate was 740 lb/NTHM).
- During the base period, permeability of the carbon layer in the blast furnace burden column (a critical parameter) indicated overall acceptable operation using low-ash, low-volatile, high-carbon coal.
- Granular coals are easier to handle in pneumatic conveying systems than pulverized coal because granular coals are not as likely to stick to conveying pipes if moisture control is not adequately maintained.
- Any decrease in furnace permeability as a result of coal injection can be minimized by increasing oxygen enrichment and raising moisture additions to the blast furnace.
- Higher ash coal had no adverse effect on furnace permeability.
- The productivity rate of the furnace was not affected by the 2.4 percentage point increase in coal ash at an injection rate of 260 lb/NTHM.
- There is a coke rate disadvantage of 3 lb/NTHM for each 1 percentage point increase of ash in the coal at an injection rate of 260 lb/NTHM.
- Hot metal quality was not affected by the increased ash content of the injection coal.

Economic

- The capital cost for one complete injection system at Burns Harbor was $15,073,106 (1990$) for the 7,200 NTHM/day blast furnace.
- The total fixed costs (labor and repair costs) at Burns Harbor were $6.25/ton of coal. The total variable costs (water, electricity, natural gas, and nitrogen) were $3.56/ton of coal. Coal costs were $50-60/ton.
- At a total cost of $60/ton and a natural gas cost of $2.85/10^6 Btu, the iron cost savings would be about $6.50/ton of iron produced.
- Based on the Burns Harbor production of 5.2 million tons of iron per year, the annual savings is about $34 million/yr.

Project Summary

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 NTHM/day. The two units use about 2,800 ton/day of coal during full operation. This project represents the first U.S. blast furnace designed to deliver granular (coarse) coal. All previous blast furnaces have been designed to deliver pulverized (fine) coal. The project also represents about a 100% scale-up from CPC-Macawber's Scunthorpe Works in England where the technology was developed.

In addition to testing the technology on large, high-production blast furnaces, Bethlehem Steel conducted testing on different types of U.S. coal to determine the effect on blast furnace performance. Tests included eastern bituminous coals with sulfur contents of 0.8–2.8% and western subbituminous coals having 0.4–0.9% sulfur. Specifically, the objective of the test program was to determine the effect of coal grind and coal type on blast furnace performance. Other trials include determining the effects of coal types and coal chemistry on furnace performance. To date, results of two trials have been reported—a base period using low-ash, low-volatile coal and a trial period using high-ash, low-volatile coal.

Operational Summary

Virginia Pocahontas and Buchanan, a chemically similar coal from the same seam, but from a different mine, were used all of 1996. During the entire month of October 1996, the Burns Harbor C blast furnace operated without interruption using Virginia Pocahontas. This low-ash, low-volatile, high-carbon coal provided a high coke replacement value for the base period test. The coal feed rate varied from 246–278 lb/NTHM on a daily basis for an average feed rate of 264 lb/NTHM. The furnace coke rate during the period averaged 661 lb/NTHM. The granular coal injected in C furnace was about 15% minus 200 mesh for the month.

The injected coal rate of 264 lb/NTHM is one of the highest achieved since startup of the coal facility. Reliability of the coal system enabled the operators to reduce furnace coke to a low rate of 661 lb/NTHM. This low coke rate is not only economically beneficial, it is an indicator of the efficiency of furnace operation with regard to displacing coke with injected coal.

Hot metal chemistry, particularly that of silicon and sulfur content, is important in iron making. Specific silicon and sulfur values with low variability are vital to meeting steel-making specifications. The average values and standard deviations for silicon and sulfur can be seen in Exhibit 2-41. These values are compared to typical operation data on natural gas collected in January 1995.

Exhibit 2-41 also shows the significant operating changes that occur with the use of injected coal versus natural gas. The wind volume on the furnace decreased significantly with the use of coal. Oxygen enrichment increased from 24.4% to 27.3% with coal. The amount of moisture added to the furnace in the form of steam significantly increased from 3.7 grains/SCF to 19.8 grains/SCF. All of these variables were increased by operating personnel to maintain adequate burden material movement. These actions also increased the permeability of the furnace burden column, which is a function of the blast rate and the pressure drop through the furnace. The larger the permeability value, the better the furnace burden movement and the better the reducing gas flow rate through the furnace column. During the base period, the permeability indicated overall acceptable operation using low-ash, low-volatile, high-carbon coal.

The next series of tests involved using a higher ash coal. In order to ensure that other variables did not influence the test results, Buchanan coal was used, but the ash content was increased by eliminating one of the usual coal cleaning steps. The ash content of the coal used for the high-ash trial was 7.70% compared with 5.30% for the base period trial and 4.72% for the period immediately prior to the high-ash coal trial. As during the base trial period, the granular coal was about 15% minus 200 mesh. To ensure comparable results, Bethlehem Steel operators maintained operation consistent with the base period trials. A comparison of the high-ash trial to the base period is also contained in Exhibit 2-41. The amount of injected coal, general blast conditions, wind volume, blast pressure, top pressure, and moisture additions were comparable during the two trials.

The primary change in operation, as expected, was the increase in the blast furnace slag volume. With the higher ash coal, the 461 lb/NTHM slag volume was 8.7% higher than the baseline period of 424 lb/NTHM. The general conclusion is that higher ash content in the injected coal can be adjusted by the furnace operators and does not adversely affect overall furnace operations. However, the results lead to the conclusion that a 2.4 percentage point increase in injected coal ash results in a 8 lb/NTHM increase in the furnace coke rate after correcting for other variables. This is the amount of coke carbon needed to replace the lower carbon in the higher-ash coal without an additional process penalty.

Environmental Summary

The greatest environmental benefit to the BFGCI is displacement of coke in favor of coal. Coke is essentially replaced on a pound-for-pound basis with granulated coal, up to 40% of the total requirements. The BFGCI technology has the potential to reduce pollutant emissions because coke production results in significant emissions of air toxics.

Economic Summary

Capital cost for one complete injection system at Burns Harbor was approximately $15 million (1990$). This does not include infrastructure improvements, which cost $87 million at Burns Harbor. The fixed operating cost, which includes labor and repair costs, was $6.25/ton of coal. The variable operating cost, which includes water, electricity, natural gas, and nitrogen, was $3.56/ton of coal. Coal costs were $50–60/ton. This brought

Exhibit 2-41
BFGCI Test Results

	Pre-Demonstration January 1995	Base October 1996	High-Ash Test May 28–June 23, 1997
Production, NTHM/day	**7,436**	**6,943**	**7,437**
Coke Rate, lb/NTHM	740	661	674
Natural Gas Rate, lb/NTHM	141	0	5.0
Injected Coal Rate, lb/NTHM	0	264	262
Total Fuel Rate, lb/NTHM	881	925	940
Blast Conditions:			
Dry Air, scfm	167,381	137,005	135,370
Blast Pressure, psig	38.9	38.8	38.3
Permeability	1.57	1.19	1.23
Oxygen in wind, %	24.4	27.3	28.6
Temp, °F	2,067	2,067	2,012
Moisture, grains/scf	3.7	19.8	20.7
Coke:			
H_2O, %	4.8	5.0	5.0
Hot Metal %:			
Silicon (Standard Dev.)	0.44 (0.091)	0.50 (0.128)	0.49 (0.97)
Sulfur (Standard Dev.)	0.043 (0.012)	0.040 (0.014)	0.035 (0.012)
Phos.	0.070	0.072	0.073
Mn.	0.40	0.43	0.46
Temp. °F	2,745	2,734	2,733
Slag %:			
SiO_2	38.02	36.54	36.21
Al_2O_3	8.82	9.63	9.91
CaO	37.28	39.03	39.40
MgO	12.02	11.62	11.32
Mn	0.45	0.46	0.45
Sulfur	0.85	1.39	1.40
B/A	1.05	1.10	1.10
B/S	1.30	1.39	1.40
Volume, lb/NTHM	394	424	461

the total operating costs to $59.81–69.81/ton of coal. Using $60/ton of coal and a natural gas cost of $.88/$10^6$ Btu, the cost savings would be about $6.50/ton of iron produced. At Burns Harbor, which produces 5.2 million tons of iron per year, the savings would be about $34 million/yr. At Burns Harbor, the payback period is 3.44 years using a simple rate of return calculation.

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 U.S. 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 Simon-Macawber (now CPC-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. CPC-Macawber has also installed a similar facility at United States Steel Corporation's Fairfield blast furnace.

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Hill, D.G. *et al.* "Blast Furnace Granular-Coal Injection System Demonstration Project." *Sixth Clean Coal Conference Proceedings: Volume II* - Technical Papers. April–May, 1998.

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

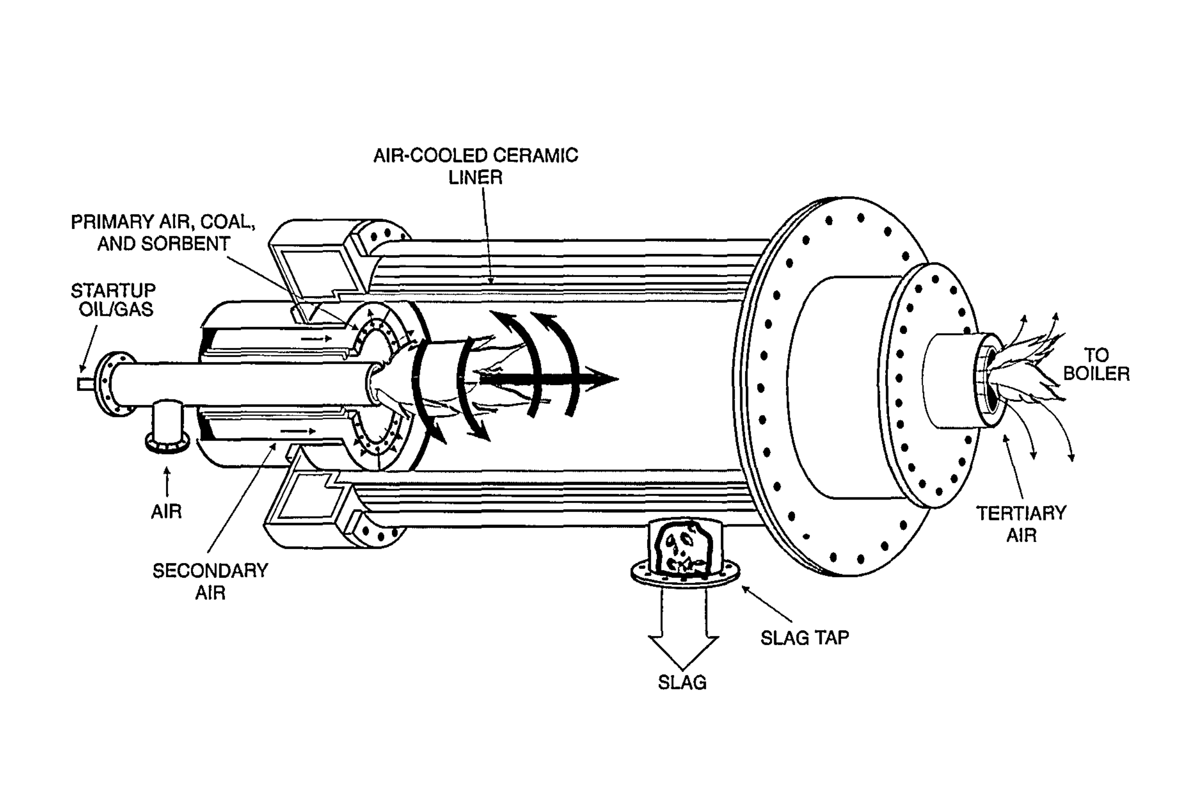
Plant Capacity/Production
23 x 10^6 Btu/hr of steam

Coal
Pennsylvania bituminous, 1.0–3.3% sulfur

Project Funding

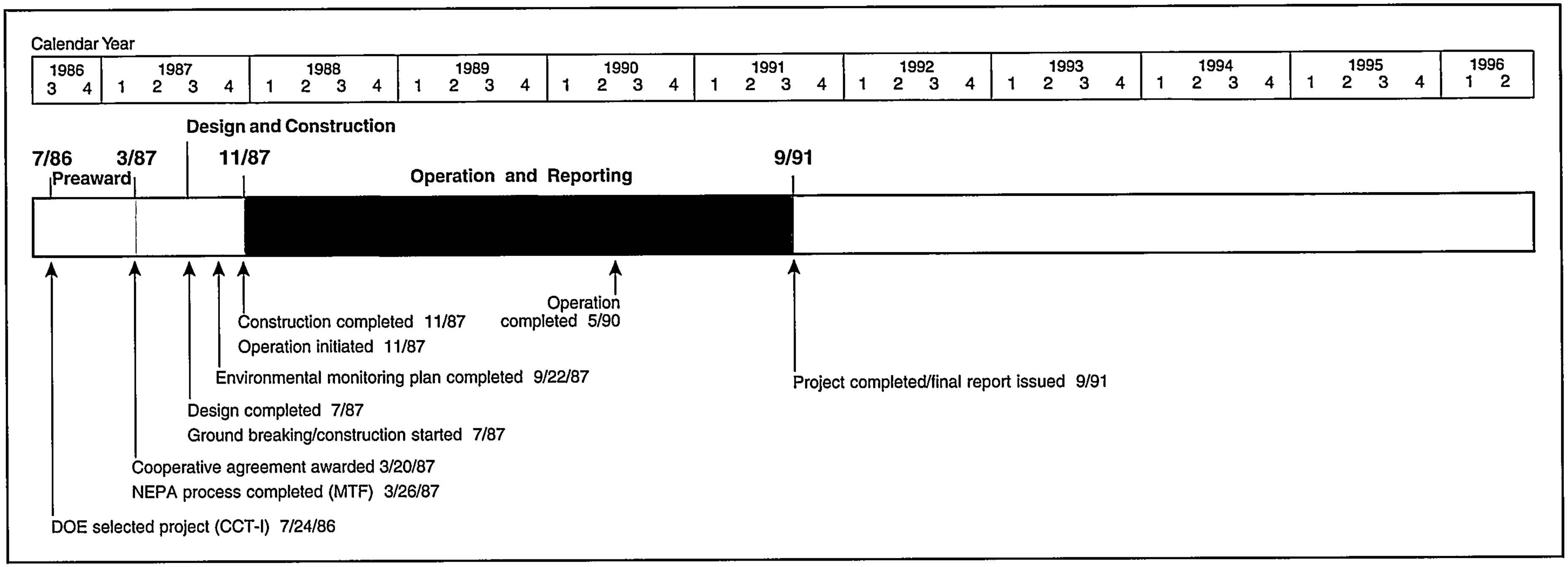
Total project cost	$984,394	100%
DOE	490,149	50
Participant	494,245	50

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 lined with an air-cooled ceramic. 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 so that a high percentage of the ash and sorbent fed to the combustor as slag. 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 x 10^6 Btu/hr, oil-fired package boiler located at the Tampella Power Corporation boiler factory in Williamsport, Pennsylvania.



Results Summary

Environmental

- SO_2 removal efficiencies of over 80% were achieved with sorbent injection in the furnace at various calcium-to-sulfur (Ca/S) molar ratios.
- SO_2 removal efficiencies up to 58% were achieved with sorbent injection in the combustor at a Ca/S molar ratio of 2.0.
- A maximum of one-third 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 55–90%. Under more fuel-lean conditions, retention averaged 80%.
- Meeting local particulate emissions standards required the addition of a wet venturi scrubber.

Operational

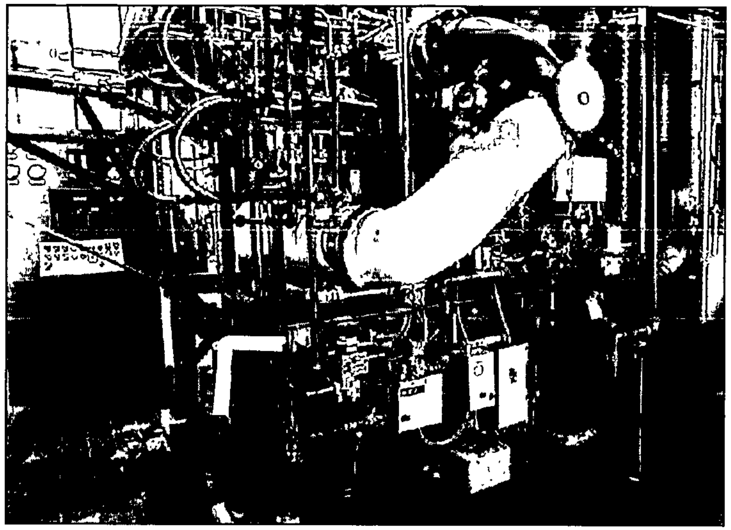
- Combustion efficiencies of over 99% were achieved.
- A 3-to-1 combustor turndown capability was demonstrated. Protection of combustor refractory with slag was shown to be possible.
- A computer-controlled system for automatic combustor operation was developed and demonstrated.

Economic

- Because the technology failed to meet commercialization criteria, economics were not developed during the demonstration. However, subsequent efforts indicate that the incremental capital cost for installing the coal combustor in lieu of oil or gas systems is $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 slagging combustor, associated piping, and control panel for Coal Tech's advanced ceramic-lined slagging combustor are shown.

The test effort consisted of 800 hours of operation, including five individual tests, each of four 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 1.0–3.3% and volatile matter contents ranging from 19–37% 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 molar ratio 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 55–90%. Under more fuel-lean conditions, the slag retention averaged 80%. After the CCT project, tests on fly ash 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.

Operational Performance

Combustion efficiencies exceeded 99% after proper operating procedures were achieved. Combustor turndown to 6 x 10^6 Btu/hr from a peak of 19 x 10^6 Btu/hr (or a 3-to-1 turndown) was achieved. The maximum heat input during the tests was around 20 x 10^6 Btu/hr, even though the combustor was designed for 30 x 10^6 Btu/hr and the boiler was thermally rated at around 25 x 10^6 Btu/hr. This situation resulted from facility limits on water availability for the boiler. In fact, due to the lack of sufficient water cooling, even 20 x 10^6 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 fly ash vitrification test 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 a project objective. Not only were procedures for properly operating an air-cooled combustor developed, but the entire operating database was incorporated into a computer-controlled system for automatic combustor operation.

Commercial Applications

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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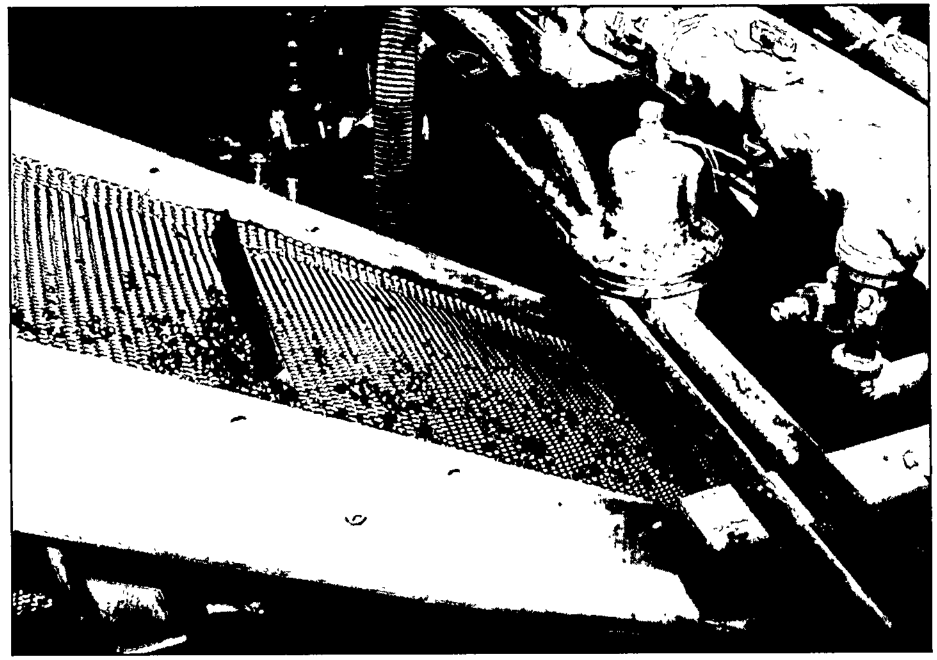
References

- *The Coal Tech Advanced Cyclone Combustor Demonstration Project—A DOE Assessment.* Report No. DOE/PC/79799-T1. U.S. Department of Energy. May 1993. (Available from NTIS as DE93017043.)
- *The Demonstration of an Advanced Cyclone Coal Combustor, with Internal Sulfur, Nitrogen, and Ash Control for the Conversion of a 23-MMBtu/Hour Oil Fired Boiler to Pulverized Coal; Vol. 1: Final Technical Report; Vol. 2: Appendixes I–V; Vol. 3: Appendix VI.* Coal Tech Corporation. August 1991. (Available from NTIS as DE92002587 and DE92002588.)
- *Comprehensive Report to Congress on the Clean Coal Technology Program: Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control.* Coal Tech Corporation. Report No. DOE/FE-0077. U.S. Department of Energy. February 1987. (Available from NTIS as DE87005804.)



▲ Coal Tech's 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 an aggregate and in the manufacture of abrasives.

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 ton/day of cement; 250,000 scfm of kiln gas; and up to 274 ton/day of coal

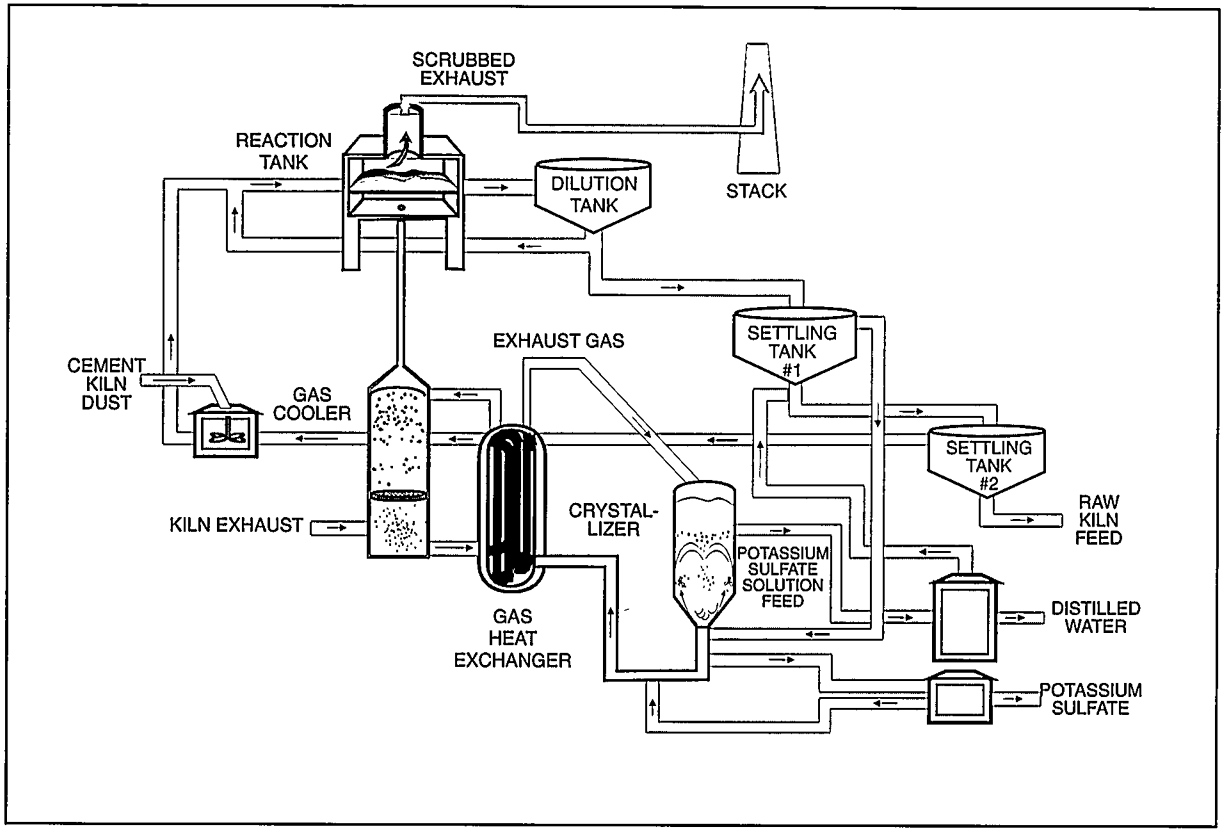
Coal
Pennsylvania bituminous, 2.5–3.0% sulfur

Project Funding

Total project cost	$17,800,000	100%
DOE	5,982,592	34
Participant	11,817,408	66

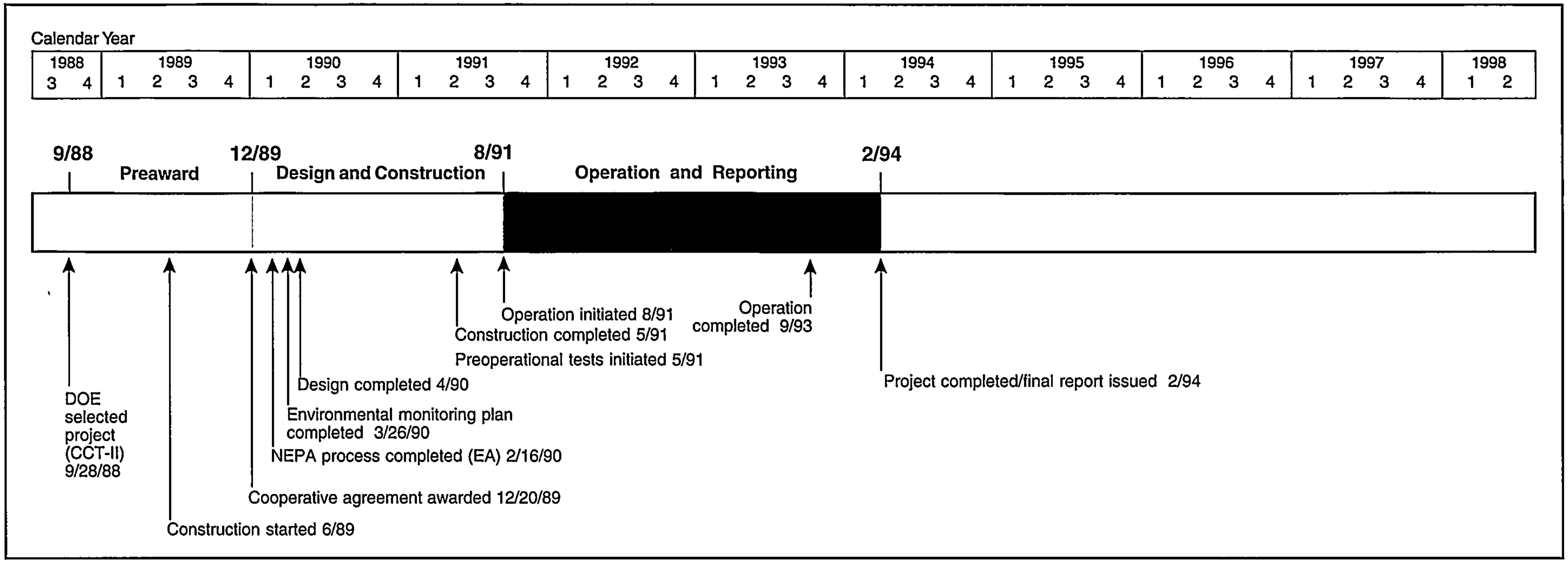
Project Objective
To retrofit and demonstrate a full-scale industrial scrubber and waste recovery system for a coal-burning wet process cement kiln using waste dust as the reagent to accomplish 90–95% SO_2 reduction using high-sulfur eastern coals; and to produce a commercial by-product, potassium-based fertilizer by-products.

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



Technology/Project Description
The Passamaquoddy Technology Recovery Scrubber™ uses cement kiln dust (CKD), an alkaline-rich (potassium) waste, to react with the acidic flue gas. This CKD, representing about 10% of the cement feedstock otherwise lost as waste, is formed into a water-based slurry and mixed with the flue gas as the slurry passes over a perforated tray that enables the flue gas to percolate through the slurry. The SO_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 Company cement 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 plant in Thomaston, Maine, a plant that can process approximately 450,000 ton/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 CKD from the cement-making process.



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, which resulted in reducing the raw feedstock requirement by 10% and eliminating solid waste disposal costs.
- Particulate emission rates of 0.005–0.007 gr/scf, about one-tenth that allowed for cement kilns, were achieved with dust loadings of approximately 0.04 gr/scf.
- 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.
- Operation 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 feedstock. 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 three 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 were 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 startup. No further problems were experienced in these areas during actual operation.

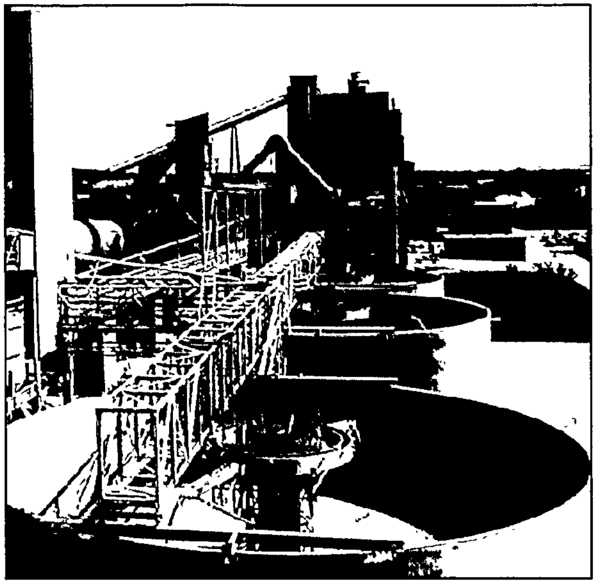
Two problems persisted into the demonstration period. The mesh-type mist eliminator, which was installed to prevent slurry entrainment in the flue gas, experienced plugging. Attempts to design a more efficient water spray for cleaning failed. However, replacement with a chevron-type mist eliminator prior 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 completed 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 ton/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 scfm of flue gas. All the CKD, or approximately 10 ton/hr, were renovated and returned to the plant as feedstock and mixed with about 90 ton/hr of fresh feed to make up the required 100 ton/hr. The alkali in the CKD was converted to potassium-based fertilizer, eliminating all solid waste. Exhibit 2-42 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.

Exhibit 2-42
Summary of Emissions and Removal Efficiencies

Operating Period	Operating Time (hr)	Inlet (lb/hr)		Outlet (lb/hr)		Removal Efficiency (%)	
		SO_2	NO_x	SO_2	NO_x	SO_2	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 operating time	5,316						
Weighted Average		**109**	**289**	**12**	**234**	**89.2**	**18.8**



▲ The Passamaquoddy Technology Recovery Scrubber™ was successfully demonstrated at Dragon Products Company's cement plant in Thomaston, Maine.

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 Maine's Department of Environmental Quality, the recovery scrubber was subjected to dust loadings of approximately 0.04 gr/scf and demonstrated particulate emission rates of 0.005–0.007 gr/scf—less than one-tenth the current allowable limit.

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 is required.

The simple payback on the investment is projected in as little as 3.1 years 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. 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 ton/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 ton/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.

Contacts

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References

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- *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.)

Appendix A: CCT Project Contacts

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, if available, for the project participant 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 National Energy Technology Laboratory (NETL) are provided.

Environmental Control Devices

SO_2 Control Technologies

10-MWe Demonstration of Gas Suspension Absorption

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Confined Zone Dispersion Flue Gas Desulfurization Demonstration

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LIFAC Sorbent Injection Desulfurization Demonstration Project

Participant:
LIFAC-North America

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Advanced Flue Gas Desulfurization Demonstration Project

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

Participant:
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NO_x Control Technologies

Micronized Coal Reburning Demonstration for NO_x Control

Participant:
New York State Electric & Gas Corporation

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(607) 762-8457 (fax)

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Demonstration of Coal Reburning for Cyclone Boiler NO_x Control

Participant:
The Babcock & Wilcox Company

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Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit

Participant:
The Babcock & Wilcox Company

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

Participant:
Energy and Environmental Research Corporation

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(949) 859-3194 (fax)

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Jerry L. Hebb, NETL, (412) 386-6079
hebb@netl.doe.gov

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

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

Participant:
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Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler

Participant:
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Enhancing the Use of Coals by Gas Reburning and Sorbent Injection

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Integrated Gasification Combined-Cycle

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Coal Processing for Clean Fuels

Indirect Liquefaction

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Appendix B: Acronyms, Abbreviations, and Symbols

Acronyms, Abbreviations, and Symbols

¢	cent
°C	degrees Celsius
°F	degrees Fahrenheit
$	dollars (U.S.)
$/kw	dollars per kilowatt
$/ton	dollars per ton
%	percent
®	registered trademark
™	trademark
ABB CE	ABB Combustion Engineering, Inc.
ABB ES	ABB Environmental Systems
ACFB	atmospheric circulating fluidized-bed
ADL	Arthur D. Little, Inc.
AEO99	*Annual Energy Outlook 1999*
AEO2000	*Annual Energy Outlook 2000*
AER98	*Annual Energy Review 1998*
AFBC	atmospheric fluidized-bed combustion
AFGD	advanced flue gas desulfurization
AIDEA	Alaska Industrial Development and Export Authority
AOFA	advanced overfire air
APF	advanced particulate filter
ARIL	Advanced Retractable Injection Lanes
ASME	American Society of Mechanical Engineers
Ass'n.	Association
ATCF	after tax cash flows
atm	atmosphere(s)
avg.	average
BFGCI	blast furnace granular-coal injection
BG	British Gas
Btu	British thermal unit(s)
Btu/kWh	British thermal units per kilowatt-hour
B&W	The Babcock & Wilcox Company
CAAA	Clean Air Act Amendments of 1990
$CaCO_3$	calcium carbonate (calcitic limestone)
CaO	calcium oxide (lime)
$Ca(OH)_2$	calcium hydroxide (calcitic hydrated lime)
$Ca(OH)_2 \cdot MgO$	dolomitic hydrated lime
Ca/N	calcium-to-nitrogen
CAPI	Clean Air Power Initiative
Ca/S	calcium-to-sulfur
$CaSO_3$	calcium sulfite
$CaSO_4$	calcium sulfate
CCOFA	close-coupled overfire air
CCT	clean coal technology
CCTDP	Clean Coal Technology Demonstration Program
CCT I	First CCT Program solicitation
CCT II	Second CCT Program solicitation
CCT III	Third CCT Program solicitation
CCT IV	Fourth CCT Program solicitation
CCT V	Fifth CCT Program solicitation
CCT Program	Clean Coal Technology Demonstration Program
CD-ROM	Compact disk-read only memory
CDL®	Coal-Derived Liquid®
CEQ	Council on Environmental Quality
CFB	circulating fluidized-bed
C/H	carbon/hydrogen
CKD	cement kiln dust
CO	carbon monoxide
CO_2	carbon dioxide
COP	Conference of Parties
CT-121	Chiyoda Thoroughbred-121
CQE™	Coal Quality Expert™
CQIM™	Coal Quality Impact Model™
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
DSE	dust stabilization enhancement
DSI	dry sorbent injection
EA	environmental assessment

EER	Energy and Environmental Research Corporation
EERC	Energy and Environmental Research Center, University of North Dakota
EFCC	externally fired combined cycle
EIA	Energy Information Administration
EIS	environmental impact statement
EIV	Environmental Information Volume
EMP	environmental monitoring plan
EPA	U.S. Environmental Protection Agency
EPAct	Energy Policy Act of 1992
EPDC	Japan's Electric Power Development Company
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
EWG	exempt wholesale generator
ext.	extension
FBC	fluidized-bed combustion
FCCC	Framework Convention on Climate Change
FeO	iron oxide
Fe_2S	pyritic sulfur
FERC	Federal Energy Regulatory Commission
FETC	Federal Energy Technology Center (now NETL)
FGD	flue gas desulfurization
FONSI	finding of no significant impact
FRP	fiberglass-reinforced plastic
ft, ft^2, ft^3	foot (feet), square feet, cubic feet
FY	fiscal year
gal.	gallon(s)
gal/ft^3	gallons per cubic feet
GB	gigabyte(s)
GE	General Electric
GHG	greenhouse gases
GNOCIS	Generic NO_x Control Intelligent System
gpm	gallons per minute
gr	grains
GR	gas reburning
GR-LNB	gas reburning and low-NO_x burner
GR-SI	gas reburning and sorbent injection
GSA	gas suspension absorption
GVEA	Golden Valley Electric Association
GW	gigawatt(s)
GWe	gigawatt(s)-electric
H	elemental hydrogen
H_2	molecular hydrogen
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid
HAP	hazardous air pollutant
HCl	hydrogen chloride
HF	hydrogen fluoride
HGPFS	hot gas particulate filter system
HHV	higher heating value
hr.	hour(s)
HRSG	heat recovery steam generator
ID	Induced Draft
IEA	International Energy Agency
IEO99	*International Energy Outlook 1999*
IEO2000	*International Energy Outlook 2000*
IGCC	integrated gasification combined-cycle
in, in^2, in^3	inch(es), square inches, cubic inches
JBR	Jet Bubbling Reactor®
KCl	potassium chloride
K_2SO_4	potassium sulfate
kW	kilowatt(s)
kWh	kilowatt-hour(s)
lb.	pound(s)
L/G	liquid-to-gas ratio
LHV	lower heating value
LIMB	limestone injection multistage burner
LNB	low-NO_x burner
LNCB®	low-NO_x cell burner
LNCFS	Low-NO_x Concentric-Firing System
LOI	loss-on-ignition
LPMEOH™	Liquid phase methanol™
LRCWF	low-rank coal-water-fuel
LSFO	limestone forced oxidation
MASB	multi-annular swirl burner
MB	megabyte(s)
MCFC	molten carbonate fuel cell
MCR	Maximum Continuous Rating
MDEA	methyldiethanolamine
$MgCO_3$	magnesium carbonate
MgO	magnesium oxide
MHz	megahertz
mills/kWh	mills per kilowatt hour
min.	minute(s)
mo.	month(s)
MTCI	Manufacturing and Technology Conversion International
MTF	memorandum (memoranda)-to-file
MW	megawatt(s)
MWe	megawatt(s)-electric
MWt	megawatt(s)-thermal
N	elemental nitrogen
N_2	molecular nitrogen
n.d.	not dated
N/A	not applicable

Na/Ca	sodium-to-calcium
Na_2/S	sodium-to-sulfur
NaOH	sodium hydroxide
Na_2CO_3	sodium carbonate
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory (formerly FETC)
NH_3	ammonia
Nm^3	Normal cubic meter
NO_2	nitrogen dioxide
NOPR	Notice of Proposed Rulemaking
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
NSR	normalized stoichiometric ratio
NTHM	net tons of hot metal
NTIS	National Technical Information Service
NYSEG	New York State Electric & Gas Corporation
O	elemental oxygen
O_2	molecular oxygen
O&M	operation and maintenance
OC&PS	Office of Coal & Power Systems
OTAG	Ozone Transport Assessment Group
OTC	Ozone Transport Commission
PASS	Pilot Air Stabilization System
PC	personal computer
PCAST	Presidential Committee of Advisors on Science and Technology
PCFB	pressurized circulating fluidized-bed
PDF®	Process-Derived Fuel®
PEIA	programmatic environmental impact assessment
PEIS	programmatic environmental impact statement
PEOA™	Plant Emission Optimization Advisor™
PENELEC	Pennsylvania Electric Company
PEP	progress evaluation plan
PFBC	pressurized fluidized-bed combustion
PJBH	pulse jet baghouse
PM	particulate matter
PM_{10}	particulate matter less than 10 microns in diameter
$PM_{2.5}$	particulate matter less than 2.5 microns in diameter
PON	program opportunity notice
PRB	Powder River Basin
ppm	parts per million (mass)
ppmv	parts per million by volume
PSCC	Public Service Company of Colorado
PSD	Prevention of Significant Deterioration
psi	pound(s) per square inch
psia	pound(s) per square inch absolute
psig	pound(s) per square inch gauge
PUHCA	Public Utility Holding Company Act of 1935
PURPA	Public Utility Regulatory Policies Act of 1978
QF	qualifying facility
RAM	random access memory
R&D	research and development
RD&D	research, development, and demonstration
REA	Rural Electrification Administration
RP&L	Richmond Power & Light
ROD	Record of Decision
ROM	run-of-mine
rpm	revolutions per minute
RUS	Rural Utility Service
S	sulfur
SBIR	Small Business Innovation Research
scf	standard cubic feet
scfm	standard cubic feet per minute
SCR	selective catalytic reduction
SCS	Southern Company Services, Inc.
SDA	spray dryer absorber
SFC	Synthetic Fuels Corporation
S-H-U	Saarberg-Hölter-Umwelttechnik
SI	sorbent injection
SIP	state implementation plan
SM	service mark
SNCR	selective noncatalytic reduction
SNRB™	SO_x-NO_x-Rox Box™
SO_2	sulfur dioxide
SO_3	sulfur trioxide
std ft^3	standard cubic feet
SOFA	separated overfire air
STTR	Small Business Technology Transfer Program
SVGA	super video graphics adapter
TAG™	Technical Assessment Guide™
TCLP	toxicity characteristics leaching procedure
TVA	Tennessee Valley Authority
UAF	University of Alaska, Fairbanks
UARG	Utility Air Regulatory Group
UBCL	unburned carbon losses
U.K.	United Kingdom
UNESCO	United Nations Educational, Scientific and Cultural Organization

U.S.	United States
VFB	vibrating fluidized bed
VOC	volatile organic compound
WC	water column
WES	wastewater evaporation system
W.G.	water gage
WLFO	wet limestone, forced oxidation
wt.	weight
yr.	year(s)

State Abbreviations

AK	Alaska
AL	Alabama
AR	Arkansas
AZ	Arizona
CA	California
CO	Colorado
CT	Connecticut
DC	District of Columbia
DE	Delaware
FL	Florida
GA	Georgia
HI	Hawaii
IA	Iowa
ID	Idaho
IL	Illinois
IN	Indiana
KS	Kansas
KY	Kentucky
LA	Louisiana
MA	Massachusetts
MD	Maryland
ME	Maine
MI	Michigan
MN	Minnesota
MO	Missouri
MS	Mississippi
MT	Montana
NC	North Carolina
ND	North Dakota
NE	Nebraska
NH	New Hampshire
NJ	New Jersey
NM	New Mexico
NV	Nevada
NY	New York
OH	Ohio
OK	Oklahoma
OR	Oregon
PA	Pennsylvania
PR	Puerto Rico
RI	Rhode Island
SC	South Carolina
SD	South Dakota
TN	Tennessee
TX	Texas
UT	Utah
VA	Virginia
VI	Virgin Islands
VT	Vermont
WA	Washington
WI	Wisconsin
WV	West Virginia
WY	Wyoming

Other

Some companies have adopted an acronym as their corporate names. The following corporate names reflect the former name of the company.

BGL	British Gas Lurgi
JEA	Jacksonville Electric Authority
KRW	Kellogg Rust Westinghouse

Index of CCT Projects and Participants

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