DOE/FE-0299P

CLEAN
COAL
TECHNOLOGY

Clean Coal Technology Demonstration Program

Program Update 1993

(As of December 31, 1993)

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

March 1994

Advanced Electric Power Generation Fact Sheets

PFBC Utility Demonstration Project

Sponsor:
The Appalachian Power Company

Additional Team Members:
American Electric Power Service Corporation—designer, constructor, and manager
The Babcock & Wilcox Company—technology supplier

Location:
New Haven, Mason County, WV (greenfield facility adjacent to Appalachian Power Company's Mountaineer Plant)

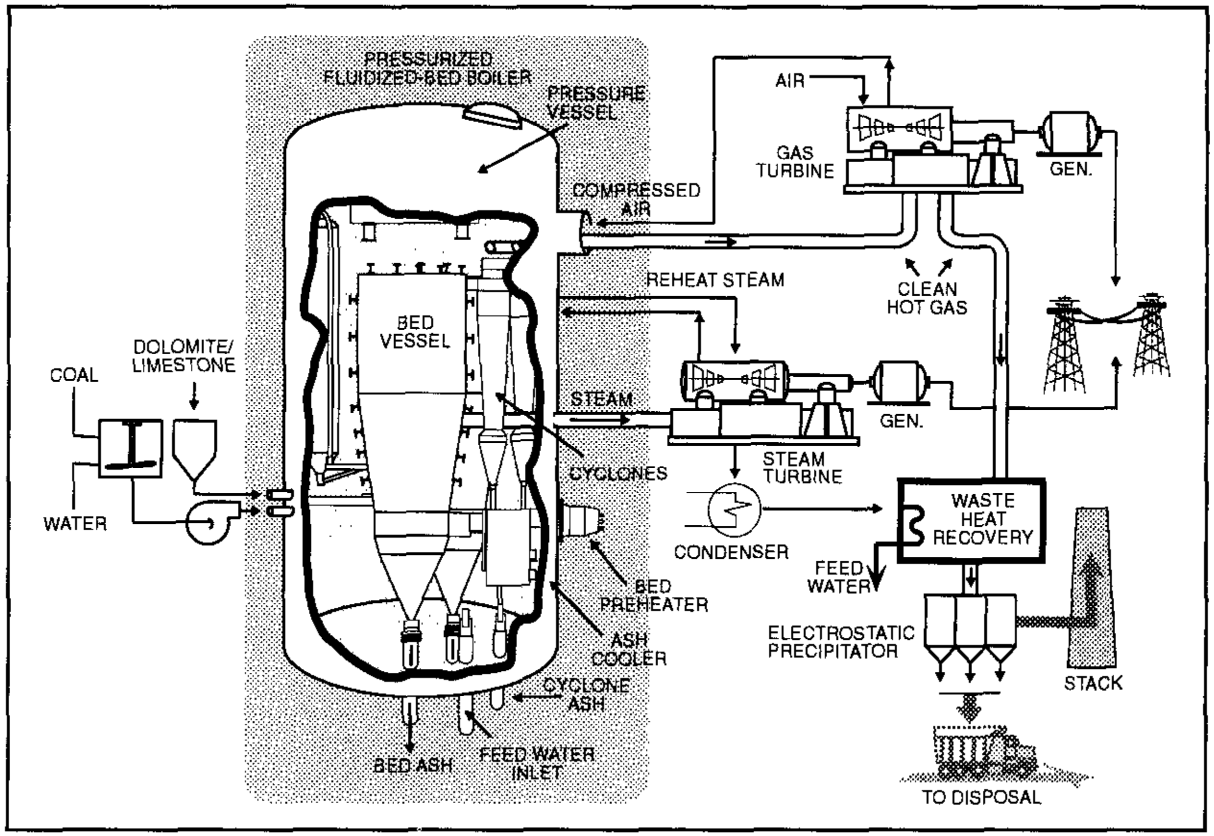
Technology:
The Babcock & Wilcox Company's pressurized fluidized-bed combustion (PFBC) system (under license from ABB Carbon) (advanced electric power generation/fluidized-bed combustion)

Plant Capacity/Production:
340 MWe (net)

Project Funding:

Total project cost	$917,944,000	100%
DOE	184,800,000	20
Participants	733,144,000	80

Project Objective:
To demonstrate PFBC at 340 MWe, a large utility scale representing a four-fold scaleup of the technology, the world's largest PFBC, and the first commercial application of PFBC in the United States; to assess long-term reliability, availability, and maintainability of PFBC in a commercial operating mode and the integration of a reheat steam cycle.

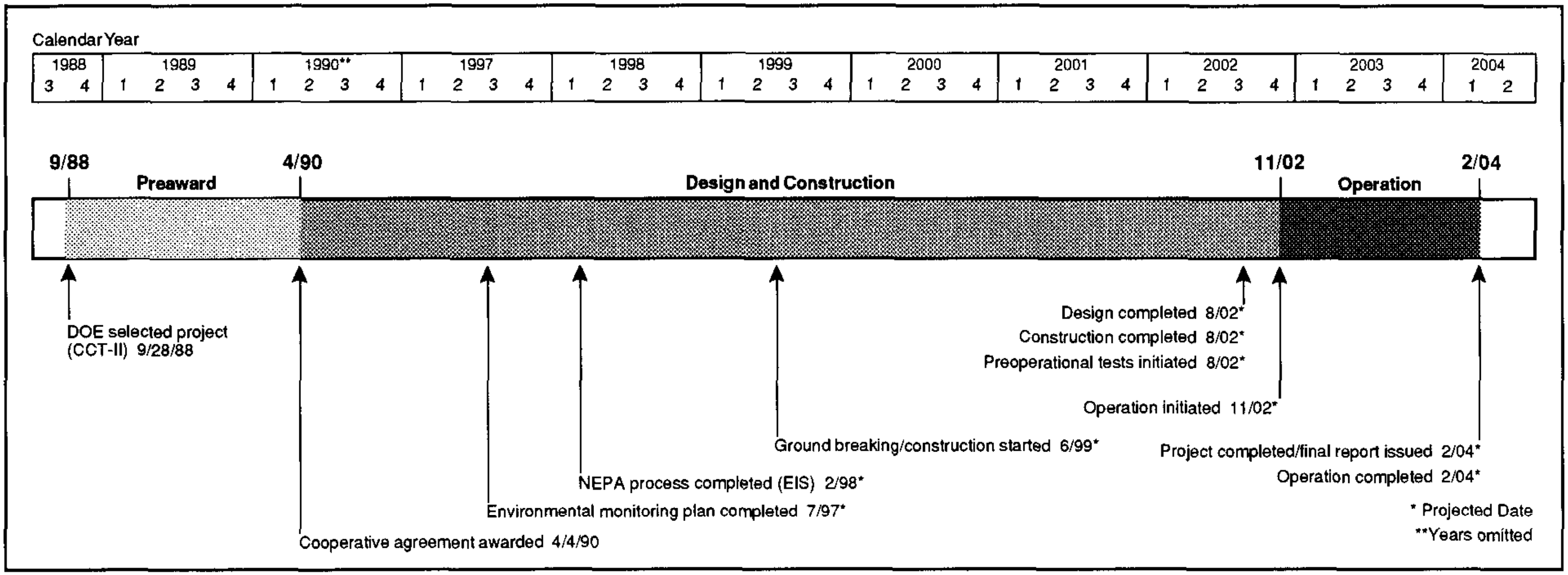


Technology/Project Description:
This project will be a greenfield facility located adjacent to the existing Mountaineer and Sporn plants. The most noticeable aspect of the unit is that the boiler, cyclones, reinjection vessel, and associated hardware are encapsulated in a pressure vessel 60 ft in diameter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

The project incorporates a bubbling fluidized-bed process operating at 16 atm (235 lb/in^2 atm). Pressurized combustion air is supplied by the turbine compressor to fluidize the bed material (consisting of a coal-water fuel paste, coal ash, and a dolomite or limestone sorbent). Dolomite or limestone in the bed reacts with sulfur to form calcium sulfate, a dry, granular bed-ash material, which is easily disposed of or used as a by-product. A low bed-temperature of 1,600 °F limits NO_x formation.

The hot combustion gases exit the bed vessel with entrained ash particles, 98% of which are removed when the gases pass through cyclones. An option being considered is to employ some advanced filtration devices in the design. The cleaned gases are then expanded through a 75-MWe gas turbine.

The reheat system turbine operates at a state-of-the-art pressure and temperature to produce at least 250 MWe. Superheated steam will be produced from pressurized boiler-feed water in the tubes submerged in the fluidized bed. The projected heat rate for this unit is 8,500 Btu/kWh (40.2% efficiency based on HHV). SO_2 emissions are expected to be reduced by 95% and NO_x emissions by 80%.



The design coal is Pittsburgh 8, high-sulfur (4% maximum), bituminous coal.

Project Status/Accomplishments:

During 1993, initial value engineering efforts aimed at reducing the technical and economic risks of the project were completed. These efforts were successful in optimizing the scaleup parameters, improving the understanding of sulfur capture, and reducing capital cost. Appalachian Power's load growth projections are being refined, but they are not expected to show a large need for power. The utility and DOE are assessing the merits of continuing the project.

Commercial Applications:

This project will be the initial version of a commercial plant. Combined-cycle PFBC systems permit the combustion of a wide range of coals, including high-sulfur coals. This technology will compete with circulating PFBC systems to repower or replace conventional power plants with a technology capable of using high-sulfur coals in an environmentally sound manner. PFBC technology appears to be best suited for a wide range of applications beginning at the 50-MWe size. Because of modular construction capability, PFBC generating plants permit utilities to add economical increments of capacity to match load growth and/or to easily repower existing plants using available coal- and waste-handling equipment, and existing steam turbines. Another advantage for repowering is the compactness of the process because of pressurized operation.

The projected net heat rate for the commercial plant will be 8,500 Btu/kWh (based on HHV) which equates to an efficiency of 40.2%. An advanced cycle that integrates a small gasifier could yield heat rates approaching 7,500 Btu/kWh (45% efficiency). Environmental attributes include in-situ sulfur reduction of 95% and NO_x emissions reduction to 0.1 lb/million Btu. Although the system may generate a slight increase of solid waste as compared to conventional systems, the dry material is either disposable or potentially usable.

PCFB Demonstration Project

Sponsor:
DMEC-1 Limited Partnership (a partnership between Dairyland Power Cooperative and Midwest Power Systems, Inc. [previously Iowa Power, Inc.])

Additional Team Members:
Pyropower Corporation —technology supplier
Black and Veatch—architect and engineer

Location:
Pleasant Hill, Polk County, IA (Des Moines Energy Center)

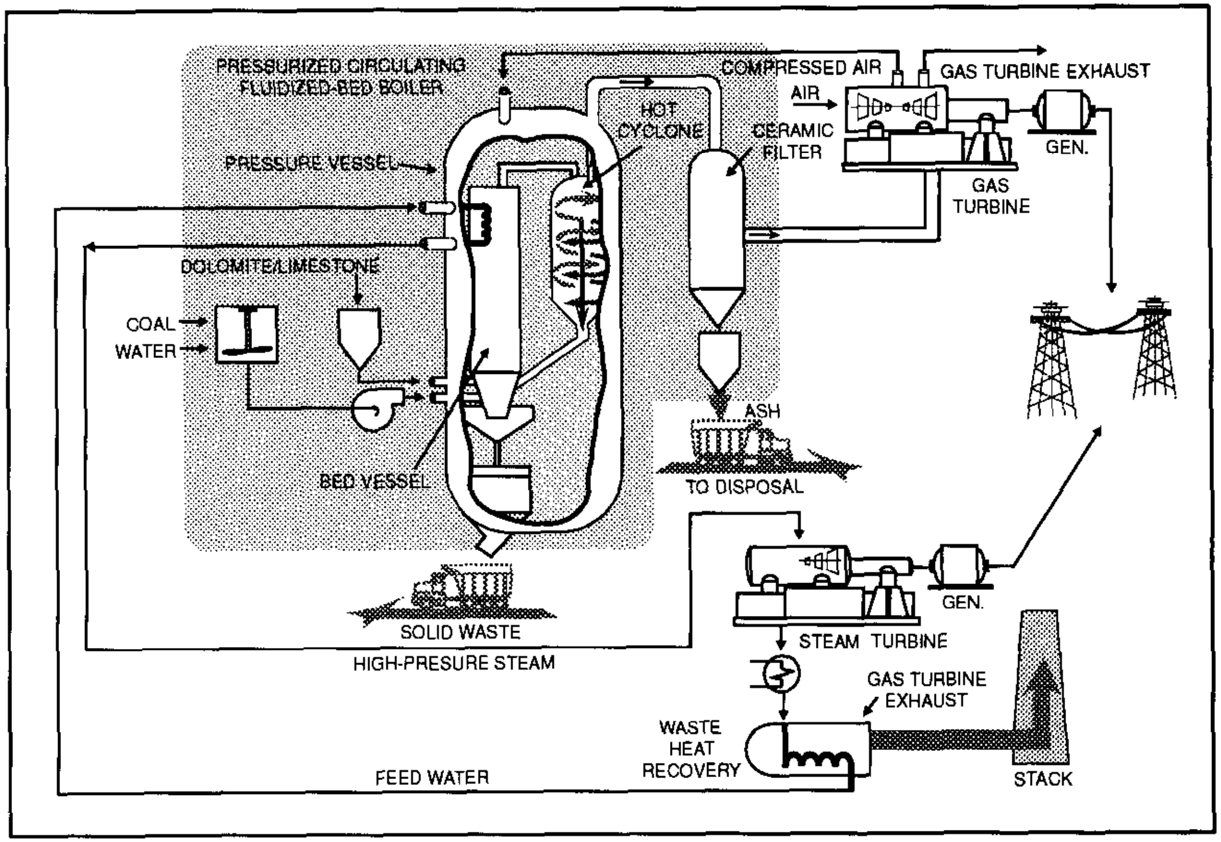
Technology:
Pyropower Corporation's PYROFLOW pressurized circulating fluidized-bed combustion (PCFB) combined-cycle system (advanced electric power generation/fluidized-bed combustion)

Plant Capacity/Production:
80 MWe

Project Funding:

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

Project Objective:
To demonstrate PCFB at sufficient scale to evaluate environmental, cost, and plant performance and to obtain the technical data required for commercialization of the technology; to assess operating performance of unique features that include an integral ceramic hot-gas filter and slightly modified, commercially available gas turbine.



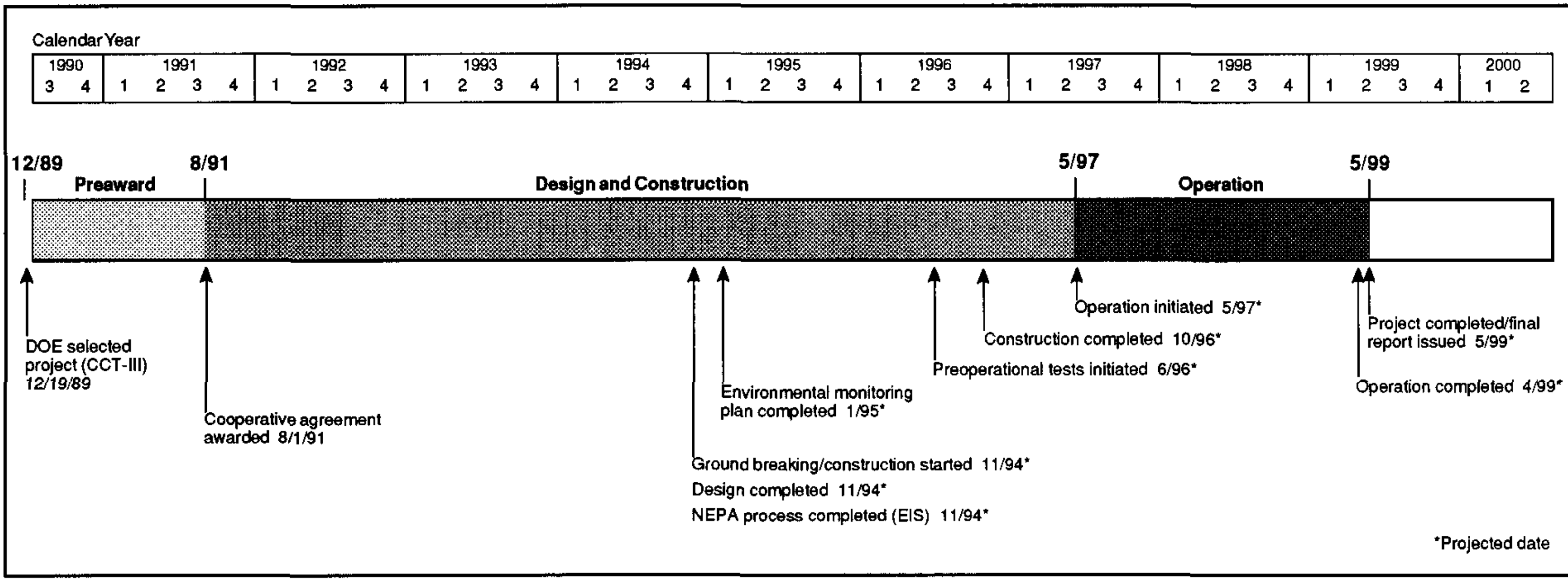
Technology/Project Description:
In the PCFB process, coal is combusted at about 1,600 °F and 12 atm in a circulating fluidized bed contained within a pressure vessel. Coal is pumped into the PCFB via a water slurry while dolomite or limestone is added to the combustion process to absorb sulfur compounds. Particulates from the hot, pressurized combustion gases are removed by a ceramic filter, and the clean gases are then expanded through a gas turbine. The solid waste (bed and fly ash) from the process is dry, easily disposed of, and potentially usable. Steam generated within the PCFB combustor and the heat recovery system downstream of the gas turbine is used to generate power in an existing steam turbine.

The project would be the world's first large-scale demonstration of PCFB technology. The project also would be the first commercial application of hot gas cleanup and the first use of a nonruggedized gas turbine in a pressurized fluidized-bed application.

A boiler at the Des Moines Energy Center is being repowered by a single PCFB combustor. The facility, owned by Midwest Power Company, is located southeast of Des Moines, IA. Midwest Power plans to continue PCFB operations commercially after the demonstration.

Repowering the plant with a PCFB will improve the plant's heat rate to 10,400 Btu/kWh (an efficiency of 32.8% based on HHV) which is a 15% improvement over the previous plant. SO_2 emissions will be limited to 0.71 lb/million Btu (90% reduction) and NO_x emissions will be less than 0.03 lb/million Btu (70% reduction).

The design coal for the facility is 0.36% sulfur, Wyoming subbituminous coal. Test coals are Iowa



subbituminous coal with 3.84% sulfur and Illinois bituminous coal with 3.0% sulfur.

Project Status/Accomplishments:

In October 1993, a modification was issued to extend the project for 12 months in order to complete project definition activities. During the extension, Midwest Power will finalize the selection of a ceramic filtration hot-gas cleanup system and conduct configuration studies to verify the economic viability of the project. A draft of the environmental impact statement has been prepared and is undergoing internal DOE review.

Commercial Applications:

By demonstrating plant reliability and performance, this project serves as a bridge for scaling up to a larger plant and a stepping stone toward moving PCFB to commercial readiness. The combined-cycle PCFB system permits the combustion of a wide range of coals, including high-sulfur coals, and would compete with the bubbling-bed PFBC system. Like the bubbling-bed system, PCFB can be used to repower or replace conventional power plants. PCFB technology appears to be best suited for utility and industrial applications of 50 MWe or larger. Because of modular construction capability, PCFB generating plants permit utilities to add economical increments of capacity to match load growth and/or to repower plants using existing coal- and waste-handling equipment, and steam turbines. Another advantage for repowering applications is the compactness of the process due to pressurized operation, which reduces space requirements per unit of energy generated.

The commercial version of PCFB technology will include the integration of a topping combustor to fully utilize commercially available gas turbines. The projected net heat rate for this system is 7,964 Btu/kWh (based on HHV) which equates to 42.8% efficiency.

Environmental attributes include in-situ sulfur removal of 95%, NO_x emissions less than 0.3 lb/million Btu, and particulate matter discharge less than 0.03 lb/million Btu. Solid waste will increase slightly as compared to conventional systems, but the dry material is disposable or potentially usable.

Four Rivers Energy Modernization Project

Sponsor:
Four Rivers Energy Partners, L.P. (a limited partnership between Four Rivers Energy Partners (I), Inc., and Air Products and Chemicals, Inc.)

Additional Team Members:
Foster Wheeler Energy Corporation—combustor, carbonizer, and heat exchanger supplier; engineer
Westinghouse Electric Corporation—gas turbine, topping combustor, and carbonizer filter supplier
LLB Lurgi Lentjes Babcock Energietechnick GmbH—combustor filter, slurry feed, and ash removal system supplier

Location:
Calvert City, Marshall County, KY (Air Products and Chemicals' chemical manufacturing plant)

Technology:
Foster Wheeler's fully integrated second-generation pressurized circulating fluidized-bed (PCFB) combustion system (advanced electric power generation/fluidized-bed combustion)

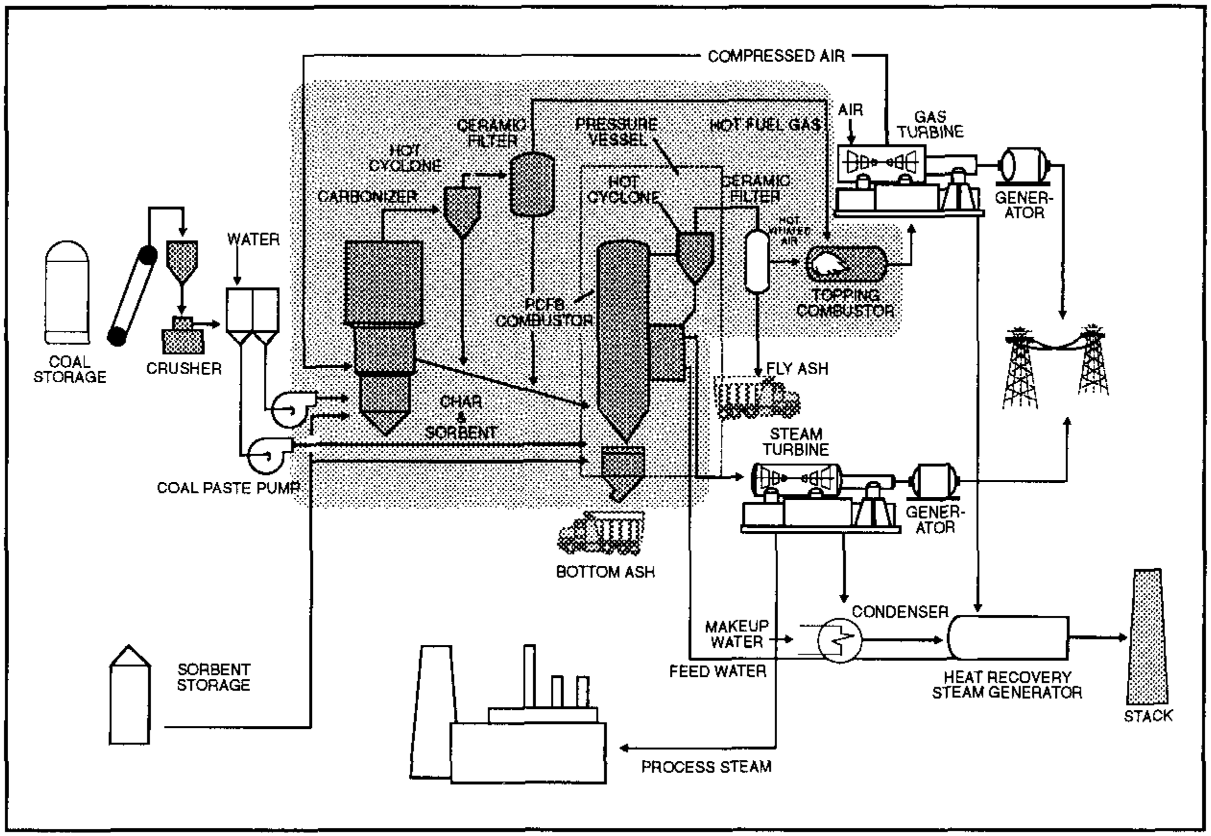
Plant Capacity/Production:
95 MWe (equivalent if all steam were converted)

Project Funding:

Total project cost	$375,178,000	100%
DOE	150,033,775	40
Participants	225,144,225	60

(Funding amounts reflect those contained in the proposal and are subject to negotiation.)

Project Objective:
To demonstrate PCFB technology at a sufficient scale to evaluate the environmental, cost, and plant performance technical data that is prerequisite to commercialization of the technology; to assess operating performance of the world's first fully integrated second-generation PCFB system that includes a combustor, carbonizer, ceramic hot-gas filtration systems, topping combustor, and a slightly modified, commercially available gas turbine.



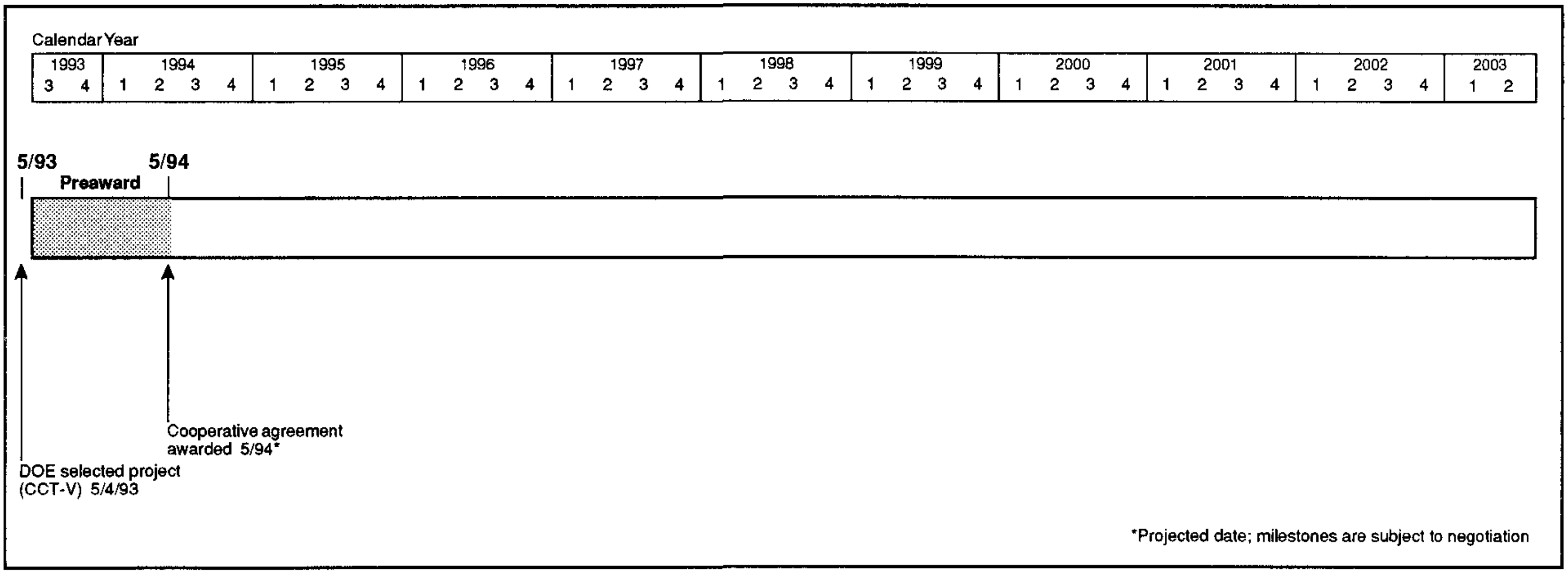
Technology/Project Description:
This project represents the first commercial application of Foster Wheeler's second-generation PCFB system. Coal is fed to a pressurized carbonizer that produces a low-Btu fuel gas and char. After the fuel gas is cleaned of particulates and alkali vapors by a cyclone, ceramic filter, and alkali removal system, it is burned in a topping combustor to drive a gas turbine.

The gas turbine drives a generator and a compressor that delivers air to the carbonizer and to a PCFB combustor. Additional coal and the carbonizer char are burned in the PCFB combustor, and the flue gas is used to combust the fuel gas in the topping combustor. Prior to the topping combustor, the hot gases pass through ceramic filtration and alkali removal units.

A steam turbine is driven by steam generated in the heat recovery steam generator, which is located down-stream of the gas turbine, an integrated ash-cooling heat exchanger, and the PCFB combustor.

Fuel is pumped into the PCFB carbonizer and combustor via a slurry mixture while dolomite or limestone is pneumatically added to absorb sulfur compounds. The solid waste (bed and fly ash) from the process is dry, easily disposable, and potentially usable.

The project is also in line to be one of the first commercial applications of hot-gas cleanup and one of the



first to use a non-ruggedized gas turbine in a pressurized fluidized-bed application.

At the Calvert City chemicals manufacturing plant, the second-generation PCFB process will replace the steam-generating capacity of two operating industrial process boilers. These two industrial units are spreader-stoker coal-fired units which were installed in the late 1950s. This equipment change will result in significant reductions in the current emissions of pollutants.

Project Status/Accomplishments:

The project is in negotiation.

Commercial Applications:

This project will serve as a stepping stone to move the second-generation PCFB technology to readiness for widespread commercial application. The project is expected to demonstrate plant reliability and performance and serve as a bridge for scaling to a larger plant. In addition to other advanced technology systems, second-generation PCFB technology will compete with bubbling fluidized-bed combustion systems to repower or replace conventional fossil-fueled power plants with a technology capable of using high-sulfur coals in an environmentally sound manner.

PCFB technology appears to be best suited for a wide range of utility and industrial applications beginning at a level of 50 MWe. Because of the modular construction capability, PCFB generating plants will permit utilities to add economical increments of capacity to match load growth and/or to easily repower an existing plant using available coal- and waste-handling equipment and steam turbine equipment.

The commercial version of PCFB technology will have a greenfield net plant efficiency of 45% (which equates to heat rates approaching 7,500 Btu/kWh, based on HHV). In addition to higher plant efficiencies, the second-generation plant will (1) have a cost of electricity that is projected to be 20% lower than that of a conventional pulverized-coal-fired plant with flue gas desulfurization, (2) meet emissions limits that are half those currently allowed by NSPS, (3) operate economically on a wide range of coals, (4) be amenable to shop fabrication, and (5) be furnished in building-block modules as large as 300 MWe.

The benefits of improved efficiency include reduced costs for fuel and a reduction in CO_2 emissions. Other environmental attributes include in-situ sulfur reduction that can meet 95% removal, NO_x emissions that will be lower than 0.3 lb/million Btu, and particulate matter discharge that approaches 0.01 lb/million Btu. Although the system will generate a slight increase of solid waste as compared to conventional systems, the material will be a dry, disposable, and potentially usable material.

Tidd PFBC Demonstration Project

Sponsor:

The Ohio Power Company

Additional Team Members:

American Electric Power Service Corporation—designer, constructor, and manager
The Babcock & Wilcox Company—technology supplier
Ohio Coal Development Office—cofunder

Location:

Brilliant, Jefferson County, OH (Ohio Power Company's Tidd Plant)

Technology:

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

Plant Capacity/Production:

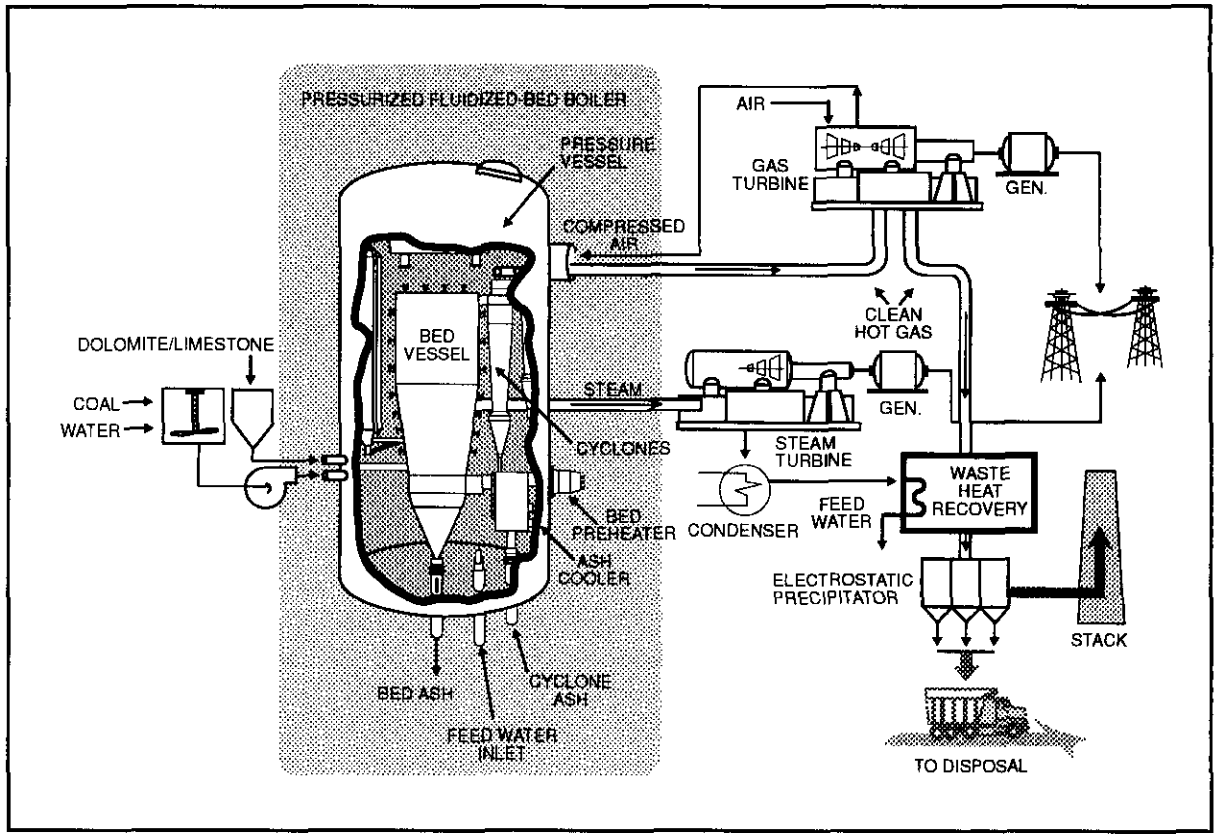
70 MWe

Project Funding:

Total project cost	$193,540,000	100%
DOE	60,200,000	31
Participants	133,340,000	69

Project Objective:

To demonstrate PFBC at a 70-MWe scale, representing a 13:1 scaleup from the pilot plant facility; to verify expectations of the technology's economic, environmental, and technical performance in a combined-cycle repowering application at a utility site; and to accomplish greater than 90% SO_2 removal, NO_x emission level of 0.2 lb/ million Btu, and an efficiency of 35% in a repowering mode using the existing steam system.



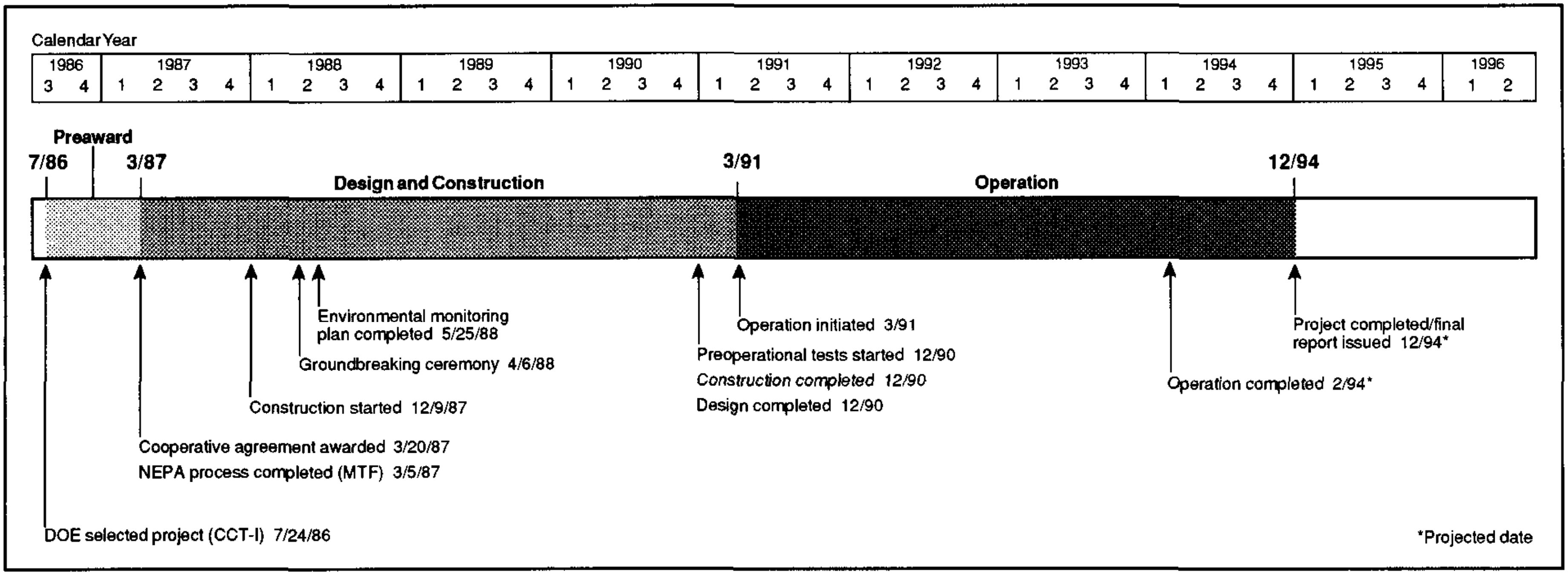
Technology/Project Description:

Tidd is the first large-scale demonstration of PFBC in the United States and one of only five worldwide. The boiler, cyclones, bed reinjection vessels, and associated hardware are encapsulated in a pressure vessel 45 ft in diameter and 70 ft high. The facility was designed so that one-seventh of the hot gases produced could be routed to a slipstream to test advanced filtration devices.

The Tidd facility is a bubbling fluidized-bed combustion process operating at 12 atm (175 lbs/in^2 atm). Pressurized combustion air is supplied by the turbine compressor to fluidize the bed material which consists of a coal-water fuel paste, coal ash, and a dolomite or limestone sorbent. Dolomite or limestone in the bed reacts with sulfur to form calcium sulfate, a dry, granular bed-ash material which is easily disposed of or is usable as a by-product. A low bed-temperature of 1,600 °F limits NO_x formation.

The hot combustion gases exit the bed vessel with entrained ash particles, 98% of which are removed when the gases pass through cyclones. The cleaned gases are then expanded through a 15-MWe gas turbine. The gases exiting the turbine are cooled via a waste heat economizer and further cleaned in an electrostatic precipitator.

The Tidd steam turbine operates at a pressure of 1,305 lbs/in^2 atm and a temperature of 925 °F to produce approximately 55 MWe. Superheated steam is produced from pressurized boiler feed water in the in-bed combustor tubes. Steam generated within the combustor and the heat recovery system downstream of the gas turbine is used to generate power in a previously existing steam



turbine. Due to repowering, plant efficiency was improved by 10% to a heat rate of 9,750 Btu/kWh (an efficiency of 35.1% based on HHV).

Ohio bituminous coals having sulfur contents of 2–4% are being used in the demonstration.

Project Status/Accomplishments:

The plant accumulated over 2,000 hours of operation during 1993. Overall, coal-fueled operation now totals more than 5,500 hours. SO_2 emissions reductions of about 93% and NO_x emission levels of 0.15–0.18 lb/million Btu were routinely achieved. These levels are well below NSPS requirements.

During 1993 operations, advanced ceramic hot-gas-filtration elements were exposed to one-seventh of the slipstream; total exposure is now in excess of 1,800 hours. The unit suffered a major mechanical problem early in 1993 whenever gas turbine blades broke during routine operation. The result was severe damage to the compressor, gas turbine blades, and rotor shafts. Disregarding a 5-month outage for repairs to the gas turbine, the unit operated for approximately 50% of the available time during 1993.

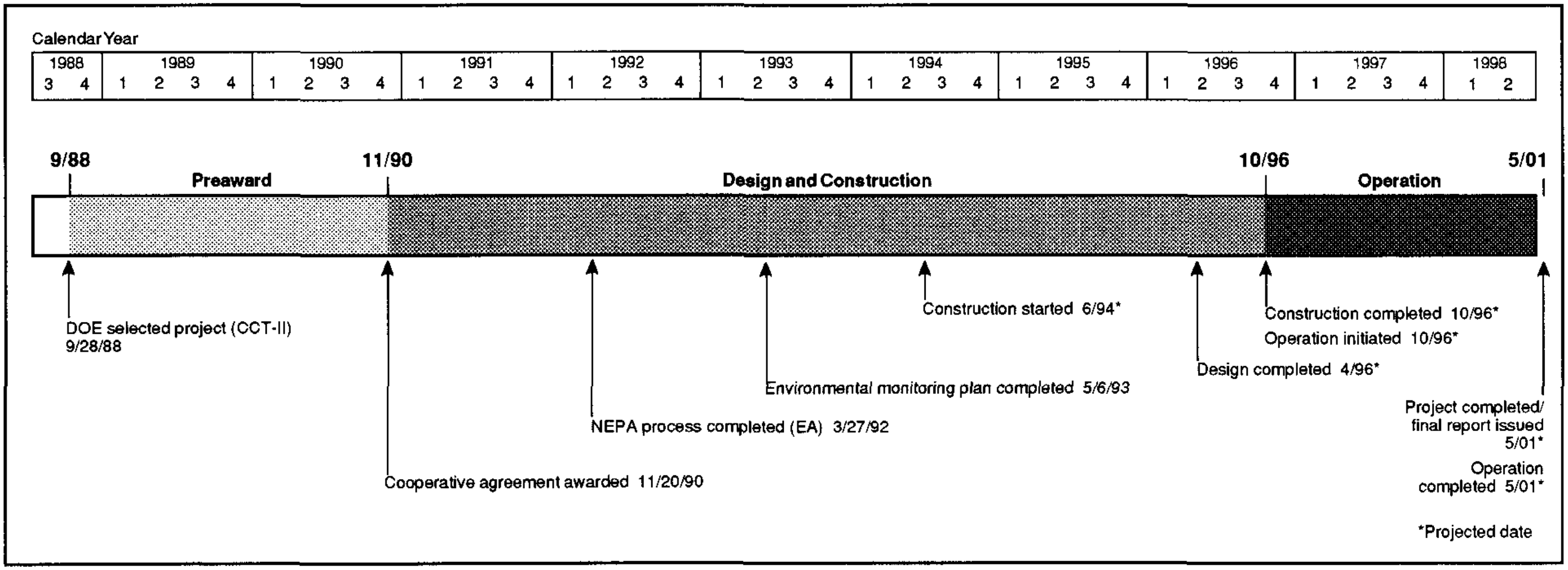
The project is due to terminate operations by the end of February 1994. However, as 1993 came to a close, Ohio Power and DOE were considering a fourth year of operations. The goal of the additional 12-month test would be to obtain additional data on long-term gas turbine survivability, economical sulfur capture at a 95% level, and exposure of advanced ceramic filtration devices.

Commercial Application:

Combined-cycle PFBC permits use of a wide range of coals, including high-sulfur coals. Bubbling PFBC technology, along with other advanced technologies, will compete with circulating PFBC systems to repower or replace conventional power plants. PFBC technology appears to be best suited for applications of 50 MWe or larger. Capable of being constructed modularly, PFBC generating plants permit utilities to add increments of capacity economically to match load growth. Plant life can be extended by repowering with PFBC using the existing plant area, coal- and waste-handling equipment, and steam turbine equipment. Another advantage for repowering applications is the compactness of the process due to pressurized operation, which reduces space requirements per unit of energy generated.

In a fully mature system, the projected net heat rate is 8,500 Btu/kWh (based on HHV) which equates to 40.2% efficiency. An advanced cycle that integrates a small gasifier could yield heat rates approaching 7,500 Btu/kWh (45% efficiency).

The environmental attributes of a mature system include in-situ sulfur removal of 95% and NO_x emissions reduction levels less than 0.1 lb/million Btu. Although the system generates a slight increase in solid waste as compared to conventional systems, the dry material is either disposable or potentially usable.



through the installation of an entrained-flow coal gasifier and the integration of a 25-MWe steam turbine with a 40-MWe gas turbine at City Water, Light and Power's Lakeside Station located in Springfield, IL. The anticipated heat rate for the repowered unit is 8,800 Btu/kWh (an efficiency of 38.8%). SO_2 emissions are expected to be less than 0.1 lb/million Btu (99% reduction). NO_x emissions are also expected to be less than 0.1 lb/million Btu (90% reduction).

Project Status/Accomplishments:

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

System definition and preliminary design activities are complete. At the completion of preliminary engineering, a revised cost estimate was completed. The updated cost projection considerably exceeds the available funding. Efforts are currently focused on reducing the projected cost or, if necessary, restructuring the project.

Commercial Applications:

The IGCC system being demonstrated in this project is suitable for both repowering and new power plant applications. Repowering aging plants with this technology will improve plant efficiency and reduce emissions of SO_2, NO_x, and CO_2. Also, the modular design of the gasifier will permit a range of units to be considered for repowering.

Due to the advantages of modularity, rapid and staged on-line generation capability, high efficiency, fuel flexibility, environmental controllability, and reduced land and natural resource needs, the IGCC system is also a strong contender for new electric power generating facilities. Further, without the need for an oxygen plant, the ABB Combustion Engineering technology represents a potentially simpler approach to gasification-based power generation. A single-train IGCC system based on this gasifier is capable of producing more than 150 MWe. A commercial-scale facility based on the ABB Combustion Engineering technology is expected to have a heat rate less than 8,000 Btu/kWh (efficiency greater than 43%). This heat rate is expected to realize at least a 20% improvement in efficiency compared to a conventional pulverized-coal-fired plant with flue gas desulfurization. The improved system efficiency also results in a similar decrease in CO_2 emissions.

Camden Clean Energy Demonstration Project

Sponsor:
Duke Energy Corp.

Additional Team Members:
General Electric Company—cofunder; designer and supplier of the power island equipment

Fuel Cell Engineering Corporation—designer and supplier of the fuel cell

J. Makowski Company—cofunder

British Gas plc—cofunder

Location:
Camden, Camden County, NJ (Pavonia Industrial Area)

Technology:
Integrated gasification combined-cycle (IGCC) using British Gas/Lurgi (BG/L) slagging fixed-bed gasification system coupled with Fuel Cell Engineering's molten carbonate fuel cell (advanced electric power generation/ integrated gasification combined cycle)

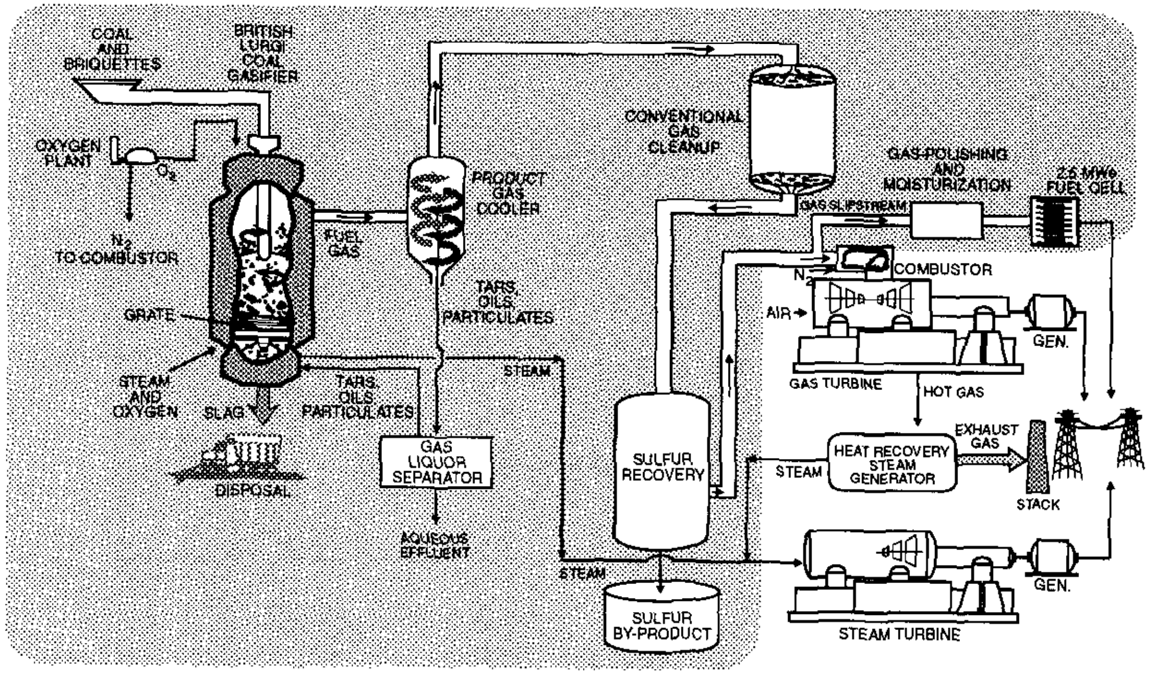
Plant Capacity/Production:
240 MWe (net)

Project Funding:

Total project cost	$779,950,000	100%
DOE	195,000,000	25
Participant	584,950,000	75

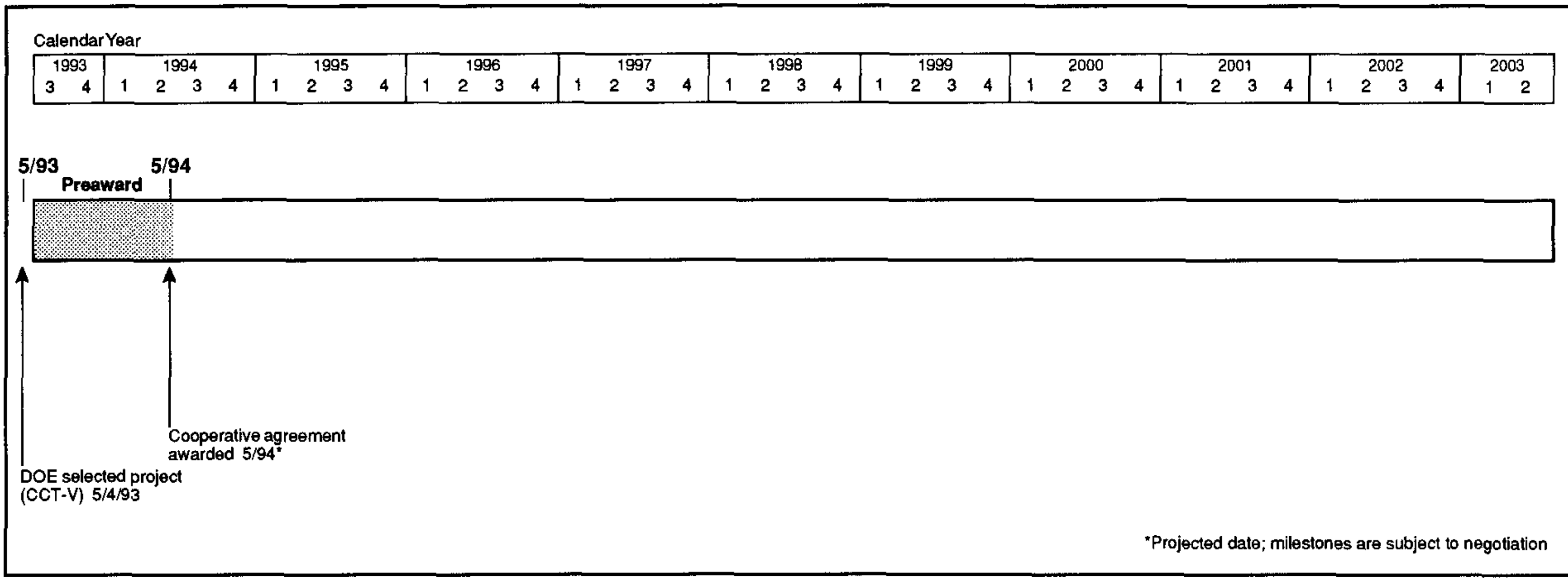
(Funding amounts reflect those contained in the proposal and are subject to negotiation.)

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



Technology/Project Description:
Bituminous run-of-mine coal is screened to remove fines. The fines are formed into briquettes and fed to the gasifier along with the screened coal. The coal and briquettes are gasified in an oxygen-blown, pressurized, slagging fixed-bed gasifier. The raw product gas is quenched to reduce the temperature and remove tars, oils, ammonia, and particulates. The particulates and condensed tars and oils are recycled to the gasifier to ensure high cold-gas efficiency. The cooled product gas is routed to a conventional cold-gas cleanup system to remove sulfur compounds. The clean, medium-Btu gas is reheated and burned in an advanced 192-MWe (gross) gas turbine. A small slipstream of clean product gas is diverted to a gas-polishing and moisturization step and used to fuel the 2.5-MWe (gross) molten carbonate fuel cell. Waste nitrogen from the air separation unit is also routed to the gas turbine to increase mass flow to the turbine and suppress NO_x formation. The hot exhaust gas from the gas turbine is passed through a heat recovery steam generator to produce high-pressure steam. The steam turbine is designed to produce 83 MWe (gross) using steam conditions of 1,450 lb/in^2 atm and 1,000 °F/ 1,000 °F reheat.

The process has the following subsystems: coal screening and briquetting; an air separation unit; a slagging, fixed-bed gasifier; a cold-gas cleanup system which produces a marketable sulfur by-product; a molten carbonate fuel cell capable of utilizing coal-derived fuel gas; a combustion turbine capable of using coal-derived



fuel gas; a heat recovery steam generator; and a steam turbine.

The demonstration unit is being designed to generate 240 MWe (net) using 1,850 tons/day of West Virginia bituminous coal containing 3% sulfur.

Project Status/Accomplishments:

The project is in negotiation.

Commercial Applications:

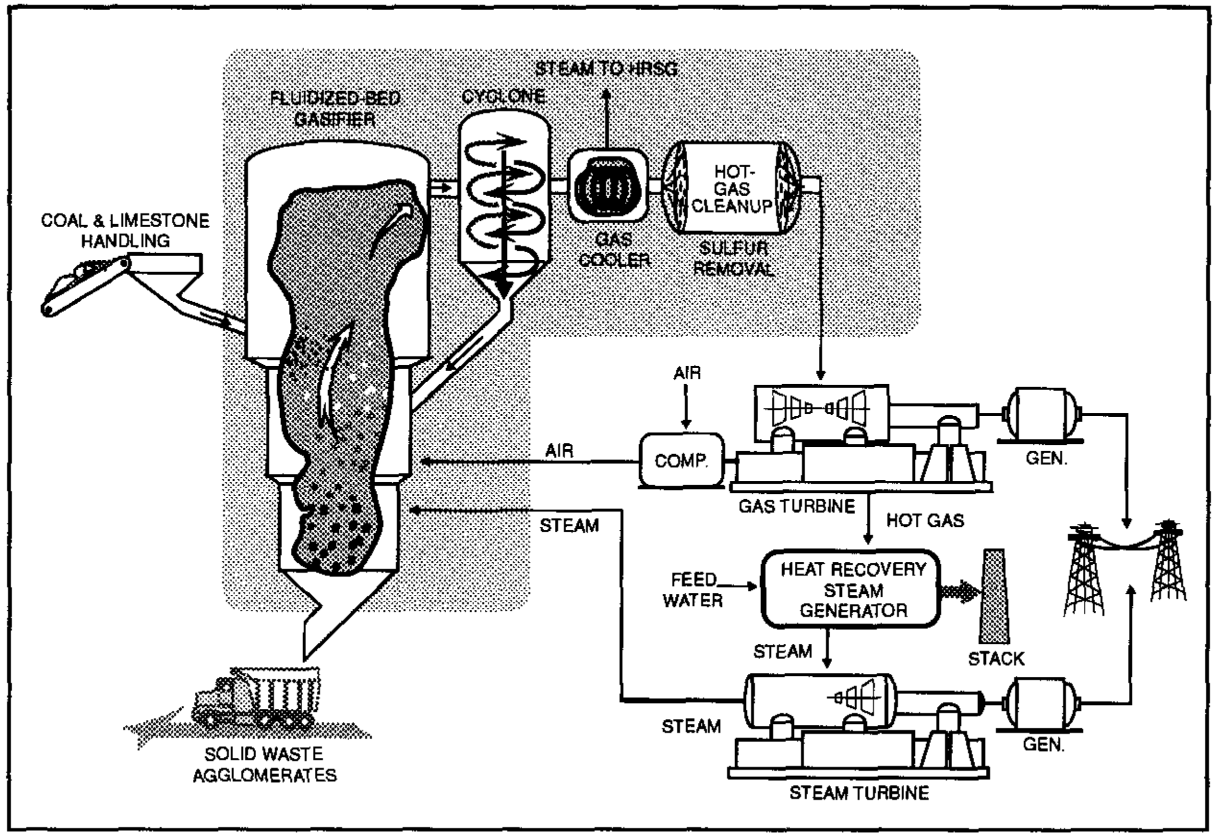
The IGCC system being demonstrated in this project is suitable for both repowering applications and new power plants. The wide variability in potential market applications and new power plants. The wide variability in potential market applications is due to several factors. First, the BG/L gasification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

The heat rate of the IGCC demonstration facility is 8,200 Btu/kWh (41.6% efficiency) and the commercial embodiment of the system has a projected heat rate of 8,035 Btu/kWh (42.5% efficiency). The commercial version of the molten carbonate fuel cell fueled by a BG/L gasifier is anticipated to have a heat rate of 7,379 Btu/kWh (46.2% efficiency). These efficiencies represent greater than 20% reduction in emissions of CO_2 when compared to a conventional pulverized coal plant equipped with a scrubber. SO_2 emissions from the IGCC system are expected to be less than 0.1 lb/million Btu (99% reduction); NO_x emissions, less than 0.15 lb/million Btu (90% reduction).

Also, the slagging characteristic of the gasifier produces a non-leaching, glass-like slag that can be marketed as a usable by-product.

The system being demonstrated is adaptable to a wide range of plant sizes and applications due to (1) its modular design, (2) its ability to utilize a wide variety of coals, and (3) the system's improved efficiency and environmental performance over conventional coal-bed power generation technologies.

Piñon Pine IGCC Power Project



Sponsor:
Sierra Pacific Power Company

Additional Team Members:
Foster Wheeler USA Corporation—architect, engineer, and constructor
The M.W. Kellogg Company—technology supplier

Location:
Reno, Storey County, NV (Sierra Pacific Power Company's Tracy Station)

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

Plant Capacity/Production:
95 MWe (net)

Project Funding:

Total project cost	$269,993,100	100%
DOE	134,996,550	50
Participant	134,996,550	50

Project Objective:
To demonstrate air-blown, pressurized, fluidized-bed IGCC technology incorporating hot gas cleanup; to evaluate a low-Btu gas combustion turbine; and to assess long-term reliability, availability, maintainability, and environmental performance at a scale sufficient to determine commercial potential.

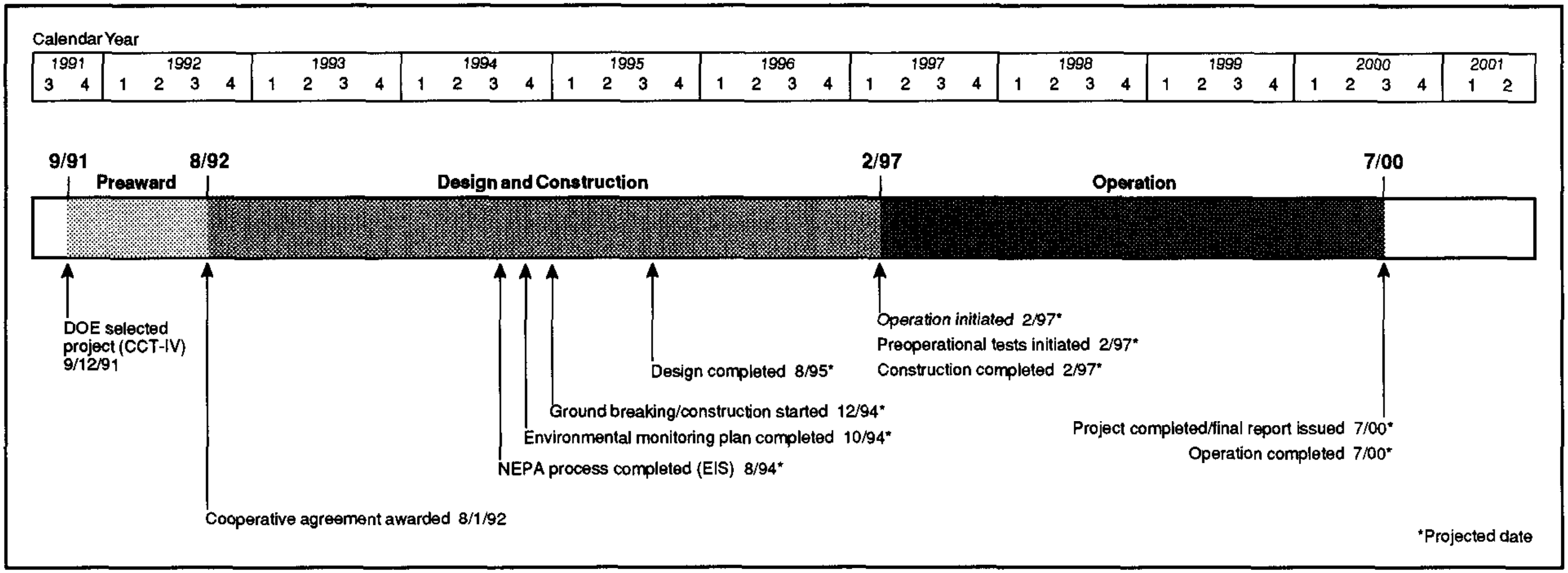
Technology/Project Description:
Dried and crushed coal is introduced into a pressurized, air-blown, fluidized-bed gasifier. Crushed limestone is added to the gasifier to capture a portion of the sulfur and to inhibit conversion of fuel nitrogen to ammonia. The sulfur reacts with the limestone to form calcium sulfide which, after oxidation, exits along with the coal ash in the form of agglomerated particles suitable for landfill.

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

The hot, cleaned gas then enters the combustion turbine which is coupled to a generator designed to produce 61 MWe (gross). Exhaust gas is used to produce steam in a heat recovery steam generator. Superheated high-pressure steam drives a condensing steam turbine-generator designed to produce about 41 MWe (gross).

Due to the relatively low operating temperature of the gasifier and the injection of steam into the combustion fuel stream, the NO_x emissions are 0.069 lb/million Btu (94% reduction). Due to the combination of in-bed sulfur capture and hot gas cleanup, SO_2 emissions are 0.069 lb/million Btu (90% reduction).

In the demonstration project, 893 tons/day of coal are converted into 102 MWe (gross), or 95 MWe (net), for export to the grid. Western bituminous coal (0.5–0.9% sulfur) from Utah is the design coal; tests



using West Virginia or Pennsylvania bituminous coal containing 2–3% sulfur also are planned. The gasifier is being built at Sierra Pacific Power Company's Tracy Station, near Reno, NV.

Project Status/Accomplishments:

Design and permitting activities continued throughout 1993. In June, DOE approved incorporation of the newly announced GE Model 6FA gas turbine into the project. Piñon Pine will be the first plant anywhere to operate with the new turbine. This change resulted in an increase in the plant size from 80 to 102 MWe (gross).

In October, the Public Service Commission of Nevada approved Sierra Pacific's resource plan, which presented the Piñon Pine Project as the preferred option for new power generation. In its order, the Commission strongly weighed the fuel diversity benefits of the plant.

Information for preparation of the environmental impact statement has been developed. A preliminary draft of the EIS was completed in December 1993. A draft for public comment is anticipated in early 1994.

The construction schedule has been slipped to accommodate delays in the Nevada Commission approval process and the NEPA process.

Commercial Applications:

The Piñon Pine IGCC system concept is suitable for new power generation, repowering needs, and cogeneration applications. The net effective heat rate for a proposed greenfield plant using this technology is projected to be 7,800 Btu/kWh (43.7% efficiency), representing a 20% increase in thermal efficiency as compared to a conventional pulverized coal plant with a scrubber and a comparable reduction in CO_2 emissions. The compactness of IGCC systems reduces space requirements per unit of energy generated relative to other coal-based power generation systems, and the advantages provided by modular construction reduce the financial risk associated with new capacity additions.

The KRW IGCC technology is capable of gasifying all types of coals, including high-sulfur and high-swelling coals, as well as bio- or refuse-derived waste, with minimal environmental impact. This versatility provides numerous economic advantages for the depressed mineral extraction and cleanup industries. There are no significant process waste streams that require remediation. The only solid waste from the plant is a mixture of ash and calcium sulfate, a non-hazardous waste. SO_2 emissions are expected to be below 0.045 lb/million Btu (98–99% reduction for most high-sulfur coals). NO_x emissions are expected to be below 0.053 lb/million Btu, and emissions of particulates are expected to be below 0.01 lb/million Btu.

Toms Creek IGCC Demonstration Project

Sponsor:

TAMCO Power Partners (a partnership between TP [TAMCO] Company, a subsidiary of Tampella Power Corporation, and CP [TAMCO] Company, a subsidiary of Coastal Power Production Company)

Additional Team Member:

Institute of Gas Technology—technology developer and consultant

Location:

Coeburn, Wise County, VA (Virginia Iron, Coal, and Coke Company's Toms Creek Mine)

Technology:

Integrated gasification combined-cycle (IGCC) using the Tampella U-GAS® fluidized-bed gasification system

Plant Capacity/Production:

190 MWe (55 MWe IGCC and 135 MWe pulverized coal) (net)

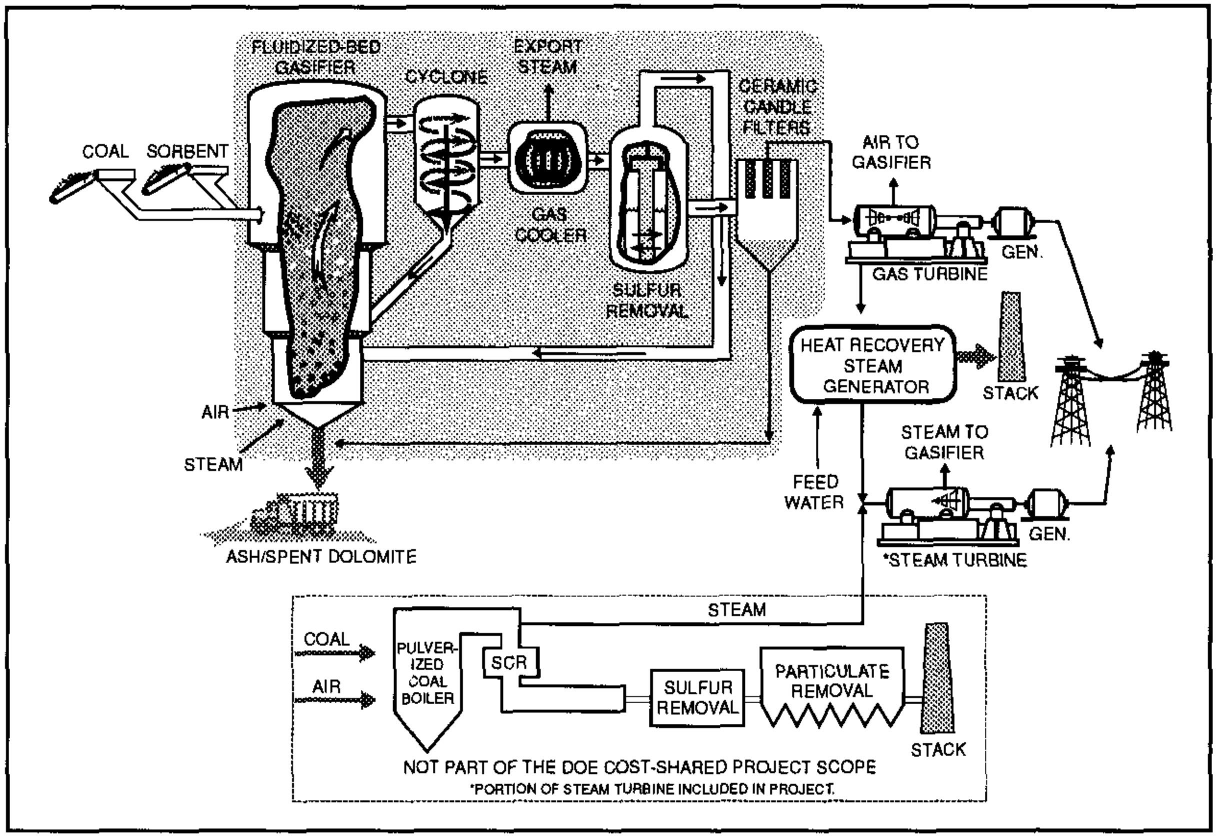
Project Funding:

Total project cost	$196,570,000	100%
DOE	95,000,000	48
Participant	101,570,000	52

Project Objective:

To demonstrate an air-blown, fluidized-bed gasification, combined-cycle technology, incorporating hot gas cleanup, for generating electricity and to assess the system's environmental and economic performance for meeting future energy needs. Also to demonstrate the newly developed zinc titanate fluidized-bed hot-gas cleanup technology.

U-GAS is a registered trademark of the Institute of Gas Technology.



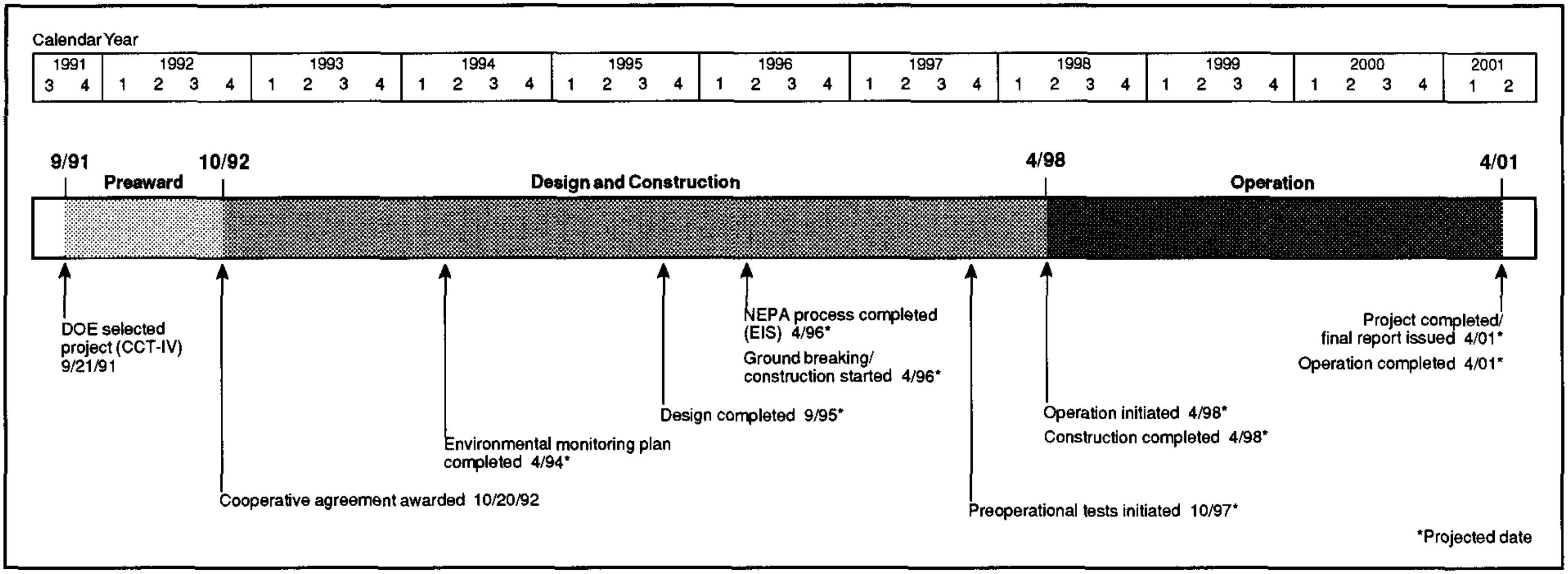
Technology/Project Description:

Being demonstrated is an IGCC system in which air-blown operation has replaced the more conventional oxygen-blown gasifier operation and hot gas cleanup has replaced cold gas cleanup with the usual associated sulfur recovery.

Coal is gasified in a pressurized, air-blown, fluidized-bed gasifier in the presence of a calcium-based sorbent. About 90% sulfur removal is accomplished in the gasifier. Solids entrained in the gas are collected by cyclones in two stages. The low-Btu gas, which leaves the secondary cyclone at 1,800–1,900 °F, is cooled to about 1,000 °F before entering the post-gasifier desulfurization unit where zinc titanate is used to remove the bulk of the remaining sulfur in the gas. This is accomplished in two fluidized beds. In the first bed, the sulfur is absorbed by the zinc titanate; the zinc titanate is regenerated in the second bed. In the final hot-gas-cleaning step, a ceramic candle filter removes particulates. The gas is then sent to the gas turbine combustor which has been modified to burn low-Btu gas.

Hot exhaust gases from the gas turbine are directed to a heat recovery steam generator. The steam generated is used both for driving a conventional steam turbine generator to produce additional electricity and to provide steam feed to the gasifier.

About 430 tons/day of bituminous coal are converted into 55 MWe by the gas turbine. A conventional pulverized coal boiler produces another 135 MWe through the shared steam turbine generator. Also, 50,000 lbs/hr of steam are generated for export to a coal preparation plant located next to the demonstration facility. The electric power is sold to a utility.



The facility is a greenfield plant located outside Coeburn, VA, next to the Toms Creek Mine owned by Virginia Iron, Coal, and Coke Company, a subsidiary of Coastal Power Production Company.

Project Status/Accomplishments:

During 1993, efforts have been geared toward obtaining a power sales agreement with a third party purchaser of power. Preliminary design and project definition studies are under way. Environmental information is being prepared for use in the NEPA process.

Commercial Applications:

The Toms Creek IGCC system is suitable for new power plants, repowering needs, and cogeneration applications.

In recent years, IGCC has become a rapidly emerging alternative for new electric generating plants. Such plants require 15% less land area than pulverized coal plants with flue gas desulfurization, and exhibit substantially improved thermal efficiency and environmental performance. Because of its advantages of modularity, rapid and staged on-line generation capability, high efficiency, environmental controllability, and reduced land and natural resource needs, IGCC is a strong contender for widespread application for meeting future U.S. energy needs. Another important application for IGCC is cogeneration under PURPA's Qualifying Facilities provisions.

The heat rate of the demonstration facility is expected to be 8,720 Btu/kWh (39% efficiency) with SO_2 emissions reductions of 99% (0.056 lb/million Btu release). NO_x emissions are estimated to be 0.09 lb/million Btu.

A larger, commercial-scale, 271-MWe greenfield facility based on the Toms Creek technology is estimated to have a heat rate of 7,750 Btu/kWh (44% efficiency). This represents a 20% increase in thermal efficiency and a corresponding reduction in CO_2 emissions as compared to a conventional pulverized coal plant equipped with a scrubber.

The U-GAS® technology is capable of gasifying all types of coals, including high-sulfur and high-swelling coal feedstocks.

The total system being demonstrated is compact, reducing space requirements, and is very amenable to smaller capacity, modular construction situations. There are no significant wastewater streams, and the solid waste from the gasifier is ash and calcium sulfate, which is discharged as a nonhazardous waste.

Tampa Electric Integrated Gasification Combined-Cycle Project

Sponsor:
Tampa Electric Company

Additional Team Members:
Texaco Development Corporation—gasification technology supplier
General Electric Company—combined-cycle technology supplier
GE Environmental Systems, Inc.—hot-gas cleanup technology supplier
TECO Power Services Corporation—project manager and marketer
Bechtel Power Corporation—architect and engineer

Location:
Lakeland, Polk County, FL (Tampa Electric Company's Polk Power Station)

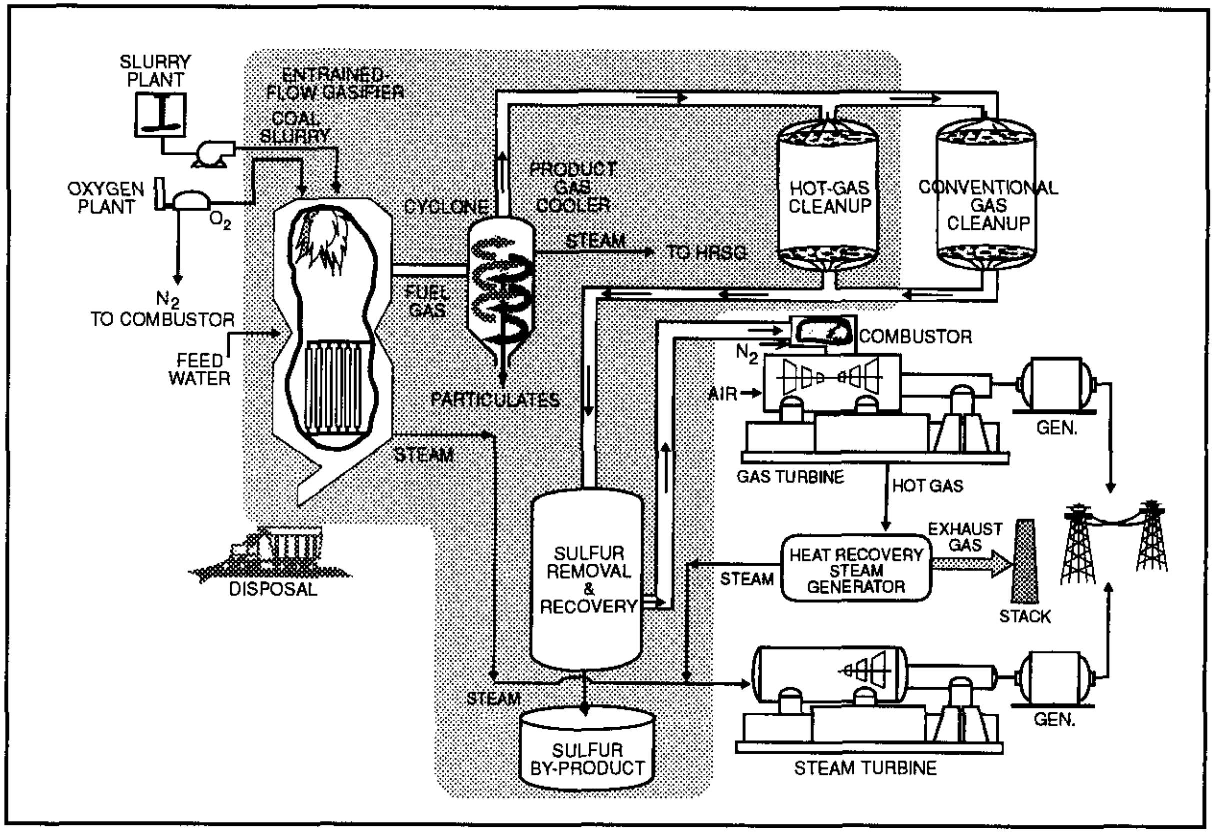
Technology:
Integrated gasification combined-cycle (IGCC) system using Texaco's pressurized, oxygen-blown, entrained-flow gasifier technology and incorporating both conventional, low-temperature acid-gas removal and hot-gas moving-bed desulfurization (advanced electric power generation/integrated gasification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

Plant Capacity/Production:
250 MWe (net)

Project Funding:

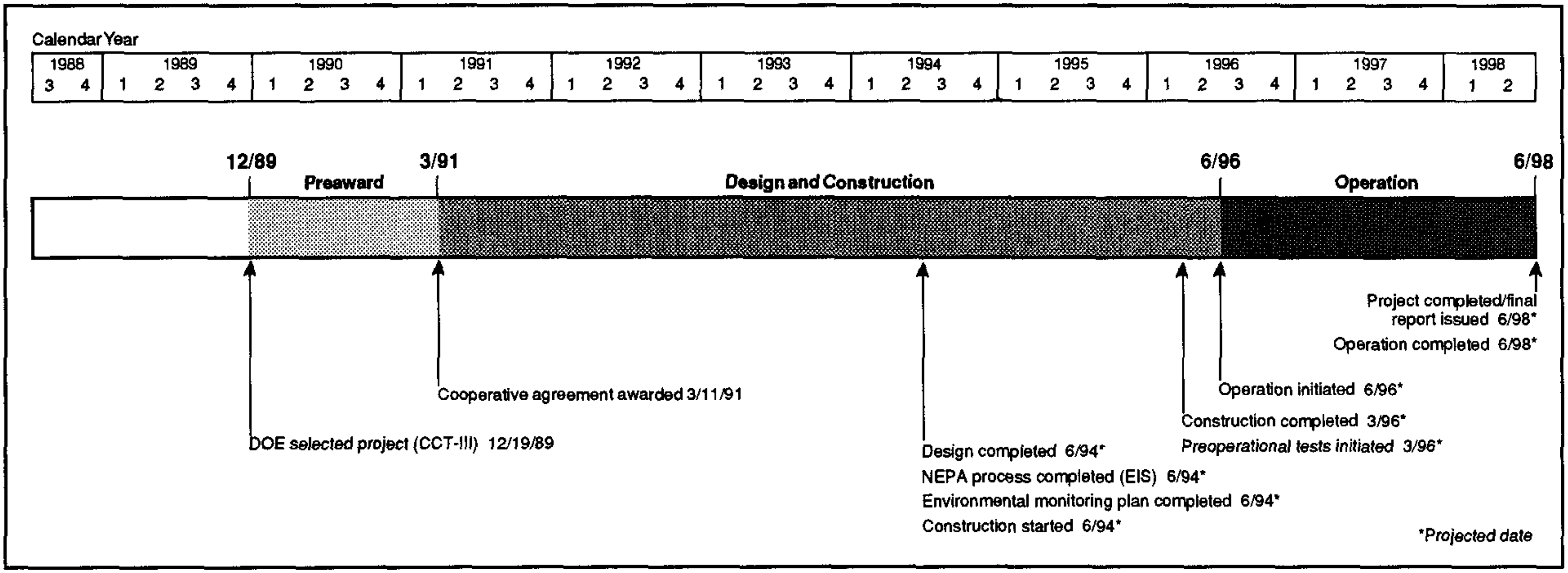
Total project cost	$260,706,446	100%
DOE	130,353,223	50
Participants	130,353,223	50

Project Objective:
To demonstrate the IGCC technology in a greenfield, commercial, electric utility application at the 250-MWe size with a Texaco gasifier. To demonstrate the integrated performance of a zinc-titanate hot-gas cleanup system, conventional cold-gas cleanup, and an advanced gas turbine with nitrogen injection (from the air separation plant) for power augmentation and NO_x control.



Technology/Project Description:
Texaco's pressurized, oxygen-blown, entrained-flow gasifier is used to produce a medium-Btu fuel gas. Coal/water slurry and oxygen are combined at high temperature and pressure to produce a high-temperature syngas. Molten coal-ash flows out of the bottom of the vessel and into a water-filled quench tank where it is turned into a solid slag. The syngas from the gasifier moves to a high-temperature heat-recovery unit which cools the gases.

The cooled gases flow to a particulate-removal section before entering gas-cleanup trains. About 50% of the syngas is passed through a moving bed of zinc-titanate absorbent to remove sulfur. The remaining syngas is further cooled through a series of heat exchangers before entering a conventional gas-cleanup train where sulfur is removed by an acid-gas removal system. These cleanup systems combined are expected to maintain sulfur levels below 0.21 lb/million Btu (96% capture). The cleaned gases are then routed to a combined-cycle system for power generation. A gas turbine generates about 192 MWe. Thermally generated NO_x is controlled to below 0.27 lb/million Btu by injecting nitrogen as a dilutent in the turbine's combustion section. A heat-recovery steam-generator uses heat from the gas-turbine exhaust to produce high-pressure steam. This



steam, along with the steam generated in the gasification process, is routed to the steam turbine to generate an additional 130 MWe (gross). The IGCC heat rate for this demonstration is expected to be approximately 8,600 Btu/kWh (40% efficient). Coals being used in the demonstration are Illinois 6 and Pittsburgh 8 bituminous coals having sulfur contents ranging 2.5–3.5%.

By-products from the process—sulfuric acid and slag—can be sold commercially, sulfuric acid by-products as a raw material to make agricultural fertilizer and the nonleachable slag for use in roofing shingles and asphalt roads and as a structural fill in construction projects.

Project Status/Accomplishments:

The project has completed the preliminary design stage. All key subcontracts and licensing have been negotiated and awarded. Bechtel Power Corporation was selected as the architect and engineer for the site and a revised cost estimate for the project was developed.

The permitting process for Florida is nearing completion. Tampa Electric's site certification application was presented before the state hearing officer in October 1993. Based on the positive comments received at the hearing, all required state permits are expected during January 1994. EPA and DOE are continuing the process of developing the EIS for the Polk Power Plant. EPA expects to release a draft EIS for public comment in early 1994. The project schedule has been revised to accommodate delays in the NEPA process and time for checkout and start-up activities.

Commercial Applications:

The IGCC system being demonstrated in this project is suitable for new electric power generation, repowering needs, and cogeneration applications. The net effective heat rate for the Texaco-based IGCC is expected to be below 8,500 Btu/kWh, which makes it very attractive for baseload applications. Commercial IGCCs should achieve better than 98% SO_2 capture with NO_x emissions reduced by 90%.

The Texaco-based system has already been proven capable of handling both subbituminous and bituminous coals. This demonstration project is scaling up the technology from Cool Water's 100-MWe to the 250-MWe size.

Wabash River Coal Gasification Repowering Project

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

Additional Team Members:
PSI Energy, Inc.—host utility

Destec Energy, Inc.—engineer, gas plant operator, and technology supplier

Location:
West Terre Haute, Vigo County, IN (PSI Energy's Wabash River Generating Station)

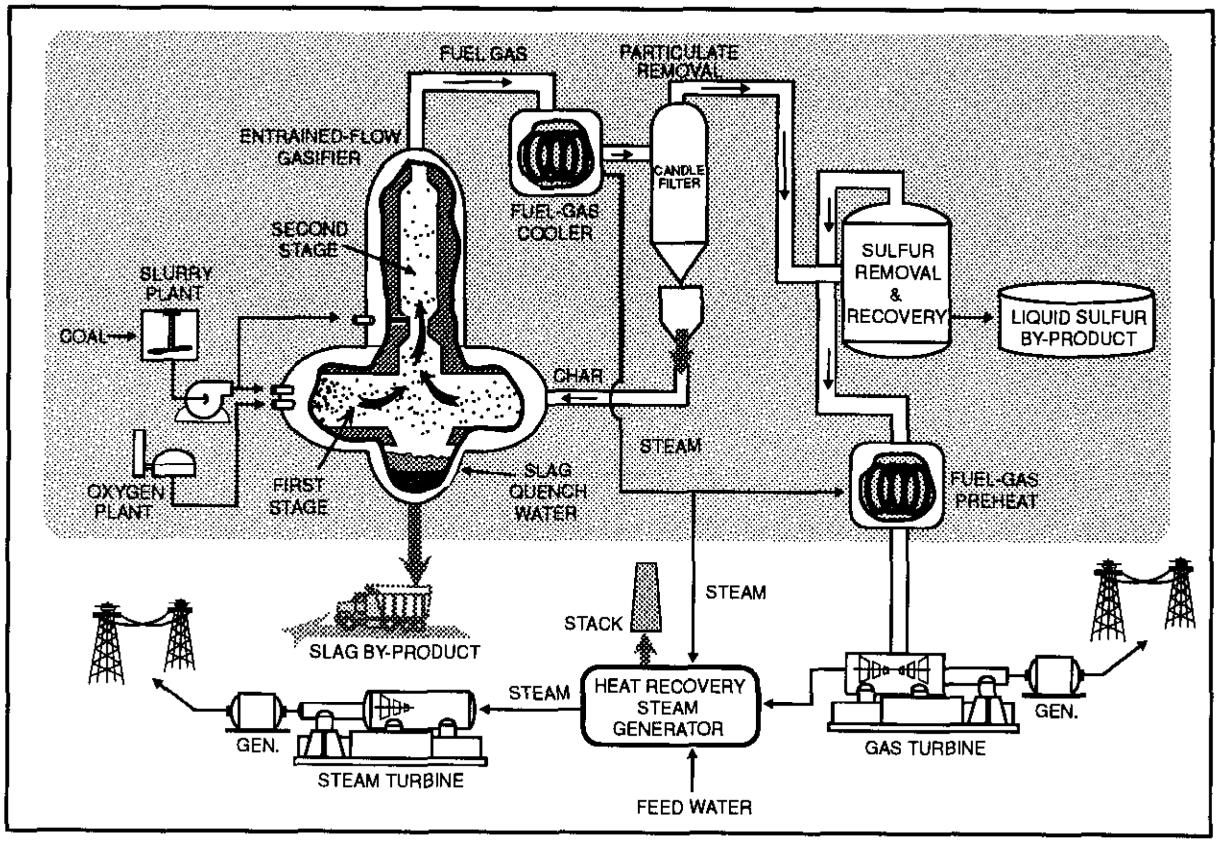
Technology:
Integrated gasification combined-cycle (IGCC) using Destec's two-stage, entrained-flow gasification system (advanced electric power generation/integrated gasification combined cycle)

Plant Capacity/Production:
262 MWe (net)

Project Funding:

Total Project cost	$396,000,000	100%
DOE	198,000,000	50
Participant	198,000,000	50

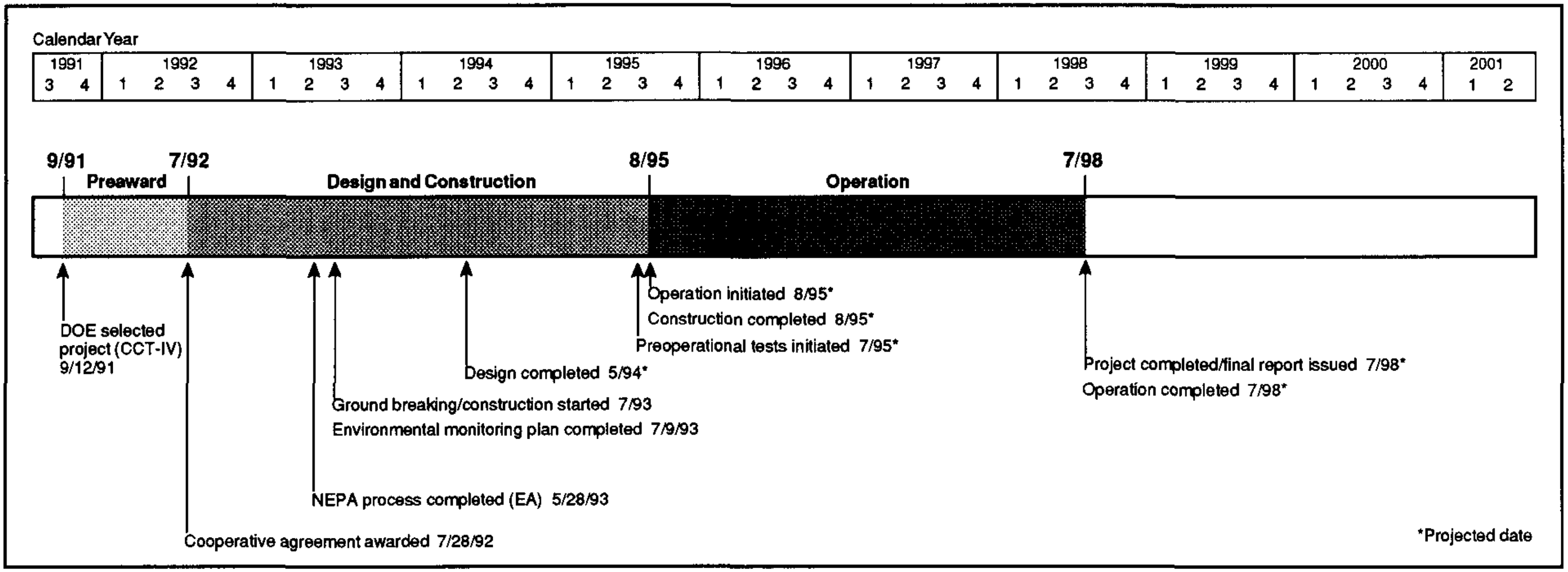
Project Objective:
To demonstrate utility repowering with a two-stage, oxygen-blown IGCC system, including advancements in the technology relevant to the use of high-sulfur bituminous coal, and to assess long-term reliability, availability, and maintainability of the system at a fully commercial scale.



Technology/Project Description:
Coal is ground, slurried with water, and gasified in a pressurized, two-stage (entrained flow slagging first stage and non-slagging second stage), oxygen-blown, entrained-flow gasifier. The product gas is cooled through heat exchangers and passed through a conventional cold gas cleanup system which removes particulates, ammonia, and sulfur. The clean, medium-Btu gas is then reheated and burned in an advanced 192-MWe (gross) gas turbine. Hot exhaust from the gas turbine is passed through a heat recovery steam generator to produce high-pressure steam. High-pressure steam is also produced from the gasification plant and superheated in the heat recovery steam generator. The combined high-pressure steam flow is supplied to an existing 104-MWe (gross) steam turbine.

The process has the following subsystems: a coal-grinding and slurry system, an entrained-flow coal gasifier, a cold gas cleanup system which produces a marketable sulfur by-product, a combustion turbine capable of using coal-derived fuel gas, a heat recovery steam generator, and a repowered steam turbine.

One of six units at PSI Energy's Wabash River Generating Station, located in West Terre Haute, IN, is being repowered. The demonstration unit will be designed to generate 262 MWe (net) using 2,544 tons/day of high-sulfur (2.3–5.9% sulfur), Illinois Basin bituminous coal. The anticipated heat rate for the repowered unit is approximately 9,000 Btu/kWh (38% efficiency). Using high-sulfur bituminous coal, SO_2 emissions are expected to be less than 0.2 lb/million Btu (98% reduction). NO_x emissions are expected to be less than



0.1 lb/million Btu (90% reduction). Upon completion, the project will represent the largest single-train IGCC plant in operation in the United States.

Project Status/Accomplishments:

The Indiana Utility Regulatory Commission issued Certificates of Public Convenience and Necessity on May 26, 1993. Project construction was officially initiated in a ceremony at the site on July 7, 1993. Major equipment procurement and construction are in progress.

Following the completion of an environmental assessment, DOE issued a finding of no significant impact on May 28, 1993, concluding the NEPA process. All required environmental permits have been granted.

The schedule has been revised to accommodate delays associated with the NEPA process and air emissions permitting.

Commercial Applications:

Throughout the United States, particularly in the Midwest and East, there are more than 95,000 MWe of existing coal-fired utility boilers which will be over 30 years old in 1996. Many of these aging plants are without air pollution controls and are candidates for repowering with IGCC technology. Repowering of these plants with IGCC systems will improve plant efficiencies and reduce SO_2, NO_x, and CO_2 emissions. The modularity of the gasifier technology will permit a range of units to be considered for repowering and the relatively short construction schedule for the technology will allow utilities greater flexibility in designing strategies to meet load requirements. Also, the high degree of fuel flexibility inherent in the gasifier design allows utilities greater choices in fuel supplies to meet increasingly stringent air quality regulations.

Due to the advantages of modularity, rapid and staged on-line generation capability, high efficiency, fuel flexibility, environmental controllability, and reduced land and natural resource needs, the IGCC system is also a strong contender for new electric power generating facilities. Commercial offerings of the technology will be based on a 300-MWe train which is ideally suited to utility-scale power generation applications. The system heat rate for a new power plant based on this technology is expected to realize at least a 20% improvement in efficiency compared to a conventional pulverized-coal-fired plant with flue gas desulfurization. The improved system efficiency also results in a similar decrease in emissions of CO_2.

Healy Clean Coal Project

Sponsor:
Alaska Industrial Development and Export Authority

Additional Team Members:
Golden Valley Electric Association—host utility
Stone and Webster Engineering Corp.—engineer
TRW, Inc.—technology supplier
Joy Technologies, Inc.—technology supplier

Location:
Healy, Denali Borough, AK (adjacent to Healy Unit #1)

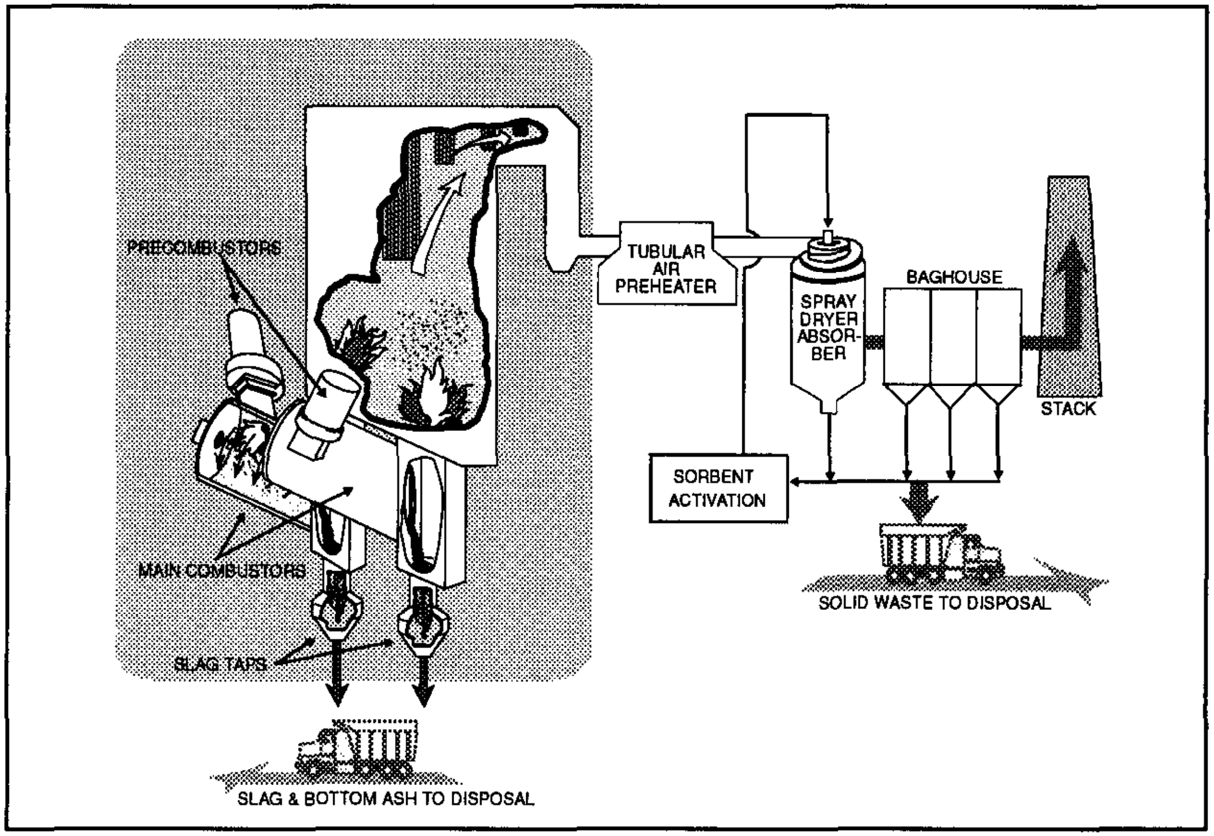
Technology:
TRW's advanced entrained (slagging) combustor
Joy Technologies' spray dryer absorber with sorbent recycle
(advanced electric power generation/advanced combustion/heat engines)

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

Project Funding:

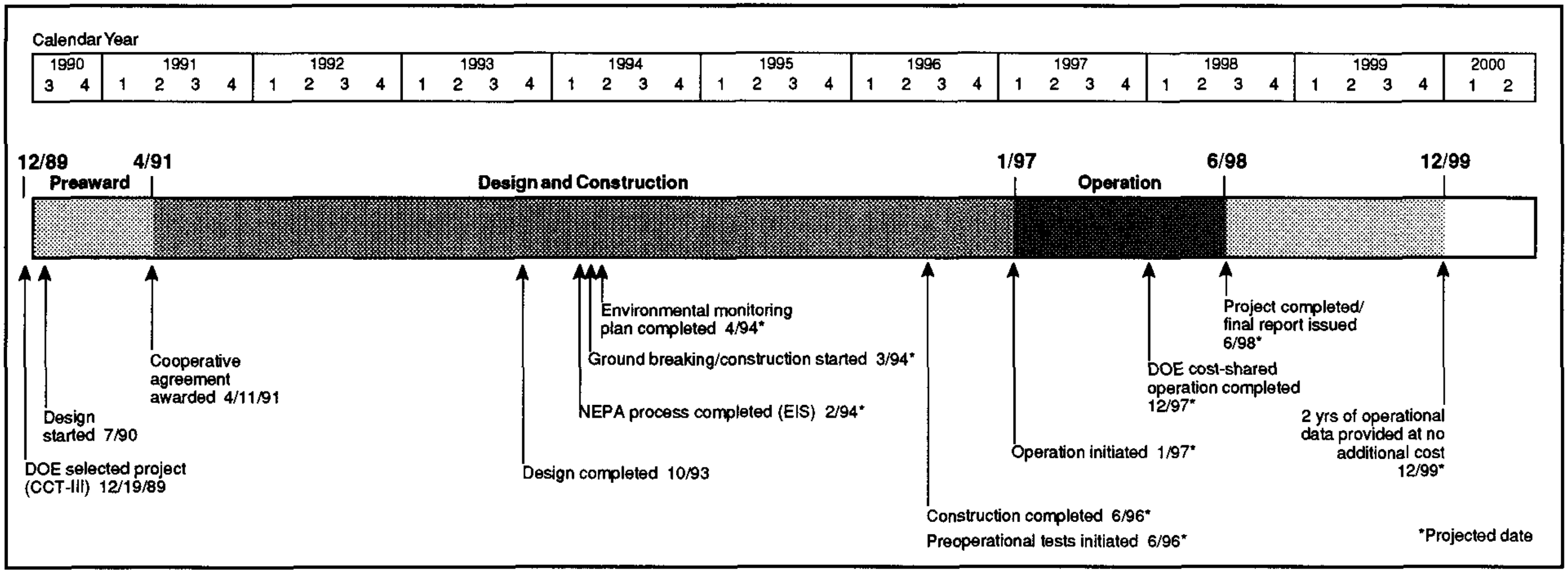
Total project cost	$227,000,000	100%
DOE	109,513,000	48
Participants	117,487,000	52

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



Technology/Project Description:
The project is to be a nominal 50-MWe facility consisting of two pulverized-coal-fired combustor systems. Emissions of SO_2 and NO_x will be controlled using TRW's slagging combustion systems with staged fuel and air, a boiler that controls fuel- and thermal-related conditions, and limestone injection. Further SO_2 will be removed using Joy's activated recycle spray dryer absorber system. Performance goals are NO_x emissions of less than 0.2 lb/million Btu, particulates of 0.015 lb/million Btu, and SO_2 removal greater than 90%. The performance coal consists of 50% run-of-mine and 50% waste coal, with the waste coal having a lower heating value and significantly more ash.

A coal-fired precombustor increases the air inlet temperature for optimum slagging performance. The TRW slagging combustors are bottom-mounted on the boiler hopper. The main slagging combustor consists of a water-cooled cylinder which slopes toward a slag opening. The precombustor burns 25–40% of the total coal input. The remaining coal is injected axially into the combustor, rapidly entrained by the swirling precombustor gases and additional air flow, and burned under substoichiometric (fuel-rich) conditions for NO_x control. The ash forms drops of molten slag which accumulate on the water-cooled walls and are driven by aerodynamic and gravitational forces through a slot into the slag recovery section. About 70–80% of the coal's ash is removed as molten slag. The hot gas is then ducted to the furnace where, to ensure complete combustion, additional air is supplied from the tertiary air windbox to NO_x ports and to final over-fire air ports located in the furnace.



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

The project site is adjacent to the existing Healy Unit #1 near Healy, AK. Power will go to the Golden Valley Electric Association. The plant will provide 3 years of data, with 2 years of data being provided at no cost to DOE. A hazardous air pollutant monitoring program will also be implemented.

In order to address concerns regarding the potential impact to the nearby Denali National Park and Preserve, DOE, the National Park Service, Golden Valley and the project sponsor entered into an agreement to reduce the emissions from Unit #1. As a result, the combined emissions from the two units should be only slightly greater than those currently emitted from Unit #1 alone. The agreement also provides that the total site emissons will be further reduced (to current levels if necessary) in order to protect the park.

Project Status/Accomplishments:

Test burns using Healy project fuel were completed at TRW's Cleveland facility. Joy/Niro testing of flash calcined sorbent was completed at the Copenhagen facility. A full-scale precombustor was constructed and test fired at TRW's Capistrano, CA, test facility to verify scaleup designs. The design and engineering is complete; construction is scheduled to start in March 1994.

A final EIS was issued in December 1993; and a record of decision is scheduled for March 1994.

Commercial Applications:

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

Coal Diesel Combined-Cycle Project

Sponsor:

Arthur D. Little, Inc.

Additional Team Members:

Ohio Coal Development Office—cofunder
The Easton Utilities Commission—host
Cooper Energy Services (Cooper-Bessemer Reciprocating Products Division is a division of Cooper Energy Services which is owned by Cooper Industries.)—engine supplier and commercializer
CQ, Inc.—coal-slurry supplier
POWERSERVE Inc.—cleanup system designer

Location:

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

Technology:

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

Plant Capacity/Production:

14 MWe (net)

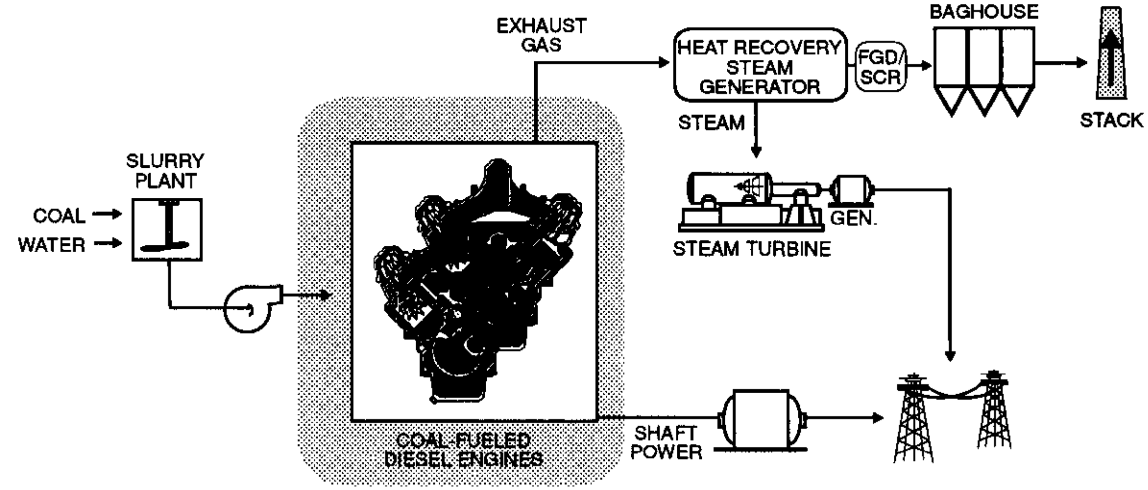
Project Funding:

Total project cost	$37,309,516	100%
DOE	18,654,758	50
Participant	18,654,758	50

(Funding amounts reflect those contained in the proposal and are subject to negotiation.)

Project Objective:

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

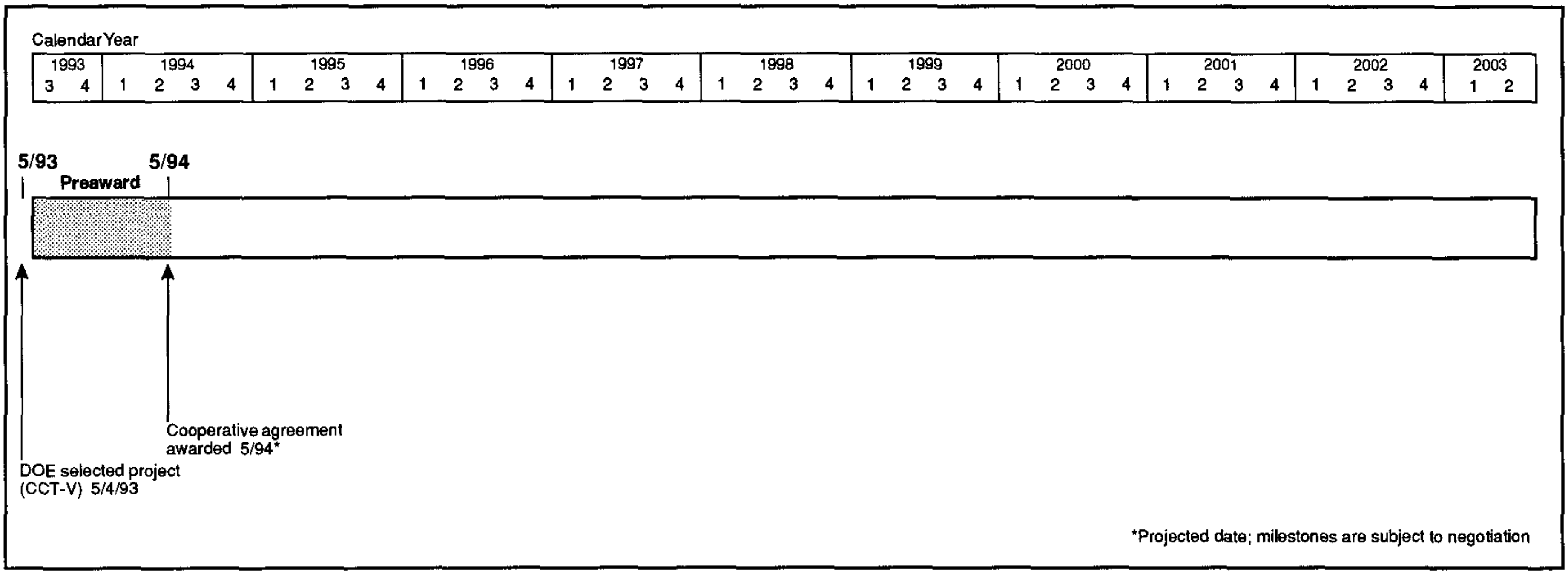


Technology/Project Description:

The project is centered around two Cooper-Bessemer medium-speed (400 rpm) diesel engines (6.3 MWe each) modified to operate on coal-water fuel. Engine modifications include a larger camshaft and fuel cams, modified engine block, hardened piston rings and liners, and hardened turbocharger blades. The CDCC system utilizes a coal-water fuel with a nominal 50% solids loading with a 2% ash clean coal. The clean coal is ground and slurried with water and then injected into each of the engine's 20 cylinders. The exhaust gases from the engine pass through an integrated emission-control system capable of reducing pollutants while protecting the engine's turbocharger and maintaining high engine and overall system efficiency (45%). The exhaust gases pass through a heat recovery steam boiler coupled to a steam turbine and generator to supply an additional 1.4 MWe. Critical data on performance, reliability, and wear are being collected for all major subsystems including the coal-water fuel metering and injection system, medium-speed diesel, lube oil protection system, exhaust cyclone, turbocharger, heat recovery steam boiler, steam turbine, and exhaust emission cleanup system.

The exhaust emission cleanup system incorporates cyclones to remove the larger particulates, a selective catalytic recovery system for NO_x control, a duct sorbent injection system for SO_2 control, and baghouse for final collection of ash particulates and spent sorbent.

The demonstration site is The Easton Utilities Commission's Plant #2 in Easton, MD. Planned for use is an Ohio bituminous coal with characteristics suitable for cleaning to ash levels of about 2% (sulfur content undetermined).



Project Status/Accomplishments:

The project is in negotiation. Environmental information is being prepared for use in the NEPA process.

Commercial Applications:

The CDCC system is particularly suited for small (below 50 MWe) electric power generation markets. Projected markets include small nonutility generators and repowering applications for small coal-fired boilers. The net effective heat rate for the mature CDCC is expected to be 6,830 Btu/kWh (48%), which makes it very competitive with similarly sized coal- and fuel-oil-fired installations. Environmental emissions from commercial CDCCs should be reduced to levels between 50% and 70% below NSPS.

Cooper-Bessemer is currently the largest U.S. manufacturer of large-scale diesel engines and commands a significant share of the U.S.-based market in that size range. The CDCC system has already achieved over 200 hours of operation using coal-water fuel in a 6-cylinder engine at Cooper's test facilities in Ohio. Over 6,000 hours of coal-water fuel operation in 20-cylinder engines are planned for this project. Demonstration of the long-term reliability of the critical components in the CDCC system will provide power generators with an efficient and environmentally superior option for future power.

Warren Station Externally Fired Combined-Cycle Demonstration Project

Sponsor:
Pennsylvania Electric Company

Additional Team Members:
Hague International—technology developer and supplier
Black & Veatch—engineer and construction manager

Location:
Warren, Warren County, PA (Pennsylvania Electric Company's Warren Station Unit 2)

Technology:
Hague International's externally fired combined-cycle (EFCC) system using a novel, high-temperature, ceramic gas-to-air heat exchanger (advanced electric power generation/advanced combustion/heat engines)

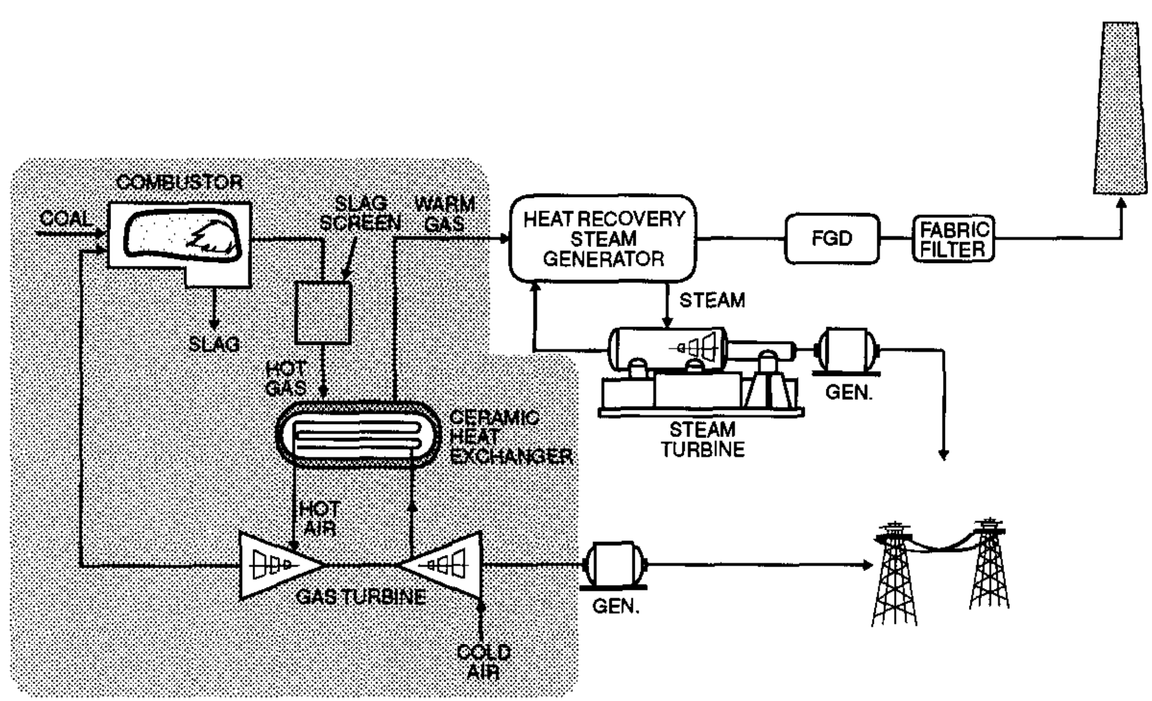
Plant Capacity/Production:
62.4 MWe (net)

Project Funding:

Total project cost	$146,438,000	100%
DOE	73,219,000	50
Participant	73,219,000	50

(Funding amounts reflect those contained in the proposal and are subject to negotiation.)

Project Objective:
To demonstrate an externally fired combined-cycle system through the use of a novel ceramic heat exchanger and to assess the system's environmental and economic performance for meeting future energy needs. Along with the heat exchanger, the system will demonstrate a ceramic slag screen for removal of combustion by-products from the product gas prior to entering the heat exchanger; a staged, wet bottom, low-NO_x combustor; and the integration of the above with a gas turbine and a steam turbine.

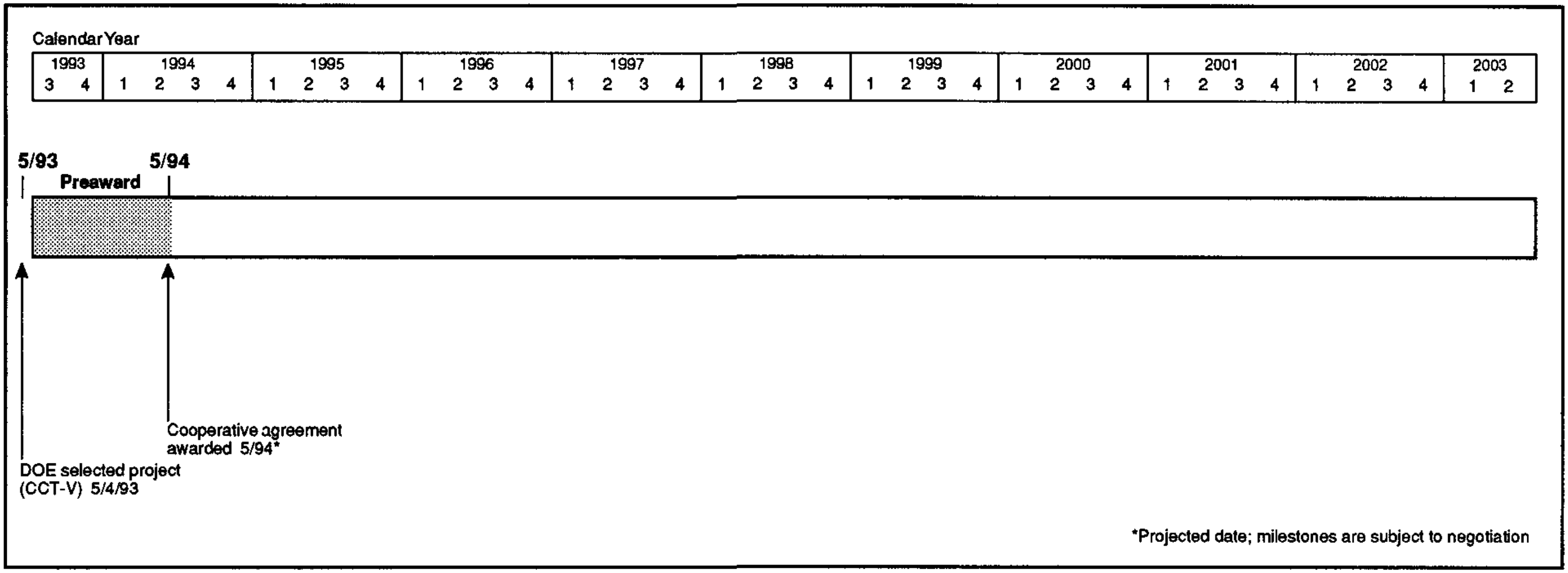


Technology/Project Description:
In this project, an existing coal-fueled steam plant is being repowered by adding an externally fired gas turbine to form a combined-cycle system. The central feature of the EFCC is a ceramic air heater or heat exchanger (CerHx®) and an atmospheric combustor which together replace a conventional combustion system in an open-cycle gas turbine.

Coal is first combusted in a staged combustor for NO_x control. Particulate-laden gases exit the combustor and enter the slag screen where all particles larger than about 10 microns are collected. Air from the turbine compressor is heated by exchange with the hot product gas in the CerHx®. The product gas is then passed through a heat recovery steam generator, where more heat is extracted to drive a steam turbine generator and produce electricity. The product gas is finally passed through a gas cleanup system consisting of a flue gas desulfurizer and a fabric filter before exiting to the atmosphere through the stack. The hot air from the CerHx® is passed through a gas turbine to produce additional electricity before firing the combustor.

The attractiveness of the EFCC lies in its ability to eliminate the need for a hot gas cleanup system to protect the costly gas turbine gas-path components from the corrosive and abrasive elements in the combustion product gas. Instead, the gas turbine operates on indirectly

CerHx is a registered trademark of Hague International.



heated clean air and the gas path is never exposed to the corrosive elements in the fuel or product gas. The CerHx® raises the temperature of the air to the turbine inlet conditions using tube elements that are manufactured from corrosion resistant, toughened, ceramic materials.

About 225,000 tons/yr of bituminous coal will be combusted to produce 62.4 MWe. The gas turbine will generate 18.3 MWe with a small amount of steam injection and the existing steam turbine will generate 47.7 MWe, for a total gross output of 66 MWe. Approximately 3.6 MWe will be consumed internally. The heat rate of the demonstration facility will be 9,650 Btu/kWh (HHV), which is a 31.3% improvement over the existing Warren Station unit. Potential SO_x release is reduced by over 90% through capture in the flue gas desulfurization system. NO_x emissions are expected to be below 0.13 lb/million Btu.

The facility being repowered is Pennsylvania Electric Company's Warren Station Unit 2 near Warren, PA. The primary coal for the project is Pennsylvania bituminous coal containing either 1.0% or 2.3% sulfur, depending on the mine. A secondary test coal is Pennsylvania bituminous coal containing 1.6% sulfur.

Project Status/Accomplishments:

The project is in negotiation. Environmental information is being prepared for use in the NEPA process.

Commercial Applications:

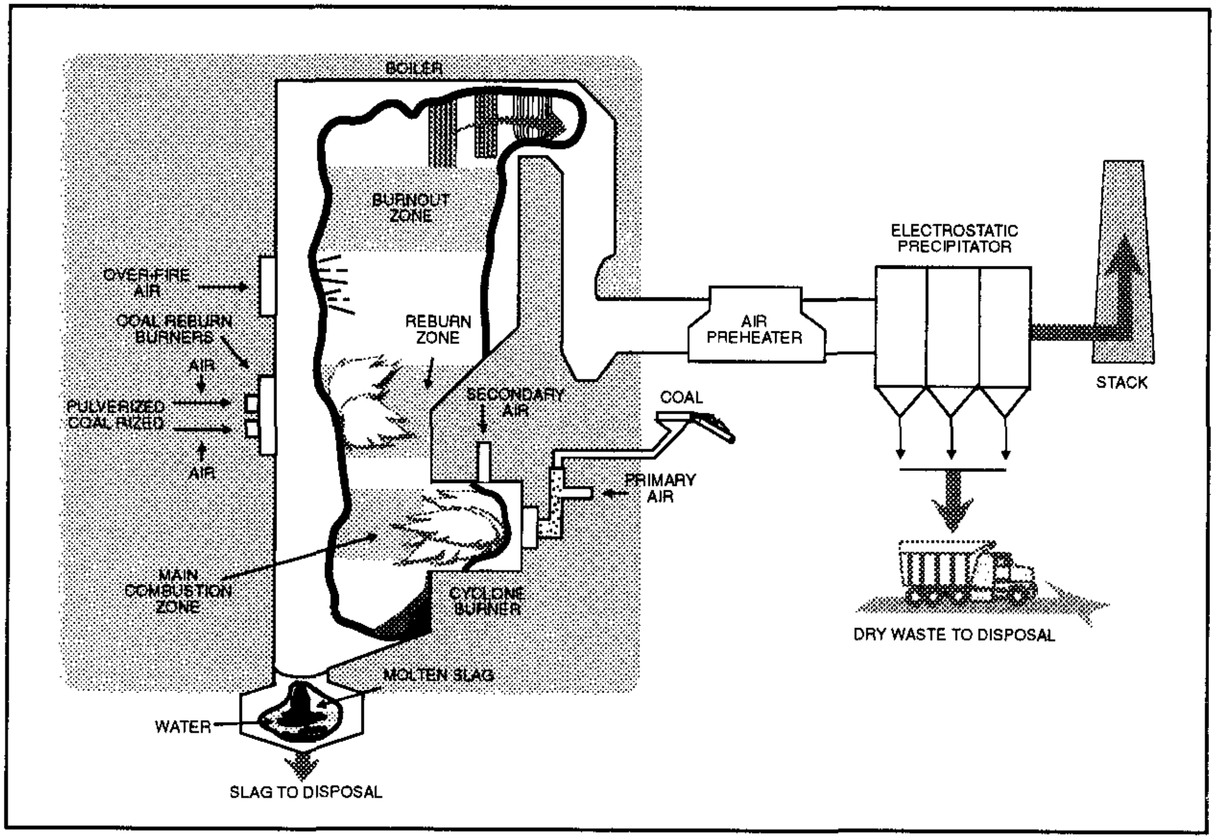
The Warren Station EFCC system concept is suitable for new electric power generation, repowering needs, and cogeneration applications. The potential commercial market for such systems is expected to be about 24 GWe by 2010. The net effective heat rate for a 300-MWe greenfield plant using this technology is projected to be 7,790 Btu/kWh. This represents a 20% increase in thermal efficiency compared to a conventional pulverized coal plant with a scrubber.

SO_2 is expected to be below 0.081 lb/million Btu, which is a reduction of over 90% for most coals. NO_x emissions are expected to be less than 0.15 lb/million Btu and particulate emissions (PM10) are expected to be below 0.015 lb/million Btu.

Environmental Control Devices Fact Sheets

Demonstration of Coal Reburning for Cyclone Boiler NO_x Control

Project completed.



Sponsor:
The Babcock & Wilcox Company

Additional Team Members:
Wisconsin Power and Light Company—cofunder and host utility
Sargent and Lundy—engineer for coal handling
Electric Power Research Institute—cofunder
State of Illinois, Department of Energy and Natural Resources—cofunder
Utility companies (14 cyclone boiler operators)—cofunders

Location:
Cassville, Grant County, WI (Nelson Dewey Station, Unit No. 2)

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

Plant Capacity/Production:
100 MWe

Project Funding:

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

Project Objective:
To evaluate the applicability of reburning technology for reducing NO_x emissions from a full-scale coal-fired cyclone boiler, pulverizing a portion of the primary coal fuel to use as the secondary, "reburning" fuel; and to achieve greater than 50% reduction in NO_x emissions with no serious impact on cyclone combustor operation, boiler efficiency, boiler fireside performance (corrosion and deposition), or ash removal system performance.

Technology/Project Description:
The coal-reburning process reduces NO_x in the furnace through the use of multiple combustion zones. The main combustion zone uses 70–80% of the total heat equivalent fuel input to the boiler and slightly less than normal combustion air input. The balance of the coal (20–30%), along with significantly less than the theoretically determined requirement of air, is fed to the reburning zone above the cyclones to create an oxygen-deficient condition. The NO_x formed in the cyclone burners reacts with the resultant reducing flue gas and is converted into nitrogen in this zone. The completion of the combustion process occurs in the third zone, called the burnout zone, where the balance of the combustion air is introduced. The combined production of boiler slag and dry waste from the electrostatic precipitator remains unchanged with coal reburning because the required coal input for the same boiler load is the same.

The coal-reburning technology can be applied with the cyclone burners operating within their normal, non-corrosive, oxidizing conditions, thereby minimizing any adverse effects of reburn on the cyclone combustor and boiler performance.

This project involved retrofitting an existing 100-MWe cyclone boiler that is representative of a large population of cyclone units. The boiler is located at Wisconsin Power and Light's Nelson Dewey Station in Cassville, WI.

Project Results/Accomplishments:

Coal-reburn tests were conducted to determine the reduction in NO_x emissions for the coal-reburning technology over a range of boiler loads varying from 37 MWe to 118 MWe (nominal maximum boiler load is 110 MWe). Two coals were tested, namely, the design Illinois Basin bituminous coal (Lamar, 1.8% sulfur) and a western subbituminous coal (Powder River Basin, 0.5% sulfur). The bituminous coal tests evaluated a fuel typical of the coals fired by utilities operating cyclones. The subbituminous coal tests evaluated coal switching for SO_2 reduction.

As a part of the test program, several parameters were optimized over the load range to achieve the optimum NO_x reduction while keeping other variables, such as unburned carbon and carbon monoxide emissions, within reasonable limits. The optimized parameters included the split of boiler fuel between the reburn system and the cyclone burners, the reburn burner and the reburn zone stoichiometries, the reburn burner pulverized coal fineness, flue gas recirculation, and economizer outlet O_2 content. Also, adjustments were made to the reburn burners and the over-fire air ports during the tests.

With the Lamar coal, the boiler NO_x emissions were reduced as follows:

- 52% (to 290 ppm or 0.394 lb/million Btu) at 110 MWe
- 47% (to 285 ppm or 0.387 lb/million Btu) at 82 MWe
- 36% (325 ppm or 0.442 lb/million Btu) at 60 MWe

With Powder River Basin coal, the NO_x emissions were reduced as follows:

- 62% (to 208 ppm or 0.278 lb/million Btu) at 110 MWe
- 55% (to 215 ppm or 0.287 lb/million Btu) at 82 MWe
- 53% (to 220 ppm or 0.294 lb/million Btu) at 60 MWe

Reburn testing with both coals indicated that varying reburn zone stoichiometry is the most critical factor in controlling NO_x. Reburn zone stoichiometry can be varied by altering air flow quantities to the reburn burners, percent reburn heat input, flue gas recirculation flow rate, or cyclone stoichiometry.

Burning subbituminous coal produced lower overall NO_x emissions levels and higher NO_x emissions reductions. This result is probably due to the higher volatile content of the western coal. The higher volatile content generates higher concentrations of hydrocarbon radicals in the reburn zone. With the reburn system contributing additional burning capacity for the cyclone boiler, the lower Btu content western fuel could be fired up to the full boiler load rating.

Additional effects of coal reburning on the retrofitted boiler follow:

- Loss of combustion efficiency, due to increased unburned carbon, amounted to 1.5% at full load with bituminous coal and 0.3% with subbituminous coal.
- The performance of the ESP remained constant even though its ash loading doubled. The increased ash consisted of larger sizes of particulates.
- The furnace exit gas temperature decreased by more than 100 °F at full load, contrary to expectations, and thus improved the boiler heat absorption efficiency correspondingly.
- Slagging and fouling were significantly reduced with bituminous coal reburning. The subbituminous reburn operations were too short in duration to make a reasonable observation.
- No furnace corrosion was observed over the 1-year test period.

Hazardous air pollutants (HAP) testing was performed using Lamar test coal. HAP emissions were generally well within expected levels and emissions with reburn comparable to baseline operations.

Commercial Applications:

The current reburn market is nearly 26,000 MWe and consists of about 120 units ranging from 100 MWe to 1,150 MWe, with most in the 100–300-MWe range. Coal reburning is a retrofit technology applicable across the size range of utility and industrial cyclone boilers.

The principal environmental benefit is reduced NO_x emissions. A secondary benefit may be reduced SO_2 emissions by enabling greater use of lower sulfur western coal; due to its lower Btu content, western coals limit cyclone capacity. With the additional firing capacity of the reburn system, full-load performance on western coal may be possible for some cyclone units.

For cyclone boilers, coal reburning offers a NO_x reduction alternative at a cost expected to be in the range of $65/kW for 100 MWe units to $40/kW for a larger 600 MWe unit. This includes costs for coal handling and pulverizers/coal piping. Coal's cost differential and dependability of supply give it the long-run advantage. Another advantage of the reburn system is its ability to utilize different coals.

Project Schedule:

DOE selected project (CCT-II)	9/28/88
Cooperative agreement awarded	4/2/90
NEPA process completed (EA)	2/12/91
Environmental monitoring plan completed	11/18/91
Construction	11/90–11/91
Operational testing	11/91–12/92
Project completed	12/93

Final Reports:

Final Technical Report	early 1994
Economic Evaluation Report	early 1994
Public Design Report	8/91

Full-Scale Demonstration of Low-NO_x Cell™ Burner Retrofit

Project completed.

Sponsor:

The Babcock & Wilcox Company

Additional Team Members:

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

Location:

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

Technology:

The Babcock & Wilcox Company's Low-NO_x Cell™ burner (LNCB™) system (environmental control devices/ NO_x control technologies)

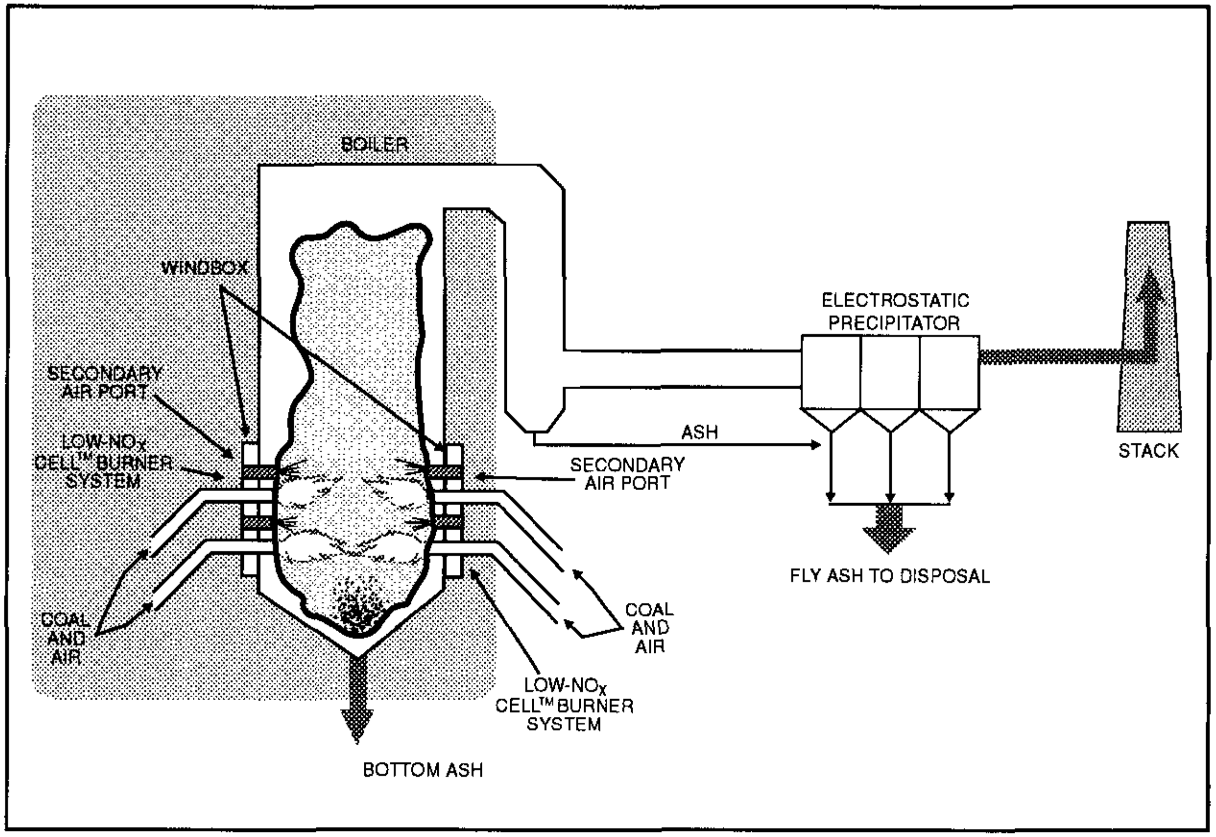
Plant Capacity/Production:

605 MWe

Project Funding:

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

Low-NO_x Cell, LNC, and LNCB are trademarks of The Babcock & Wilcox Company.



Project Objective:

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

Technology/Project Description:

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

The net effect of this technology is greater than 50% reduction in NO_x formation with no boiler pressure part changes and no impact on boiler operation or performance. In addition, the technology is compatible with most commercial and emerging SO_2 control technologies, including confined zone dispersion, gas suspension absorption, duct injection, and advanced wet scrubbers.

The demonstration was conducted at a large-scale power plant operated by The Dayton Power and Light Company and jointly owned with the Cincinnati Gas and

Electric Company and the Columbus Southern Power Company. The boiler unit is a Babcock & Wilcox-designed, supercritical, once-through boiler equipped with an electrostatic precipitator. This unit contained 24 two-nozzle cell burners arranged in an opposed-firing configuration. Twelve burners (arranged in two rows of six burners each) were mounted on each of two opposing walls of the boiler. All 24 standard cell burners were removed, and 24 new Low-NO_x Cell™ burners were installed. Alternate Low-NO_x Cell™ burners on the bottom rows were inverted, with the air port then being on the bottom to insure complete combustion in the lower furnace.

Project Results/Accomplishments:

The initial test results on the LNCB™ were disappointing. Reducing gases containing high concentrations of carbon monoxide and hydrogen sulfide accumulated in the lower furnace below the burners, and the NO_x emissions reduction was only about 35%. By numerically modelling several possible burner configurations, Babcock & Wilcox was able to select an optimum new burner arrangement. On the lower row of burners, alternate LNC™ burners were inverted so that the air ports integral to these burners directed air into the lower furnace. Also, a design change for the burners' coal impellers increased the NO_x reduction to above the design goal.

The LNC™ burner demonstration emphasized evaluation of boiler performance, boiler life, and environmental impact. Key boiler performance parameters included boiler output (steam temperatures); flue gas temperatures at the furnace, economizer, and air heat exits; the slagging tendencies of the unit; and unburned carbon losses. Boiler life potentials (corrosion tendencies) were measured by gas sampling for high H_2S concentrations in the furnace, ultrasonic testing of lower furnace tube walls, and destructive examination of a corrosion test panel. Environmentally, NO_x, CO, CO_2, total hydrocarbons, and particulate matter were measured at varying test conditions.

At full load (605 MWe) with all mills in service, average NO_x emissions were 0.53 lb/million Btu, a 54.4% reduction from the baseline. CO emissions ranged from 28 to 55 ppm. Flyash unburned carbon averaged 1.12%, for a 0.2% loss unburned carbon efficiency. This is a 56% improvement over baseline unburned carbon losses, probably resulting from improved air flow distribution achieved by the LNC™ burner retrofit. At reduced loads of 460 MWe and 350 MWe, the NO_x emissions reductions were 54% and 48% respectively, and CO emissions and unburned carbon values were comparable with baseline emissions.

Long-term NO_x emissions data were accumulated using a third-party continuous emissions monitor over an 8-month test period that followed the parametric and optimization test periods. On days when the boiler was operating at 590 MWe or above, and with all mills in service, NO_x emissions averaged 0.49 lb/million Btu, a 58% reduction from baseline emissions. This data set covered 79 days.

Overall unit efficiency remained essentially unchanged from baseline to optimized LNC™ burner operation. The demonstration boiler is operating at a lower overall excess air since the optimization testing, which has reduced the dry gas loss and increased the boiler efficiency slightly.

A corrosion test panel was installed when the LNC™ burners were installed. The panel consisted of SA-213T2 bare tube material with some of this material aluminized, some stainless weld overlaid, and some chromized. This level of corrosion is roughly equivalent to the boiler's corrosion prior to the retrofit. The coated materials had no loss.

Commercial Applications:

Currently there are 34 operating cell-burner-fired boilers for which the LNCB™ system is applicable. Of these boilers, 29 are opposed-wall-fired with two rows of two-nozzle cells. The average size is 766 MWe.

The low cost and short outage time for retrofit make the LNCB™ design attractive. Typically, the retrofit capital-cost will be \$5.50–\$8.00/kW in 1993 dollars, based upon DOE's 500-MWe reference unit. The outage time can be as short as 5 weeks because of the "plug-in" design. The LNCB™ system can be installed at about half the cost and outage time for other commercial low-NO_x burner installations.

Project Schedule:

DOE selected project (CCT-III)	12/19/89
Cooperative agreement awarded	10/11/90
NEPA process completed (MTF)	8/10/90
Environmental monitoring plan completed	8/9/91
Construction	9/91–11/91
Operational testing	12/91–4/93
Project completed	12/93

Final Reports:

Final Technical Report	early 1994
Economic Evaluation Report	early 1994
Public Design Report	8/91

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

Sponsor:
Energy and Environmental Research Corporation

Additional Team Members:
Public Service Company of Colorado—cofunder and host utility
Gas Research Institute—cofunder
Colorado Interstate Gas Company—cofunder
Electric Power Research Institute—cofunder

Location:
Denver, Adams County, CO (Public Service Company of Colorado's Cherokee Station, Unit No. 3)

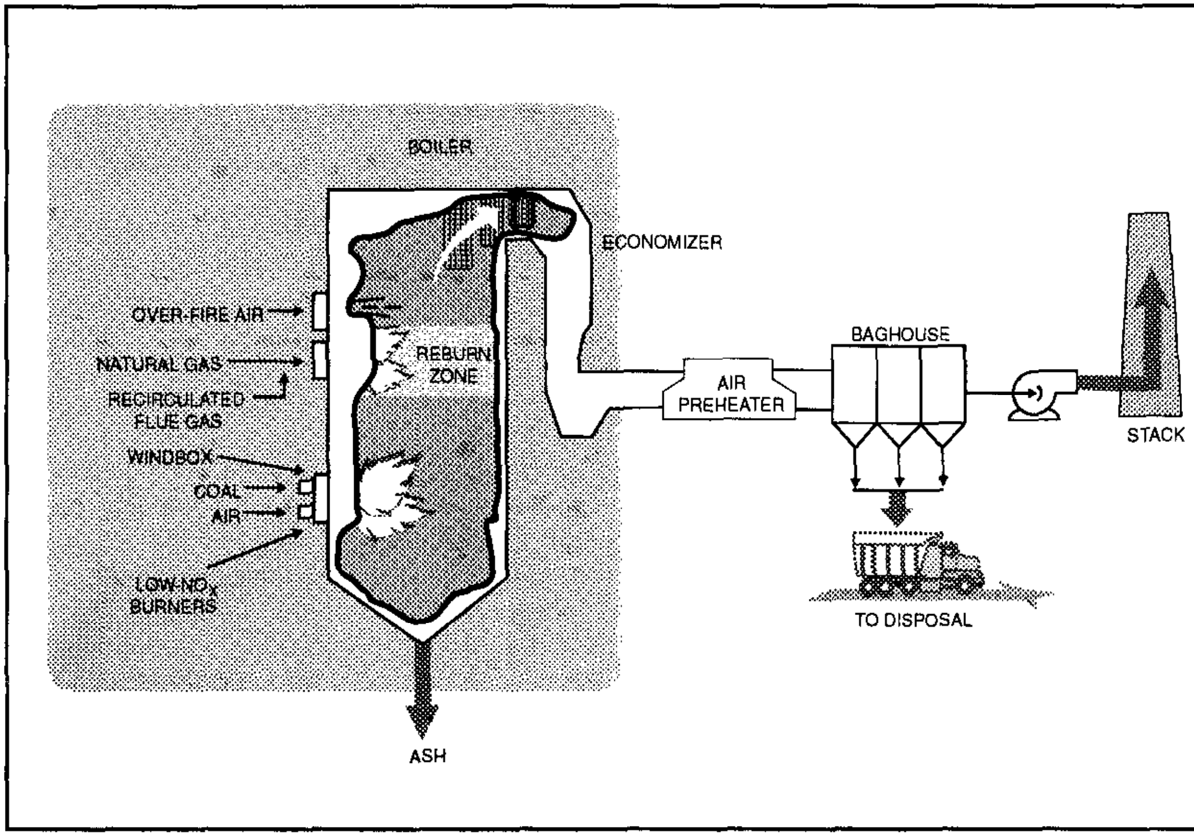
Technology:
Energy and Environmental Research Corporation's gas reburning and low-NO_x burner (GR–LNB) system (environmental control devices/NO_x control technologies)

Plant Capacity/Production:
172 MWe

Project Funding:

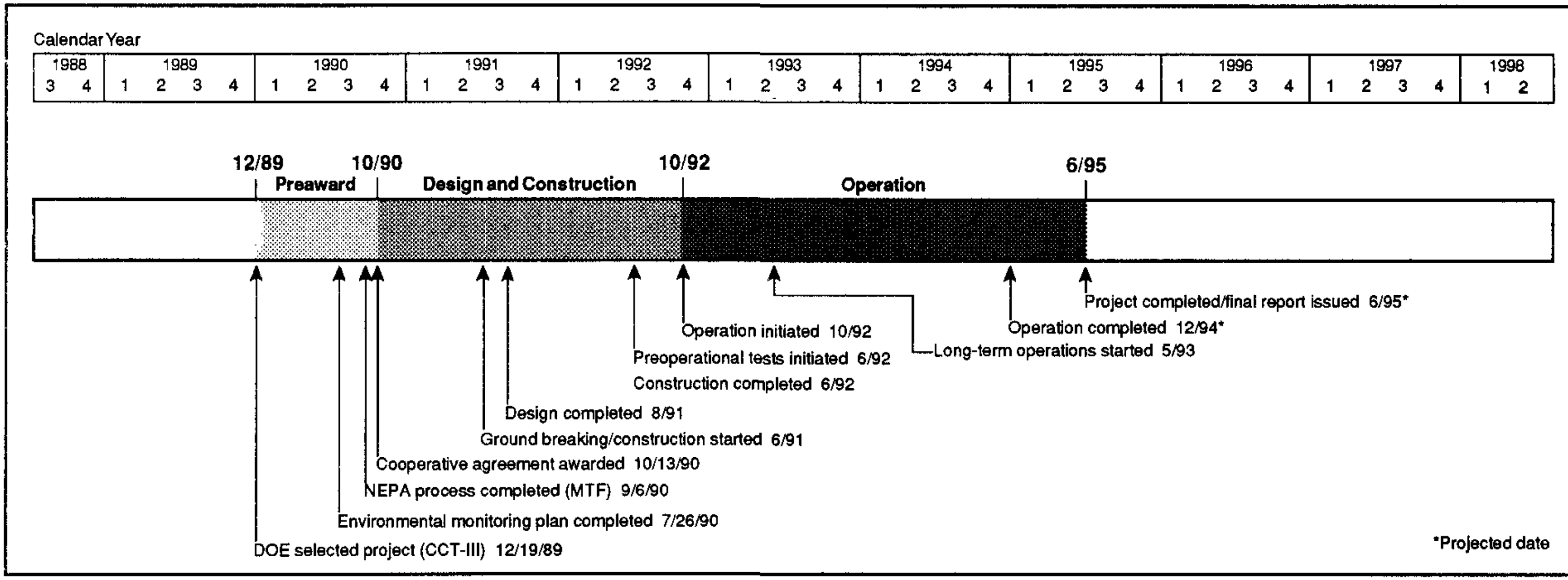
Total project cost	$17,811,172	100%
DOE	8,905,585	50
Participants	8,905,587	50

Project Objective:
To attain up to a 70% decrease in the emissions of NO_x from an existing wall-fired utility boiler firing low-sulfur coal using both gas reburning and low-NO_x burners.



Technology/Project Description:
Gas reburning involves firing natural gas (up to 20% of total fuel input) above the main coal combustion zone in a boiler. This upper-level firing creates a slightly fuel-rich zone. NO_x drifting upward from the lower region of the furnace is "reburned" in this zone and converted to molecular nitrogen. Low-NO_x burners positioned in the coal combustion zone retard the production of NO_x by staging the burning process so that the coal-air mixture can be carefully controlled at each stage. The synergistic effect of adding a reburning stage to wall-fired boilers equipped with low-NO_x burners is projected to lower NO_x emissions by 70% or more. Gas reburning is being demonstrated with and without the use of recirculated flue gas.

The project site is Public Service Company of Colorado's Cherokee Station, Unit No. 3, in Denver, CO. This project combines gas reburning and low-NO_x burners on a 172-MWe wall-fired utility boiler. Western bituminous coals containing 0.35–0.66% sulfur are being used in this demonstration.



Project Status/Accomplishments:

Permitting activities have been completed. Construction started in mid-1991 and was completed in June 1992, about 3 months ahead of schedule. Construction included the installation of new boiler penetrations, new burners, refractory, and insulation. All of the equipment *that was installed during construction was checked out* and found to be functional. Start of operation was delayed during the period July–August 1992 when the Public Service Company of Colorado rebuilt the four coal-pulverizing mills to enhance the flow of primary air to the boiler. Optimization of the gas-reburning unit started in late-September and was followed by a brief outage in November for minor modifications to the tertiary air system. Parametric studies were started in October 1992 and were completed in April 1993. Preliminary analysis indicated NO_x reductions of up to 70% at 150 MWe. Long-term 1-year load-following operations started in May 1993. Long-term operations will be completed in 1994. Following long-term operations, gas reburning without the use of recirculated flue gas will be demonstrated along with gas firing-gas reburning.

Commercial Applications:

Gas reburning in combination with low-NO_x burners is applicable to wall-fired utility and industrial boilers. The technology can be used in new and pre-NSPS wall-fired boilers.

Specific features of this technology that increase its potential for commercialization are as follows:

- Can be retrofitted to existing units
- Reduces NO_x emissions by 70% or more
- Suitable for use with a wide range of coals
- Has the potential to improve boiler operability
- Has the potential to reduce the cost of electricity
- Consists of commercially available components
- Requires minimal space

Current estimates indicate that about 35 existing wall-fired utility installations, plus industrial boilers, could make immediate use of this technology. The technology would apply to retrofit, repowering or to new, greenfield installations. There is no known limit to the size or scope of the application of this technology combi*nation. Presently, the largest existing utility boiler is* estimated at about 1,300 MWe. The GR–LNB combination could be applied directly to this size boiler because the equipment is an integral part of the unit. For this reason, GR–LNB is expected to be less capital intensive, or less costly, than a scrubber, selective catalytic reduction, or other technology approaches. GR–LNB functions equally well with any kind of coal. NO_x emissions are reduced with internally staged low-NO_x burners, followed by gas reburning. As a side benefit, SO_2 is decreased in direct proportion to the amount of natural gas that is substituted for coal.

Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler

Sponsor:

Southern Company Services, Inc.

Additional Team Members:

Electric Power Research Institute—cofunder
Foster Wheeler Energy Corporation—technology supplier
Georgia Power Company—host utility

Location:

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

Technology:

Foster Wheeler's low-NO_x burner (LNB) with advanced over-fire air (AOFA) (environmental control devices/NO_x control technologies)

Plant Capacity/Production:

500 MWe

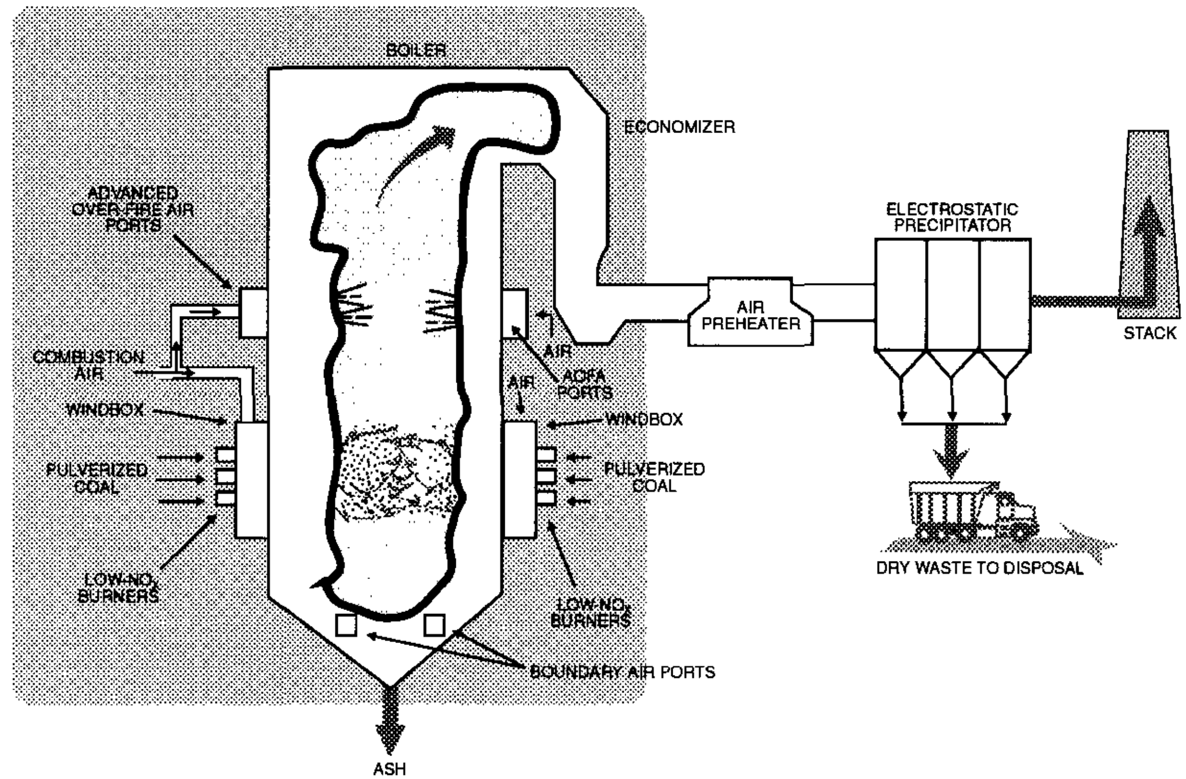
Project Funding:

Total project cost	$14,710,909	100%
DOE	6,553,526	45
Participants	8,157,383	55

(Of the total project cost, $523,680 are for toxics testing.)

Project Objective:

To achieve 50% NO_x reduction with the AOFA/LNB system; to determine the contributions of AOFA and the LNB to NO_x reduction and the parameters determining optimum AOFA/LNB system performance; and to assess the long-term effects of AOFA, LNB, and combined AOFA/LNB and advanced digital controls on NO_x reduction and boiler performance.



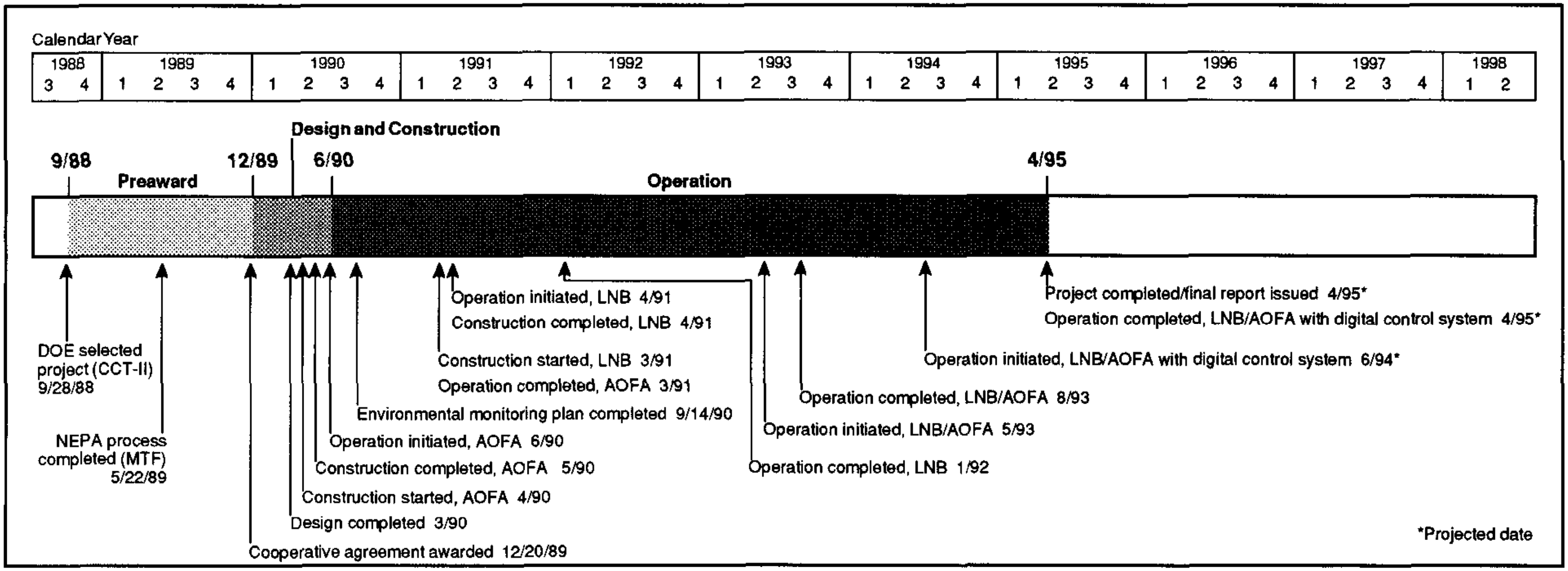
Technology/Project Description:

AOFA involves (1) improving the mixing of over-fire air with the furnace gases to achieve complete combustion, (2) depleting the air from the burner zone to minimize NO_x formation, and (3) supplying air over furnace wall tube surfaces to prevent slagging and furnace corrosion. The AOFA technique is expected to reduce NO_x emissions by about 35%.

In an LNB, fuel and air mixing is controlled to preclude the formation of NO_x. This is accomplished by regulating the initial fuel-air mixture, velocities, and turbulence to create a fuel-rich flame core and by controlling the rate at which additional air required to complete combustion is mixed with the flame solids and gases so as to maintain a deficiency of oxygen. Typical results for utilities indicate that LNB technology is capable of reducing NO_x emissions by about 45%.

Based on earlier experience, the use of AOFA in conjunction with LNB can reduce NO_x emissions by as much as 65% compared with conventional burners.

The demonstration is located at the Georgia Power Company's Plant Hammond, Unit No. 4. The boiler is a nominal 500-MWe pulverized coal, wall-fired unit, which is representative of most of the existing pre-NSPS wall-fired utility boilers in the United States. The project also includes installation and testing of an advanced LNB digital control system that optimizes LNB/AOFA performance.



Project Status/Accomplishments:

Baseline, AOFA, LNB, and LNB/AOFA test segments have been completed. Analysis of more than 80 days of AOFA operating data has provided statistically reliable results indicating that, depending upon load, NO_x reductions of 24% are achievable under normal long-term operation. Analysis of the 94 days of LNB long-term data collected show the full-load NO_x emission levels to be approximately 0.65 lb/million Btu. This NO_x level represents a 48% reduction when compared to the baseline, full-load value of 1.24 lb/million Btu. These reductions were sustainable over the long-term test period and were consistent over the entire load range. Full-load, flyash loss-on-ignition values in the LNB configuration were near 8%, compared to 5% for baseline. Initial results from the LNB/AOFA testing indicate that full-load NO_x emissions are approximately 0.40 lb/million Btu with a corresponding flyash loss-on-ignition value of near 8%. Full-load, long-term NO_x emission reductions in the LNB/AOFA configuration are near 67%. However, preliminary analysis of emissions data suggests that the incremental NO_x reduction effectiveness of the AOFA system (beyond the use of the LNB) was approximately 17 percent with additional reductions resulting from other operational changes. On September 3, 1993, Hammond Unit 4 began a 9-month outage. Configuration of the digital control system and selection of the artificial intelligence software package for optimizing NO_x reduction and boiler efficiency is continuing, and modification of the Hammond Unit 4 control room is now in progress.

Completion of the final analysis of project data and issuance of the final report are scheduled for December 1995.

Pre-retrofit LNB air toxics testing was performed to establish a baseline. Additional air toxics testing with the combined LNB/AOFA configuration has been completed. A report on this work was issued the end of December 1993.

Commercial Applications:

The technology is applicable, in the United States, for retrofitting the 422 existing pre-NSPS wall-fired boilers, which burn a variety of coals, including bituminous, subbituminous, and lignite coal.

Commercialization of the technology will be aided by the following characteristics:

- Reduced NO_x emissions by as much as 65%
- Competitive capital and operating costs
- Relatively easy retrofit
- Little or no derating of the boiler
- Use of commercially available components
- Automatic control of boiler efficiency and maximum pollution abatement through use of artificial intelligence technology in conjunction with digital control

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

Project completed.

Sponsor:
Southern Company Services, Inc.

Additional Team Members:
Gulf Power Company—cofunder and host utility
Electric Power Research Institute—cofunder
ABB Combustion Engineering, Inc.—cofunder and technology supplier

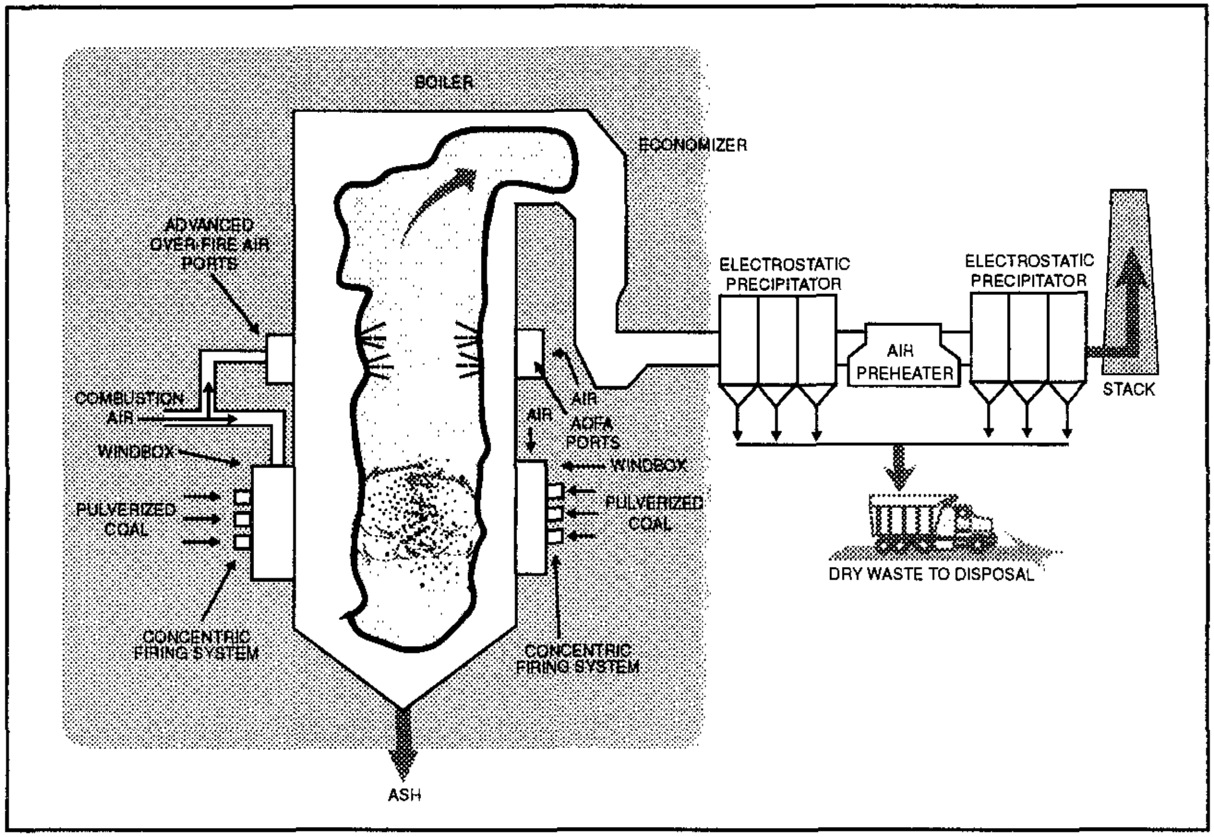
Location:
Lynn Haven, Bay County, FL (Gulf Power Company's Plant Lansing Smith, Unit No. 2)

Technology:
ABB Combustion Engineering's low-NO_x concentric firing system (LNCFS) with advanced over-fire air (AOFA), clustered coal nozzles, and offset air (environmental control devices/NO_x control technologies)

Plant Capacity/Production:
180 MWe

Project Funding:

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



Project Objective:
To demonstrate in a stepwise fashion the short- and long-term NO_x reduction capabilities of low-NO_x concentric firing system (LNCFS) Levels I, II, and III on a single reference boiler under typical dynamic operating conditions, and evaluate the cost effectiveness of each low-NO_x combustion technique.

Technology/Project Description:
Three different low-NO_x combustion technologies for tangentially fired boilers were demonstrated. The concept of over-fire air was demonstrated in all of these systems. In LNCFS Level I, a close-coupled over-fire air (CCOFA) system is integrated directly into the windbox of the boiler. Compared to the baseline windbox configuration, LNCFS Level I is arranged by exchanging the highest coal nozzle with an air nozzle immediately below it. This configuration provides the NO_x reducing advantages of an over-fire air system without pressure part modifications to the boiler.

In LNCFS Level II, a separated over-fire air (SOFA) system is used. This advanced over-fire air system has backpressuring and flow measurement capabilities. The air supply ductwork for the SOFA is taken off from the secondary air duct and routed to the corners of the furnace above the existing windbox. The inlet pressure to the SOFA system can be increased above windbox pressure using dampers downstream of the takeoff in the secondary air duct. Operating at a higher pressure increases the quantity and injection velocity of the over-fire air into the furnace. A multicell venturi is used to measure the amount of air through the SOFA system. LNCFS Level III utilizes both CCOFA and SOFA.

In addition to over-fire air, the LNCFS incorporates other NO_x reducing techniques into the combustion process. Using offset air, two concentric circular combustion regions are formed. The majority of the coal is contained in the fuel-rich inner region. This region is surrounded by a fuel-lean zone containing combustion air. The size of this outer circle of combustion air can be varied using adjustable offset air nozzles. Separation of air and coal at the burner level further reduces production of NO_x.

The names of the technologies described above have been changed from those originally considered for this project to reflect the most recent knowledge. However, the basic concepts for the reduction of NO_x emissions have remained constant. These technologies provide a stepwise reduction in NO_x emissions, with LNCFS Level III expected to provide the greatest reduction.

Project Results/Accomplishments:

The LNCFS Level II tests were completed in September 1991, resulting in a maximum NO_x reduction of 40% at full load. The LNCFS Level II was converted to LNCFS Level III during a 2-week outage in November 1991 by installing close-couple over-fire air nozzles in the top of the main windbox. The LNCFS Level III testing, completed in April 1992, showed that NO_x emissions were reduced by a maximum of 48%; however, this decrease in NO_x emissions was accompanied by an increase in flyash carbon content. Finally, LNCFS Level I was evaluated by closing the separated over-fire air dampers of the Level III system. Testing of the Level I system, completed in December 1992, showed a maximum NO_x reduction of 37% at full load.

Testing to investigate the effects of low-NO_x combustion on the emissions of air toxics was also completed. These tests showed that the LNCFS had little or no impact on the emissions of air toxics. A report has been prepared.

Commercial Applications:

Commercial applications of this technology include a wide range of tangentially fired utility and industrial boilers throughout the United States and abroad. There are nearly 600 U.S. pulverized coal tangentially fired utility units. These units range in electric generating capacity from 25 MWe to 950 MWe. A wide range of coals, from low-volatile bituminous through lignite, are being fired in these units. LNCFS technologies can be used in retrofit as well as new boiler applications. Boiler operation with these in-furnace technologies does not require intensive retraining.

Environmental benefits to be realized with these in-furnace emission control technologies are primarily based upon reducing NO_x emissions from fossil-fuel-fired power plants. Potential exists for annual NO_x emission reductions of 10%, depending on the unit load scenario and the tangentially fired NO_x control selected.

Project Schedule:

DOE selected project (CCT-III)	9/28/88
Cooperative agreement awarded	9/20/90
NEPA process completed (MTF)	7/21/89
Environmental monitoring plan completed	12/27/90
Construction	11/90–5/91
Operational testing	5/91–12/92
Project completed	3/94

Final Reports:

Final Report and Key Project Findings	12/93
Chemical Emissions Report (draft)	10/93
Final Design Report	9/93

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

Sponsor:
Southern Company Services, Inc.

Additional Team Members:
Electric Power Research Institute—cofunder
Ontario Hydro—cofunder
Gulf Power Company—host utility

Location:
Pensacola, Escambia County, FL (Gulf Power Company's Plant Crist)

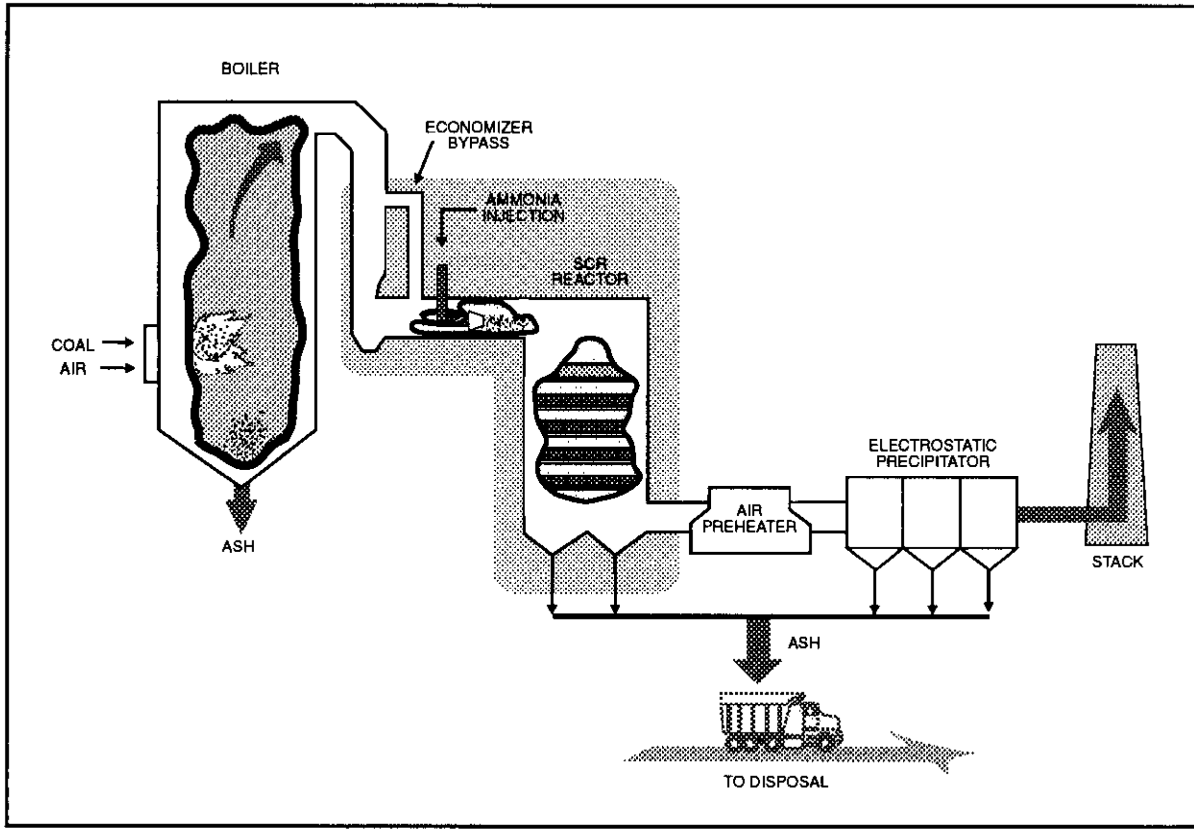
Technology:
Selective catalytic reduction (SCR) (environmental control devices/NO_x control technologies)

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

Project Funding:

Total project cost	$23,229,729	100%
DOE	9,406,673	40
Participants	13,823,056	60

Project Objective:
To evaluate the performance of commercially available SCR catalysts when applied to operating conditions found in U.S. pulverized coal-fired utility boilers using U.S. high-sulfur coal under various operating conditions while achieving as much as 80% NO_x removal.

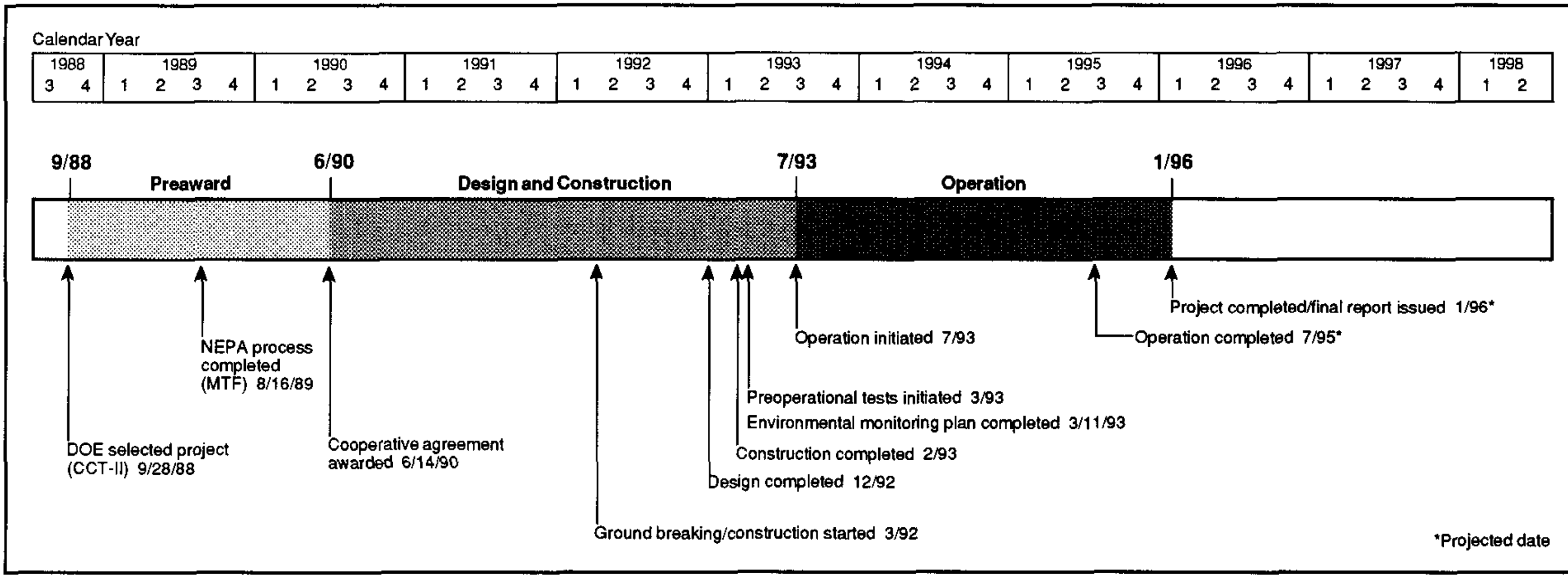


Technology/Project Description:
The SCR technology consists of injecting ammonia into boiler flue gas and passing it through a catalyst bed where the NO_x and ammonia react to form nitrogen and water vapor.

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

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

The demonstration plant, located at Gulf Power Company's Plant Crist near Pensacola, FL, utilizes flue gas from the burning of principally Illinois No. 5 coal with approximately 3% sulfur under various NO_x and particulate levels.



Project Status/Accomplishments:

Preliminary design engineering for the SCR test facility was concluded at the end of February 1991. Construction began in late-March 1992; a dedication ceremony was held on July 1, 1992. Detailed engineering was completed in December 1992. Flue gas was first passed through the SCR facility during equipment checkout on January 10, 1993. Construction was completed in February 1993. Commissioning tests without catalysts began the first week of March 1993, and the 2-year-long operations phase began on July 1, 1993.

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

Commercial Applications:

SCR technology can be applied to existing and new utility applications for removal of NO_x from flue gas for virtually any size boiler. There are approximately 1,041 coal-fired utility boilers in active commercial service in the United States; these boilers represent a total generating capacity of 296,000 MWe. Assuming that SCR technology is installed on dry-bottom boilers that are not equipped with low-NO_x combustion technologies (i.e., low-NO_x burners, over-fire air, and atmospheric fluidized-bed combustion), the potential total retrofit market for SCR technology is 154,560 MWe (642 boilers). In addition, SCR technology could be applicable to 34,700 MWe (70 boilers) of new firm (i.e., announced, sited, and committed in terms of service date or under construction) and 144,500 MWe (290 boilers) of planned dry-bottom electric generating capacity in the United States.

Micronized Coal Reburning Demonstration for NO_x Control on a 175-MWe Wall-Fired Unit

Sponsor:
Tennessee Valley Authority

Additional Team Members:
Duke/Fluor Daniel (partnership between Duke Engineering & Services, Inc., and Fluor Daniel, Inc.)—engineer and constructor
Fuller Company—technology supplier
Radian Corporation—testing/environmental/technical consultant

Location:
West Paducah, McCracken County, KY (Tennessee Valley Authority's Shawnee Fossil Plant)

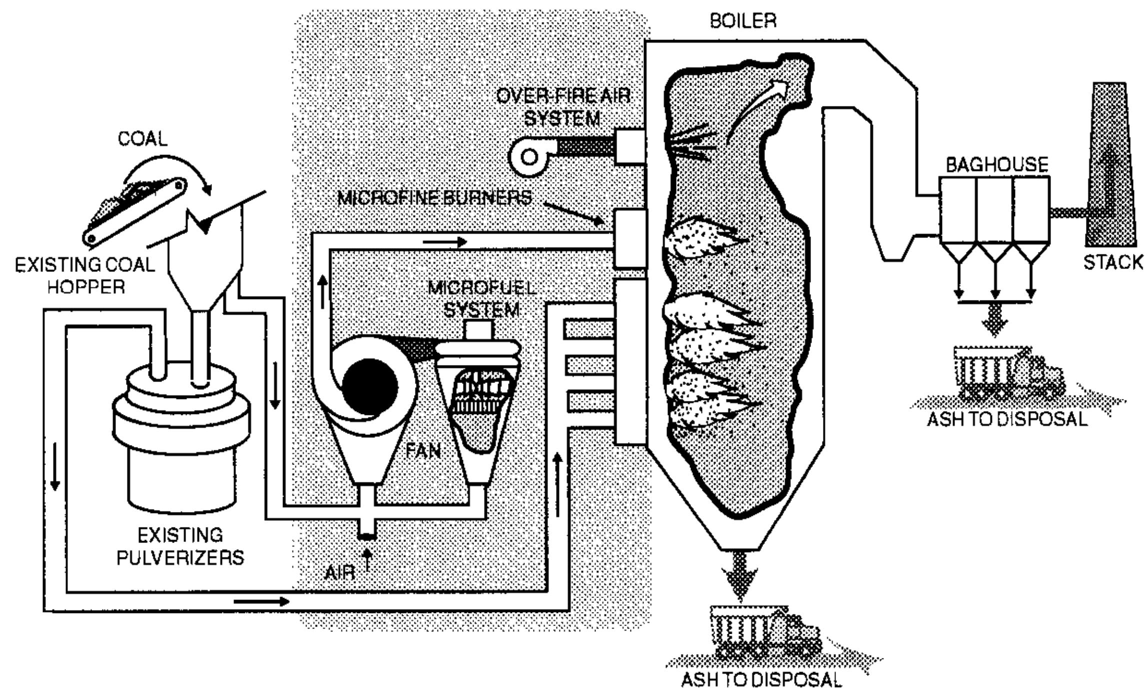
Technology:
Advanced NO_x control using Fuller's micronized-coal-reburning combustion technology (environmental control devices/NO_x control technologies)

Plant Capacity/Production:
175 MWe

Project Funding:

Total project cost	$7,330,041	100%
DOE	3,514,755	48
Participants	3,815,286	52

Project Objective:
To reduce NO_x emissions by 50–60% using micronized coal as the reburning fuel combined with advanced coal-reburning technology.



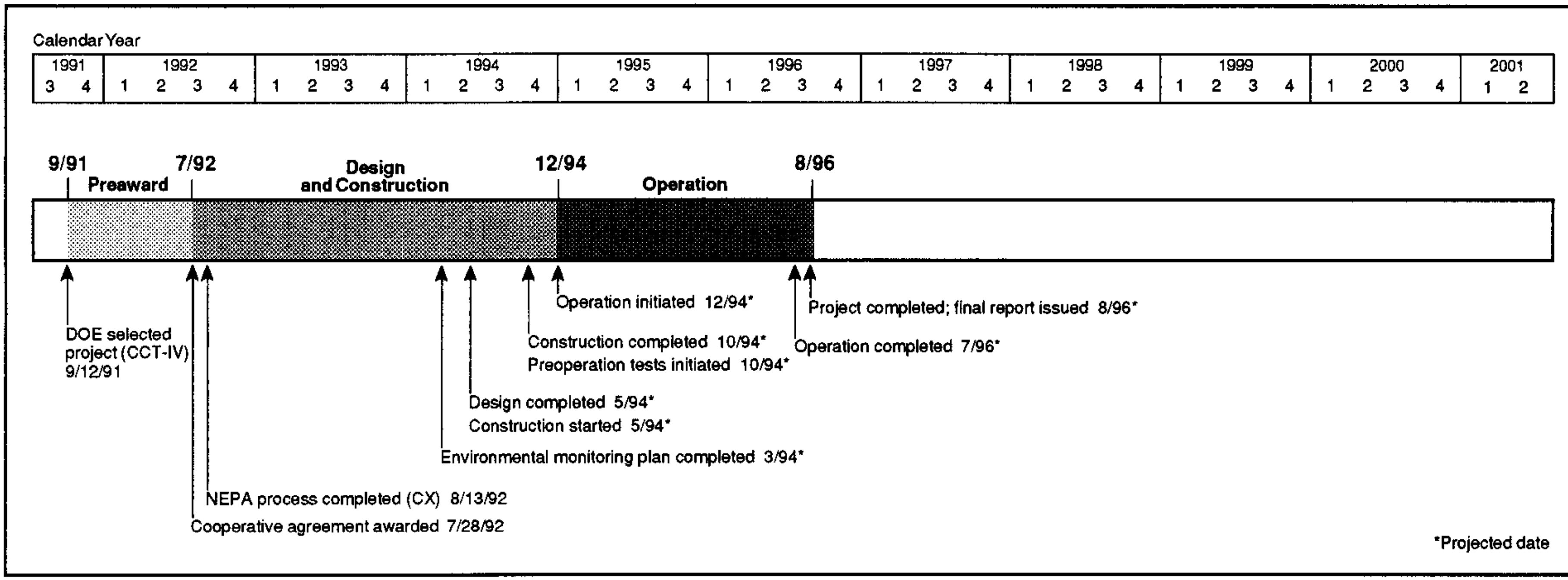
Technology/Project Description:
The technology is being applied to a 175-MWe front-wall-fired, dry-bottom furnace. The coal currently used to fire the furnace (low-sulfur bituminous coal from Kentucky or West Virginia) will be the reburning fuel. The reburning coal, which can comprise up to 30% of the total fuel, is micronized (80% below 325 mesh) and injected into the furnace above the main burner, the region where NO_x formation occurs.

Central to the project technology is the two-element system which consists of a patented centrifugal-pneumatic MicroMill™ and an external classifier. The mill is capable of grinding coal into a fine powder without the mechanical attrition or roll crushing normally associated with coal mills. The MicroMill™ takes coal away from the existing bunker and supplies it to the new micronized coal burners.

Micronized coal has the surface area and combustion characteristics of an atomized oil flame, which allows carbon conversion within milliseconds and release of volatiles at a more even rate. This uniform, compact combustion envelope allows for complete combustion of the coal/air mixture in a smaller furnace volume than conventional pulverized coal because heat rate, carbon loss, boiler efficiency, and NO_x formation are affected by coal fineness.

The combination of micronized coal, supplying 30% of the total furnace fuel requirements, and advanced reburning utilizing that requirement in conjunction with fuel/air staging, provides flexible options for significant combustion operations and environmental improvements.

MicroMill is a trademark of the Fuller Company.



These options can prevent higher operating costs or furnace performance derating often associated with conventional environmental controls.

The Tennessee Valley Authority plans to retrofit its Shawnee Fossil Plant, located near West Paducah, KY, with the micronized-coal-reburning technology. Bituminous coals from Kentucky and West Virginia, containing about 1% sulfur, will be used.

Project Status/Accomplishments:

Design efforts began shortly after the cooperative agreement was awarded in July 1992. Design and construction are expected to overlap for a short period, with construction being completed in mid-1994. The environmental monitoring plan is being prepared and is expected to be complete in early 1994.

The Fuller Company purchased MicroFuel Corporation (the technology supplier) in September 1992 and assumed MicroFuel's obligations to this project. Radian Corporation joined the team in August 1993. Radian replaced Research Cottrell which withdrew in early 1993. Radian is responsible for modeling, testing, and conceptual reburner design. Boiler baseline and characterization testing started in November 1993.

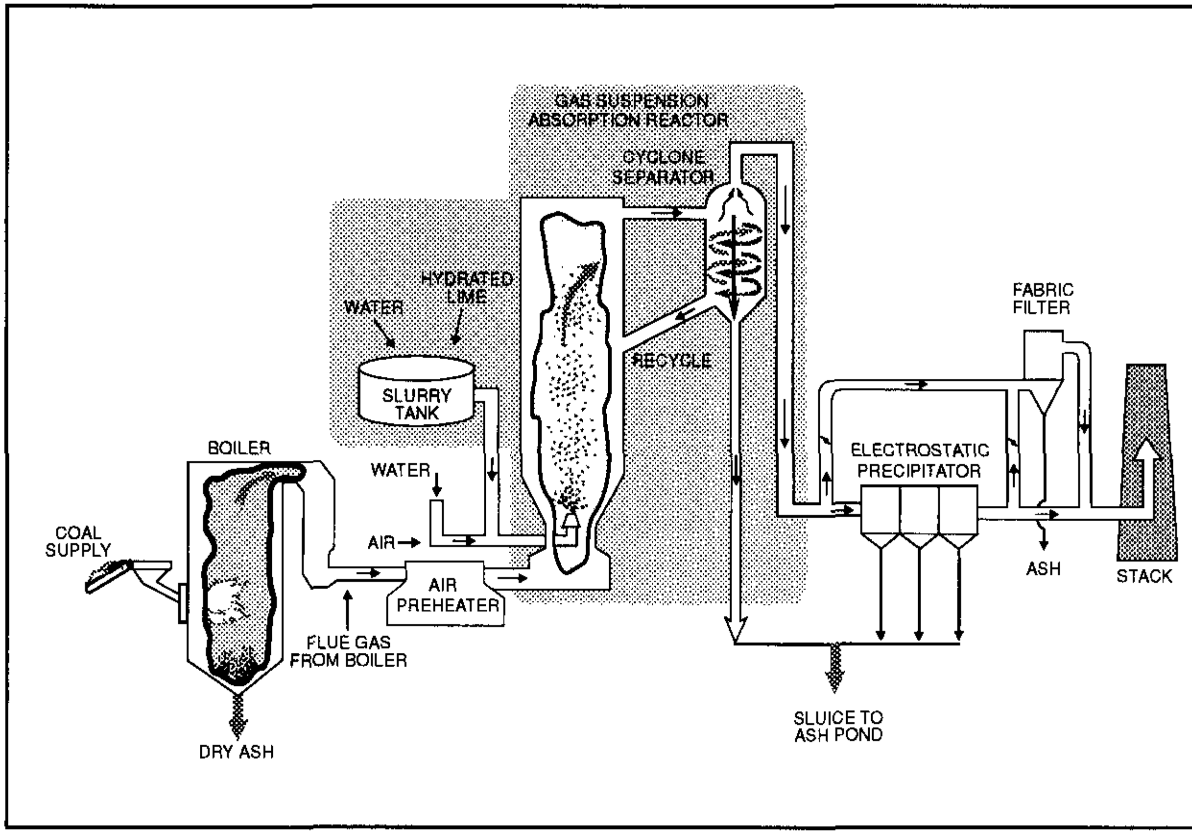
NEPA compliance has been satisfied through a categorical exclusion approved on August 13, 1992.

Commercial Applications:

Micronized-coal-reburning technology can be applied to existing and greenfield cyclone-fired, wall-fired, and tangential-fired pulverized coal units. The technology reduces NO_x emissions by 50–60% with minimal furnace modifications for existing units. For greenfield units, the technology can be designed as an integral part of the system. Either way, the technology enhances boiler performance with the improved burning characteristics of micronized coal. About 25% of the more than 1,000 existing units could benefit from the use of this technology.

The availability of a coal-reburning fuel, as an additional fuel to the furnace, solves several problems concurrently. Existing units unable to switch fuels because of limited mill capacity would be able to reach their maximum continuous rating. NO_x emissions reductions will enable lost capacity to be restored, creating a very economic source of generation. For both retrofit and greenfield facilities, reburn burners also can serve as low-load burners, and commercial units can achieve a turndown of 8:1 on nights and weekends without consuming expensive auxiliary fuel. Existing pulverizers can be operated on a variety of coals with improved performance. The combination of micronized-coal-reburning fuel and better pulverizer performance will increase overall pulverized-fuel surface area for better carbon burnout.

10-MW Demonstration of Gas Suspension Absorption



Sponsor:
AirPol, Inc.

Additional Team Members:
FLS miljo a/s (parent company of AirPol, Inc.)—technology owner

Tennessee Valley Authority—cofunder and site owner

Location:
West Paducah, McCracken County, KY (Tennessee Valley Authority's National Center for Emissions Research)

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

Plant Capacity/Production:
10-MWe equivalent slipstream of flue gas from a 150-MWe boiler

Project Funding:

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

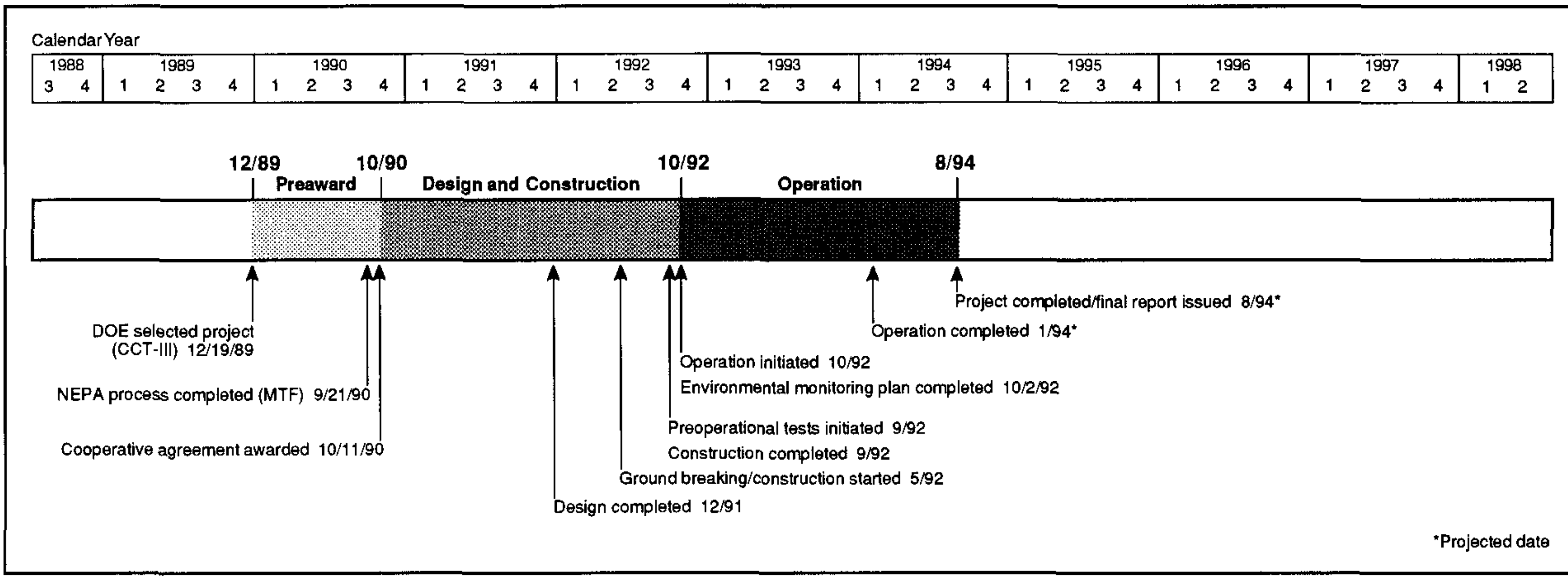
Project Objective:
To demonstrate the applicability of gas suspension absorption for flue gas desulfurization using high-sulfur U.S. coals by installing and testing a 10-MWe GSA demonstration system.

Technology/Project Description:
The GSA system consists of a vertical reactor in which flue gas comes into contact with suspended solids consisting of lime, reaction products, and fly ash. About 99% of the solids are recycled to the reactor via a cyclone while the exit gas stream passes through an electrostatic precipitator before being released to the atmosphere. The lime slurry, prepared from hydrated lime, is injected through a spray nozzle at the bottom of the reactor. The volume of lime slurry is regulated with a variable-speed pump controlled by the measurement of the acid content in the inlet and outlet gas streams. The dilution water added to the lime slurry is controlled by on-line measurements of the flue gas exit temperature. Solids collected from the cyclone and particulate control device are combined and disposed of in an existing site disposal area.

GSA has the potential to remove in excess of 90% of the SO_2 as well as to increase lime utilization efficiency with solids recycle.

This project is located at the National Center for Emissions Research and is utilizing a 10-MWe slipstream of flue gas from a 150-MWe coal-fired boiler at the Tennessee Valley Authority's Shawnee Fossil Plant in West Paducah, KY. A western Kentucky coal with about 3% sulfur is being used.

Project Status/Accomplishments:
Optimization testing was conducted February–August 1993 to determine the effect of the process design variables on the SO_2 removal efficiency in the reactor/cyclone and the ESP. The test indicated that the order of importance of key variables is (1) calcium-to-sulfur ratio,



(2) approach-to-adiabatic-saturation temperature, and (3) coal chloride content.

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

Air toxics testing was conducted during October 1993. The results showed that a removal rate of over 95% could be achieved by the GSA. A 4-week around-the-clock demonstration run was conducted in November 1993. Results indicate that the GSA is capable of consistently maintaining 90+% SO_2 removal at a moderate lime requirement. The GSA has also demonstrated high availability.

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

Commercial Applications:

The GSA process offers several advantages over conventional FGD technologies: (1) GSA is 30% cheaper than wet FGD and 20% cheaper than spray drying; (2) GSA is much simpler to build and operate than wet FGD and regenerable processes and requires much less space; (3) space requirements, operability, and ease of installation are comparable to spray dryers and duct injection; and (4) the SO_2 removal capability (90%) compares to that of wet FGD and the regenerable processes. This high removal rate makes the GSA process suitable for use with high-sulfur coal.

TVA is evaluating the possibility of retrofitting a full-scale GSA unit for a 150-MWe coal-fired boiler. In addition, FLS miljo has been awarded a major project in Sweden for a high-performance GSA system to remove sulfur from the flue gas of a 4-million-ton/year iron ore sinter plant. Sweden has stringent sulfur emission standards which require a removal efficiency of 90–95%.

The GSA should fulfill the need of the utility industry to meet the new SO_2 emission standard as set forth by the CAAA of 1990. Based on a comparison of GSA capital and operating costs with other FGD processes, the GSA is especially suited for 50–250-MWe utility plants. Simplicity in GSA design and operation plus modest space requirements make GSA ideal for retrofitting to existing plants as well as for greenfield plants. One major advantage of the GSA, as compared to other semi-dry scrubbing processes, is that operation of the GSA will not result in excessive dust loading to the gas stream, thus minimizing the cost for upgrading the existing dust collector. The potential market for the GSA is estimated at $300 million within the next 20 years.

Confined Zone Dispersion Flue Gas Desulfurization Demonstration

Project completed.

Sponsor:
Bechtel Corporation

Additional Team Members:
Pennsylvania Electric Company—cofunder and host utility
Pennsylvania Energy Development Authority—cofunder
New York State Electric & Gas Corporation—cofunder
Rockwell Lime Company—cofunder

Location:
Seward, Indiana County, PA (Pennsylvania Electric Company's Seward Station, Unit No. 5)

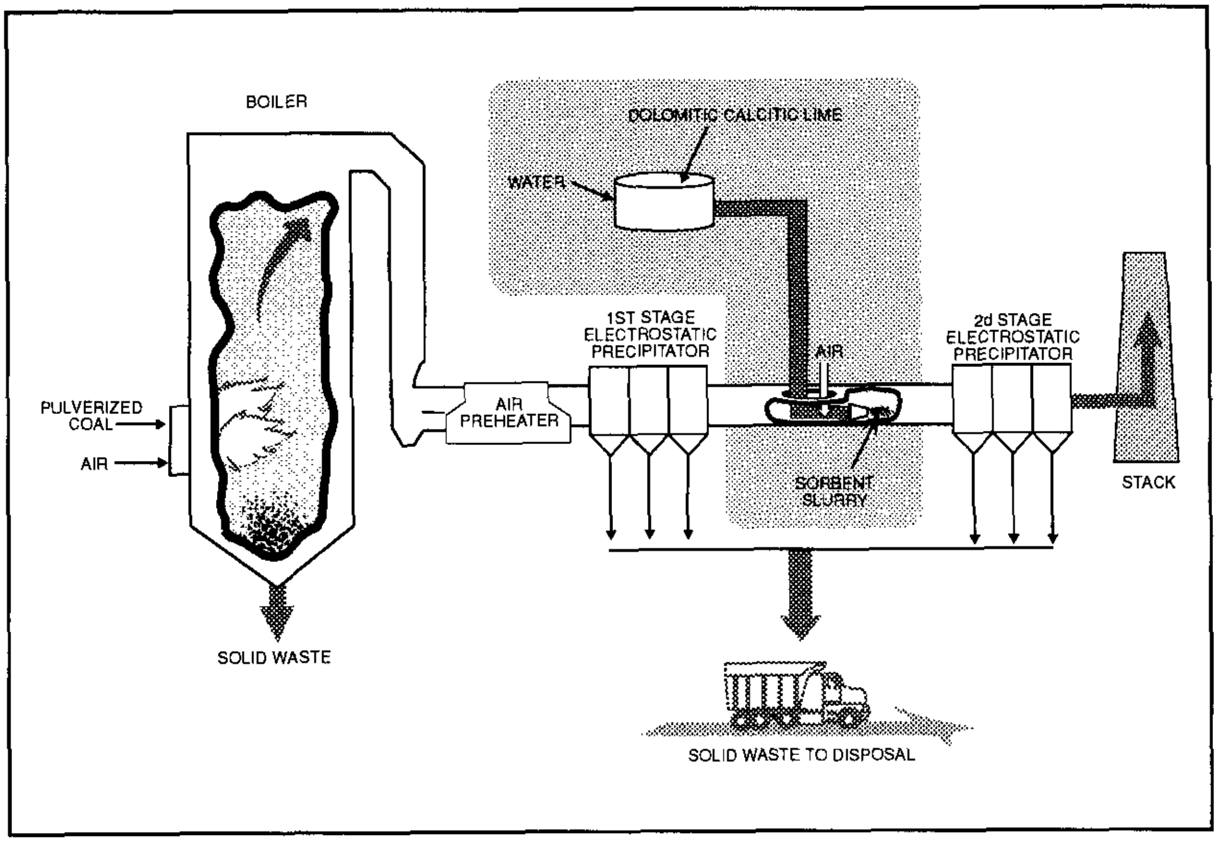
Technology:
Bechtel Corporation's in-duct, confined zone dispersion flue gas desulfurization (CZD/FGD) process (environmental control devices/SO_2 control technologies)

Plant Capacity/Production:
73.5 MWe

Project Funding:

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

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



Technology/Project Description:
In Bechtel's CZD/FGD process, a finely atomized slurry of reactive lime is sprayed into the flue gas stream between the boiler air heater and the electrostatic precipitator (ESP). The lime slurry is injected into the center of the duct by spray nozzles designed to produce a cone of fine spray. As the spray moves downstream and expands, the gas within the cone cools and the SO_2 is rapidly absorbed in the liquid droplets. The droplets mix with the hot flue gas, and the water evaporates rapidly. Fast drying precludes wet particle buildup in the duct and aids the flue gas in carrying the dry reaction products and the unreacted lime to the ESP.

The CZD/FGD process is expected to remove up to 50% of the SO_2 emissions from coal-fired boilers. If successfully demonstrated, this technology would be an alternative to conventional FGD processes, requiring less physical space and lower capital, operating, and maintenance costs.

This project includes injection of different types of sorbents (dolomitic and calcitic limes) with several atomizer designs using low- and high-sulfur coals to verify the effects on SO_2 removal and the capability of the ESP to control particulates. The demonstration is located at Pennsylvania Electric Company's Seward Station in Seward, PA. One-half of the flue gas capacity of the 147-MWe Unit No. 5 is being routed through a modified, longer duct between the first and second ESP. Pennsylvania bituminous coal (approximately 1.2–2.5% sulfur) is being used in the project.

Project Results/Accomplishments:

Bechtel began its 18-month, two-part test program for the CZD process in July 1991. The first 12 months of the test program consisted primarily of parametric testing. The second part was supposed to include a 6-month continuous operation test period with the system being operated under fully automatic control by the host utility boiler operators. Initially, the new atomizing nozzles were thoroughly tested both outside and inside the duct. The lime slurry injection parametric test program, which began in October 1991, was completed in August 1992.

In summary, the demonstration showed the following:

- CZD/FGD can achieve 50% SO_2 removal efficiency.
- The process requires that drying and SO_2 absorption take place within 2 seconds. A long, straight (horizontal or vertical) gas duct of about 100 feet is required to assure residence time of 2 seconds.
- During normal operations, no deposits of fly ash or reaction products took place in the flue gas duct.
- The fully automated system, fully integrated with power plant operation, demonstrated that the CZD/FGD process responded well to automated control operation.
- Availability of the system was very good.
- At Seward Station, stack opacity was not detrimentally affected by the CZD/FGD system.
- Results of the demonstration indicated that the CZD/FGD process can achieve costs of $300/ton of SO_2 removed when operating a 500-MWe unit burning 4% sulfur coal. Based on a 500-MWe plant retrofitted with CZD/FGD for a 50% rate of SO_2 removal, the total capital cost is estimated to be less than $30/kW.

Bechtel notified DOE on June 30, 1993, that it was discontinuing the demonstration project effective July 1, 1993. Bechtel is in the process of modifying the CZD process design to improve SO_2 removal during continuous operation. Once the CZD process modifications are made, a follow-on period of continuous boiler-integrated operation will be required. Bechtel is pursuing this follow-on work with the host utility, the Pennsylvania Electric Company.

Bechtel is continuing efforts to submit and finalize all reports required under the cooperative agreement.

Commercial Applications:

If successful, CZD can be used for retrofit of existing and installation in new utility boiler flue gas facilities to remove SO_2 derived from a wide variety of sulfur-containing coals.

A CZD system can be added to a utility boiler with a capital investment of about $25–50/kW of installed capacity, or approximately one-fourth the cost of building a conventional wet scrubber. In addition to low capital cost, other advantages include small space requirements, ease of retrofit, low energy requirements, fully automated operation, and production of only nontoxic, disposable waste. The CZD technology is particularly well suited for retrofitting existing boilers, independent of type, age, or size. The CZD installation does not require major power station alterations and can be easily and economically integrated into existing power plants.

Project Schedule:

DOE selected project (CCT-III)	12/19/89
Cooperative agreement awarded	10/13/90
NEPA process completed (MTF)	9/25/90
Environmental monitoring plan completed	6/12/91
Construction	3/91–6/91
Operational testing	7/91–6/93
Project completed	3/94

Final Reports:

Final Technical Report	early 1994
Public Design Report	early 1994

LIFAC Sorbent Injection Desulfurization Demonstration Project

Sponsor:
LIFAC–North America (a joint venture partnership between Tampella Power Corporation and ICF Kaiser Engineers, Inc.)

Additional Team Members:
ICF Kaiser Engineers, Inc.—cofunder and project manager
Tampella Power Corporation—cofunder
Tampella, Ltd.—technology owner
Richmond Power and Light—cofunder and host utility
Electric Power Research Institute—cofunder
Black Beauty Coal Company—cofunder
State of Indiana—cofunder

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

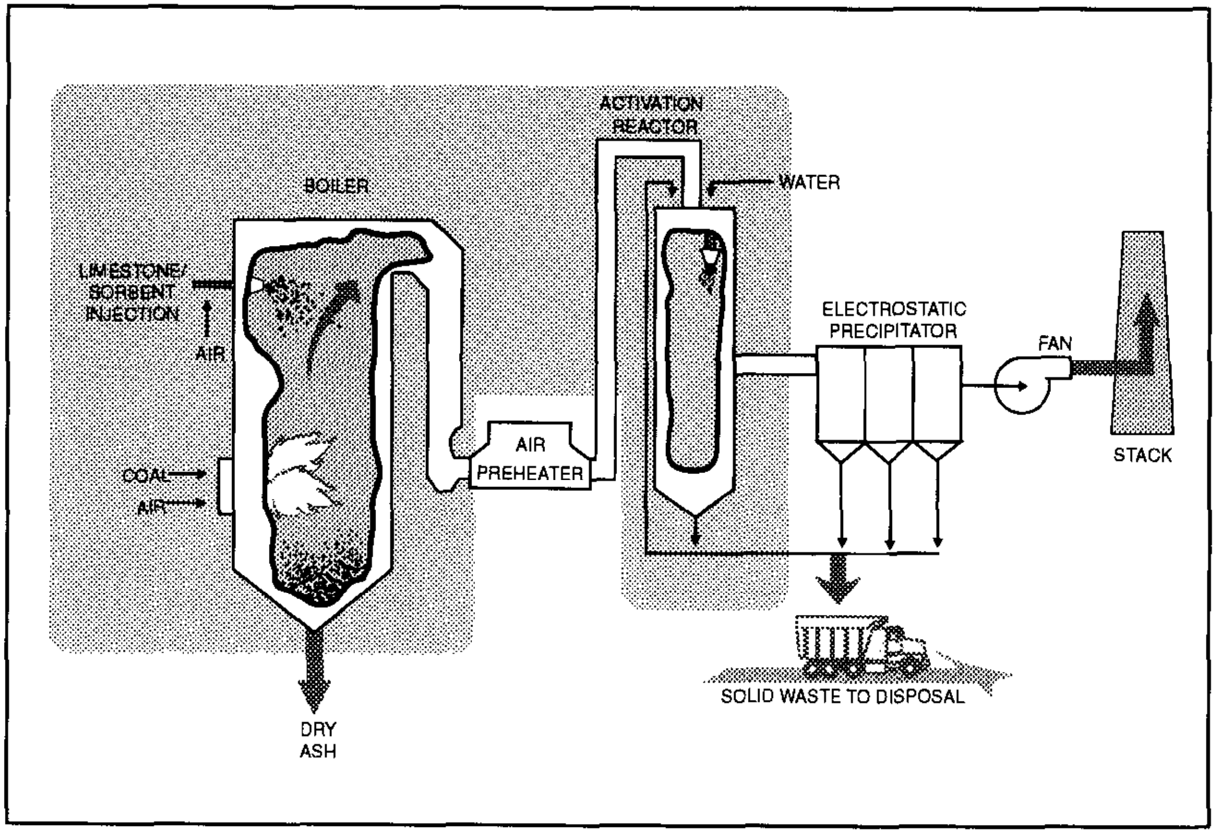
Technology:
LIFAC's sorbent injection process with sulfur capture in a unique, patented vertical activation reactor (environmental control devices/SO_2 control technologies)

Plant Capacity/Production:
60 MWe

Project Funding:

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

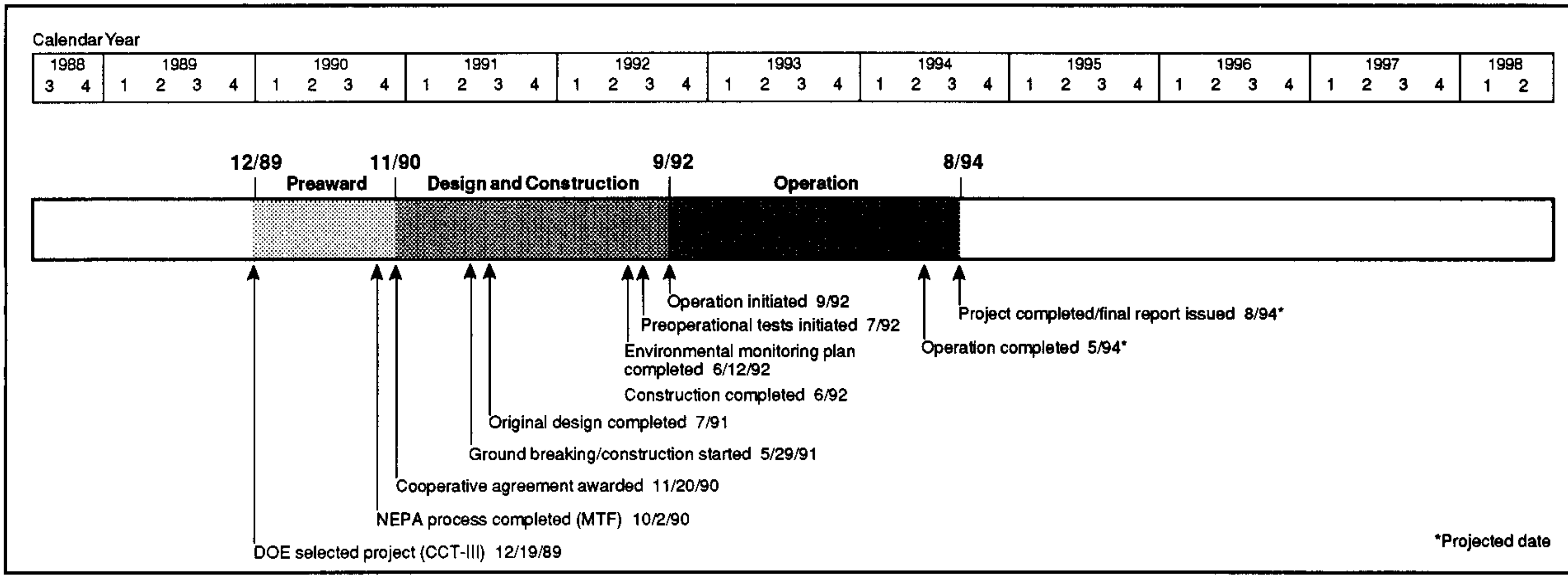
Project Objective:
To demonstrate that electric power plants—especially those with space limitations—burning high-sulfur coals, can be retrofitted successfully with the LIFAC limestone injection process to remove 75–85% of the SO_2 from flue gas and produce a dry solid waste product for disposal in a landfill.



Technology/Project Description:
Pulverized limestone is pneumatically blown into the upper part of the boiler near the superheater where it absorbs some of the SO_2 in the boiler flue gas. The limestone is calcined into calcium oxide and is available for capture of additional SO_2 downstream in the activation, or humidification, reactor. In the vertical chamber, water sprays initiate a series of chemical reactions leading to SO_2 capture. After leaving the chamber, the sorbent is easily separated from the flue gas along with the fly ash in the electrostatic precipitator. The sorbent material from the reactor and electrostatic precipitator will be recirculated back through the reactor for increased efficiency. The waste is dry, making it easier to handle than the wet scrubber sludge produced by conventional wet limestone scrubber systems.

The technology enables power plants with space limitations to use high-sulfur midwestern coals by providing an injection process that removes 75–85% of the SO_2 from flue gas and produces a dry solid waste product suitable for disposal in a landfill.

The process is being demonstrated at the Whitewater Valley Station, 60-MWe Unit No. 2. This coal-fired unit is owned and operated by Richmond Power and Light and is located in Richmond, IN.



Project Status/Accomplishments:

Operational testing began in September 1992 after baseline tests to characterize the 60-MWe unit were completed. Mechanical start-up and checkout were completed in February 1993.

Parametric testing was initiated in March 1993; however, LIFAC operations increased opacity levels above acceptable limits. Tests conducted during May and June 1993 showed the increased opacity levels were due to reduced ash resistivity caused by lower operating temperatures in the ESP resulting from humidification of the flue gas in the activation reactor. Bypassing a portion of the flue gas maintains the ESP operating temperature above 200 °F, which results in acceptable opacity levels. Preliminary LIFAC results show that SO_2 reductions in the boiler are between 20% and 30% and reductions through the reactor are an additional 40–55%, yielding total SO_2 reductions approaching 80–85%. Parametric testing was completed at the end of December 1993. Optimization testing is scheduled to begin in February 1994.

Commercial Applications:

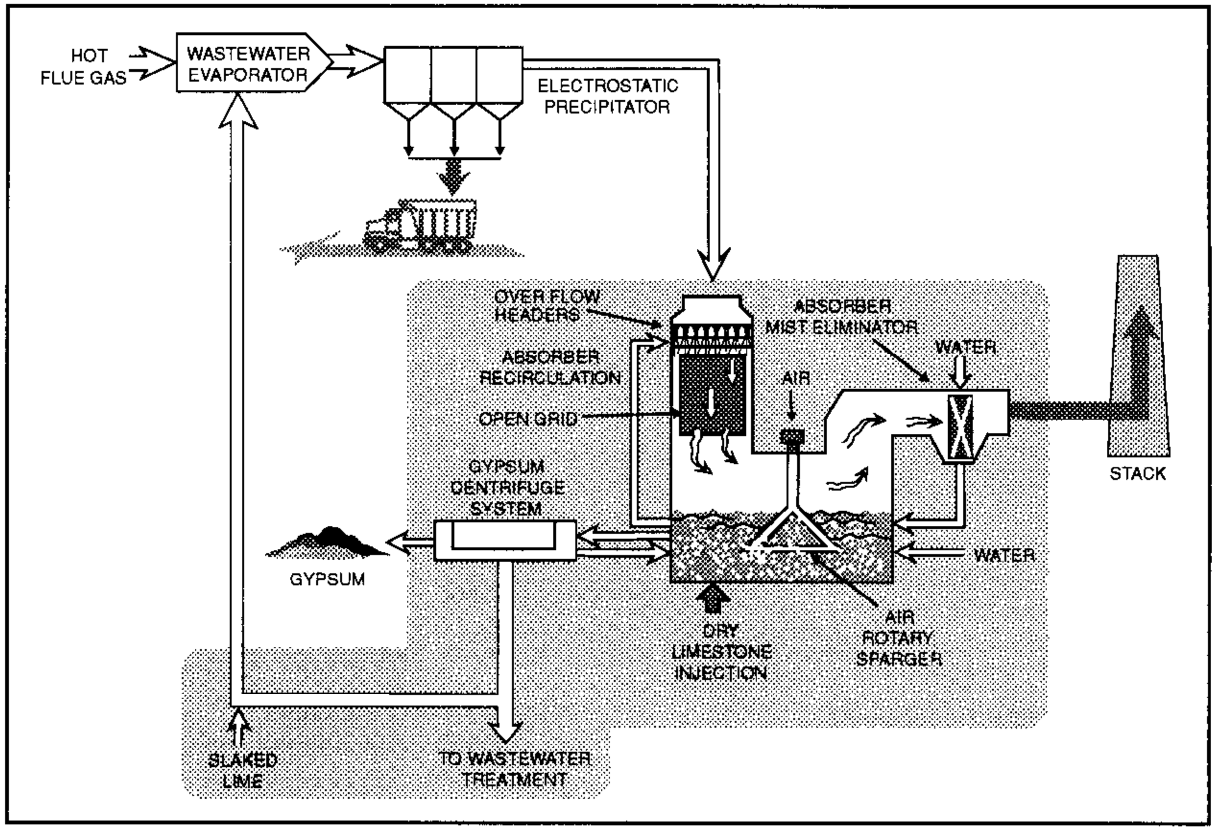
This process is suitable for application to all coal-fired utility or industrial boilers, especially those with tight space limitations. The LIFAC process offers the following advantages:

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

The benign waste material can be disposed of in a landfill along with the fly ash. The material also may be used as a road bed or excavation fill material. Commercial use of the LIFAC by-product in the manufacture of construction materials is currently being investigated in Finland.

The potential market penetration of LIFAC is assumed to be 20% of the smaller and medium-size power plants (500 MWe or less) and some industrial sites. LIFAC sales are projected to total 18,000 MWe of capacity over the next decade.

Advanced Flue Gas Desulfurization Demonstration Project



Sponsor:

Pure Air on the Lake, L.P. (a project company of Pure Air which is a general partnership between Air Products and Chemicals, Inc., and Mitsubishi Heavy Industries America, Inc.)

Additonal Team Members:

Northern Indiana Public Service Company—cofunder and host utility
Mitsubishi Heavy Industries, Ltd.—process designer
United Engineers and Constructors (Stearns-Roger Division)—facility designer
Air Products and Chemicals, Inc.—constructor and operator

Location:

Chesterton, Porter County, IN (Northern Indiana Public Service Company's Bailly Generating Station)

Technology:

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

Plant Capacity/Production:

528 MWe

Project Funding:

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

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

Project Objective:

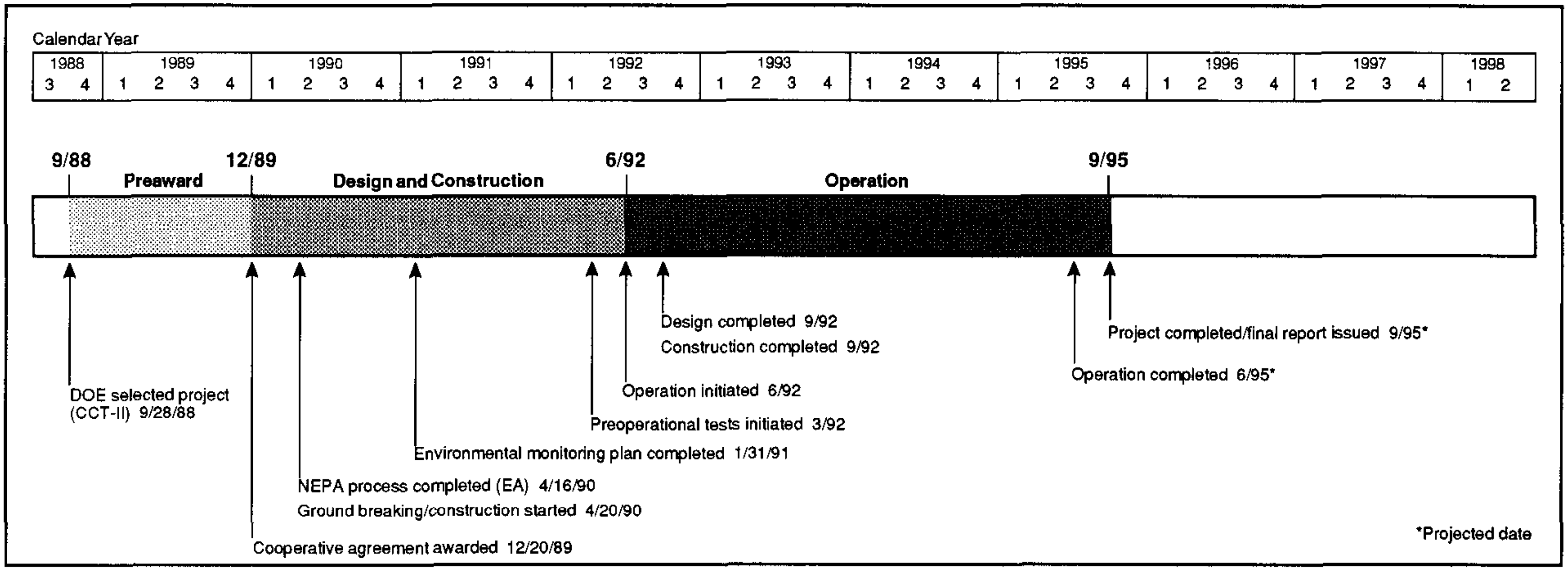
To demonstrate removal of 90–95% or more of the SO_2 at approximately one-half the cost of conventional scrubbing technology; and to demonstrate significant reduction of space requirements.

Technology/Project Description:

In this project, Pure Air has built a single SO_2 absorber for a 528-MWe power plant. Although this is the largest capacity absorber module in the United States, it has relatively modest space requirements because no spare or backup absorber modules are required. The absorber performs three functions in a single vessel: prequencher, absorber, and oxidation of sludge to gypsum. Additionally, the absorber is of a cocurrent design, in which the flue gas and scrubbing slurry move in the same direction and at a relatively high velocity compared to conventional scrubbers. These features all combine to yield a state-of-the-art SO_2 absorber that is more compact and less expensive than conventional scrubbers.

Technical features include the injection of pulverized limestone directly into the absorber, a device called an air rotary sparger located within the base of the absorber, and a novel wastewater evaporation system. The air rotary sparger combines the functions of agitation and air distribution into one piece of equipment to facilitate the oxidation of calcium sulfite to gypsum.

The AFGD process has demonstrated simultaneous removal of 90–95% or more of the SO_2 while providing a commercial gypsum by-product in lieu of solid waste. Some of the by-product gypsum will be agglomerated and flaked into PowerChip™ gypsum to enhance its



transportation and marketability to gypsum end-users. Additionally, wastewater treatment will be demonstrated to minimize water disposal problems inherent with many high-chloride coals.

The project also seeks to demonstrate a novel business concept whereby Pure Air owns and operates the AFGD facility. Thus, Pure Air expects to specialize in pollution control activities, relieving the electric utility of the operation of the AFGD unit. Assuming that the 3-year demonstration is successful, Pure Air will continue to own the AFGD facility and to operate it as a contracted service to the utility for an additional 17-year period. The demonstration is located at Northern Indiana Public Service Company's 528-MWe Bailly Generating Station near Chesterton, IN.

Project Status/Accomplishments:

Design is complete. To confirm process design, pilot testing was performed in 1990, successfully meeting both SO_2 removal and gypsum purity levels using U.S. high-sulfur coal and limestone feedstocks. A long-term performance test was conducted in 1991 to verify operational parameters for the air rotary sparger; it, too, was successful.

Construction was completed ahead of schedule, despite the occurrence of a ground subsidence event at the Bailly station on July 2, 1991. The AFGD facility began operations in June 1992. Operations to date have gone very well; SO_2 removals in excess of 95% and average by-product gypsum purities of 96–97% have been achieved. Tests on the utility's standard coal (3–3.5% sulfur) were completed in 1992.

During 1993, tests were conducted on coals with 3.5–4% sulfur and 2.5–3% sulfur. Additionally, air-toxics measurements were taken by the Southern Reseach Institute as part of a separate project that is being sponsored by DOE's Flue Gas Cleanup R&D Program.

Operations will continue through 1994 with commencement of wastewater evaporation and PowerChip™ gypsum agglomeration.

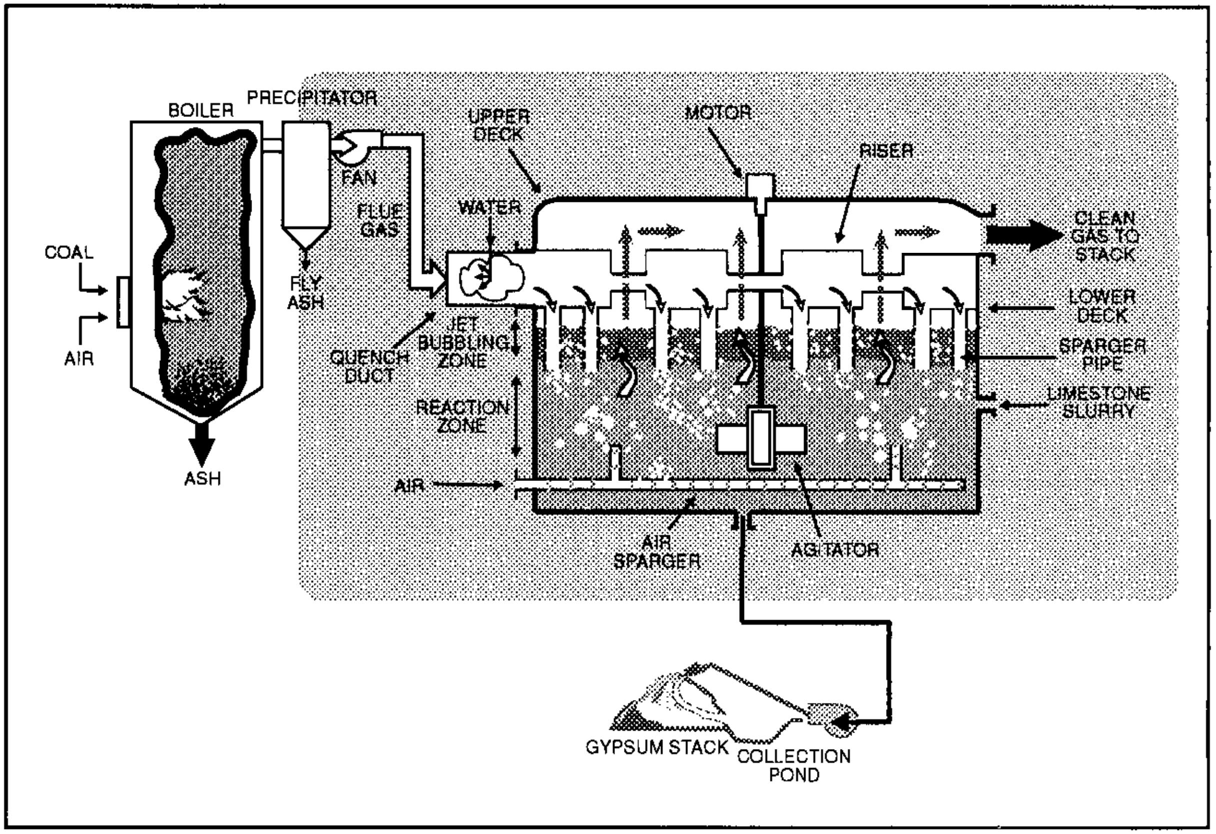
Commercial Applications:

The AFGD process is attractive for both new and retrofit utility applications. The demonstration project is using bituminous coals primarily from the Indiana-Illinois coal basin, with sulfur content ranging from 2.0% to 4.5%.

The AFGD facility will reduce SO_2 emissions at the Bailly Station by approximately 50,000 tons/yr. Further, the gypsum by-product and wastewater evaporation will demonstrate that SO_2 control can occur without increased solid waste or wastewater production.

All this can be accomplished with costs (and space requirements) that are roughly one-half of those associated with a conventional scrubber.

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



Sponsor:

Southern Company Services, Inc.

Additional Team Members:

Georgia Power Company—host utility
Electric Power Research Institute—cofunder
Radian Corporation—environmental and analytical consultant
Ershigs, Inc.—fiberglass fabricator
University of Georgia Research Foundation—by-product utilization studies

Location:

Newnan, Coweta County, GA (Georgia Power Company's Plant Yates, Unit No. 1)

Technology:

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

Plant Capacity/Production:

100 MWe

Project Funding:

Total project cost	$44,388,886	100%
DOE	21,728,169	49
Participants	22,660,717	51

Project Objective:

To demonstrate the CT-121 flue gas desulfurization system, including several design innovations, at the 100-MWe scale; more specifically, to demonstrate 90% SO_2 control at high reliability with and without simultaneous particulate control with possible additional reductions in operating costs.

Technology/Project Description:

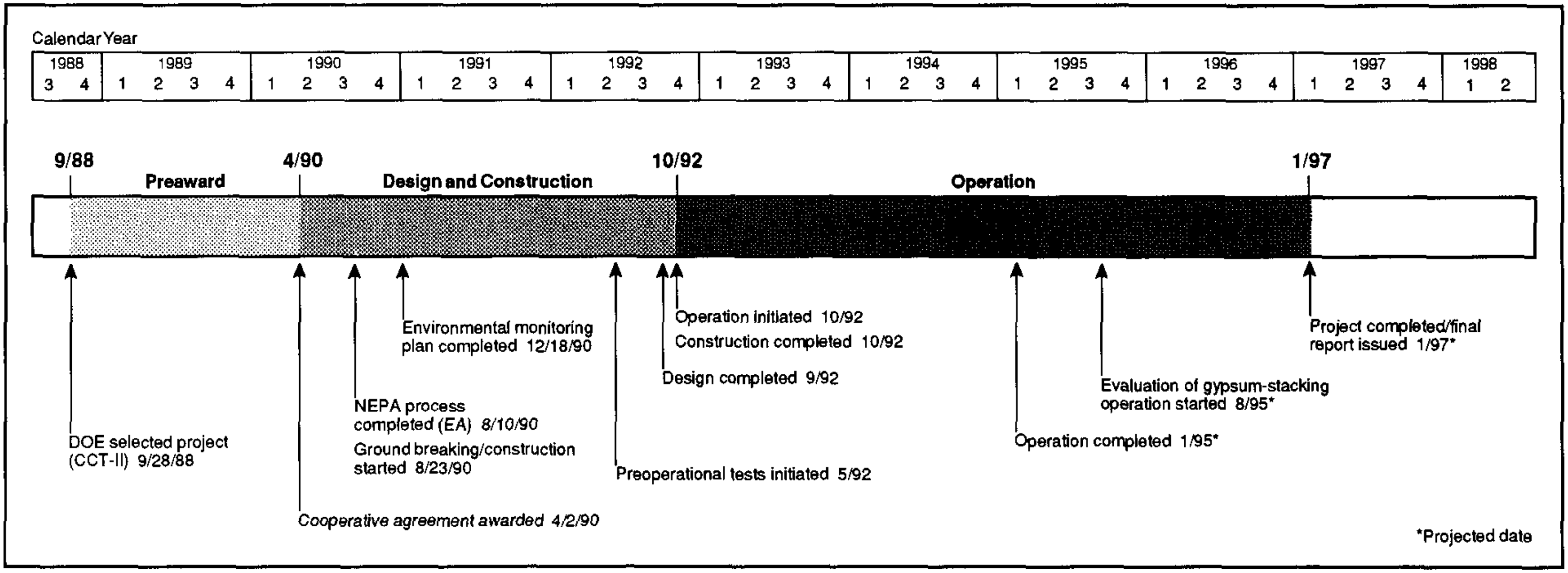
The project is demonstrating the CT-121 FGD process, which uses a unique absorber design known as the jet-bubbling reactor (JBR). The process combines limestone FGD reaction, forced oxidation, and gypsum crystallization in one process vessel. The process is mechanically and chemically simpler than conventional FGD processes and can be expected to exhibit lower cost characteristics.

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

The project is also evaluating process innovations to determine whether costs can be reduced further by using fiberglass-reinforced plastic (FRP) absorbers, eliminating flue gas reheat and spare absorber modules, and stacking gypsum to reduce waste management costs. The ability of this technology to capture SO_2 and particulates simultaneously is also being evaluated.

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

A gypsum washing/drying operation will be used to determine if the scrubber by-product will be usable in cement and wallboard manufacturing.



Project Status/Accomplishments:

Construction at Plant Yates was completed in October 1992, and start-up activities began immediately afterward. Experience has been very good with almost no off-line time attributable to the scrubber. Cumulative availability and reliability are both 98%. Over 8,150 hours of successful operations have been logged.

At inlet SO_2 levels of about 2,000 ppm, the CT-121 system removes more than 90% of the SO_2 at all loads and conditions at expected pH and pressure drop with *100% limestone utilization. Initial testing of simultaneous* particulate removal by the JBR shows over 90% removal following a fully energized ESP. Continuous emission monitors and the flow monitors were calibrated and certified in November 1992 and recertified in October 1993.

The calcium sulfate produced has been placed in a Hypalon-lined gypsum "stacking" area for the development of an above-ground gypsum stack similar to those found in the phosphate fertilizer industry. Preliminary observations show no evidence of acidic "rain out" from *the FRP scrubber chimney, indicating that the static* aerodynamic internal modifications in the chimney elbow are working as expected. DOE-sponsored supplemental air toxics sampling was done in mid-1993; results will be available in 1994. Late in 1993, testing on an alternate limestone was conducted demonstrating the flexibility of the process. Early in 1994 a higher sulfur coal will be tested. The ESP will be de-energized in stages in 1994 for the last year of operation in order to evaluate the particulate removal capability of the scrubber.

Commercial Applications:

The CT-121 FGD system is applicable to both new and pre-NSPS utility and industrial boilers.

Specific features of this technology that will enhance its potential for commercialization follow: (1) fiberglass construction can be used, eliminating the need for rubber-lined carbon steel or costly alloys; (2) no spare absorber is required because the system is at least 98% reliable; (3) reheating of the flue gas is not necessary; (4) both SO_2 *and particulates are removed from flue gas;* (5) more than 99% of the calcium in the limestone reagent is used; (6) the gypsum by-product can be stored safely and easily or used in commercial applications; (7) the CT-121 operating costs are the lowest for state-of-the-art FGD systems; (8) there is no known size limit for this technology; (9) utilities and industrial concerns could make immediate use of this technology; and (10) the system is not sensitive to the type of coal used or its sulfur content.

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

SNOX™ Flue Gas Cleaning Demonstration Project

Sponsor:
ABB Environmental Systems

Additional Team Members:
Ohio Coal Development Office—cofunder
Ohio Edison Company—cofunder and host utility
Haldor Topsoe—patent owner for process technology, catalysts, and WSA Tower
Snamprogetti, U.S.A.—cofunder and process designer

Location:
Niles, Trumbull County, OH (Ohio Edison's Niles Station, Unit No. 2)

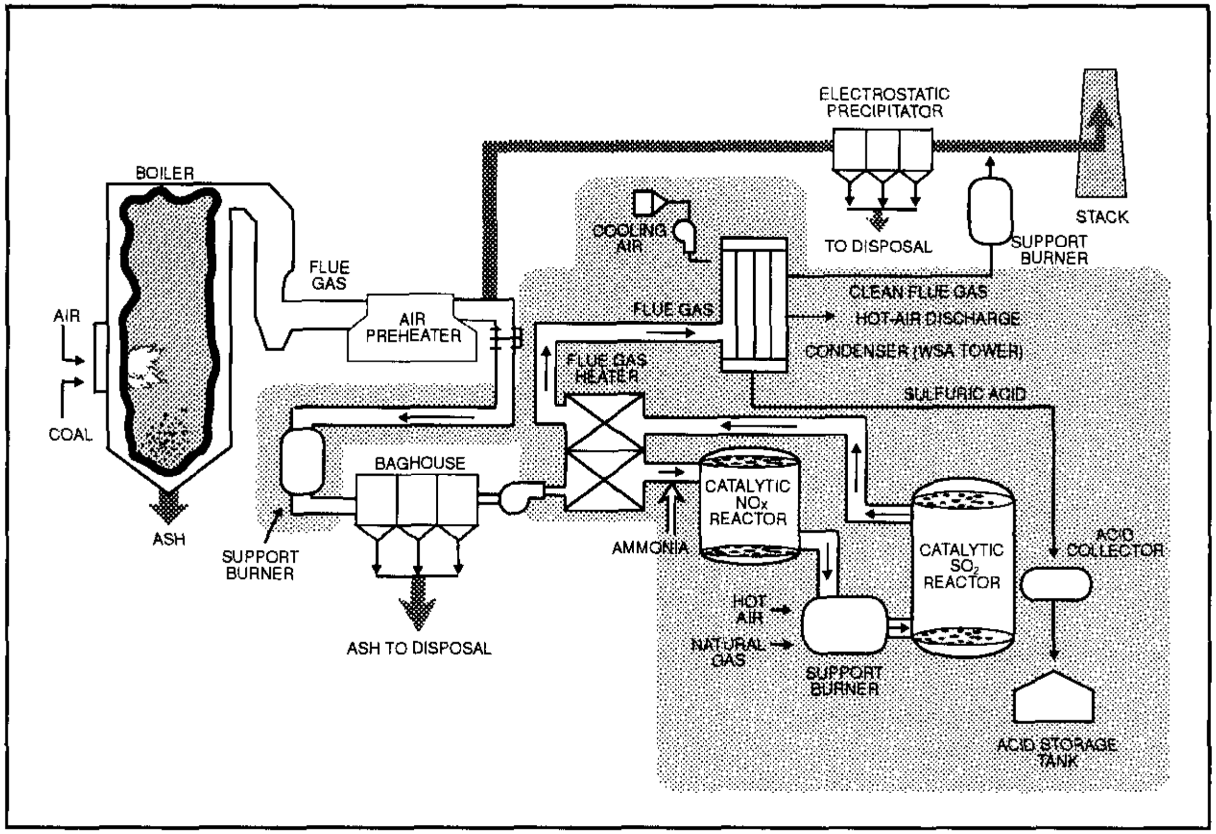
Technology:
Haldor Topsoe's SNOX™ catalytic advanced flue gas cleanup system (environmental control devices/combined SO_2/NO_x control technologies)

Plant Capacity/Production:
35-MWe equivalent slip-stream from a 108-MWe boiler

Project Funding:

Total project cost	$31,438,408	100%
DOE	15,719,200	50
Participants	15,719,208	50

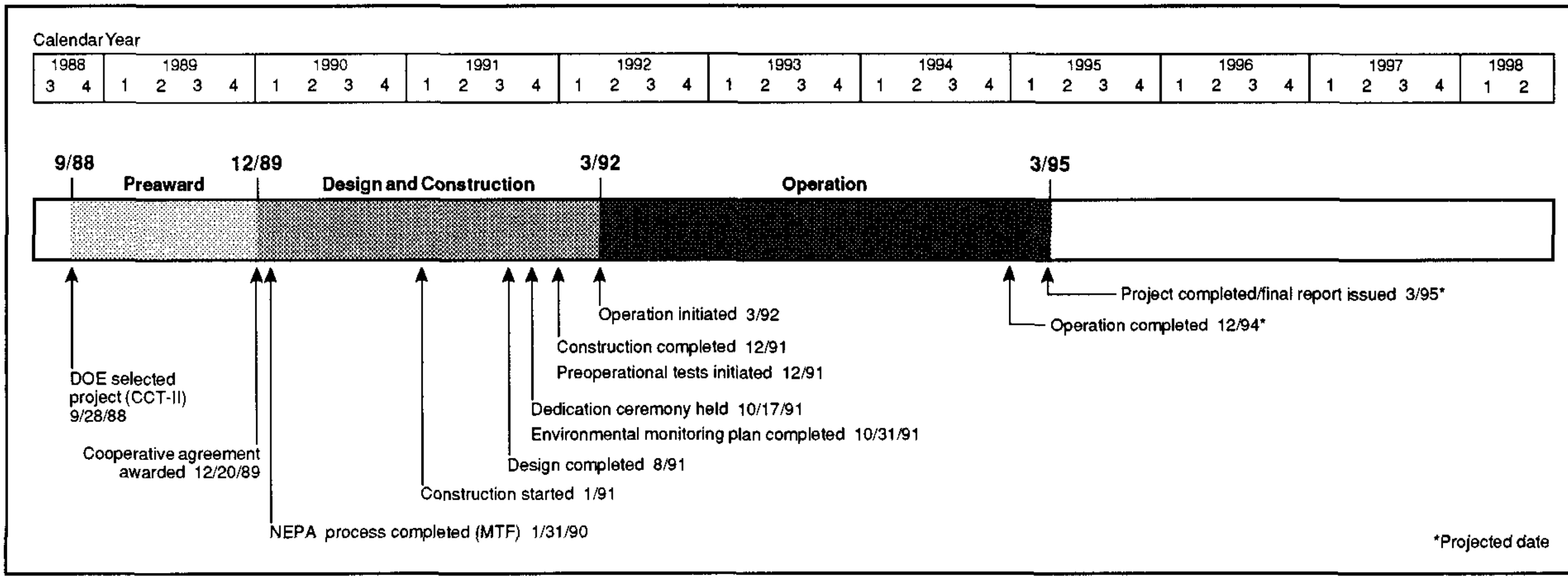
Project Objective:
To demonstrate on U.S. coals at an electric power plant that SNOX™ technology will catalytically remove 95% of SO_2 and more than 90% of NO_x from flue gas and produce a salable by-product of concentrated sulfuric acid.



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

The technology, while using U.S. coals, is designed to remove 95% of the SO_2 and more than 90% of the NO_x from flue gas and produce a salable sulfuric acid by-product. This is accomplished without using sorbents and without creating waste by-products.

The demonstration unit is installed at Ohio Edison's Niles Station in Niles, OH. The process is treating a 35-MWe equivalent slipstream of flue gas from the 108-MWe Unit No. 2 boiler that burns a 3.4% sulfur coal. The process steps are virtually the same as for a full-scale plant, and commercial-scale components are being used.



Project Status/Accomplishments:

Construction was completed in December 1991, and operation commenced in March 1992. After 2 months of operation, test results met or exceeded design objectives, as follows:

- SO_2 removal—96% in tests (95% design)
- NO_x removal—94% in tests (90% design)
- H_2SO_4 purity—93% in tests (93% design)

In addition, hazardous air pollutant monitoring was conducted. Removal efficiencies for hazardous air pollutant elements were determined for the SNOX™ baghouse and for the entire SNOX™ process. The results indicate that most elements had removal efficiencies that exceeded 99% for both cases. The substances measured include 5 major and 16 trace elements, such as mercury, chromium, cadmium, lead, selenium, arsenic, beryllium, and nickel.

The system has operated more than 5,700 hours, producing approximately 3,800 tons of sulfuric acid, which was sold for industrial use.

The host utility, Ohio Edison, has decided that the SNOX™ technology has performed so well during the CCT demonstration project that it will become a permanent part of the pollution control system at Niles Station. *Consequently, money set aside for site restoration will be* used to fund extended operations through December 1994.

Commercial Applications:

The SNOX™ technology is applicable to all electric power plants and industrial/institutional boilers firing coal, oil, or gas. The high removal efficiency for NO_x and SO_2 will make the process attractive in many applications. Elimination of additional solid waste (except ash) enhances the marketability in urban and other areas where solid waste disposal issues are a significant impediment.

LIMB Demonstration Project Extension and Coolside Demonstration

Project completed.

Sponsor:
The Babcock & Wilcox Company

Additional Team Members:
Ohio Coal Development Office—cofunder
Consolidation Coal Company—cofunder and technology supplier
Ohio Edison Company—host utility

Location:
Lorain, OH (Ohio Edison's Edgewater Station)

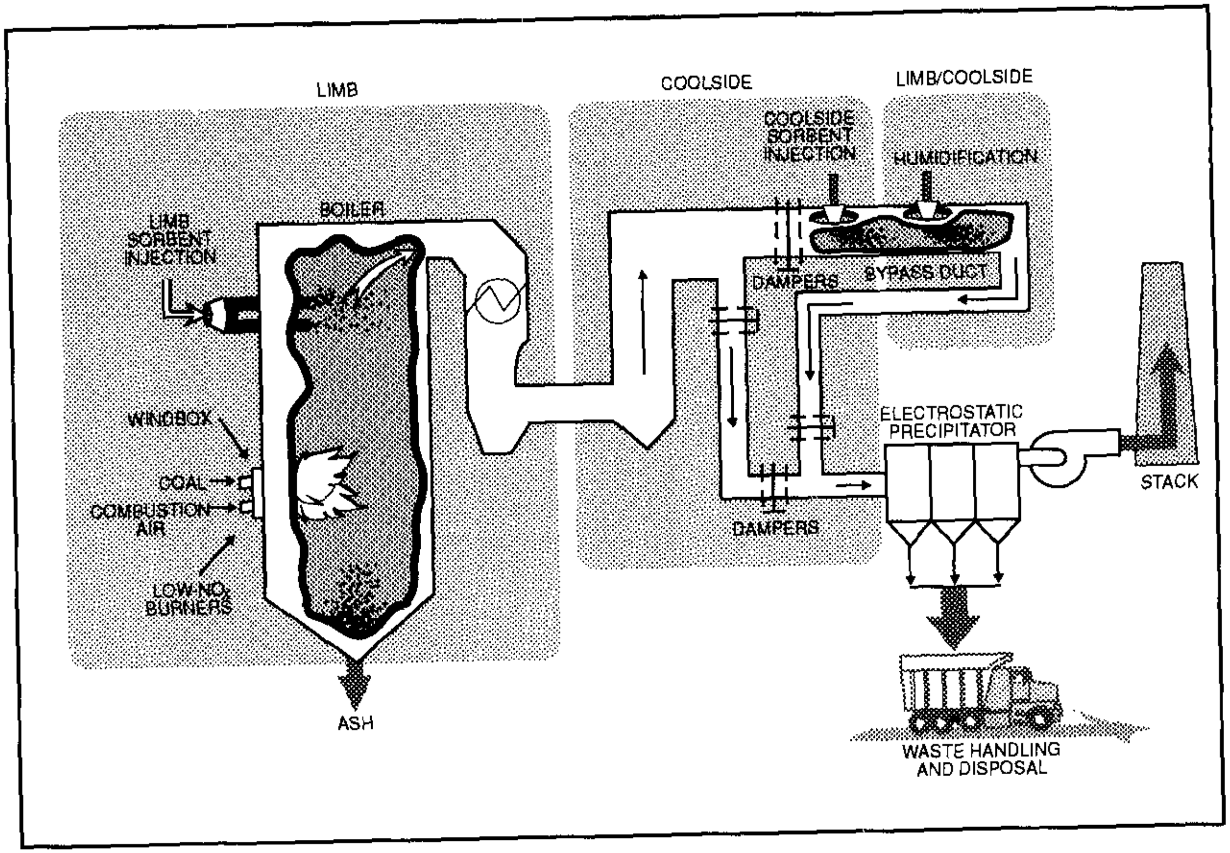
Technology:
The Babcock & Wilcox Company's limestone injection multistage burner (LIMB) system; Babcock & Wilcox DRB-XCL™ low-NO_x burners
Consolidation Coal Company's Coolside duct injection of lime sorbents
(environmental control devices/combined SO_2/NO_x control technologies)

Plant Capacity/Production:
105 MWe

Project Funding:

Total project cost	$19,404,940	100%
DOE	7,597,026	39
Participants	11,807,914	61

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



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

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

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

This project was conducted at Ohio Edison's Edgewater Plant in Lorain, OH, on a commercial, Babcock & Wilcox Carolina-design, wall-fired 105-MWe boiler.

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

Project Results/Accomplishments:

LIMB tests were conducted over a range of calcium-to-sulfur ratios (Ca/S) and humidification conditions. Each of four sorbents (calcitic limestone, type-N atmospherically hydrated dolomitic lime, calcitic hydrated lime, and calcitic hydrated lime with added calcium lignosulfonate) was injected while burning each of three coals (Ohio bituminous, 1.6%, 3.0%, and 3.8% sulfur). Tests were conducted under minimal humidification, defined as operation at a humidifier outlet temperature sufficient to maintain ESP performance. That temperature was typically 250–275 °F. Tests were also conducted at a 20 °F approach to the adiabatic saturation temperature of the flue gas to enhance SO_2 removal of the LIMB system. Close-approach operation typically meant controlling the flue gas temperature at the humidifier outlet (ESP inlet) to about 145 °F. Other variables were stoichiometry and injection level. Highlights of reported test results follow:

- The coal's sulfur content, as reflected in the SO_2 concentration in the flue gas, affected SO_2 removal efficiency—the higher the sulfur content, the greater the SO_2 removal for a given sorbent at a comparable stoichiometry. A 5–7% increase in removal occurred when switching to 3.8% from 1.6% sulfur coal and injecting at a stoichiometry of 2.0.
- The highest sulfur removal efficiencies, without humidification to close approach, were attained using the ligno lime—61% SO_2 removal was achieved while burning 3.8% sulfur coal. All sorbents tested were capable of removing SO_2 although calcium utilization of even finely pulverized limestone was not nearly as high as those of the limes.
- While injecting commercial limestone with 80% of the particles less than 44 microns in size, removal efficiencies of about 22% were obtained at a stoichiometry of 2.0 while burning 1.6% sulfur coal. However, removal efficiencies of about 32% were achieved at a stoichiometry of 2.0 when using a limestone with all particles less than 44 microns. For a third limestone with essentially all particles less than 10 microns, the removal efficiency was about 5–7% higher than that obtained at similar conditions for limestone with all particles less than 44 microns.
- Sorbent injection at the 181-ft plant elevation level inside the boiler, just above the boiler's nose, yielded the highest SO_2 removal rates. Here, the sorbent was injected at close to the optimum furnace temperature of 2,300 °F.
- SO_2 removal efficiencies were enhanced by about 10% over the range of stoichiometries tested when humidification down to a 20 °F approach to saturation was used.

During the Coolside demonstration, compliance (1.2–1.6% sulfur) and noncompliance (3.0% sulfur) coals were burned. Key process variables—Ca/S, Na/Ca, and approach to adiabatic saturation—were evaluated in short-term (6–8-hr) parametric tests and longer term (1–11-day) process operability tests.

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

NO_x removal was in the 40–50% range throughout both LIMB and Coolside testing.

Commercial Applications:

Both LIMB and Coolside technologies are applicable to most utility and industrial coal-fired units and provide alternatives to conventional wet flue gas desulfurization (FGD) processes. They can be retrofitted with modest capital investment and downtime, and their space requirements are substantially less. Depending on the plant capacity factor and the coal's sulfur content, they can be economically competititive with FGD systems. For example, using 2.5% sulfur coal at a 65% plant capacity factor, LIMB can be cost competitive with conventional wet FGD up to 450 MWe and Coolside up to 220 MWe. The environmental benefits for LIMB are 40–50% lower NO_x and more than 20% lower SO_2 emissions, and for Coolside up to 70% lower SO_2 emissions. The waste from each of these processes is dry and easily handled and contains unreacted lime that has potential commercial application. Both processes have the ability to handle all coal types, especially low- to medium-sulfur coals.

Project Schedule:

DOE selected project (CCT-I)	7/24/86
Cooperative agreement awarded	6/25/87
NEPA process completed (MTF)	6/2/87
Environmental monitoring plan completed	10/19/88
Construction	8/87–9/89
Coolside operational testing	7/89–2/90
LIMB extension operational testing	4/90–8/91
Project completed	11/92

Final Reports:

Final Report (LIMB/Coolside)	11/92
Topical Report (Coolside)	2/92
Topical Report (LIMB/Coolside)	9/90
Public Design Report	12/88

SOx-NOx-Rox-Box™ Flue Gas Cleanup Demonstration Project

Project completed.

Sponsor:
The Babcock & Wilcox Company

Additional Team Members:
Ohio Edison Company—cofunder and host utility
Ohio Coal Development Office—cofunder
Electric Power Research Institute—cofunder
Norton Company—cofunder and SCR catalyst supplier
3M Company—cofunder and filter bag supplier
Owens Corning Fiberglas Corporation—cofunder and filter bag supplier

Location:
Dilles Bottom, Belmont County, OH (Ohio Edison Company's R.E. Burger Plant, Unit No. 5)

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

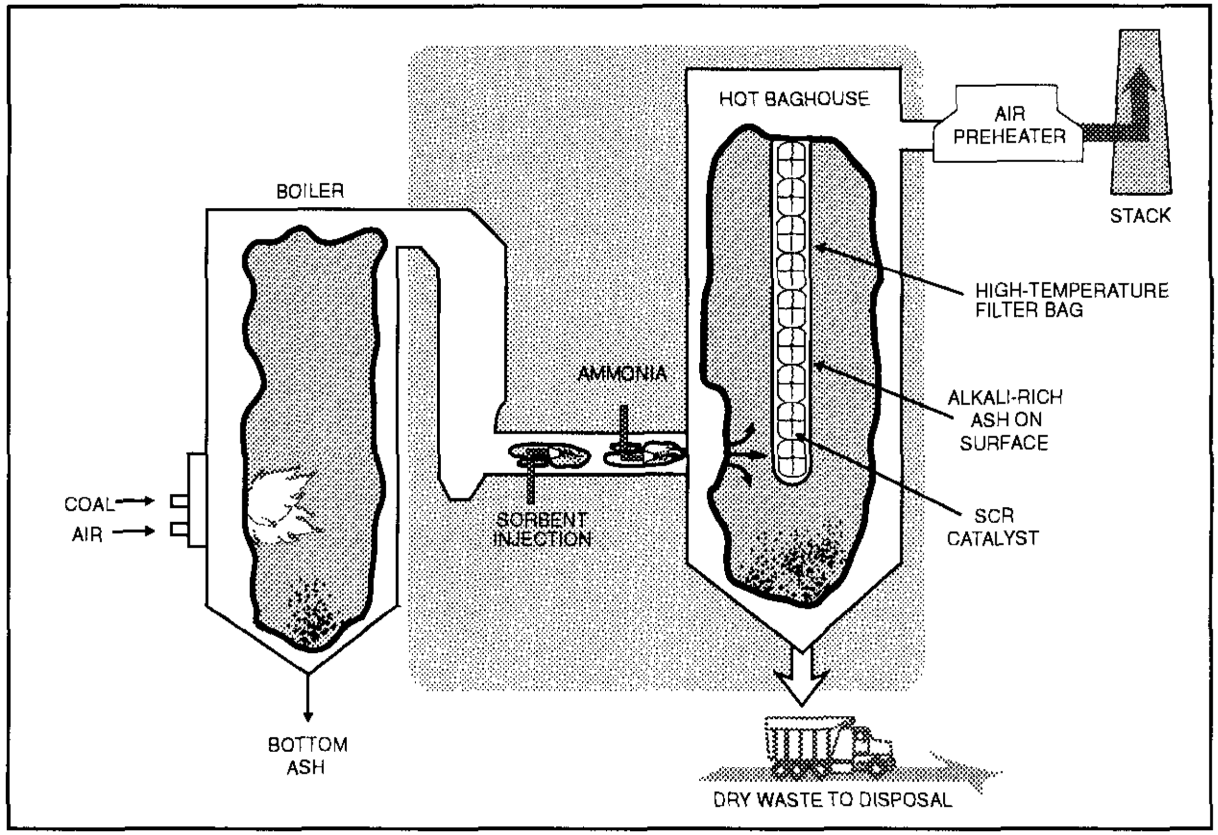
Plant Capacity/Production:
5-MWe equivalent slipstream from a 156-MWe boiler

Project Funding:

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

Project Objective:
To demonstrate that the SNRB™ process, used in retrofitting a high-sulfur-coal-fired power plant, can remove high levels of all three pollutants using a single processing unit for treating flue gas, thereby lessening on-site space requirements and capital costs.

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



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

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

The project demonstrated the technical and economic feasibility of achieving greater than 80% SO_2 removal, above 90% NO_x removal, and 99% particulate removal at lower capital, operating, and maintenance costs than a combination of conventional systems. The demonstration was conducted at Ohio Edison Company's R.E. Burger Plant, Unit No. 5, in Dilles Bottom, OH. Bituminous coal with an average sulfur content of 3.4% was burned at this site during the demonstration.

Project Status/Accomplishments:

SNRB™ demonstration tests were conducted for emissions control of SO_2, NO_x, and particulates. Four different sorbents were tested for SO_2 capture. Calcium-based sorbents included commercial-grade hydrated lime, sugar hydrated lime, and lignosulfonate hydrated lime. In addition, sodium bicarbonate was tested. The optimum location for injecting the sorbent into the flue gas was immediately upstream of the baghouse. Effectively, the SO_2 was captured by the sorbent while the sorbent was in the form of a filter cake on the filter bags (along with fly ash). To capture NO_x, ammonia was injected between the sorbent injection point and the baghouse. The ammonia and NO_x reacted to form nitrogen and water in the presence of Norton Company's NC-300 series zeolite SCR catalyst. With the catalyst being located inside the filter bags, it was well protected from potential particulate erosion or fouling. The sorbent reaction products, unreacted lime, and fly ash were collected on the filter bags and thus removed from the flue gas.

With commercial-grade lime, at a Ca/S ratio of 2, and with the baghouse temperature between 800 and 850 °F, sulfur capture was well above 80%. With the modified hydrated limes, at the same operating temperature range, and with an NH_3/NO_x ratio of 0.9, the reduction in NO_x emissions was consistently above 90% and the ammonia slip was consistently below 5 ppm. Particulate emissions were always below 0.03 lb/million Btu, the NSPS for particulates. Particulate emissions averaged 0.018 lb/million Btu (0.009 grains/std ft^3), corresponding to a collection efficiency of 99.89%.

High SO_2 removal efficiency was demonstrated in a brief test program with sodium bicarbonate injection. Removal efficiency increased from 80% to 98% and the ratio of Na/S was increased from 1:1 to 2:1.

All of the demonstration tests were conducted using 3M's Nextel ceramic fiber filter bags or Owens Corning Fiberglas's S-Glass filter bags. All of the test work was carried out at air-to-cloth ratios of 3–4 ft/min. No excessive wear or failures occurred in over 2,000 hours of elevated temperature operation.

A preliminary evaluation has been made of the projected capital cost of the SNRB™ system for various utility boilers. For a 250-MWe boiler fired with 3.5% sulfur coal and generating NO_x emissions of 1.2 lbs/million Btu, the projected cost of a SNRB™ system is approximately $260/kW including various standard technology and project contingency factors. A combination of fabric filter, SCR, and wet scrubber for achieving comparable emissions control has been estimated at $360–400/kW.

Commercial Applications:

Commercial application of the technology offers the potential for significant reductions of multiple pollutants from fossil-fired plants with the potential for increasing thermal efficiency. SNRB™ offers the potential for lower capital and operating costs and smaller space requirements than a combination of conventional, high-efficiency control technologies. SNRB™ is capable of reducing emissions from plants burning high- or low-sulfur coal. In retrofit applications, SNRB™ provides a means of improving particulate emissions control with the addition of SO_2 and NO_x emissions control capacity.

Commercialization of the technology is expected to develop with an initial larger scale application equivalent to 50–100 MWe. The focus of marketing efforts will be tailored to match the specific needs of potential industrial, utility, and independent power producers for both retrofit and new plant construction. SNRB™ is a flexible technology which can be tailored to maximize control of SO_2, NO_x, or combined emissions to meet current performance requirements while providing flexibility to address future needs.

Project Schedule:

DOE selected project (CCT-II)	9/28/88
NEPA process completed (MTF)	9/22/89
Cooperative agreement awarded	12/20/89
Construction	5/91–12/91
Environmental monitoring plan completed	12/31/91
Operational testing	5/92–5/93
Project completed	3/94

Final Reports:

Final Technical Report	early 1994
Economic Evaluation Report	early 1994
Detailed Design Report	11/92

Enhancing the Use of Coals by Gas Reburning and Sorbent Injection

Sponsor:

Energy and Environmental Research Corporation

Additional Team Members:

Gas Research Institute—cofunder

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

Illinois Power Company—host utility

City Water, Light and Power—host utility

Locations:

Hennepin, Putnam County, IL (Illinois Power Company's, Hennepin Plant)

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

Technology:

Energy and Environmental Research Corporation's gas reburning and sorbent injection process (environmental control devices/combined SO_2/NO_x control technologies)

Plant Capacity/Production:

Hennepin: tangentially fired 80 MWe (nominal)

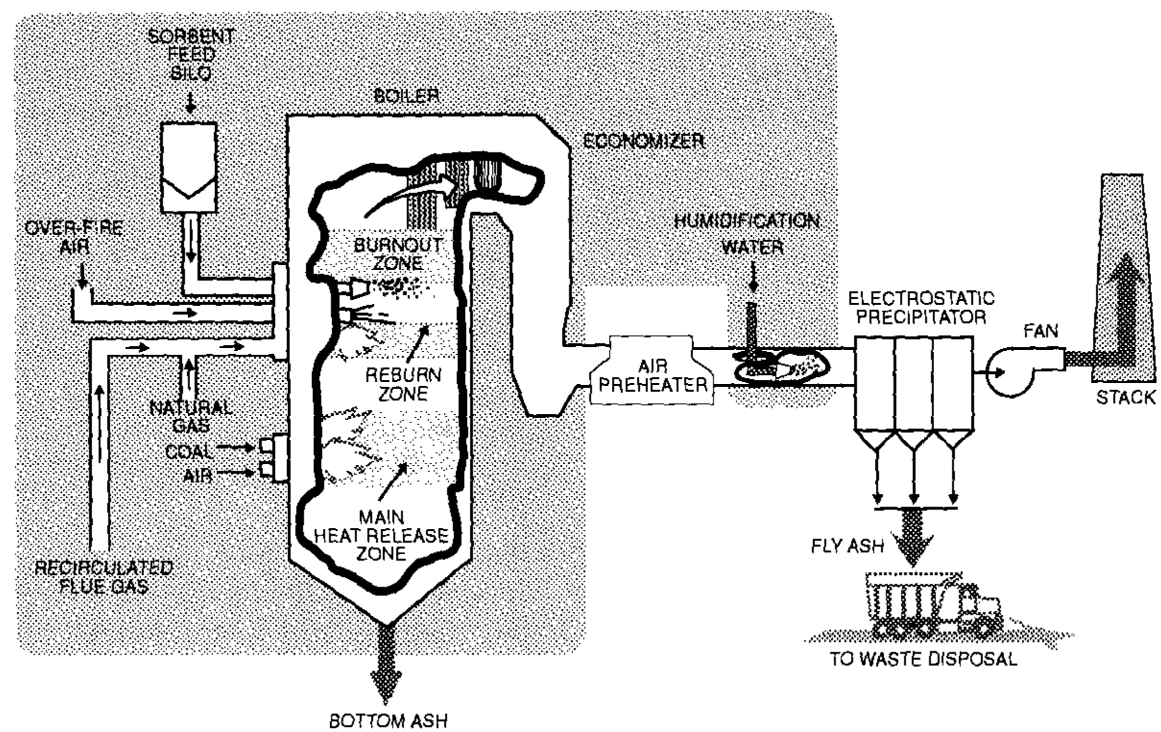
Lakeside: cyclone-fired 40 MWe (nominal)

Project Funding:

Total project cost	$37,497,816	100%
DOE	18,747,816	50
Participants	18,750,000	50

Project Objective:

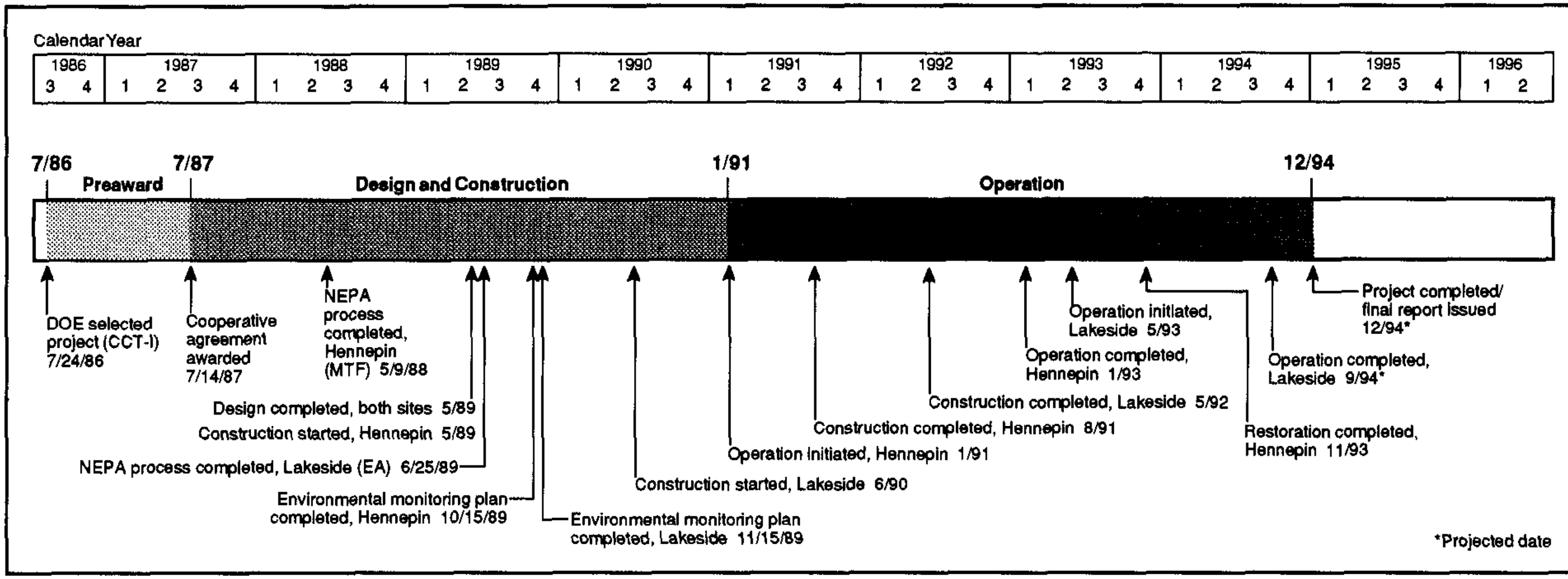
To demonstrate gas reburning to attain 60% NO_x reduction along with sorbent injection to capture 50% of the SO_2 on two different boiler configurations: tangentially fired and cyclone fired.



Technology/Project Description:

Gas reburning is a postcombustion technology that is being developed primarily for the removal of NO_x. In this process, 80–85% of the fuel is coal and is supplied to the main combustion zone. The remaining 15–20% of the fuel, generally natural gas or a hydrocarbon, bypasses the main combustion zone and is injected above the main burners to form a reducing zone in which NO_x is converted to nitrogen. A calcium compound (sorbent) is injected in the form of dry, fine particulates above the reburning zone in the boiler or even further downstream. The calcium compound to be tested is $Ca(OH)_2$ (lime). The process is expected to achieve 60% NO_x reduction and 50% SO_2 reduction on different boiler configurations at power plants burning high-sulfur midwestern coal.

This project will demonstrate the gas reburning and sorbent injection process on two separate boilers representing two different firing configurations—a tangentially fired 80-MWe boiler at Illinois Power Company's Hennepin Plant in Hennepin, IL, and a cyclone-fired 40-MWe boiler at City Water, Light and Power's Lakeside Station in Springfield, IL. Illinois bituminous coal containing 3% sulfur is the test coal for both Hennepin and Lakeside.



Project Status/Accomplishments:

Permitting and engineering design efforts were completed for the three original project sites; however, in 1990, plans for the third site (Bartonville, IL) were suspended.

Operations at the Hennepin site began January 1991. Long-term testing at Hennepin started in mid-1991 after shakedown operations had been completed. All testing, including testing with a promoted and a high-surface-area lime, was completed in January 1993. During the course of testing, NO_x reductions through gas reburning have ranged as high as 77%, 65% being routine, exceeding the project objective of 60%. Sorbent injection reduced SO_2 emissions as much as 62%, with 52% reduction being routine, also exceeding the project objective of 50%. The calcium-to-sulfur ratio was about 1.75:1. The system installed at Hennepin operated for more than 2,100 hours.

Illinois Power, the host utility, has chosen to retain the gas-reburning portion of the gas-reburning and sorbent-injection system for potential use in NO_x control at the Hennepin Plant. The sorbent injection portion has been removed and the site restored.

At City Water, Light and Power's Lakeside site in Springfield, IL, construction was essentially completed in May 1992, and the unit was temporarily placed on hold. Some minor construction activities were completed between October 1992. Operation with sorbent injection began in May 1993 and with gas reburning in June 1993. Parametric testing began in July 1993. As at the Hennepin site, the Springfield site achieved NO_x and SO_2 reductions better than the targets of 60% and 50% respectively. The long-term test program began November 15, 1993, under optimized conditions and will conclude in September 1994.

The project schedule allows at least 12 months of gas-reburning and sorbent-injection demonstration operation under normal load dispatch at Lakeside and demonstration of one or more alternate sorbents.

Commercial Applications:

Gas reburning and sorbent injection is the unique combination of two separate technologies. The commercial applications for these technologies, both separately and combined, extend to both utility companies and industry in the United States and abroad. In the United States alone, these two technologies can be applied to over 900 pre-NSPS utility boilers; the technologies also can be applied to new utility boilers. With NO_x and 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. The technologies are not sensitive to the type of coal used, regardless of its nitrogen or sulfur content.

Milliken Clean Coal Technology Demonstration Project

Sponsor:

New York State Electric & Gas Corporation

Additional Team Members:

Consolidation Coal Company—technical consultant
Saarberg-Hölter-Umwelttechnik, GmbH—technology supplier
The Stebbins Engineering and Manufacturing Company—technology supplier
NALCO Fuel Tech—technology supplier

Location:

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

Technology:

Flue gas cleanup using Saarberg-Hölter-Umwelttechnik's (S-H-U) formic-acid-enhanced, wet limestone scrubber technology; NALCO Fuel Tech's NO_xOUT urea injection system; Stebbins' tile-lined split-module absorber; and heat-pipe air-heater system (environmental control devices/combined SO_2/NO_x control technologies)

Plant Capacity/Production:

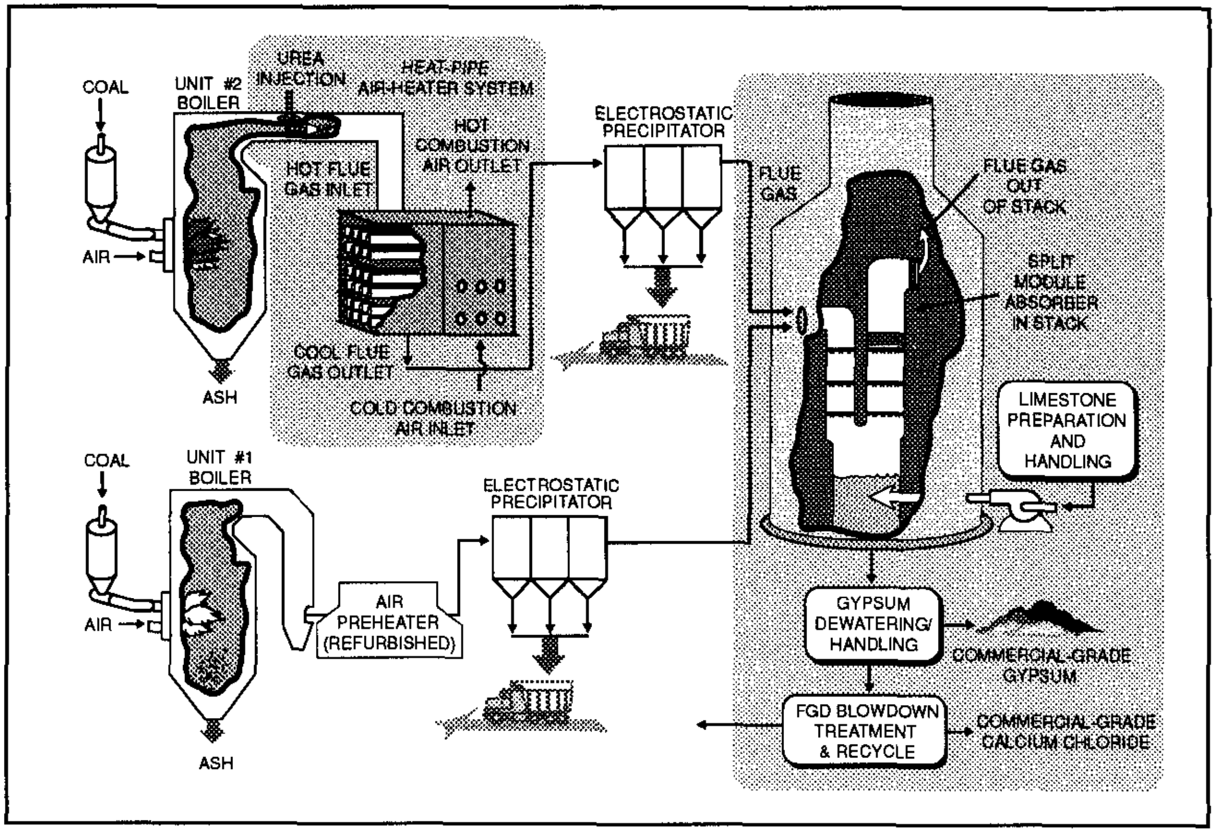
300 MWe

Project Funding:

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

Project Objective:

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



Technology/Project Description:

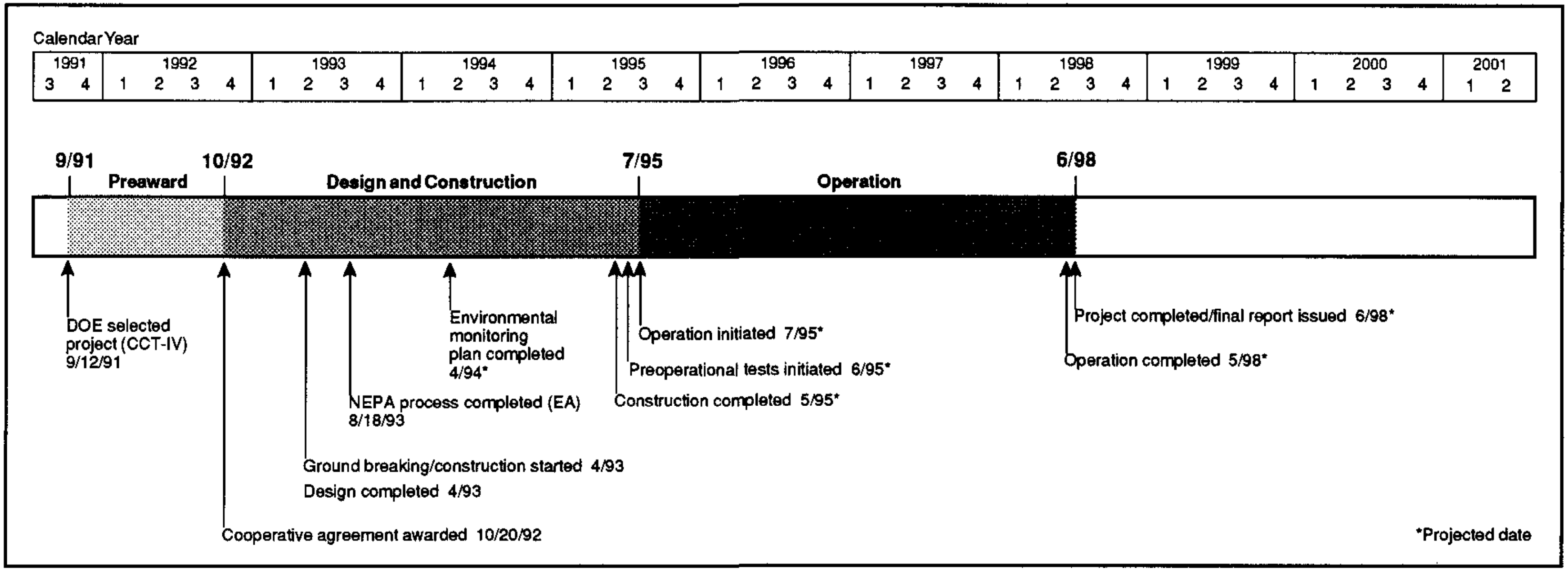
The S-H-U wet flue gas desulfurization process is a formic-acid-enhanced, wet limestone process which results in very high SO_2 removal with low energy consumption and the production of commercial-grade gypsum.

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

The NALCO Fuel Tech NO_xOUT system removes NO_x by the injection of urea into the boiler gas. This facet of the project, in conjunction with other combustion modifications, will reduce NO_x emissions and produce marketable fly ash.

A heat-pipe air-heater system by ABB Air Preheater Inc. will be used with advanced temperature controls to reduce both air leakage and the air heater's flue gas exit temperature. Ultimate emissions reductions with increased boiler efficiencies will result.

The project is designed for "total environmental and energy management," a concept encompassing low emissions, low energy consumption, improved combustion, upgraded boiler controls, and reduced solid waste. The system is being designed to achieve at least a 95% SO_2 removal efficiency (or up to 98%) using limestone



while burning high-sulfur coal. NO_x reductions will be achieved using selective non-catalytic reduction technology and separate combustion modifications. The system has zero wastewater discharge and produces marketable by-products (e.g., commercial-grade gypsum, calcium chloride, and fly ash), minimizing solid waste.

New York State Electric & Gas plans to demonstrate these technologies at Units 1 and 2 of its Milliken Station located in Lansing, NY. Pittsburgh, Freeport, and Kittaning coals, with sulfur contents of 1.5%, 2.9%, and 4.0%, will be used.

Project Status/Accomplishments:

The cooperative agreement was awarded on October 20, 1992. The NEPA process has been completed. The environmental assessment with a finding of no significant impact was signed August 18, 1993. The environmental monitoring plan was completed in December 1993. New York State completed its environmental review and issued permits in August 1992.

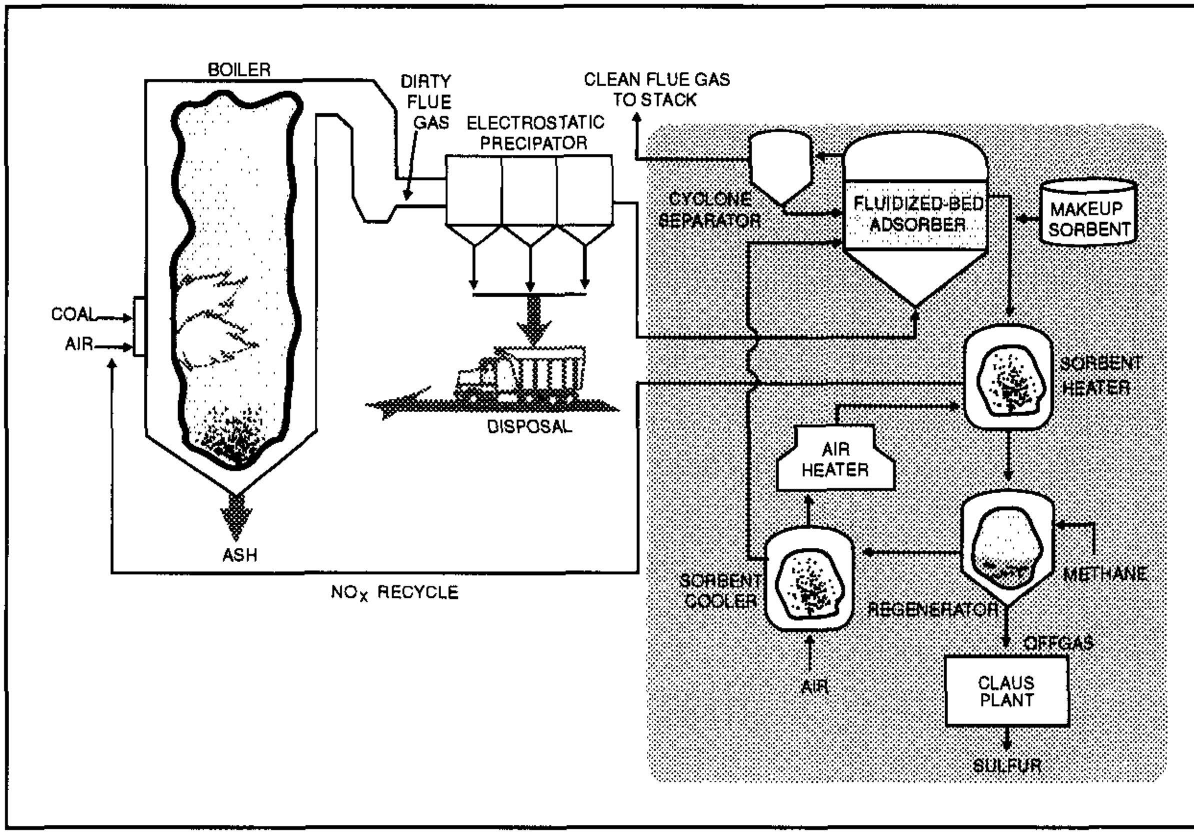
Construction is expected to continue through mid-1995 and operations are scheduled through mid-1998. Hazardous air pollutant monitoring will be part of the test program.

Commercial Applications:

The S-H-U SO_2 removal process, the NALCO NO_xOUT non-catalytic reduction process, Stebbins' tile-lined split-module absorber, and heat-pipe air-heater technology are applicable to virtually all electric utility power plants. Commercialization of all technologies in both retrofit and greenfield applications of virtually any megawatt size is expected. The high removal efficiency, up to 98% for SO_2 and up to 30% beyond combustion modifications for NO_x, will make the combination of these technologies attractive.

The space-saving design features of the S-H-U, NALCO, Stebbins, and heat-pipe technologies, combined with the production of marketable by-products, offer significant incentives to generating stations with limited on-site space. In addition, the inherent energy efficiency of the combined technologies minimizes any secondary environmental impacts from the operation of pollution control equipment.

Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System



Cosponsors:

NOXSO Corporation
MK-Ferguson Company

Additional Team Members:

W.R. Grace and Company—cofunder
Ohio Coal Development Office—cofunder
Gas Research Institute—cofunder
Electric Power Research Institute—cofunder
East Ohio Gas Company—cofunder

Location:

Negotiations for a new site and host utility are under way.

Technology:

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

Plant Capacity/Production:

100 MWe (typical)

Project Funding:

Total project cost	$66,249,696	100%
DOE	33,124,848	50
Participants	33,124,848	50

Project Objective:

To demonstrate removal of 97% of the SO_2 and 70% of the NO_x from a coal-fired boiler's flue gas using the NOXSO process.

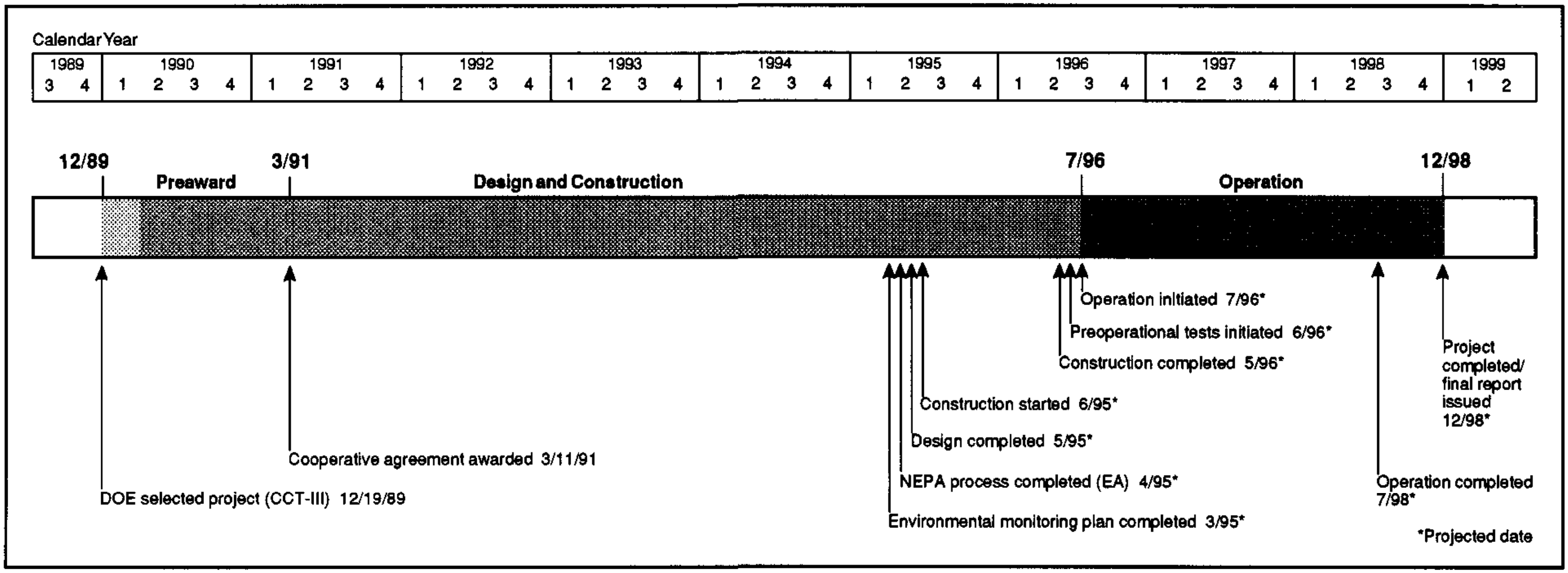
Technology/Project Description:

The NOXSO process is a dry, regenerable system capable of removing both SO_2 and NO_x in flue gas from coal-fired utility boilers burning medium- to high-sulfur coals. In the basic process, the flue gas passes through a fluidized-bed adsorber located downstream of the precipitator; the SO_2 and NO_x are adsorbed by the sorbent. The sorbent consists of spherical beads of high-surface-area alumina impregnated with sodium carbonate. The cleaned flue gas then passes to the stack.

The NO_x is desorbed from the NOXSO sorbent when heated by a stream of hot air. The hot air containing the desorbed NO_x is recycled to the boiler where equilibrium processes cause destruction of the NO_x. The adsorbed sulfur is recovered from the sorbent in a regenerator where it reacts with methane at high temperature to produce an offgas with high concentrations of SO_2 and hydrogen sulfide (H_2S). This offgas is processed in a Claus plant to produce elemental sulfur, a salable by-product.

The process is expected to achieve SO_2 reductions of 97% and NO_x reductions of 70%.

The NOXSO process will be demonstrated on a typical 100-MWe cyclone boiler. Presently, NOXSO Corporation is negotiating with several potential host utilities for a new site for the demonstration project. MK-Ferguson will design, construct, and operate a full-scale commercial NOXSO unit to demonstrate process feasibility. The project is being structured so that data from the proof-of-concept facility at Ohio Edison Company's Toronto Station (now completed) can be incorporated into the project definition activity.



Project Status/Accomplishments:

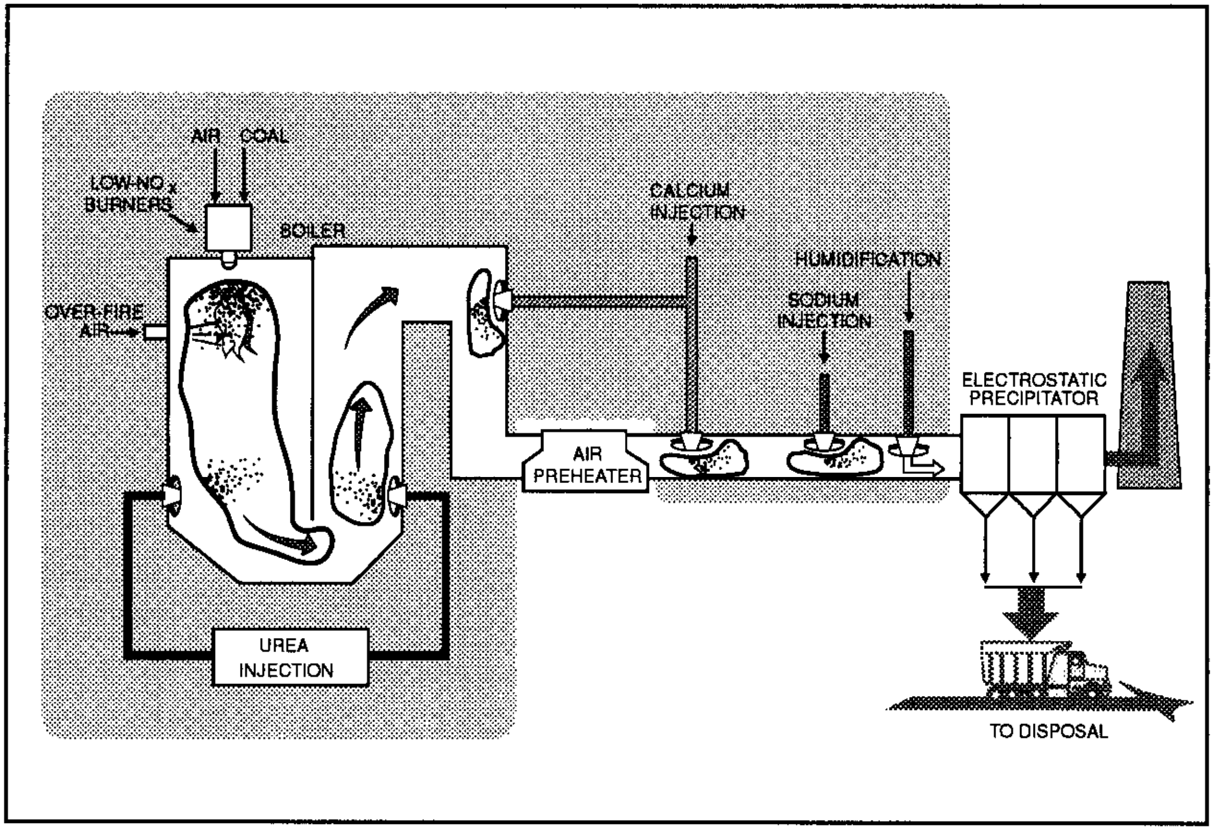
The proof-of-concept, pilot-plant testing, which was proceeding in parallel with the project definition phase of the demonstration project, is complete, with results as expected. Preliminary process flow diagrams, piping and instrumentation diagrams, equipment specifications, and plant arrangement drawings have been prepared. Power plant, site, and process-specific environmental information has been compiled for use in the NEPA process.

Commercial Applications:

The NOXSO process is applicable for retrofit or new facilities. The process is suitable for utility and industrial coal-fired boilers of 75 MWe or larger. Southeastern Ohio and western Pennsylvania coal (3.2–3.5% sulfur average) are intended for use in the demonstration; however, the process is adaptable to coals with higher sulfur content.

Commercial-grade sulfur, a salable by-product, is produced. The technology is expected to be especially attractive to utilities that require high removal efficiencies for both SO_2 and NO_x and/or need to eliminate solid wastes.

Integrated Dry NO_x/SO_2 Emissions Control System



Sponsor:
Public Service Company of Colorado

Additional Team Members:
Electric Power Research Institute—cofunder
Stone and Webster Engineering Corp.—engineer
The Babcock & Wilcox Company—burner developer
Fossil Energy Research Corporation—operational testing
Western Research Institute—flyash evaluator
Colorado School of Mines—bench-scale engineering research and testing
Noell, Inc.—urea-injection system provider

Location:
Denver, Denver County, CO (Public Service Company of Colorado's Arapahoe Station, Unit No. 4)

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

Plant Capacity/Production:
100 MWe

Project Funding:

Total project cost	$27,411,462	100%
DOE	13,705,731	50
Participants	13,705,731	50

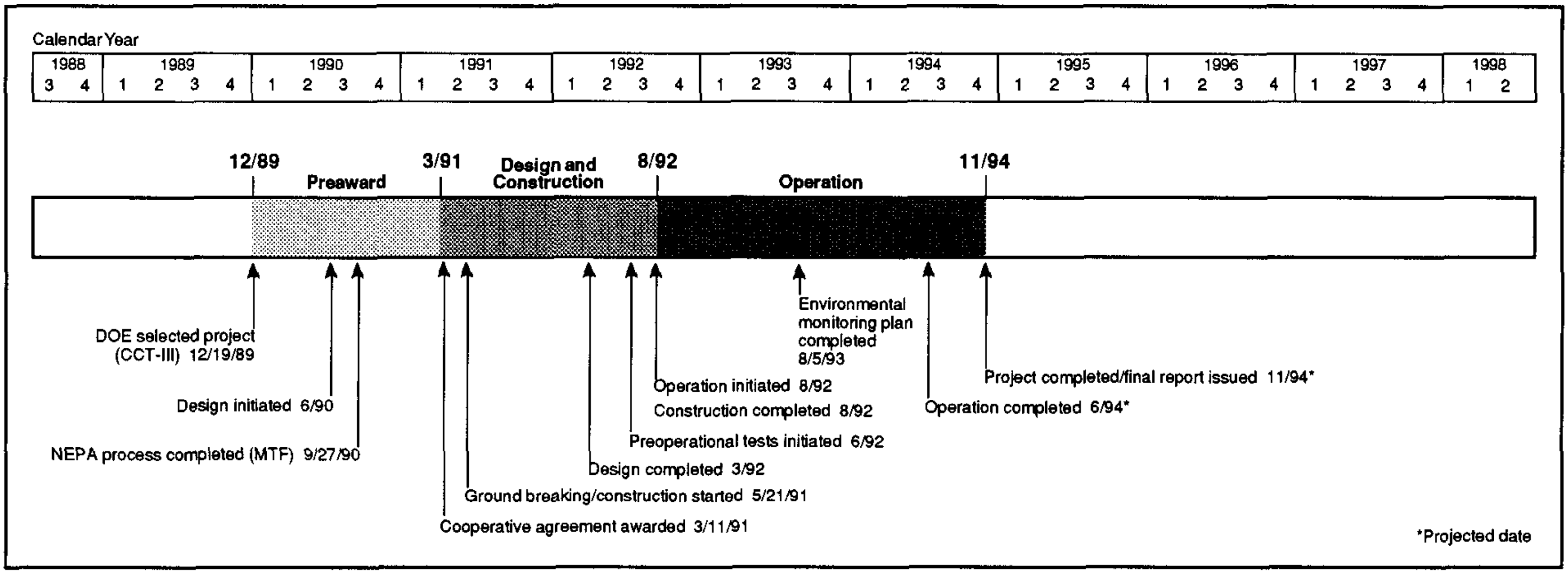
Project Objective:
To demonstrate the integration of three technologies to achieve up to 70% reduction in NO_x and SO_2 emissions; more specifically, to assess the integration of a down-fired low-NO_x burner with in-furnace urea injection for additional NO_x removal and dry sorbent in-duct injection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

Technology/Project Description:
All of the testing is using Babcock & Wilcox's low-NO_x DRB-XCL® down-fired burners with over-fire air. These burners control NO_x by injecting the coal and the combustion air in an oxygen-deficient environment. Additional air is introduced via over-fire air ports to complete the combustion process and further enhance NO_x removal. The low-NO_x burners are expected to reduce NO_x emissions by up to 50%, and, with added air, by up to 70%. To reduce NO_x emissions even further, in-furnace urea injection is being tested to determine how much additional NO_x can be removed from the combustion gas.

Two types of dry sorbents are being injected into the ductwork downstream of the boiler to reduce SO_2 emissions. Either calcium is injected upstream of the air heater or sodium or calcium is injected downstream of the air heater. Humidification downstream of the dry sorbent injection aids SO_2 capture and lowers flue gas temperature and gas flow, which can decrease pressure drop at the fabric filter dust collector.

Low-sulfur (0.4%) bituminous coal from Colorado is the main fuel being tested, but for a run of short duration (less than 1 month), Illinois bituminous coal containing 2.5% sulfur is the planned test fuel.

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



The three basic technology systems have been installed on Public Service Company of Colorado's Arapahoe Station Unit No. 4, a 100-MWe down-fired, pulverized-coal boiler with roof-mounted burners.

Project Status/Accomplishments:

Baseline testing of the boiler without any modifications was completed in mid-December 1991. Baseline testing of the boiler with urea injection began in early February 1992 and continued for approximately 1 month. Construction requiring plant outage was completed in May 1992, and then preoperational testing of the boiler with low-NO_x burners and over-fire air began. Operational testing of these two key components started in early August 1992.

Testing of the combustion modifications was completed in late October 1992. While firing western bituminous coal, NO_x was reduced from an original baseline of 1.15 lbs/million Btu to about 0.4 lb/million Btu—a 65% reduction—with no operating problems. Short-term testing while firing natural gas was also completed. In-furnace urea injection testing began in January 1993 and continued for 3 months. At full load, 44% NO_x reduction was achieved with a 10-ppm ammonia slip. Duct sorbent-injection testing began in August 1993. Preliminary results with sodium injection indicate that over 70% SO_2 removal can be obtained. Baseline and urea injection air toxics monitoring has been performed. Preliminary data indicate that the baghouse successfully removes nearly all air toxics emissions. Air toxics testing during calcium and sodium injection was conducted during October 1993.

Arapahoe 4 has operated over 12,000 hours since combustion modifications were completed in May 1992. The availability factor during this period was over 96%.

Commercial Applications:

Either the entire integrated dry NO_x/SO_2 emissions control system or the individual technologies are applicable to most utility and industrial coal-fired units. They provide a lower capital-cost alternative to conventional wet flue gas desulfurization processes. They can be retrofitted with modest capital investment and downtime, and their space requirements are substantially less. They can be applied to any unit size but are mostly applicable to the older, small- to mid-size units. They can reduce NO_x emissions by up to 70% and SO_2 emissions by 50–70%, and they produce a dry solid waste product. These processes have the ability to handle all coal types, especially coals with low- to mid-sulfur content.

Coal Processing for Clean Fuels Fact Sheets

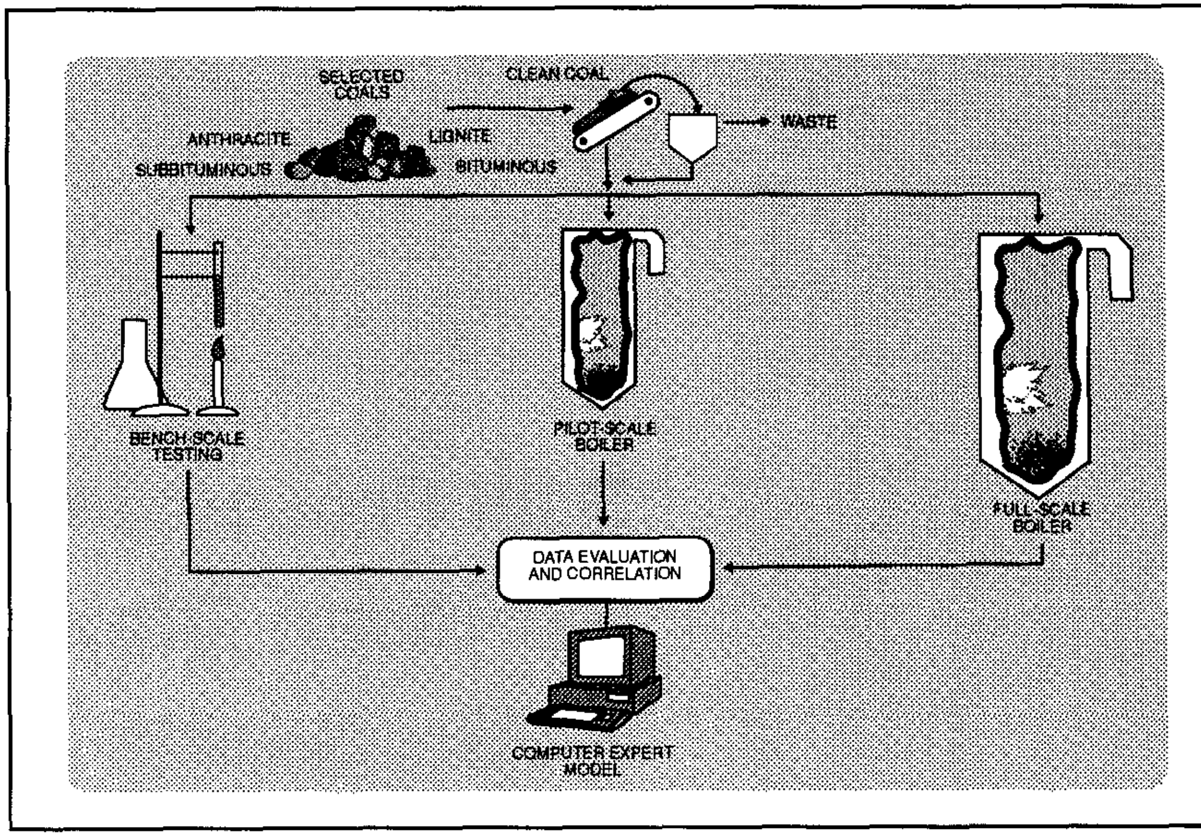
Development of the Coal Quality Expert

Cosponsors:
ABB Combustion Engineering, Inc.
CQ, Inc.

Additional Team Members:
Black and Veatch—cofunder and expert system developer
Electric Power Research Institute—cofunder
The Babcock & Wilcox Company—cofunder and pilot-scale testing
Guild Products, Inc.—expert system architecture developer
Electric Power Technologies, Inc.—field testing
University of North Dakota, Energy and Minerals Research Center—bench-scale testing
Alabama Power Company—host utility
Mississippi Power Company—host utility
New England Power Company—host utility
Northern States Power Company—host utility
Public Service of Oklahoma—host utility

Locations:
Alliance, Columbiana County, OH (pilot-scale tests)
Windsor, Hartford County, CT (pilot-scale tests)
Grand Forks, Grand Forks County, ND (bench tests)
Wilsonville, Shelby County, AL (Gatson, Unit 5)
Gulfport, Harrison County, MS (Watson, Unit 4)
Somerset, Bristol County, MA (Brayton Point, Units 2 and 3)
Bayport, Washington County, MN (King Station)
Oologah, Rogers County, OK (Northeastern, Unit 4)

Technology:
CQ, Inc.'s EPRI coal quality expert (CQE) computer model (coal processing for clean fuels/coal preparation technologies)



Plant Capacity/Production:
Full-scale testing will take place at six utility sites ranging in size from 250 to 880 MWe.

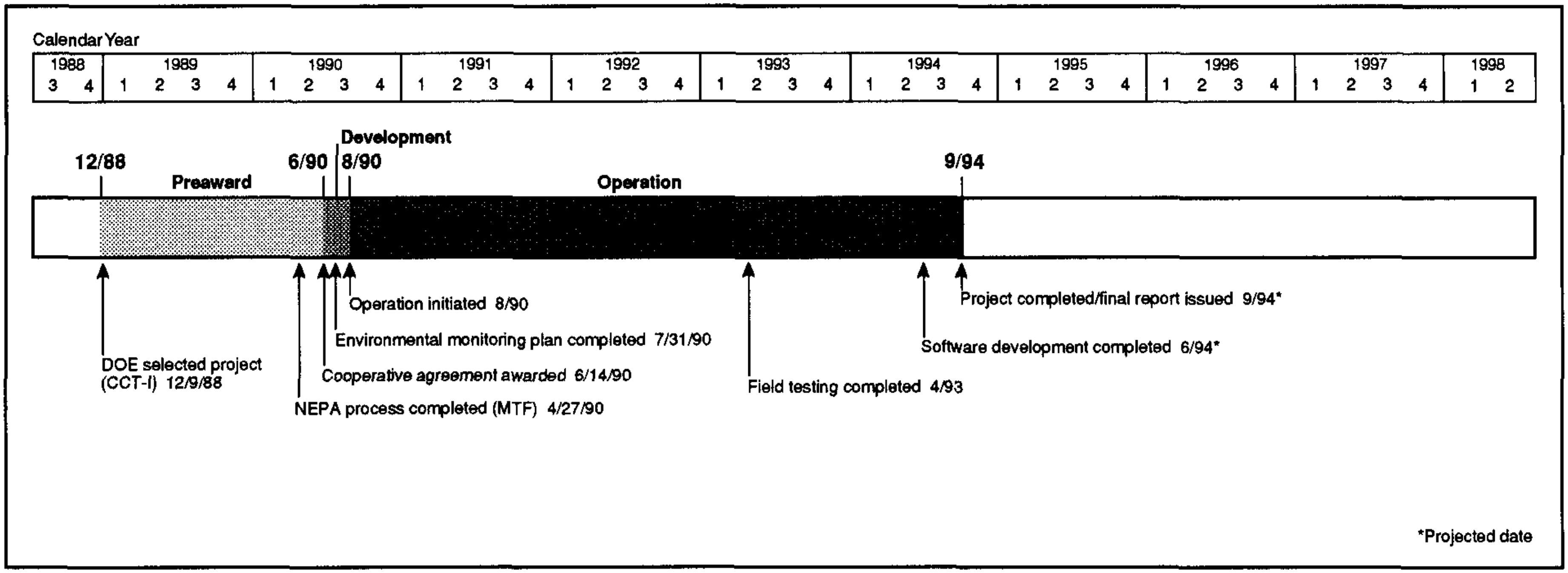
Project Funding:

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

Project Objective:
To demonstrate an expert system that can be run on a personal computer and provide coal-burning utilities with a predictive tool to assist in the selection of optimum quality coal for a specific boiler based on operational efficiency, cost, and environmental emissions.

Technology/Project Description:
Data derived from bench-, pilot-, and full-scale testing are being used to develop algorithms for inclusion into an expert model, the Coal Quality Expert, that can be run on a personal computer. Utilities may use the information to predict the operating performance and cost of coals not previously burned at a particular facility.

Six large-scale field tests consist of burning a baseline coal and an alternate coal over a 2-month period. The baseline coal, the one currently used as fuel, is used to characterize the operating performance of the boiler. The alternate coal, a blended or cleaned coal of improved quality, is burned in the boiler for the remaining test period.



The baseline and alternate coals for each test site also are burned in bench- and pilot-scale facilities under similar conditions. The alternate coal is cleaned at CQ, Inc., to determine what quality levels of clean coal can be produced economically and then transported to the bench- and pilot-scale facilities for testing. All data from bench-, pilot-, and full-scale facilities are evaluated and correlated to formulate algorithms being used to develop the model.

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

Project Status/Accomplishments:

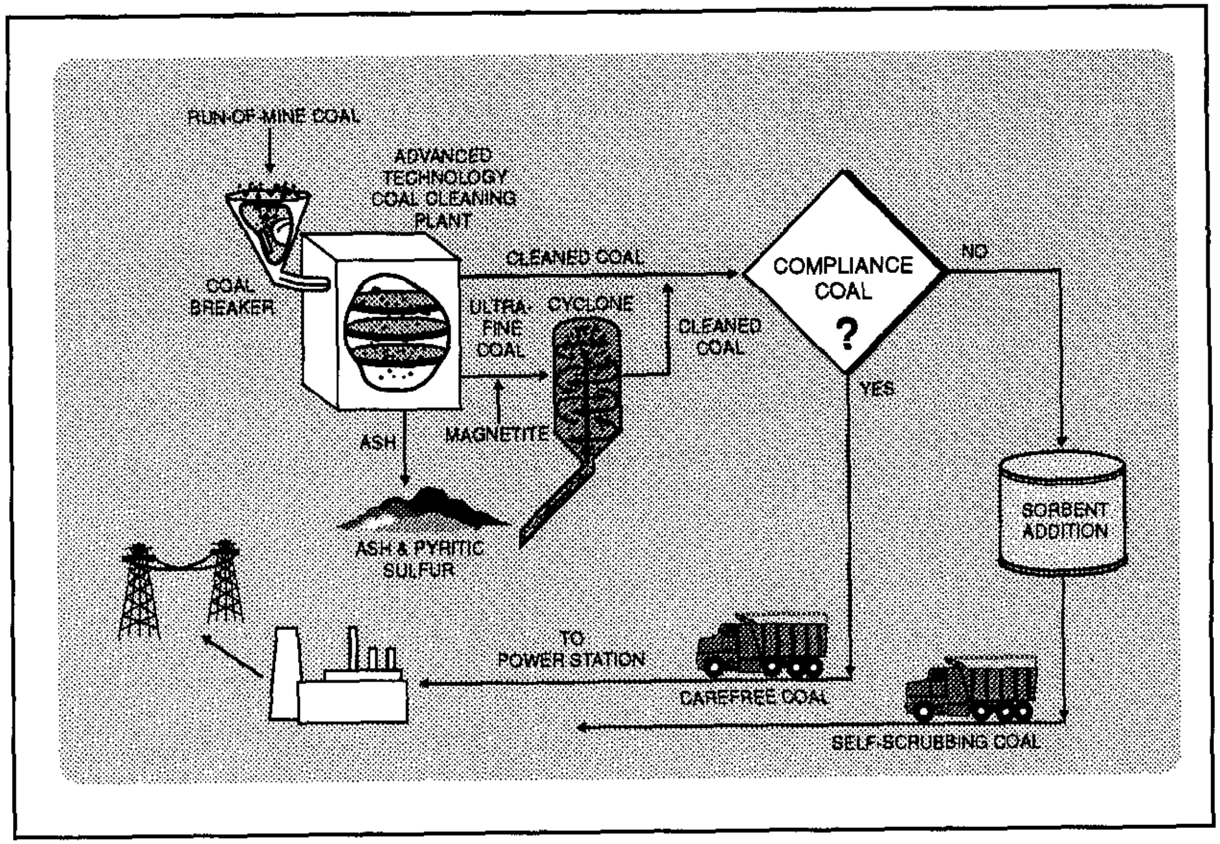
All six field tests have been completed. A commercial sale of the CQE Acid Rain Advisor software package was made in 1993. A CQE prototype was showcased in September 1993. A CQE beta version is scheduled for testing in March 1994.

Commercial Applications:

The expert system will enable coal-fired utilities to select the optimum quality coals at the lowest price for their specific boilers to reduce SO_2 and NO_x emissions.

The CQE system is applicable to all electric power plants and industrial/institutional boilers that burn coal. The system will predict the operational and emission reduction benefits of using cleaned coal. Following the demonstration, CQ, Inc., and Black and Veatch, will market the CQE system in the United States and abroad.

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



Sponsor:

Custom Coals International (a joint venture between Genesis Coals Limited Partnership and Genesis Research Corporation)

Additional Team Members:

Duquesne Light Company—host utility
Richmond Power & Light—host utility
Centerior Service Company—host utility
CQ, Inc.—operator

Locations:

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

Technology:

Coal preparation using Custom Coals' advanced physical coal cleaning and fine magnetite separation technology plus sorbent addition technology (coal processing for clean fuels/coal preparation technologies)

Plant Capacity/Production:

500 tons/hr

Project Funding:

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

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

Project Objective:

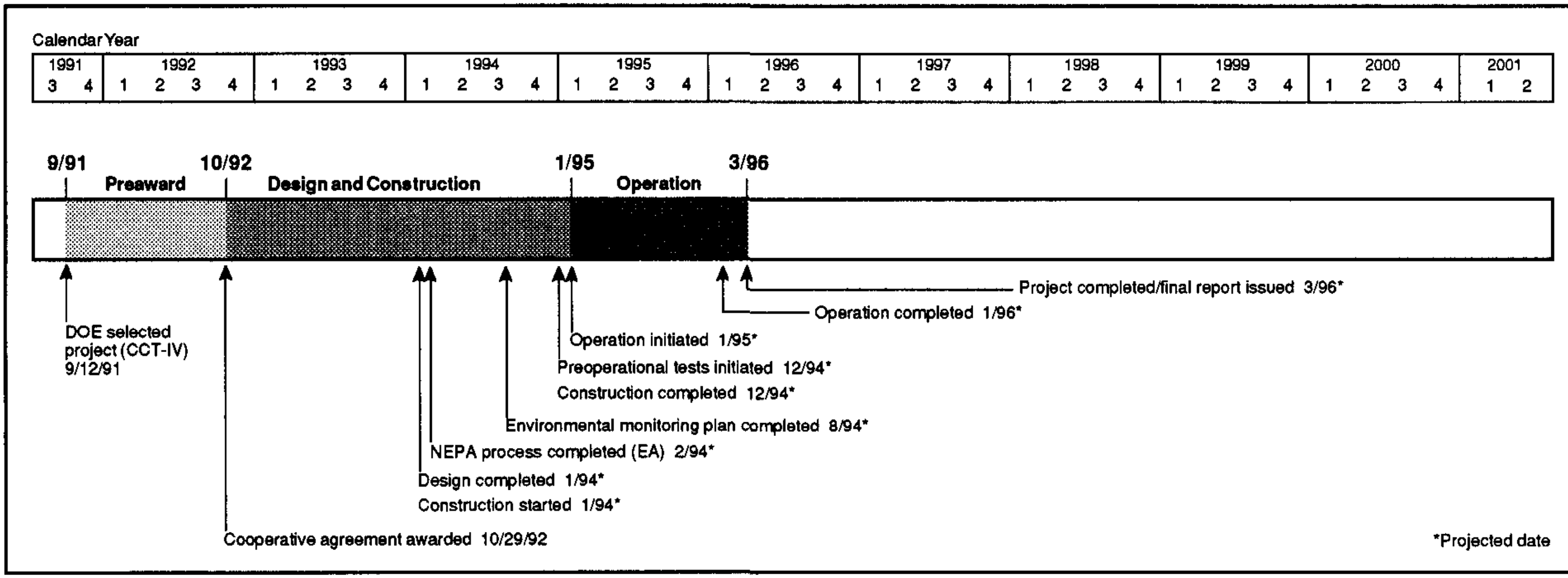
To demonstrate advanced coal-cleaning unit processes to produce low-cost compliance coals that can meet full requirements for commercial-scale utility power plants to satisfy CAAA of 1990 provisions.

Technology/Project Description:

An advanced coal-cleaning plant will be designed, blending existing and new processes, to produce, from high-sulfur bituminous feedstocks, two types of compliance coals—Carefree Coal™ and Self-Scrubbing Coal™.

Carefree Coal™ is produced by breaking and screening run-of-mine coal and by using innovative dense-media cyclones and finely sized magnetite to remove up to 90% of the *pyritic* sulfur and most of the ash. Carefree Coal™ is designed to be a competitively priced, high-Btu fuel that can be used without major plant modifications or additional capital expenditures. While many utilities can use Carefree Coal™ to comply with SO_2 emissions limits, others cannot due to the high content of *organic* sulfur in their coal feedstocks. When compliance coal cannot be produced by reducing pyritic sulfur, Self-Scrubbing Coal™ can be produced to achieve compliance.

Self-Scrubbing Coal™ is produced by taking Carefree Coal™, with its reduced pyritic sulfur and ash content, and adding to it sorbents, promoters, and catalysts. Self-Scrubbing Coal™ is expected to achieve compliance with virtually any U.S. coal feedstock through in-boiler absorption of SO_2 emissions. The reduced ash content of the Self-Scrubbing Coal™ permits the addition of relatively large amounts of sorbent without exceeding the



ash specifications of the boiler or overloading the electrostatic precipitator.

A 500-ton/hr advanced coal-cleaning plant is being designed and constructed at a site near Central City, PA. The advanced coal-cleaning plant will manufacture Self-Scrubbing Coal™ and Carefree Coal™. Two medium- to high-sulfur coals—Illinois No. 5 from Wabash County, IL, and Lower Freeport Seam coal from Belmont County, OH—will be used to produce Self-Scrubbing Coal™. Carefree Coal™ will be made using Sewickley coal from Greene County, PA. The Sewickley coal will be combustion tested at Duquesne Light Company's Cheswick Power Station located near Pittsburgh, PA; the Illinois No. 5 coal will be tested at Richmond Power & Light's Whitewater Valley Station Unit No. 2 located in Richmond, IN; and the Lower Freemont Seam coal will be tested at Centerior Service Company's Ashtabula C-Plant.

Project Status/Accomplishments:

The cooperative agreement was awarded in October 1992. Design work has started. Foundations were completed in January 1994. An environmental assessment has been prepared, and approval is expected in February 1994.

Commercial Applications:

Commercialization of Self-Scrubbing Coal™ has the potential of bringing into compliance about 164 million tons/yr of bituminous coal that cannot meet emissions limits through conventional coal cleaning. This represents over 38% of the bituminous coal burned in 50-MWe or larger U.S. generating stations.

The technology produces coal products that can be used to reduce a utility or industrial power plant's total sulfur emissions 80–90%.

Advanced Coal Conversion Process Demonstration

Sponsor:
Rosebud SynCoal Partnership (a partnership between Western Energy Company and the NRG Group, a nonregulated subsidiary of Northern States Power Company)

Additional Team Member:
Stone and Webster Engineering Corp.—architect/engineer

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

Technology:
Western Energy Company's advanced coal conversion process for upgrading low-rank subbituminous and lignite coals (clean processing for clean fuels/coal preparation technologies)

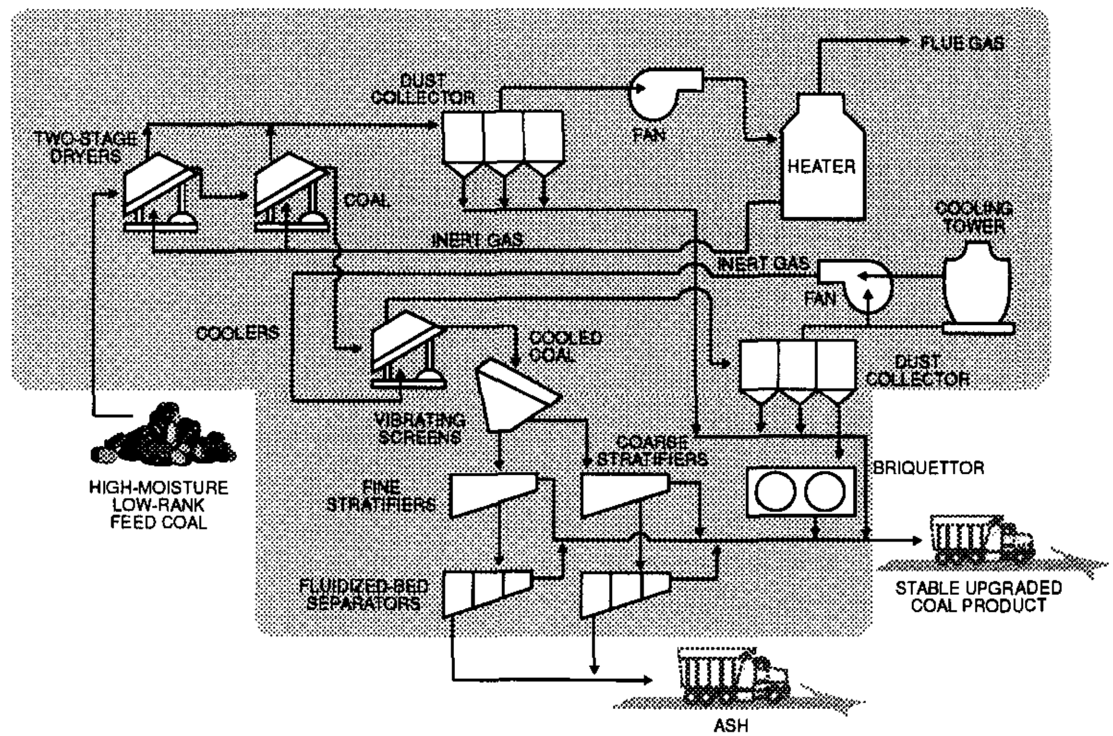
Plant Capacity/Production:
45 tons/hr of SynCoal™ product (300,000 tons/yr)

Project Funding:

Total project cost	$69,000,000	100%
DOE	34,500,000	50
Participants	34,500,000	50

Project Objective:
To demonstrate Western Energy's advanced coal conversion process to produce a stable coal product having a moisture content as low as 1%, sulfur content as low as 0.3%, and heating value up to 12,000 Btu/lb.

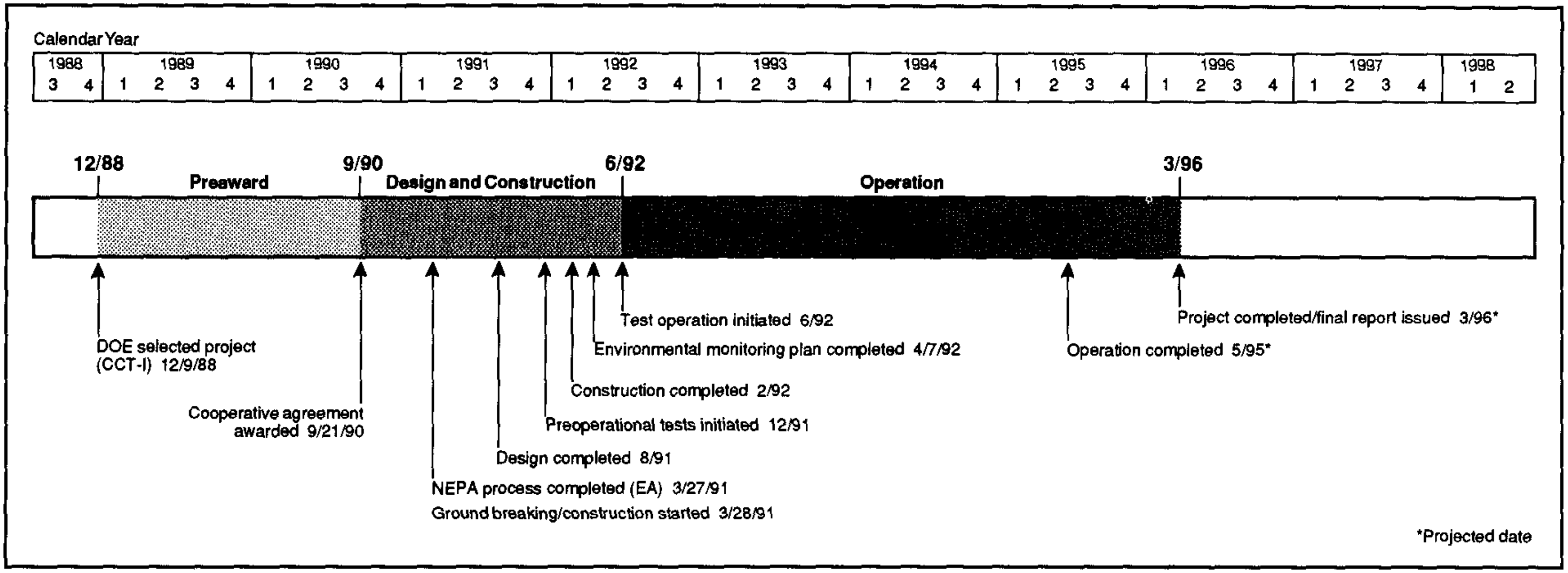
SynCoal is a trademark of the Rosebud SynCoal Partnership.



Technology/Project Description:
Being demonstrated is an advanced thermal coal-drying process coupled with physical cleaning techniques to upgrade high-moisture, low-rank coals to produce a high-quality, low-sulfur fuel. The coal is processed through two fluidized-bed reactors that remove loosely held water and then chemically bound water, carboxyl groups, and volatile sulfur compounds. After drying, the coal is put through a deep-bed stratifier cleaning process to effect separation of the ash.

The technology, if successfully demonstrated, enhances low-rank western coals, usually with a moisture content of 25–55%, sulfur content of 0.5–1.5%, and heating value of 5,500–9,000 Btu/lb, by producing a stable, upgraded SynCoal™ product with a moisture content as low as 1%, sulfur content as low as 0.3%, and heating value up to 12,000 Btu/lb.

The 45-ton/hr unit is located adjacent to a unit train loadout facility at Western Energy Company's Rosebud coal mine in Colstrip, MT. Although the demonstration plant is one-tenth the size of a commercial facility, the process equipment is at commercial scale because a full-sized commercial plant has multiple process trains.



Project Status/Accomplishments:

On December 12, 1990, Western Energy Company, a subsidiary of Montana Power Company, announced that it had joined with the NRG Group, a nonregulated subsidiary of Northern States Power Company based in Minneapolis, MN, to demonstrate and commercialize this coal conversion technology.

Ground was broken on March 28, 1991. By June, pieces of major equipment were arriving on site. The construction of two 6,000-ton product storage silos and all foundation work was completed by July. The main process facility structure and the control/administration building were completed by November. Initial "turnover" of equipment started in December, and final construction was completed in February 1992. Initial "hot" operations began in March 1992.

During the summer of 1993, the facility was shut down for extended maintenance and retrofit to the dust transport system. The plant resumed operation in August 1993 and reached 100% capacity on December 6, 1993. SynCoal™ is being shipped by truck and rail to industrial and utility customers for handling tests and short-term test burns.

Commercial Applications:

Western Energy's advanced coal conversion process has the potential to enhance the use of low-rank western subbituminous and lignite coals. Many of the power plants located throughout the upper midwest have cyclone boilers, which burn low-ash-fusion-temperature coals. Presently, most of these plants burn Illinois Basin high-sulfur coal. SynCoal™ would be an ideal low-sulfur coal substitute for these and other plants, because it will allow operation under more restrictive emissions guidelines without requiring derating of the units or the addition of costly flue gas desulfurization systems. The advanced coal conversion process will produce SynCoal™ which has a very low sulfur content, high heating value, and stable physical/chemical characteristics; it could have significant impact on SO_2 reduction. Western Energy's process, therefore, will be attractive to utilities because the upgraded fuel will be less costly to use than would the construction and use of flue gas desulfurization equipment. This will allow plants that would otherwise be closed to remain in operation.

On December 20, 1993, Rosebud SynCoal Partnership announced the signing of a letter of intent with Minnkota Power Cooperative to prepare a $2-million study to examine the merits of scaling up the coal processing technology to an $80-million commercial plant. If results are positive a commercial plant could be in place by 1996.

ENCOAL Mild Coal Gasification Project

Sponsor:

ENCOAL Corporation (a subsidiary of SMC Mining Company)

Additional Team Members:

SMC Mining Company—cofunder

TEK-KOL (partnership between SMC Mining Company and SGI International)—technology owner, supplier, and licenser

SGI International—technology developer

Triton Coal Company (subsidiary of SMC Mining Company)—host facility and coal supplier

The M.W. Kellogg Company—engineer and constructor

Location:

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

Technology:

SGI International's liquids from coal process (coal preparation for clean fuels/mild gasification)

Plant Capacity/Production:

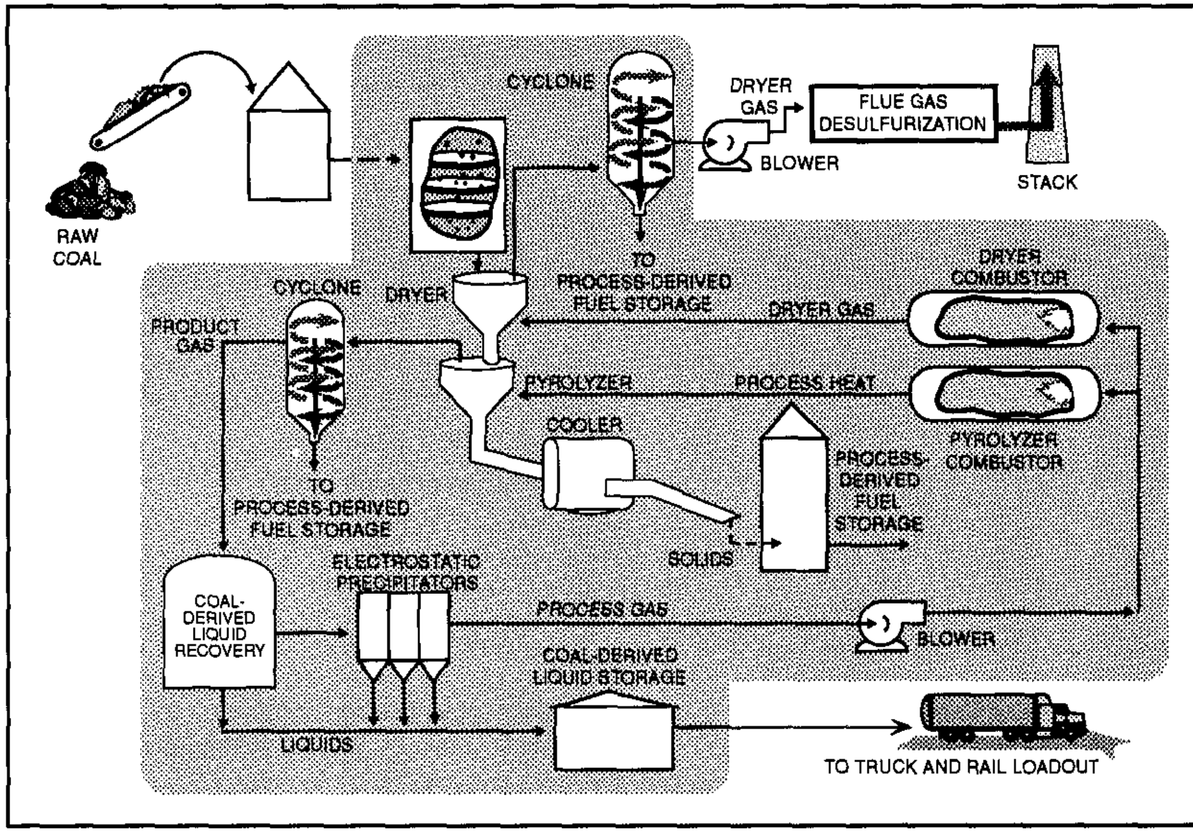
1,000 tons/day of subbituminous coal feed

Project Funding:

Total project cost	$72,564,000	100%
DOE	36,282,000	50
Participants	36,282,000	50

Project Objective:

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



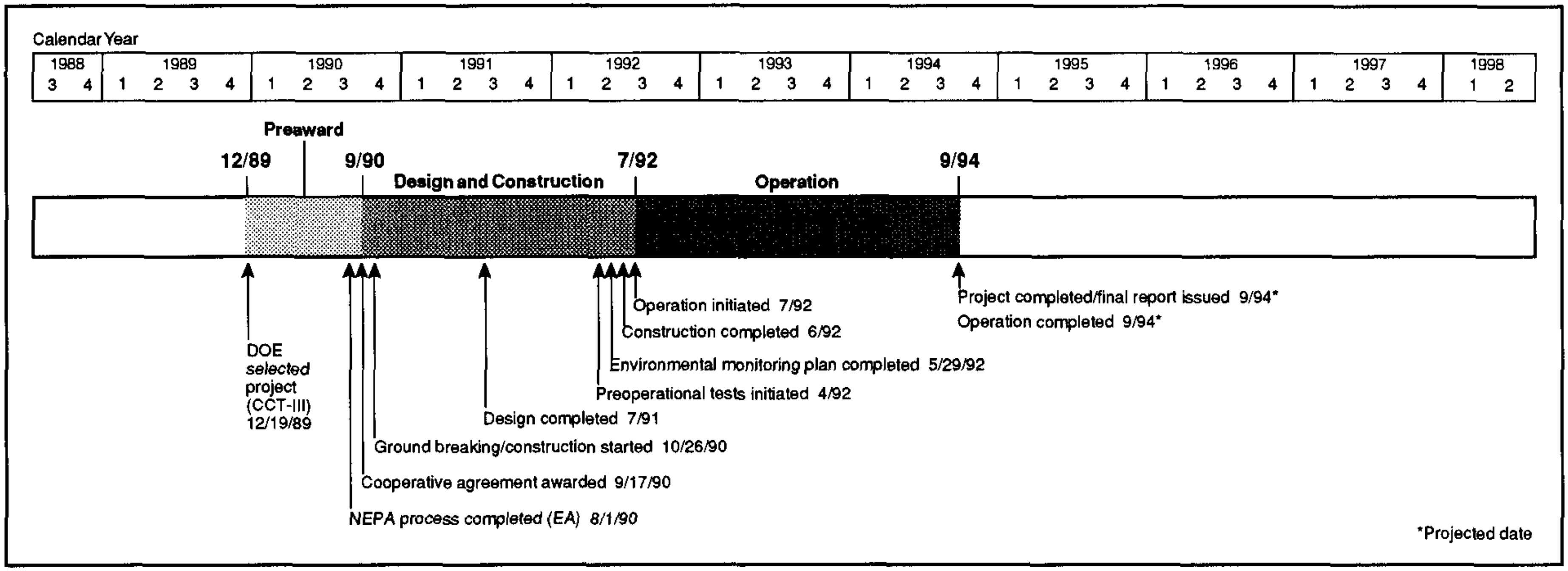
Technology/Project Description:

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

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

The offgas from the dryer is treated in a wet venturi scrubber to remove particulates and a horizontal scrubber to remove SO_2, both using a sodium carbonate solution. The treated gas is vented to a stack, and the spent solution is discharged into a pond for evaporation.

The ENCOAL project is located within Campbell County, WY, at Triton Coal Company's Buckskin Mine, 10 miles north of Gillette. The plant makes use of the



present coal-handling facilities at the mine. Subbituminous coal having sulfur content of 0.4–0.9% is being used.

Project Status/Accomplishments:

Operation continued during 1993. Fifteen runs have been conducted to date, logging more than 1,400 hours of operation. A major milestone was achieved in April 1993 when the plant completed a 16-day run. The run confirmed that the plant had been able to overcome several mechanical problems that had previously prevented sustained operations beyond 7 days. During the run, more than 5,000 tons of low-rank Powder River Basin coal were processed, yielding more than 125,000 gallons of high-quality liquid fuel and several thousand tons of clean solid product.

ENCOAL operators logged another milestone run in June 1993, this one 12 days in duration. The plant reached 100% of design capacity for a short period during the run, which ended in a planned shutdown. On June 15, the plant was shut down to enable a major modification which incorporates a new step in the overall solids-cooling system to continuously produce a solid product sufficiently stable for long-distance shipping. Operations are expected to resume in January 1994.

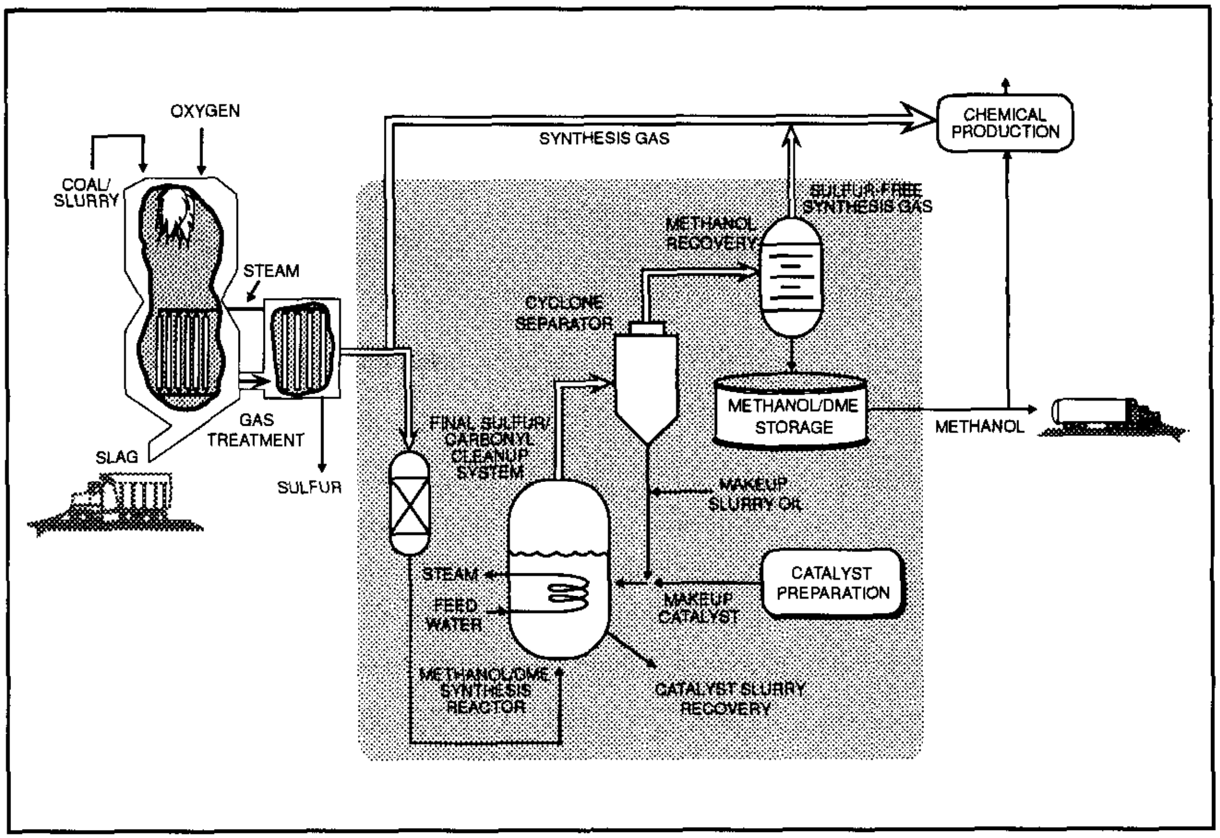
The ENCOAL plant continued to attract a large number of international visitors, especially from Pacific Rim countries, interested in using the technology or in purchasing fuel products. Among these was the Indonesian ambassador to the United States who visited the plant in June. On the domestic front, commercial contracts are in place for the first customers of its products. A Wisconsin utility will buy 30,000 tons of the solid product and TEXPAR Energy Inc., of Waukesha, WI, will buy up to 135,000 barrels of the liquid product. Further, ENCOAL announced in November an agreement with Dakota Gasification Company to burn up to 250,000 barrels of product liquid at the Great Plains Synfuel Plant at Beulah, ND.

Commercial Applications:

The liquid products from mild coal gasification can be used in existing markets in place of No. 6 fuel oil. The solid product can be used in most industrial or utility boilers. The feedstock for mild gasification facilities is being limited to high-moisture, low-heating-value coals.

The potential benefits of this mild gasification technology in its commercial configuration are attributable to the increased heating value (about 12,000 Btu/lb) and lower sulfur content (per unit of fuel value) of the new solid-fuel product compared to the low-rank coal feedstock, and the production of low-sulfur liquid products requiring no further treatment for the fuel oil market. The product fuels are expected to be used economically in commercial boilers and furnaces and to reduce significantly SO_2 emissions at industrial and utility facilities currently burning high-sulfur bituminous coals or fuel oils.

Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process



Sponsor:
Air Products and Chemicals, Inc.

Additional Team Members:
Acurex Environmental Corporation—fuel methanol testing and cofunder

Eastman Chemical Company—host site and cofunder

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

Technology:
Air Products and Chemicals' liquid-phase methanol (LPMEOH™) process (coal processing for clean fuels/ indirect liquefaction)

Plant Capacity/Production:
200 tons/day of methanol

Project Funding:

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

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

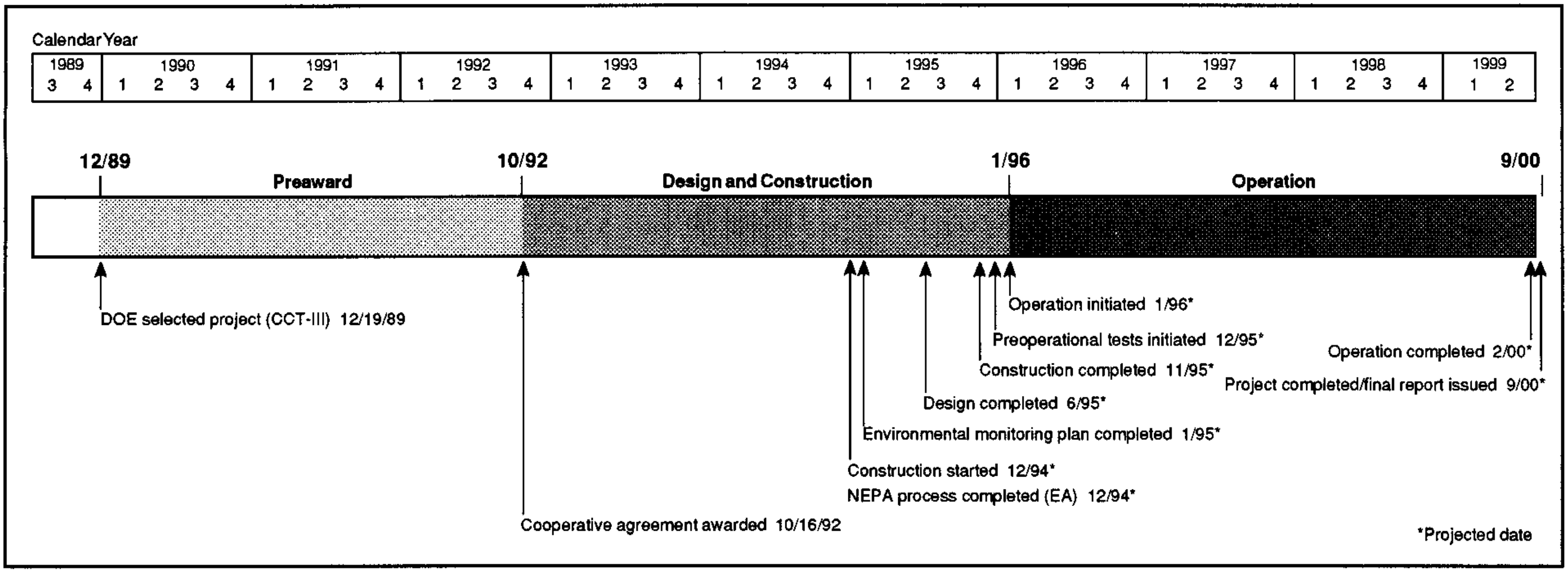
LPMEOH is a trademark of Air Products and Chemicals, Inc.

Technology/Project Description:
This project is demonstrating the LPMEOH™ process to produce methanol from coal-derived synthesis gas on a commercial scale. The combined reactor and heat removal system is different from other commercial methanol processes. The liquid phase not only supports the catalyst but functions as an efficient means to remove the heat of reaction away from the catalyst surface. This feature permits the direct use of synthesis gas streams as feed to the reactor without the need for shift conversion.

The performance of the LPMEOH™ process for the synthesis of methanol is characterized as follows:

- Carbon monoxide conversion to methanol—13% per reactor per pass in a hydrogen-rich feed
- Methanol productivity comparable to gas-phase systems—6,000 lbs of methanol per 1 lb of catalyst
- Raw methanol purity—97.5%
- Feed gas flexibility—permits the synthesis gas produced by any commercial coal gasification system to be used without shift conversion

The Eastman Chemical Company's integrated coal gasification facility at Kingsport, TN, has operated commercially since 1983. At this site, it will be possible to ramp up and down to demonstrate the unique load-following flexibility of the LPMEOH™ unit for application to coal-based electric power generation facilities. Methanol fuel testing will be conducted in both on- and off-site stationary and mobile applications, such as boilers,



buses, and van pools. The operation at Kingsport also includes the planned production of DME as a mixed coproduct with methanol for demonstration as storable fuel.

Project Status/Accomplishments:

The cooperative agreement was modified in October 1993 to recognize a change in the host site from the Cool Water Gasification Facility in Daggett, CA, to Eastman Chemical Company's Integrated Coal Gasification Facility in Kingsport, TN. The host-site change became necessary when the project sponsors determined that restarting the mothballed Cool Water facility—a demonstration coal-gasification combined-cycle power plant—was not economically feasible.

The participants are initiating project definition activities and developing the relevant environmental information needed for the NEPA process. The Eastman Chemical site offers the advantage of using existing, operating coal gasifiers which will require little, if any, modification to support the LPMEOH™ demonstration.

Commercial Applications:

The LPMEOH™ process has been developed to enhance integrated gasification combined-cycle (IGCC) power generation by producing a clean burning, storable liquid fuel—methanol—from the clean coal-derived gas. Methanol also has a broad range of commercial applications. Methanol can be substituted for conventional fuels in stationary and mobile combustion applications. Methanol is an excellent fuel for peak power production. Methanol contains no sulfur and has exceptionally low-NO_x characteristics when burned. Methanol can be produced from coal as a co-product in an IGCC facility.

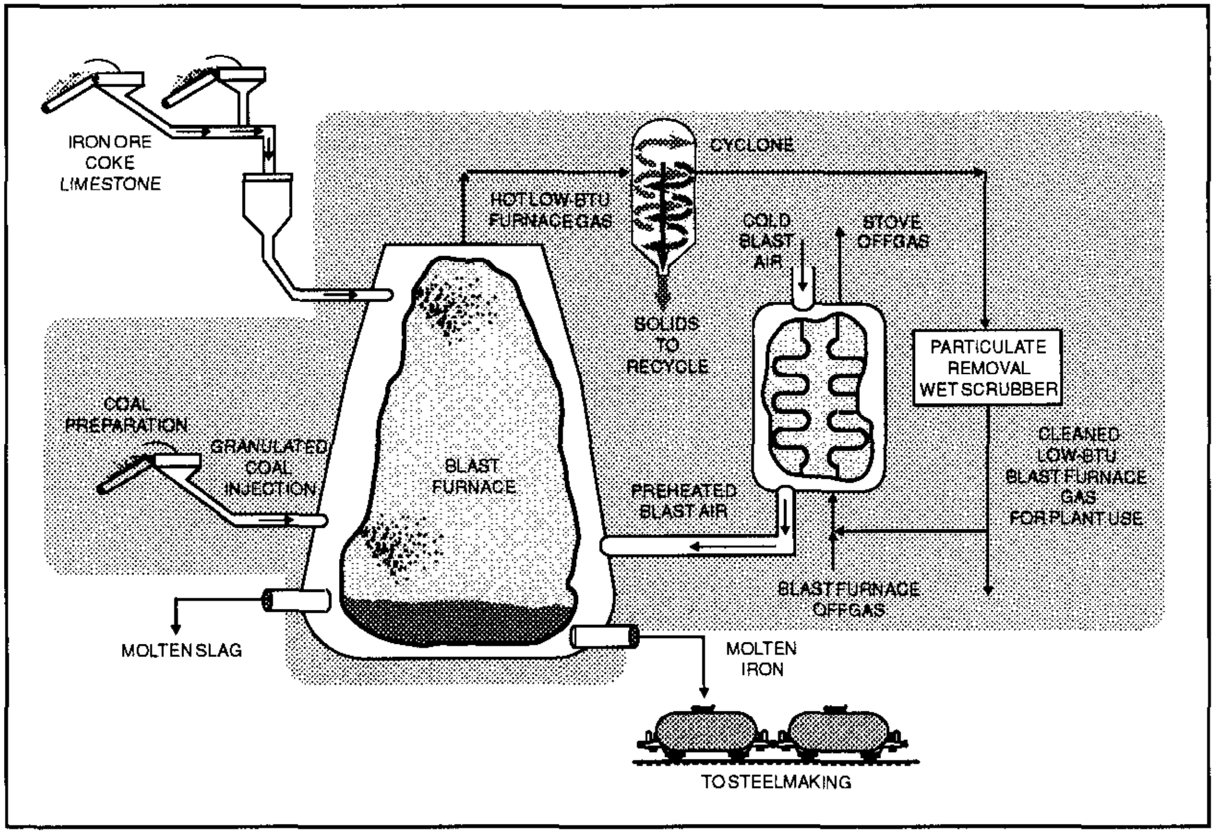
Among the cleanest coal technologies for generating electric power, IGCC can economically satisfy the most stringent environmental limits for SO_2 and NO_x. About 99% of the sulfur can be removed in the manufacturing process and converted into salable elemental sulfur or sulfuric acid. The solid waste from the gasifier is an inert, granular slag which can be used as an aggregate for road and building materials.

DME has several commercial uses. In a storable blend with methanol, the mixture can be used as peaking fuel in IGCC electric power generating facilities. DME can also be used to increase the vapor pressure of a methanol blend. The resulting higher volatility is expected to provide beneficial "cold start" properties to methanol being used as a diesel engine fuel. Blends of methanol and DME can also be used as a chemical feedstock for the synthesis of chemicals or new, oxygenate fuel additives. Pure DME has been gaining acceptance as an environmentally friendly aerosol in personal products.

Typical commercial-scale LPMEOH™ units are expected to range in size from 150 to 1,000 tons/day of methanol produced when associated with commercial IGCC power generation trains of 200–350 MWe. Air Products and Chemicals expects to market the LPMEOH™ technology through licensing, owning/operating, and tolling arrangements.

Industrial Applications
Fact Sheets

Blast Furnace Granulated-Coal Injection System Demonstration Project



Sponsor:

Bethlehem Steel Corporation

Additional Team Members:

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

Simon-Macawber, Ltd.—equipment supplier

Fluor Daniel, Inc.—architect and engineer

ATSI, Inc.—injection equipment engineer (U.S. technology licensee)

Location:

Burns Harbor, Porter County, IN (Bethlehem Steel's Burns Harbor Plant, Blast Furnace Units C and D)

Technology:

British Steel's blast furnace granulated-coal injection (BFGCI) process (industrial applications)

Plant Capacity/Production:

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

Project Funding:

Total project cost	$191,700,000	100%
DOE	31,259,530	16
Participants	160,440,470	84

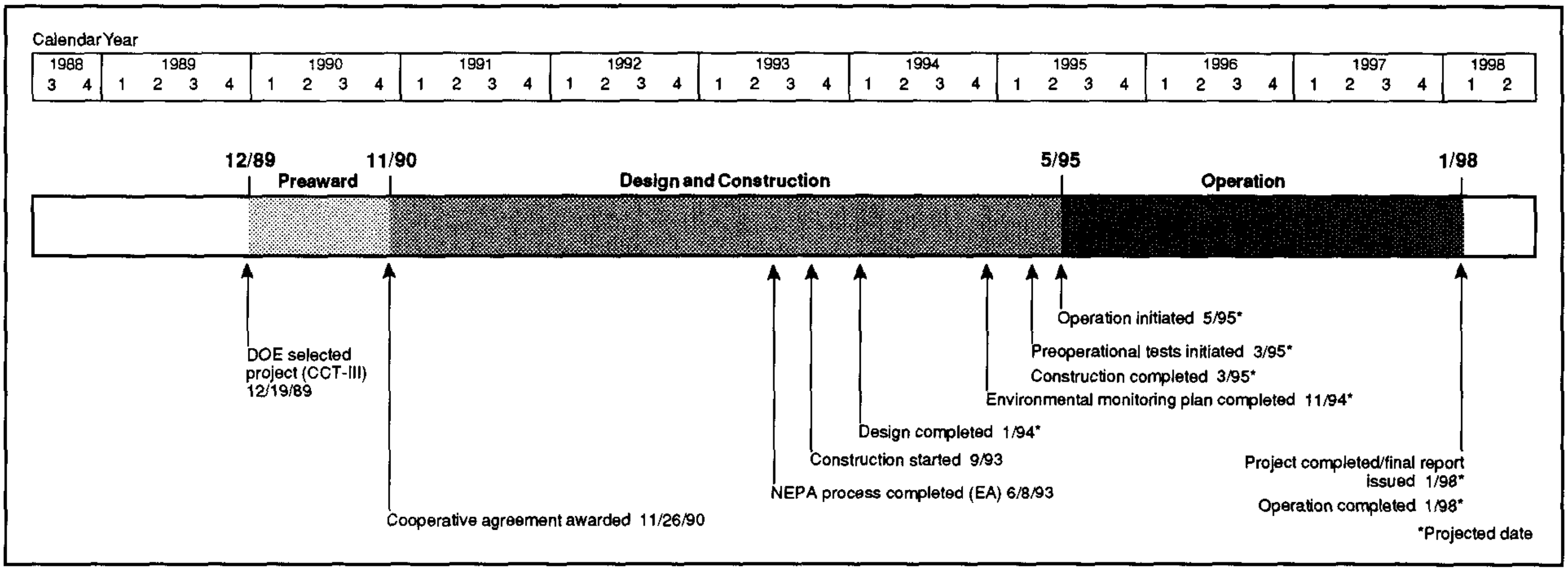
Project Objective:

To demonstrate that existing iron-making blast furnaces can be retrofitted with blast furnace granulated-coal injection technology; and to demonstrate sustained operation with a variety of coal particle sizes, coal injection rates, and coal types, and to assess the interactive nature of these parameters.

Technology/Project Description:

In the BFGCI process, both granulated and pulverized coal is injected into the blast furnace in place of natural gas (or oil) as a blast furnace fuel supplement. The coal along with heated air is blown into the barrel-shaped section in the lower part of the blast furnace through passages called tuyeres, which creates swept zones in the furnace called raceways. The size of a raceway is important and is dependent upon many factors including temperature. Lowering of a raceway temperature, which can occur with gas injection, reduces blast furnace production rates. Coal, with a lower hydrogen content than either gas or oil, does not cause as severe a reduction in raceway temperatures. In addition to displacing injected natural gas, the coal injected through the tuyeres displaces coke, the primary blast furnace fuel and reductant (reducing agent), on approximately a pound-for-pound basis. Because coke production results in significant emissions of NO_x, SO_2, and air toxics and coal could replace up to 40% of the coke requirement, BFGCI technology has significant potential to reduce emissions and enhance blast furnace production.

Emissions generated by the blast furnace itself remain virtually unchanged by the injected coal; the gas exiting the blast furnace is clean, containing no measurable SO_2 or NO_x. Sulfur from the coal is removed by the limestone flux and bound up in the slag, which is a salable by-product. In addition to the net emissions reduction realized by coke displacement, blast furnace production is increased by maintaining high raceway temperatures.



Two high-capacity blast furnaces, Units C and D at Bethlehem Steel Corporation's Burns Harbor Plant, are being retrofitted with BFGCI technology. Each unit has a production capacity of 7,000 net tons/day of hot metal. The two units will use about 2,800 tons/day of coal during full operation. Bituminous coals with sulfur content ranging from 0.8% to 2.8% from West Virginia, Pennsylvania, Illinois, and Kentucky are to be used. A western subbituminous coal having 0.4–0.9% sulfur might be tested also.

Project Status/Accomplishments:

Bethlehem Steel has signed a turnkey contract with Fluor Daniel, Inc., of Greenville, SC, for the project's engineering, procurement, and construction. Project design continued throughout the year and by December 1993 was approximately 90% complete.

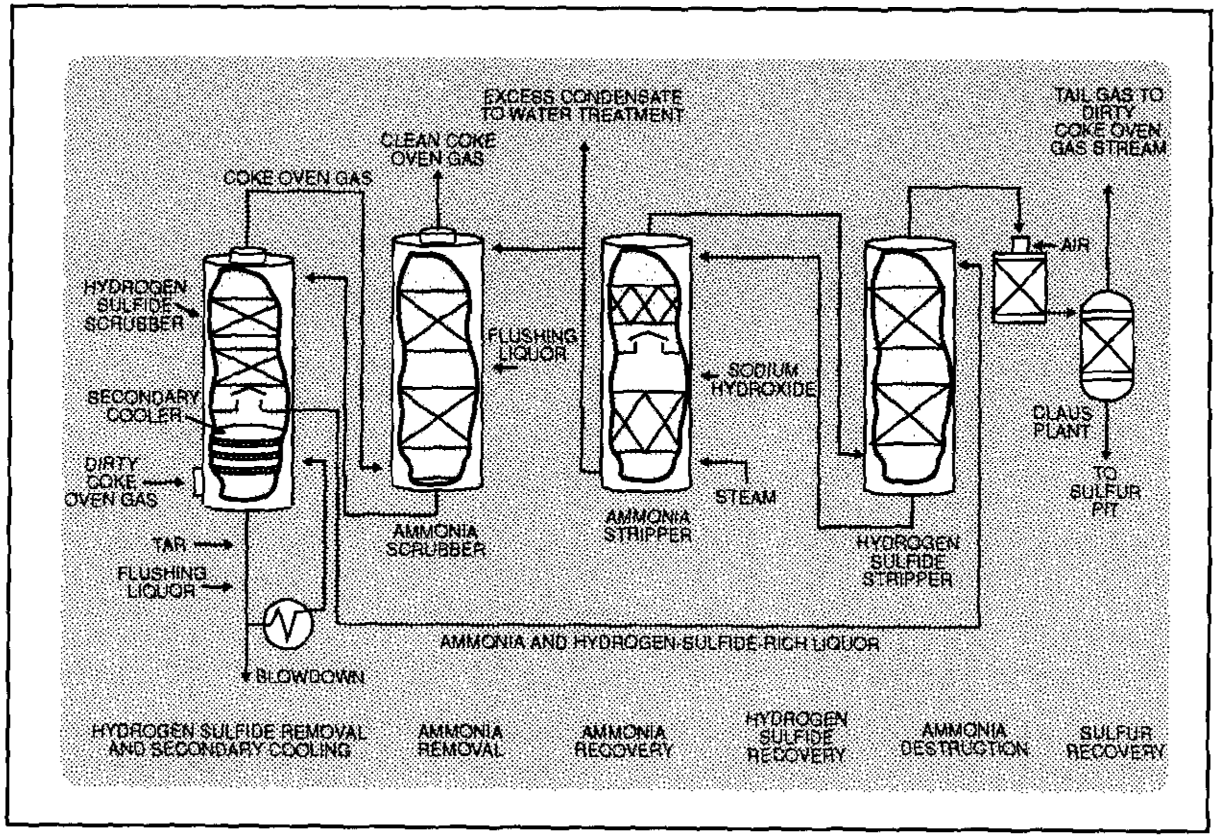
An environmental assessment with a finding of no significant impact was approved in June 1993, completing the NEPA process. With receipt of a construction permit from the state of Indiana also in June, site work was initiated. By the end of the year, excavation work was completed, the pouring of foundations was well under way, and erection of structural steel was beginning.

Facilities being constructed include those needed to prepare the coal, to deliver the prepared coal to the two blast furnaces, and to inject it into the furnaces. In addition, the blast furnaces will be modified to accept the prepared coal. The necessary modifications to furnace D will be made on-the-fly through a series of short outages on the operating furnace. Furnace C will be modified during a reline scheduled for third quarter 1994.

Commercial Applications:

BFGCI technology can be applied to essentially all U.S. blast furnaces. The technology should be applicable to any rank coal commercially available in the United States. The environmental impacts of commercial application are primarily indirect and consist of a significant reduction of emissions resulting from diminished coke-making requirements.

Innovative Coke Oven Gas Cleaning System for Retrofit Applications



Sponsor:
Bethlehem Steel Corporation

Additional Team Member:
Still-Otto—*technology developer*

Location:
Sparrows Point, Baltimore County, MD (Bethlehem Steel Corporation's Sparrows Point Plant, Coke Oven Batteries A, 11, and 12)

Technology:
Still-Otto's process for precombustion cleaning of coke oven gas (COG) (industrial applications)

Plant Capacity/Production:
74 million std ft^3/day of COG

Project Funding:

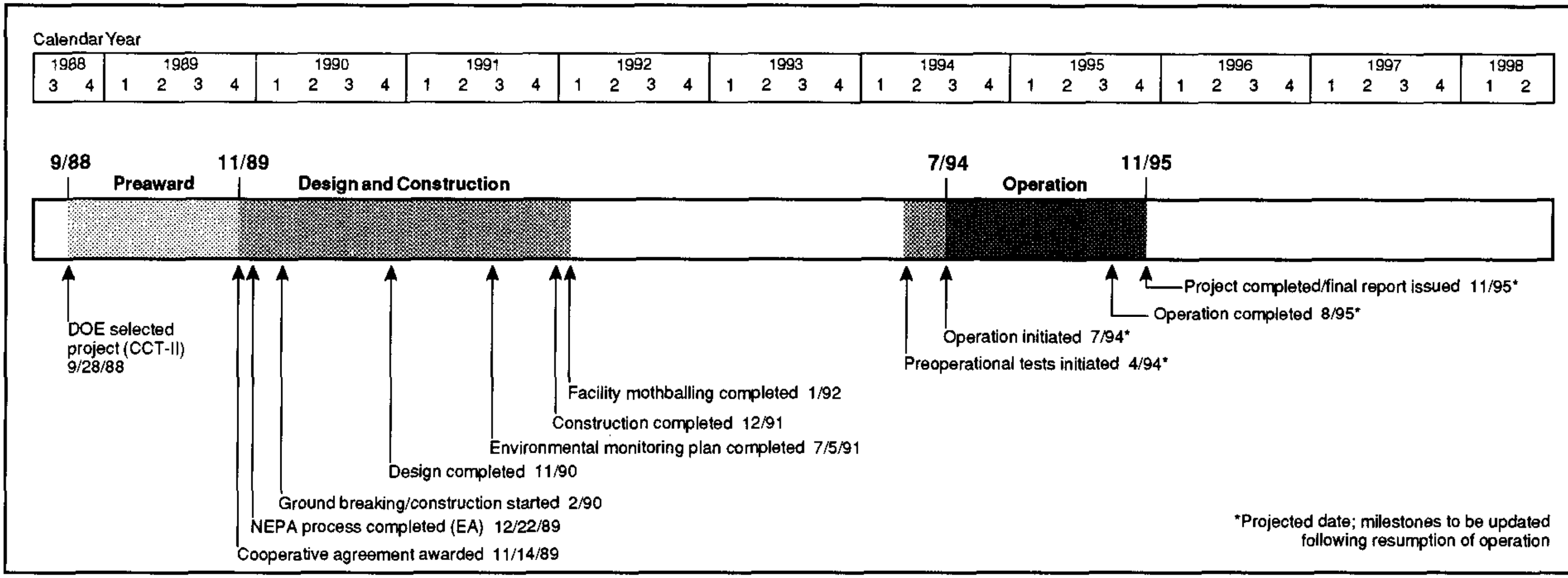
Total project cost	$45,239,781	100%
DOE	13,500,000	30
Participant	31,739,781	70

Project Objective:
To demonstrate a first-of-a-kind novel integration of commercially available process steps for simultaneous removal of hydrogen sulfide and ammonia from COG, recovery of hydrogen sulfide and ammonia, destruction of ammonia, and recovery of sulfur in a commercial-sized application; and to reduce SO_2 emissions by at least 80% accompanied by substantially reduced emissions of volatile organic compounds and discharge of ammonia to wastewater treatment.

Technology/Project Description:
This project is demonstrating an innovative technology developed by Still-Otto for removing hydrogen sulfide and ammonia from COG. The process uses contaminated water produced in the coke oven batteries to absorb the hydrogen sulfide and ammonia contained in the COG. Both hydrogen sulfide and ammonia are steam stripped from the absorption liquor. The ammonia is destroyed in a catalytic reactor; hydrogen sulfide is converted to elemental sulfur in a conventional Claus plant, and sulfur is recovered as a salable by-product.

The technology is expected to reduce the hydrogen sulfide concentration in the cleaned COG by 88% and the ammonia concentration by approximately 99%. Because the reagents used are indigenous in COG, costs associated with the purchase and handling of feed reagents, the handling and treatment of by-products, labor, and utilities are reduced.

This project involves the modification of the COG processing units at Bethlehem Steel's Sparrows Point Plant in Baltimore County, MD. The demonstration facility is designed to process the entire COG stream from Coke Oven Batteries A, 11, and 12, which amounts to74 million std ft^3/day. These coke oven batteries have the capability to produce up to 1.2 million tons/yr of coke from a blend of Pennsylvania and Virginia coals having sulfur contents ranging from 0.8% to 1.37%. The raw COG has a hydrogen sulfide content of 175–340 grains/100 ft^3. Currently, only 60% of this COG stream is desulfurized. The remaining 40% is used directly for fueling the fire under the coke ovens.



Project Status/Accomplishments:

On September 16, 1991, Bethlehem Steel Corporation announced that all coke production will be suspended at its Sparrows Point facility for at least 2 years. This decision was made due to the rapid deterioration of the coke ovens. During this period, an evaluation will be made to explore alternatives for resumption of coke production. Bethlehem Steel's intent is for long-term coke independence at the facility.

Construction of the coke oven gas cleaning demonstration facility is complete, and the unit has been mothballed to maintain it in good shape so that hot commissioning, start-up, and operation can be accomplished successfully when coke-making operations are resumed.

Given the high background levels of contaminants present in the coke oven batteries, specific air toxics monitoring is not contemplated at this time. Baseline environmental sampling is complete.

Commercial Applications:

The design for this innovative COG cleaning system is based on operating data that have been collected from individual process steps or combinations of individual process steps that have been successfully operated at commercial-sized COG treatment facilities. The novel integration of commercially available process steps is expected to reduce the overall cost of desulfurization, ensure reliable operation in applications exceeding 20 years, and provide a viable alternative to conventional technologies. Because the demonstration is designed to treat 74 million std ft^3/day of COG (a commercial size), the project will demonstrate that it is possible to retrofit any existing coke-making facility in the United States with essentially no scaleup involved and without significant downtime.

Bethlehem Steel will license the use of this COG-cleaning technology through Still-Otto to the existing 30 coke oven plants in the United States which emit about 300,000 tons/yr of SO_2. This COG-cleaning process could be applicable to 24 plants with corresponding SO_2 emission levels of 200,000 tons/yr. If the technology were installed in all 24 plants, the SO_2 emissions could be reduced by 160,000 tons/yr. Eliminated would be the ammonium sulfate which is difficult to market and usually is disposed of as a solid waste. Every 5–8 years, 5 tons of spent nickel catalyst would need to be returned to the vendor or disposed of as a hazardous waste, and 10 tons of spent alumina catalyst would need to be disposed of as a nonhazardous solid waste. Depending on the configuration of the coke oven facility where the technology is being implemented, the amount of water needed for cooling purposes would remain the same or be reduced, and the amount of pollutants in the wastewater would remain the same or be reduced.

Clean Power from Integrated Coal/Ore Reduction (COREX®)

Sponsor:
Centerior Energy Corporation

Additional Team Members:
LTV Steel Company—site owner; constructor and operator of COREX® unit

Air Products and Chemicals, Inc.—designer, engineer, constructor, and operator of air separation and combined-cycle units

Deutsche Voest-Alpine Industrieanlagenbau GmbH—COREX® developer/supplier; designer and engineer of COREX® unit

Electric Power Research Institute—cofunder

Ohio Coal Development Office—cofunder

Location:
Cleveland, Cuyahoga County, OH (LTV Steel Company's Cleveland Works)

Technology:
Integration of Deutsche Voest-Alpine Industrieanlagenbau's COREX® iron-making process with a combined-cycle power generation system (industrial applications)

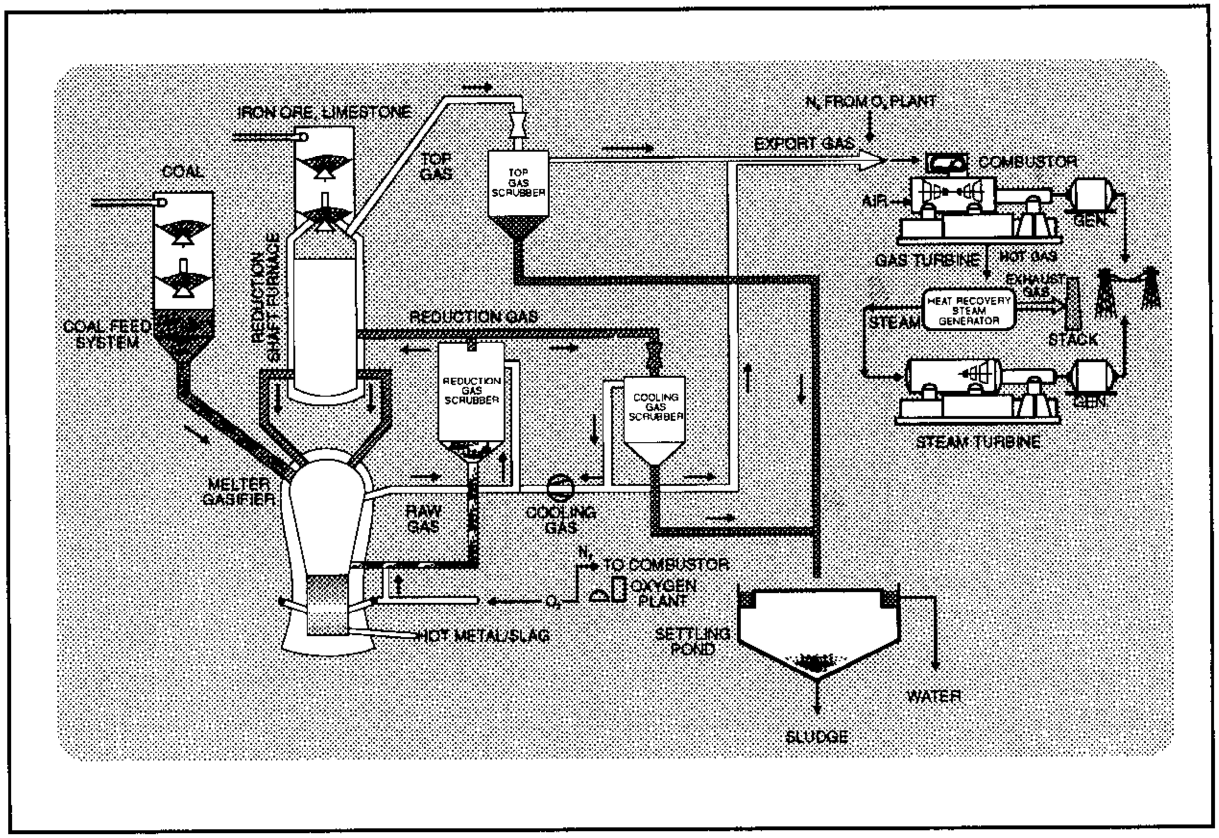
Plant Capacity/Production:
150 MWe (net) and 3,200 tons/day of hot metal (liquid iron)

Project Funding:

Total project cost	$825,092,000	100%
DOE	150,000,000	18
Participants	675,092,000	82

(Funding amounts reflect those contained in the proposal and are subject to negotiation.)

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



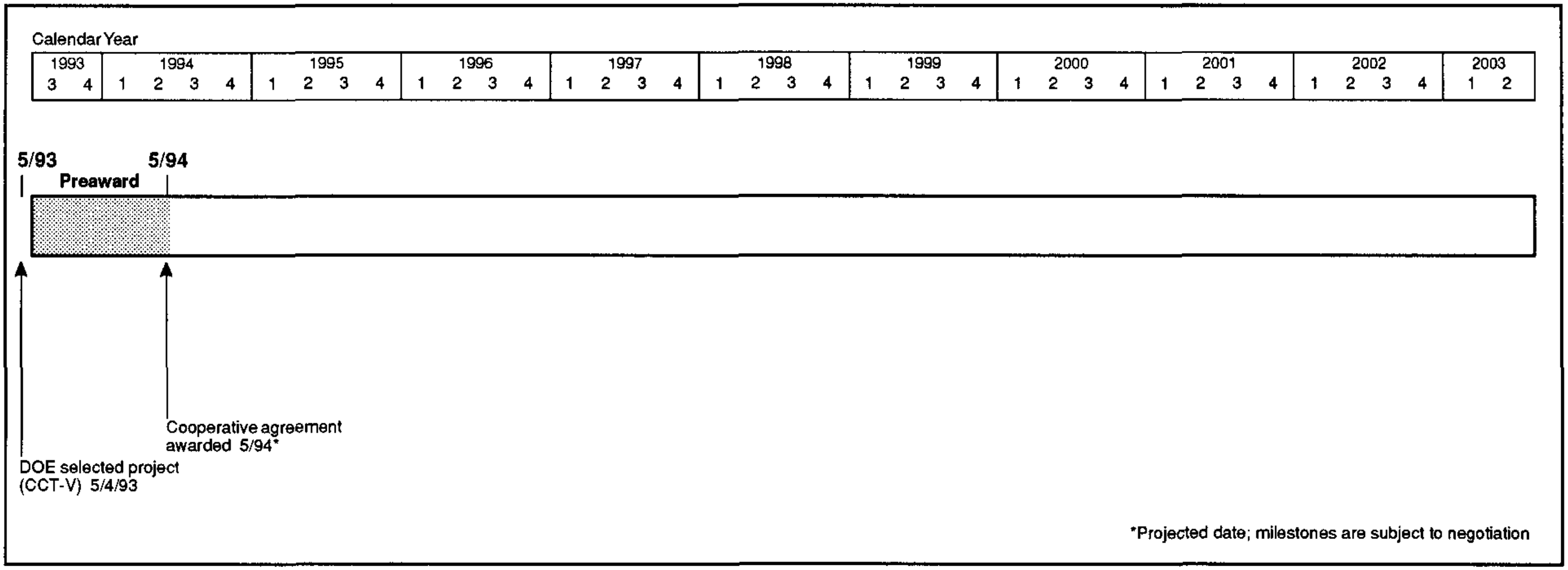
Project Objective:
To demonstrate the integration of a direct iron-making process (COREX®) with the production of electricity using various U.S. coals in an efficient and environmentally responsible manner.

Technology/Project Description:
The clean power from integrated coal/ore reduction (CPICOR) process integrates two historically distinct processes—iron-making and electric power generation. COREX® is a novel iron-making technology which eliminates the need for coke production. The key innovative features of the COREX® process include the reduction shaft furnace, which is used to reduce the iron ore to iron, and the melter-gasifier, located beneath the reduction furnace, which gasifies the coal and melts the iron. The gasification process generates the reducing gas for use in the reduction furnace as well as sufficient heat to melt the resulting iron in the melter-gasifier.

Excess reducing gas exiting the reduction furnace is cooled, cleaned, compressed, mixed with air and nitrogen, and burned in a gas turbine generator system capable of combusting low-Btu fuel gas. The hot exhaust from the turbine is then delivered to a heat recovery steam generator where process steam is made for utilization in a steam turbine generator system to produce additional electric power.

During the demonstration, about 2,800 tons/day of coal will be gasified to produce 3,200 tons/day of hot metal and 150 MWe for sale.

CPICOR technology is less complex and environmentally superior when compared to competing



iron-making and power-generating technologies. All criteria air pollutants are reduced by more than 85% due largely to (1) the inherent desulfurizing capability of the COREX® process wherein the limestone fed to the reduction furnace captures the sulfur present in the coal and (2) the efficient control systems within the combined-cycle power generation process. Because coke is not used, coke plants and their associated pollutants can be eliminated.

The energy efficiency of the CPICOR process is over 35% greater than competing commercial technology. This efficiency advantage is gained by more effective use of both the sensible heat in the process and the volatile matter in the coal, as well as by incorporation of the combined-cycle power generation system.

The technology is being demonstrated at LTV Steel Company's Cleveland Works in Cleveland, OH.

Project Status/Accomplishments:

The project is in negotiation.

Commercial Applications:

The CPICOR technology is a direct replacement for existing blast furnace and coke-making capacity with the additional benefit of combined-cycle power generation. A full-scale commercial plant based on the CPICOR demonstration project will produce nearly 200 MWe (net exportable) and 1,200,000 tons/yr of hot metal while expanding the type of coals that can be used to produce hot metal into the much larger non-coking range.

The total emissions of NO_x from the commercial plant are expected to be 0.012 lb/million Btu, which is a reduction of more than 97% from the combination of a comparably sized blast furnace, associated coke-making facilities, and a comparably sized pulverized coal power plant with flue gas desulfurization. Similarly, the total emissions of SO_2 from the commercial facility are expected to be 0.0244 lb/million Btu, a reduction of more than 90%. The net electrical generating efficiency of the commercial facility will be 47.2% (a net effective heat rate of 7,232 Btu/kWh on an LHV basis). This is to be compared to a net efficiency of 29.1% for comparably sized conventional facilities.

Overall, a CPICOR commercial plant would produce minimal solid or liquid impacts to the environment, especially when compared to existing competing facilities. All solid wastes are expected to be exempt from the Resource Conservation and Recovery Act requirements. The majority of solid wastes are beneficially reused, which increases the economic benefit of the technology and avoids burdening landfills. Most of the solid waste is slag from the iron-making process, which is reusable as ballast for road construction and foundations.

Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control

Project completed.

Sponsor:
Coal Tech Corporation

Additional Team Members:
Commonwealth of Pennsylvania Energy Development Authority—cofunder

Pennsylvania Power and Light Company—supplier of test coals

Tampella Power Corporation—host site

Location:
Williamsport, Lycoming County, PA (Tampella Power Corporation boiler manufacturing plant)

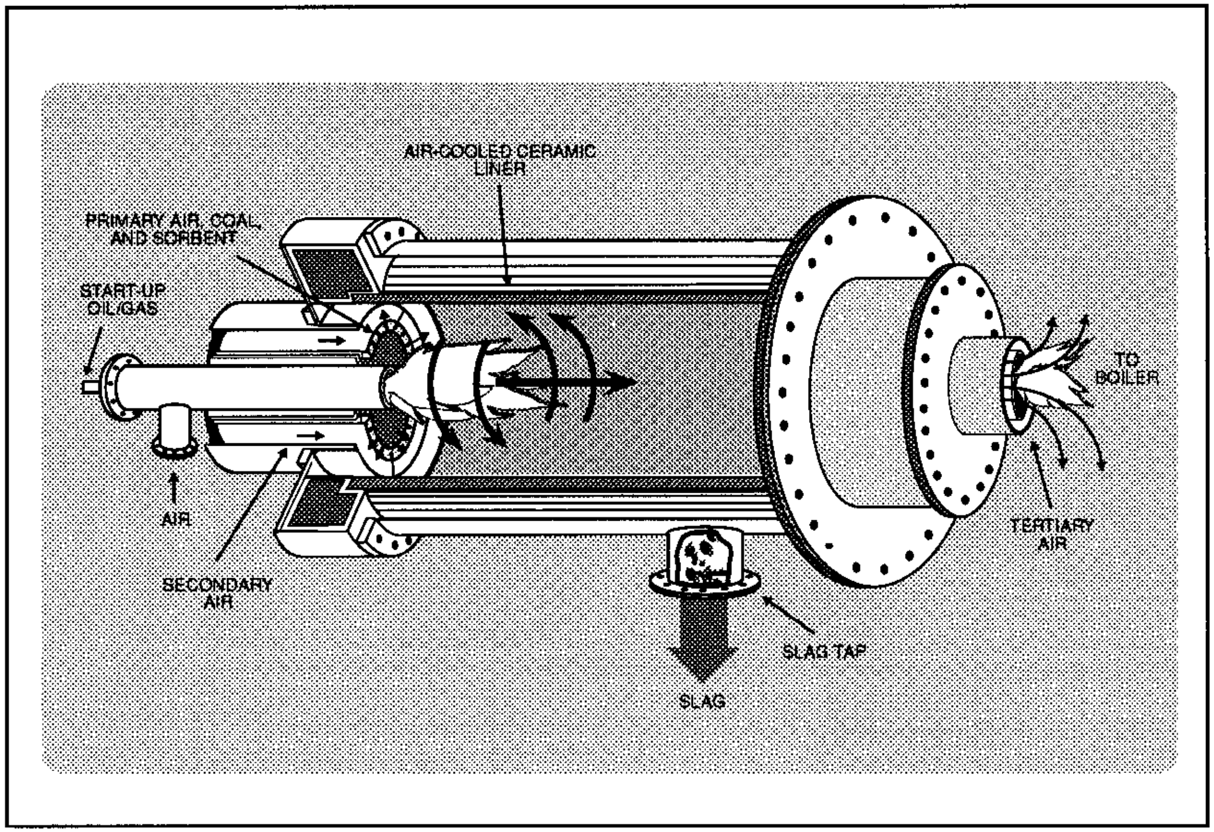
Technology:
Coal Tech's advanced, air-cooled, slagging combustor (industrial applications)

Plant Capacity/Production:
23 million Btu/hr

Project Funding:

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

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



Technology/Project Description:
Coal Tech's horizontal cyclone combustor is internally lined with ceramic that is air-cooled. Pulverized coal, air, and sorbent are injected tangentially toward the wall through tubes in the annular region of the combustor to cause cyclonic action. In this manner, coal-particle combustion takes place in a swirling flame in a region favorable to particle retention in the combustor. Secondary air is used to adjust the overall combustor stoichiometry. The ceramic liner is cooled by the secondary air and maintained at a temperature high enough to keep the slag in a liquid, free-flowing state. The secondary air is preheated by the combustor walls to attain efficient combustion of the coal particles in the fuel-rich cumbustor. Fine coal pulverization allows combustion of most of the coal particles near the cyclone wall, with the balance burned on or near the wall. This improves combustion in the fuel-rich chamber, as well as slag retention. The slag contains over 80% of the ash and sorbent fed to the combustor. For NO_x control, the combustor is operated fuel rich, with final combustion taking place in the boiler furnace to which the combustor is attached.

In Coal Tech's demonstration, an advanced, air-cooled, cyclone coal combustor was retrofitted to a 23-million-Btu/hr, oil-designed package boiler located at the Tampella Power Corporation boiler factory in Williamsport, PA. Air cooling in this combustor takes place in a very compact combustor which can be retrofitted to a wide range of industrial and utility boiler designs without disturbing the boiler's water-steam circuit. NO_x reduction is achieved by staged combustion, and SO_2 is captured by injection of limestone into the combustor.

The cyclonic action inside the combustor forces the coal ash and sorbent to the walls where it can be collected as liquid slag. Under optimum operating conditions, the slag contains a significant fraction of vitrified coal sulfur. Downstream sorbent injection into the boiler provides additional sulfur removal capacity.

Project Results/Accomplishments:

The test effort consisted of 800 hours of operation which included five individual tests, each of 4 days duration, plus another 100 hours of operation as part of separate ash vitrification tests. Eight Pennsylvania bituminous coals with sulfur contents ranging from 1% to 3.3% and volatile matter ranging from 19% to 37% were tested.

Under fuel-rich conditions, combustion efficiencies exceeding 99% after proper operating procedures were achieved. Turndown to 6 million Btu/hr from a peak of 19 million Btu/hr was achieved. Due to facility limits on water availability for the boiler and for cooling the combustor, the maximum heat input during the tests was around 20 million Btu/hr even though the combustor was designed for 30 million Btu/hr and the boiler was thermally rated at around 25 million Btu/hr.

Coal Tech reported the following test results:

- With fuel-rich operation of the combustor, a 75% reduction in boiler-outlet-stack NO_x was obtained, corresponding to 0.3 lb/million Btu (184 ppmv). An additional 5–10% NO_x reduction was obtained by the action of the wet particulate scrubber, resulting in atmospheric NO_x emissions as low as 0.26 lb/million Btu (160 ppmv).
- Over 80% SO_2 reduction measured at the boiler outlet stack was achieved using sorbent injection in the furnace at various calcium-to-sulfur molar ratios (Ca/S). A maximum SO_2 reduction of 58% was measured at the stack with limestone injection into the combustor at a Ca/S of 2. A maximum of 33% of the coal sulfur was retained in the dry ash removed from the combustor and furnace hearths, and a high of 11% of the coal sulfur was retained in the slag rejected through the slag tap.
- Local stack particulate emission standards were met with the wet venturi particulate scrubber.
- Total slag/sorbent retention in the combustor, under efficient combustion operating conditions, averaged 72% and ranged from 55% to 90%. Under more fuel-lean conditions, the slag retention averaged 80%. In post-CCT-project tests on flyash vitrification in the combustor, modifications to the solids injection method and increases in the slag flow rate produced substantial increases in the slag retention rate.
- All slag removed from the combustor produced trace metal leachates well below the EPA drinking water standard.
- Different sections of the combustor had different materials requirements. Suitable materials for each section were identified. Also, the test effort showed that operational procedures were closely coupled with materials durability. By implementing certain procedures, such as changing the combustor wall temperature, it was possible to replenish the combustor refractory wall thickness with slag.
- Procedures for properly operating an air-cooled combustor were developed, and the entire operating database was incorporated into a computer-controlled system for automatic combustor operation.

Commercial Applications:

Coal Tech has concluded that, while the combustor is not yet fully ready for sale with commercial guarantees, it is ready to be further scaled up for commercial applications (100 million Btu/hr), such as combustion of waste solid fuels, limited sulfur control in coal-fired boilers, and conversion of ash to slag.

Coal Tech's advanced, air-cooled, slagging combustor can use a wide range of U.S. coals and can be retrofitted to existing or new units. The target market is industrial and utlity boilers sized 20–100 million Btu/hr or more; multiple combustors can be attached to larger boilers. The near-term focus in on using the combustor in combined-cycle industrial and small utility power plants in the 10–50-MWe range. The combustor is capable of using pulverized coal, coal-water slurry, cofired pulverized coal, and refuse-derived fuels (e.g., industrial sludge and coal-mine waste).

Project Schedule:

DOE selected project (CCT-I)	7/24/86
Cooperative agreement awarded	3/20/87
NEPA process completed (MTF)	3/26/87
Environmental monitoring plan completed	9/22/87
Construction	7/87–11/87
Operational testing	11/87–5/90
Project completed	9/91

Final Reports:

Final Technical Report	8/91
DOE Assessment	5/93

Cement Kiln Flue Gas Recovery Scrubber

Project completed.

Sponsor:

Passamaquoddy Tribe

Additional Team Members:

Dragon Products Company—project manager and host
E.C. Jordan Company—engineer for overall scrubber system
HPD, Incorporated—designer and fabricator of tanks and heat exchanger
Cianbro Corporation—constructor

Location:

Thomaston, Knox County, ME (Dragon Products Company's coal-fired cement kiln)

Technology:

Passamaquoddy Technology Recovery Scrubber™ (industrial applications)

Plant Capacity/Production:

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

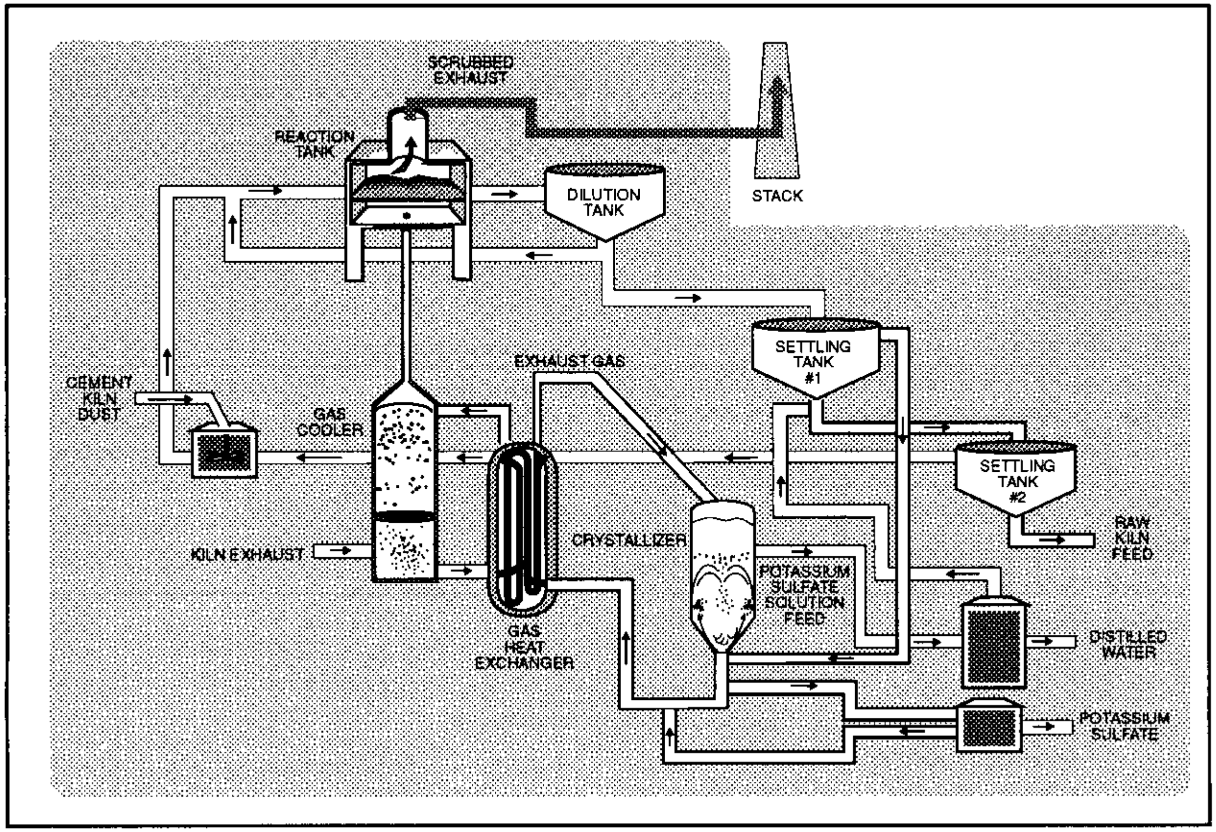
Project Funding:

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

Project Objective:

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

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



Technology/Project Description:

The Passamaquoddy Technology Recovery Scrubber™ uses a water solution/slurry containing potassium-rich dust recovered from the kiln flue gas, which serves as the scrubbing medium. No other chemicals are required for the process. After scrubbing the gas, the slurry is separated into liquid and solid fractions. The solid fraction is returned to the cement plant as renovated and usable raw feed material. The liquid fraction is passed to a crystallizer that uses waste heat in the exhaust gas to evaporate the water and recover dissolved alkali metal salts.

The Passamaquoddy Tribe's recovery scrubber was constructed at the Dragon Products Company's cement plant in Thomaston, ME, a plant that processes approximately 470,000 tons/yr of cement. The process was developed by the Passamaquoddy Indian Tribe while it was seeking ways to solve landfill problems, which resulted from the need to dispose of waste kiln dust from the cement-making process.

The kiln burns Pennsylvania bituminous coal containing approximately 3% sulfur.

Project Results/Accomplishments:

The recovery scrubber began operations in August 1991 and has continued operations with several temporary shutdowns for normal kiln repairs and maintenance and a more lengthy shutdown from January to May 1992 due to poor economic conditions in the area. In a 5-month period from May to September 1992, the plant produced approximately 140,000 tons of cement while the scrubber removed 70 tons of SO_2 and treated 6,000 tons of kiln dust for return to the kiln as raw feed. Initial testing of the scrubbing system achieved the project objective of 90–95% SO_2 emission reduction, with a maximum reduction of 98%. Operations have totaled 5,316 hours. Capital costs are approximately $10 million for a 450,000-ton/yr plant, with a simple payback estimated to be 3–4 years. Project operations continued through September 1993 when the scrubber became a permanent part of the Dragon Products facility.

Commercial Applications:

The recovery scrubber permits the use of high-sulfur coal in cement kilns using available waste dust as the reagent, without requiring the purchase of other materials as scrubber reactant.

There are over 250 cement kiln installations in the United States and along the St. Lawrence River in Canada emitting approximately 230,000 tons/yr of SO_2. Based upon the characteristics of the technology, the applicable market would include approximately 75% of these installations. If the technology were installed in the applicable market facilities, the SO_2 emissions could be reduced by approximately 150,000 tons/yr.

The effect on NO_x emissions is being determined during the demonstration. Some reductions in NO_x emissions are expected.

Water usage might or might not increase depending on the configuration of the existing kiln facility. However, the quality of wastewater would be improved and the amount reduced because the technology produces distilled water either for sale or discharge.

The waste dust that previously would have been sent to a landfill would be recovered for recycling to the kiln and to produce by-product fertilizer. Essentially, the solid waste stream would be eliminated through recovery.

Project Schedule:

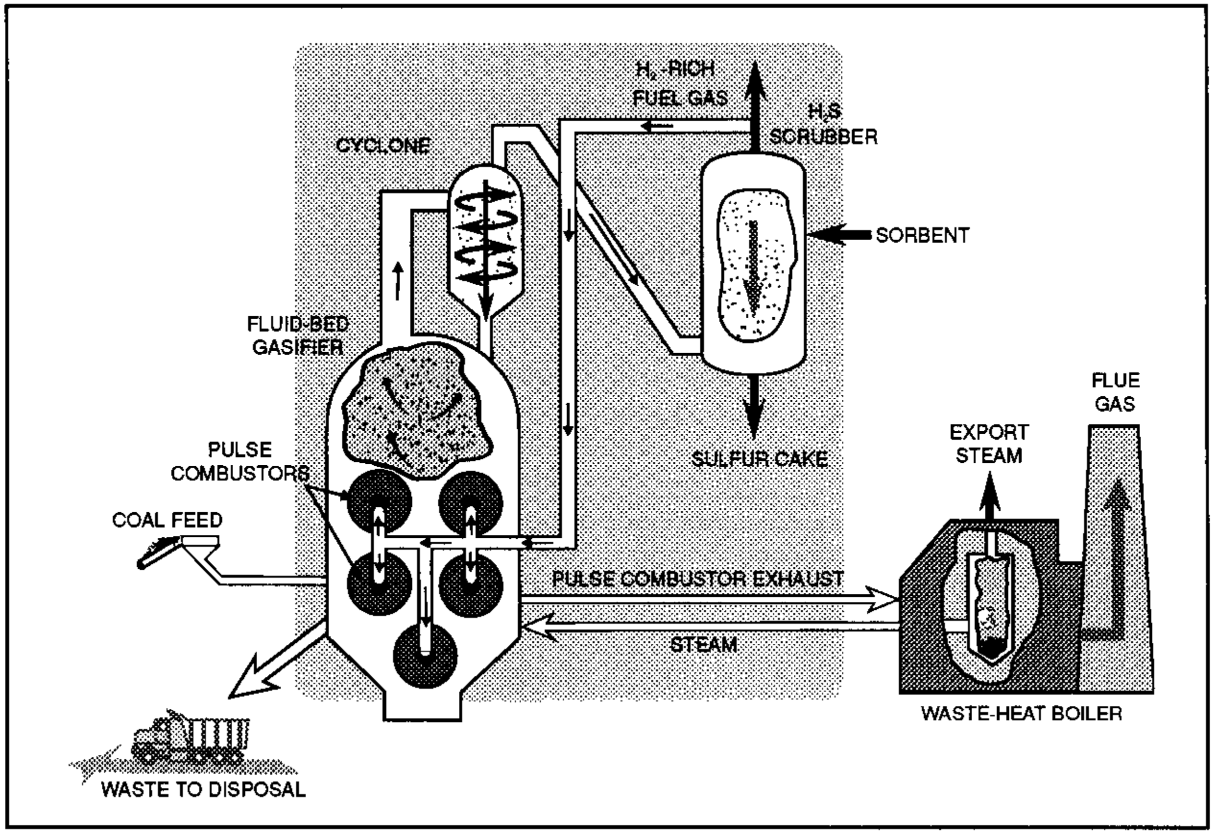
DOE selected project (CCT-II)	9/28/88
Cooperative agreement awarded	12/20/89
NEPA process completed (EA)	2/16/90
Environmental monitoring plan completed	3/26/90
Construction	4/90–5/91
Operational testing	8/91–9/93
Project completed	2/94

Final Reports:

Final Technical Report	early 1994
Topical Report	3/92
Public Design Report	10/93

An economic assessment will be conducted after project completion.

Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal



Sponsor:
ThermoChem, Inc.

Additional Team Member:
Manufacturing and Technology Conversion International, Inc.—technology supplier

Location:
Near Gillette, Campbell County, WY (Caballo Rojo Mine)

Technology:
Advanced combustion using Manufacturing and Technology Conversion International's (MTCI) pulse combustor/gasifier (industrial applications)

Plant Capacity/Production:
161 million Btu/hr of 325 Btu/std ft^3 medium-Btu fuel gas plus 40,000 lb/hr of export steam

Project Funding:

Total project cost	$37,333,474	100%
DOE	18,666,737	50
Participants	18,666,737	50

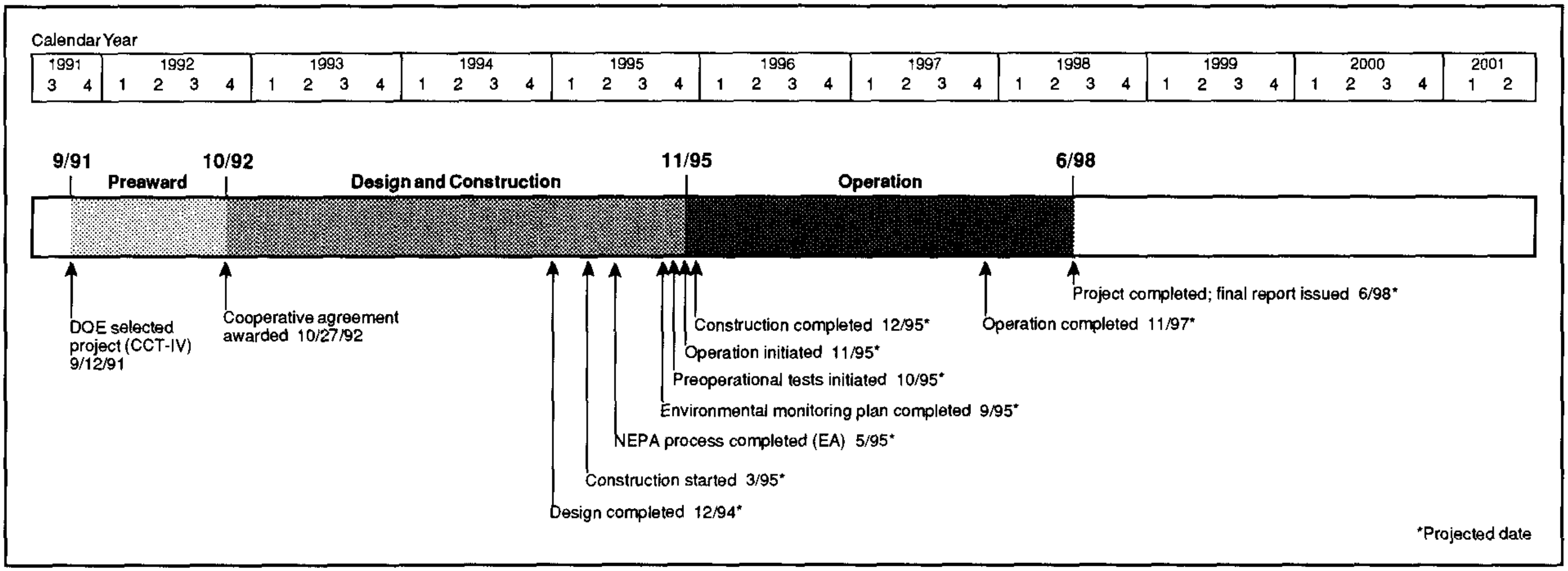
Project Objective:
To demonstrate the MTCI pulse combustor in an application for steam gasification of coal to produce a medium-Btu fuel gas from subbituminous coal.

Technology/Project Description:
The MTCI fluidized-bed gasifier incorporates an innovative indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean, medium-Btu fuel gas without the need for an oxygen plant. The indirect heat transfer is provided by MTCI's multiple resonance tube pulse combustor technology with the resonance tubes comprising the heat exchanger immersed in the fluidized-bed reactor. Heat transfer is 3–5 times greater than other indirectly heated gasifier concepts, allowing the heat transfer surface to be minimized.

The demonstration plant's overall efficiency is expected to be 72% or more. In major commercial applications, char combustion and heat recovery operations can be included to enhance overall plant efficiency.

SO_2 emissions are controlled by scrubbing the product gas using commercially available processes. A market for the by-product sulfur is being sought, and disposal methods are being evaluated.

The demonstration facility will be built at the Caballo Rojo Mine in conjunction with a new facility to demonstrate the K-Fuel coal-upgrading process. Water required to gasify the subbituminous coal will be produced by the K-Fuel process and the steam produced in the gasification demonstration facility will be used in the K-Fuel facility. The product gas will be burned in a gas turbine to generate electricity to operate both facilities.



Project Status/Accomplishments:

The cooperative agreement was awarded on October 27, 1992, and design activities are under way. Design verification tests are under way at MTCI's Baltimore facility. The design tests include the construction and test firing of one full-size pulse combustor tube bundle. Environmental information is being prepared for use in the NEPA process.

Commercial Applications:

The MTCI fluidized-bed gasifier is expected to provide the exceptional environmental performance exhibited by coal gasification in general. SO_2 emissions are controlled by removing hydrogen sulfide from the product gas prior to combustion; removal efficiencies approaching 99% are possible. Particulate emissions are also controlled in highly efficient scrubbers. Finally, the MTCI pulse combustion technology that provides the required gasifier heat is an inherently low-NO_x combustion process, thereby assuring that NO_x emissions are substantially below acceptable limits.

Because of its potential for reducing emissions while producing a clean-burning, hydrogen-rich fuel gas, the MTCI fluidized-bed gasifier is expected to have considerable commercial potential. Some of the early industrial applications of this technology are expected to be waste-to-energy or waste and coal cofired facilities for power and steam generation. One of the more promising non-coal applications is processing of kraft black liquor.

The processing of pulp results in the production of about 88 million tons of by-product black liquor. The current practice of using black liquor recovery boilers to produce steam and electricity is inefficient. Replacing these boilers with MTCI gasifiers would significantly improve the conversion efficiency. The estimated market for MTCI gasifiers in this application alone is 28 units annually.

Another potential application for the technology is in industrial coal gasification because of its modularity and ability to produce a medium-Btu gas without requiring an oxygen plant.

Appendix E: CCT Project Contacts

In this section are listed contacts for obtaining further information about specific CCT Program demonstration projects. Each listing provides the name, title, phone number, and mailing address of the contact person. In those instances where the project sponsor consists of more than one company, a partnership, or joint venture, the mailing address listed is that of the contact person.

Advanced Electric Power Generation/ Fluidized-Bed Combustion

PFBC Utility Demonstration Project

Sponsor:
The Appalachian Power Company

Contacts:
Mario Marrocco, Manager, PFBC Programs
(614) 223-1740

American Electric Power Service Corporation
1 Riverside Plaza
Columbus, OH 43215

Jeffrey Summers, DOE/HQ, (301) 903-4412
Larry K. Carpenter, METC, (304) 291-4161

PCFB Demonstration Project

Sponsor:
DMEC-1 Limited Partnership

Contacts:
Gary E. Kruempel, Project Manager
(515) 281-2459

Midwest Power Systems, Inc.
907 Walnut
P.O. Box 657
Des Moines, IA 50303

John Geffken, DOE/HQ, (301) 903-9430
Larry K. Carpenter, METC, (304) 291-4161

Four Rivers Energy Modernization Project

Sponsor:
Four Rivers Energy Partners, L.P.

Contacts:
Edward Holley, Senior Project Manager
(215) 481-8568

Air Products and Chemicals, Inc.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

George Lynch, DOE/HQ, (301) 903-9449
Larry K. Carpenter, METC, (304) 291-4161

Tidd PFBC Demonstration Project

Sponsor:
American Electric Power Service Corporation as agent for The Ohio Power Company

Contacts:
Mario Marrocco, Manager, PFBC Programs
(614) 223-1740

American Electric Power Service Corporation
1 Riverside Plaza
Columbus, OH 43215

Jeffrey Summers, DOE/HQ, (301) 903-4412
Larry K. Carpenter, METC, (304) 291-4161

Nucla CFB Demonstration Project

Sponsor:
Tri-State Generation and Transmission Association, Inc.

Contacts:
Marshall L. Pendergraff, Assistant General Manager
(303) 249-4501

Tri-State Generation and Transmission Association, Inc.
P.O. Box 1149
Montrose, CO 81402

John Geffken, DOE/HQ, (301) 903-9430
Nelson F. Rekos, METC, (304) 291-4066

York County Circulating Fluidized-Bed Cogeneration Project

Sponsor:
York County Energy Partners, L.P.

Contacts:
Bradley F. Hahn, Project Manager
(717) 225-6601

York County Energy Partners, L.P.
25 South Main Street
Spring Grove, PA 17362

John Geffken, DOE/HQ, (301) 903-9430
Nelson F. Rekos, METC, (304) 291-4066

Advanced Electric Power Generation/ Integrated Gasification Combined Cycle

Combustion Engineering IGCC Repowering Project

Sponsor:
ABB Combustion Engineering, Inc.

Contacts:
Robert W. Glamuzina, Project Director
(203) 285-5904

ABB Combustion Engineering, Inc.
P.O. Box 500
Windsor, CT 06095-0500

Jeffrey Summers, DOE/HQ, (301) 903-4412
R. Daniel Brdar, METC, (304) 291-4666

Camden Clean Energy Demonstration Project

Sponsor:
Duke Energy Corp.

Contacts:
Victor Shellhorse, Vice President
(704) 373-2474

Duke Energy Corp.
400 S. Tryon Street
Charlotte, NC 28202

George Lynch, DOE/HQ, (301) 903-9449
R. Daniel Brdar, METC, (304) 291-4666

Piñon Pine IGCC Power Project

Sponsor:
Sierra Pacific Power Company

Contacts:
John W. (Jack) Motter, Project Manager
(702) 689-4013

Sierra Pacific Power Company
6100 Neil Road
P.O. Box 10100
Reno, NV 89520-0400

John Geffken, DOE/HQ, (301) 903-9430
Douglas M. Jewell, METC, (304) 291-4720

Toms Creek IGCC Demonstration Project

Sponsor:
TAMCO Power Partners

Contacts:
Michael Schmid, Project Director
(717) 327-4457

TAMCO Power Partners
2600 Reach Road
P.O. Box 3308
Williamsport, PA 17701-0308

John Geffken, DOE/HQ, (301) 903-9430
Robert B. Reuther, METC, (304) 291-4578

Tampa Electric Integrated Gasification Combined-Cycle Project

Sponsor:
Tampa Electric Company

Contacts:
Donald E. Pless, Director, Advanced Technology
(813) 228-1332

TECO Power Services Corporation
P.O. Box 111
Tampa, FL 33601-0111

John Geffken, DOE/HQ, (301) 903-9430
Nelson F. Rekos, METC, (304) 291-4066

Wabash River Coal Gasification Repowering Project

Sponsor:
Wabash River Coal Gasification Repowering Project Joint Venture

Contacts:
W. Paul Ruwe, Jr., Joint Venture Manager
(713) 735-4138

Destec Energy, Inc.
2500 City West Boulevard, Suite 1700
Houston, TX 77042

Jeffrey Summers, DOE/HQ, (301) 903-4412
R. Daniel Brdar, METC, (304) 291-4666

Advanced Electric Power Generation/ Advanced Combustion/Heat Engines

Healy Clean Coal Project

Sponsor:
Alaska Industrial Development and Export Authority

Contacts:
John Olson, Project Manager
(907) 561-8050

Alaska Industrial Development and Export Authority
480 West Tudor
Anchorage, AK 99503-6690

Stan Roberts, DOE/HQ, (301) 903-9431
Steven J. Heintz, PETC, (412) 892-4466

Coal Diesel Combined-Cycle Project

Sponsor:
Arthur D. Little, Inc.

Contacts:
Robert P. Wilson, Vice President
(617) 498-5806

Arthur D. Little, Inc.
200 Acorn Park
Cambridge, MA 02140

George Lynch, DOE/HQ, (301) 903-9449
Nelson F. Rekos, METC, (304) 291-4066

Warren Station Externally Fired Combined-Cycle Demonstration Project

Sponsor:
Pennsylvania Electric Company

Contacts:
Thomas J. Bradish, Manager, Research and Development
(814) 533-8593

Pennsylvania Electric Company
1001 Broad Street
Johnsontown, PA 15907

George Lynch, DOE/HQ, (301) 903-9449
Robert B. Reuther, METC, (304) 291-4578

Environmental Control Devices/NO_x Control Technologies

Demonstration of Coal Reburning for Cyclone Boiler NO_x Control

Sponsor:
The Babcock & Wilcox Company

Contacts:
Todd Johnson, Senior Marketing Specialist
(216) 829-7355

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

William Fernald, DOE/HQ, (301) 903-9448
Ronald W. Corbett, PETC, (412) 892-6141

Full-Scale Demonstration of Low-NO_x Cell™ Burner Retrofit

Sponsor:
The Babcock & Wilcox Company

Contacts:
Todd Johnson, Senior Marketing Specialist
(216) 829-7355

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

William Fernald, DOE/HQ, (301) 903-9448
Ronald W. Corbett, PETC, (412) 892-6141

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

Sponsor:
Energy and Environmental Research Corporation

Contacts:
Blair A. Folsom, Senior Vice President
(714) 859-8851

Energy and Environmental Research Corporation
18 Mason
Irvine, CA 92718

William Fernald, DOE/HQ, (301) 903-9448
Harry J. Ritz, PETC, (412) 892-6137

Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler

Sponsor:
Southern Company Services, Inc.

Contacts:
John N. Sorge, ICCT Project Manager
(205) 877-7426

Southern Company Services, Inc.
P.O. Box 2625
Birmingham, AL 35202-2625

William Fernald, DOE/HQ, (301) 903-9448
Arthur L. Baldwin, PETC, (412) 892-6011

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

Sponsor:
Southern Company Services, Inc.

Contacts:
Robert R. Hardman, Project Manager
(205) 877-7772

Southern Company Services, Inc.
P.O. Box 2625
Birmingham, AL 35202-2625

William Fernald, DOE/HQ, (301) 903-9448
Gerard G. Elia, PETC, (412) 892-5862

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

Sponsor:
Southern Company Services, Inc.

Contacts:
J.D. (Doug) Maxwell, Project Manager
(205) 877-7614

Southern Company Services, Inc.
P.O. Box 2625
Birmingham, AL 35202-2625

William Fernald, DOE/HQ, (301) 903-9448
Arthur L. Baldwin, PETC, (412) 892-6011

Micronized Coal Reburning Demonstration of NO_x Control on a 175-MWe Wall-Fired Unit

Sponsor:
Tennessee Valley Authority

Contacts:
Tom Butler, Mechanical Engineer
(615) 751-6120

Tennessee Valley Authority
1101 Market Street, ATTN: MR-3A
Chattanooga, TN 37402

William Fernald, DOE/HQ, (301) 903-9448
James U. Watts, PETC, (412) 892-5991

Environmental Control Devices/SO_2 Control Technologies

10-MW Demonstration of Gas Suspension Absorption

Sponsor:
AirPol, Inc.

Contacts:
Frank E. Hsu, Project Manager
(201) 288-7070

AirPol, Inc.
32 Henry Street
Teterboro, NJ 07608

Stan Roberts, DOE/HQ, (301) 903-9431
Sharon K. Marchant, PETC, (412) 892-6008

Confined Zone Dispersion Flue Gas Desulfurization Demonstration

Sponsor:
Bechtel Corporation

Contacts:
Joseph T. Newman, Project Manager
(415) 768-6514

Bechtel Corporation
P.O. Box 3965
San Francisco, CA 94119-3965

William Fernald, DOE/HQ, (301) 903-9448
Arthur L. Baldwin, PETC, (412) 892-6011

LIFAC Sorbent Injection Desulfurization Demonstration Project

Sponsor:
LIFAC–North America

Contacts:
Jim Hervol, Project Manager
(412) 497-2735

ICF Kaiser Engineers, Inc.
4 Gateway Center
Pittsburgh, PA 15222-1207

William Fernald, DOE/HQ, (301) 903-9448
Robert J. Evans, PETC, (412) 892-5988

Advanced Flue Gas Desulfurization Demonstration Project

Sponsor:
Pure Air on the Lake, L.P.

Contacts:
Don Vymazal, Manager, Contract Administration
(215) 481-3687

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

Stan Roberts, DOE/HQ, (301) 903-9431
Thomas A. Sarkus, PETC, (412) 892-5981

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

Sponsor:
Southern Company Services, Inc.

Contacts:
David P. Burford, Project Manager
(205) 870-6329

Southern Company Services, Inc.
P.O. Box 2625
Birmingham, AL 35202-2625

Stan Roberts, DOE/HQ, (301) 903-9431
Harry J. Ritz, PETC, (412) 892-6137

Environmental Control Devices/Combined SO_2/NO_x Control Technologies

SNOX Flue Gas Cleaning Demonstration Project

Sponsor:
ABB Environmental Systems

Contacts:
Bill Kingston, Project Manager
(205) 995-5368

Environmental Systems Division
ABB Combustion Engineering, Inc.
P.O. Box 43030
Birmingham, AL 35243

Stan Roberts, DOE/HQ, (301) 903-9431
Robert J. Evans, PETC, (412) 892-5988

LIMB Demonstration Project Extension and Coolside Demonstration

Sponsor:
The Babcock & Wilcox Company

Contacts:
Todd Johnson, Senior Marketing Specialist
(216) 829-7355

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

William Fernald, DOE/HQ, (301) 903-9448
Thomas W. Arrigoni, PETC, (412) 892-6258

SOx-NOx-Rox-Box™ Flue Gas Cleanup Demonstration Project

Sponsor:
The Babcock & Wilcox Company

Contacts:
Todd Johnson, Senior Marketing Specialist
(216) 829-7355

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

Stan Roberts, DOE/HQ, (301) 903-9431
Ronald W. Corbett, PETC, (412) 892-6141

Enhancing the Use of Coals by Gas Reburning and Sorbent Injection

Sponsor:
Energy and Environmental Research Corporation

Contacts:
Blair A. Folsom, Senior Vice President
(714) 859-8851

Energy and Environmental Research Corporation
18 Mason
Irvine, CA 92718

William Fernald, DOE/HQ, (301) 903-9448
Harry J. Ritz, PETC, (412) 892-6137

Milliken Clean Coal Technology Demonstration Project

Sponsor:
New York State Electric & Gas Corporation

Contacts:
Dennis O'Dea, Project Manager
(607) 729-2551

New York State Electric & Gas Corporation
120 Chenango Street
Binghamton, NY 13902

Stan Roberts, DOE/HQ, (301) 903-9431
Gerard G. Elia, PETC, (412) 892-5862

Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System

Sponsor:
NOXSO Corporation and MK-Ferguson Company

Contacts:
Eugene R. Recher, Program Manager
(216) 523-5923

MK-Ferguson Company
1500 West 3d Street
Cleveland, OH 44114

Stan Roberts, DOE/HQ, (301) 903-9431
Gerard G. Elia, PETC, (412) 892-5862

Integrated Dry NO_x/SO_2 Emissions Control System

Sponsor:
Public Service Company of Colorado

Contacts:
Gordon A. Schott, Project Manager
(303) 329-1702

Public Service Company of Colorado
5900 East 39th Avenue
Denver, CO 80207

William Fernald, DOE/HQ, (301) 903-9448
Thomas W. Arrigoni, PETC, (412) 892-6258

Coal Processing for Clean Fuels/Coal Preparation Technologies

Development of the Coal Quality Expert

Sponsors:
ABB Combustion Engineering, Inc., and CQ, Inc.

Contacts:
Clark Harrison, President
(412) 479-6016

CQ, Inc.
One Quality Center
P.O. Box 280
Homer City, PA 15748-0280

Douglas Archer, DOE/HQ, (301) 903-9443
Stan Roberts, DOE/HQ, (301) 903-9431
Robert J. Evans, PETC, (412) 892-5988

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

Sponsor:
Custom Coals International

Contacts:
Robin Godfrey, Project Manager
(412) 642-2625

Custom Coals International
100 First Avenue, Suite 500
Pittsburgh, PA 15222

Douglas Archer, DOE/HQ, (301) 903-9443
Robert J. Evans, PETC, (412) 892-5988

Advanced Coal Conversion Process Demonstration

Sponsor:
Rosebud SynCoal Partnership

Contacts:
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(406) 748-2366 and/or (406) 252-2277

Rosebud SynCoal Partnership
P.O. Box 7137
Billings, MT 59103-7137

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Coal Processing for Clean Fuels/Mild Gasification

ENCOAL Mild Coal Gasification Project

Sponsor:
ENCOAL Corporation

Contacts:
J.P. (Jim) Frederick, Project Manager
(307) 686-5493

ENCOAL Corporation
P.O. Box 3038
Gillette, WY 82717

Douglas Archer, DOE/HQ, (301) 903-9443
Douglas M. Jewell, METC, (304) 291-4720

Coal Processing for Clean Fuels/Indirect Liquefaction

Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process

Sponsor:
Air Products and Chemicals, Inc.

Contacts:
William R. Brown, Project Manager
(215) 481-7584

Air Products and Chemicals, Inc.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

Douglas Archer, DOE/HQ, (301) 903-9443
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Industrial Applications

Blast Furnace Granulated-Coal Injection System Demonstration Project

Sponsor:
Bethlehem Steel Corporation

Contacts:
Daniel Kwasnoski, Program Manager
(215) 694-6478

Bethlehem Steel Corporation
Homer Research Laboratory
Building C, Room 229
Bethlehem, PA 18016

Jeffrey Summers, DOE/HQ, (301) 903-4412
Douglas M. Jewell, METC, (304) 291-4720

Innovative Coke Oven Gas Cleaning System for Retrofit Applications

Sponsor:
Bethlehem Steel Corporation

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Clean Power from Integrated Coal/Ore Reduction (COREX®)

Sponsor:
Centerior Energy Corporation

Contacts:
J. Lee Bailey, Manager, Corporate Communications
(216) 447-3235

Centerior Energy Corporation
6200 Oak Tree Boulevard
Independence, OH 44131

George Lynch, DOE/HQ, (301) 903-9449
Robert B. Reuther, METC, (304) 291-4578

Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control

Sponsor:
Coal Tech Corporation

Contacts:
Bert Zauderer, President
(215) 667-0442

Coal Tech Corporation
P.O. Box 154
Merion, PA 19066

Stan Roberts, DOE/HQ, (301) 903-9431
Arthur L. Baldwin, PETC, (412) 892-6011

Cement Kiln Flue Gas Recovery Scrubber

Sponsor:
Passamaquoddy Tribe

Contacts:
Garrett Morrison, Project Manager
(207) 594-5555

Passamaquoddy Technology, L.P.
P.O. Box 350
Thomaston, ME 04861-0350

Jeffrey Summers, DOE/HQ, (301) 903-4412
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Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal

Sponsor:
ThermoChem, Inc.

Contacts:
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ThermoChem, Inc.
5570 Sterrett Place, Suite 210
Columbia, MD 21044

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