DOE/FE-0330

CLEAN COAL TECHNOLOGY

Clean Coal Technology Demonstration Program

Program Update 1994

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

April 1995

Advanced Electric Power Generation Fact Sheets

PFBC Utility Demonstration Project

Participant:
The Appalachian Power Company

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

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

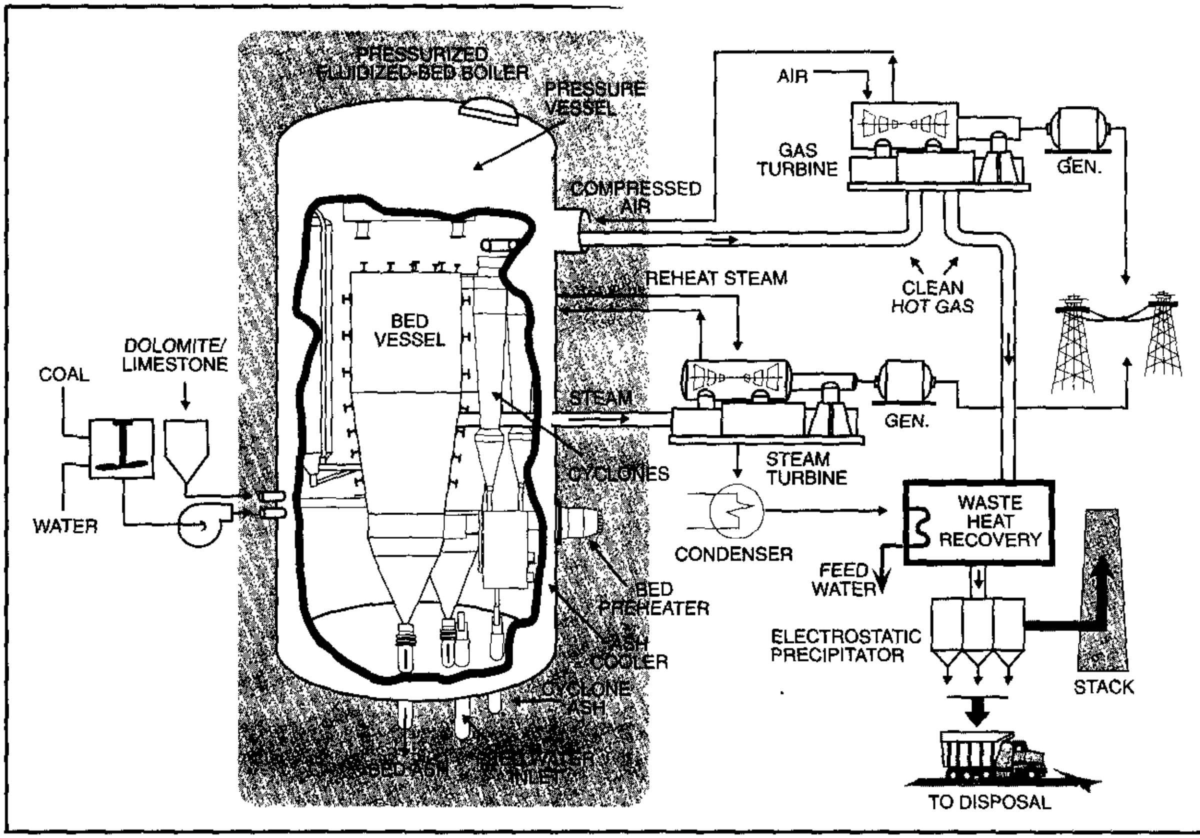
Technology:
The Babcock & Wilcox Company's pressurized fluidized-bed combustion (PFBC) system (under license from ABB Carbon) (advanced electric power generation/ fluidized-bed combustion)

Plant Capacity/Production:
340 MWe (net)

Project Funding:

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

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

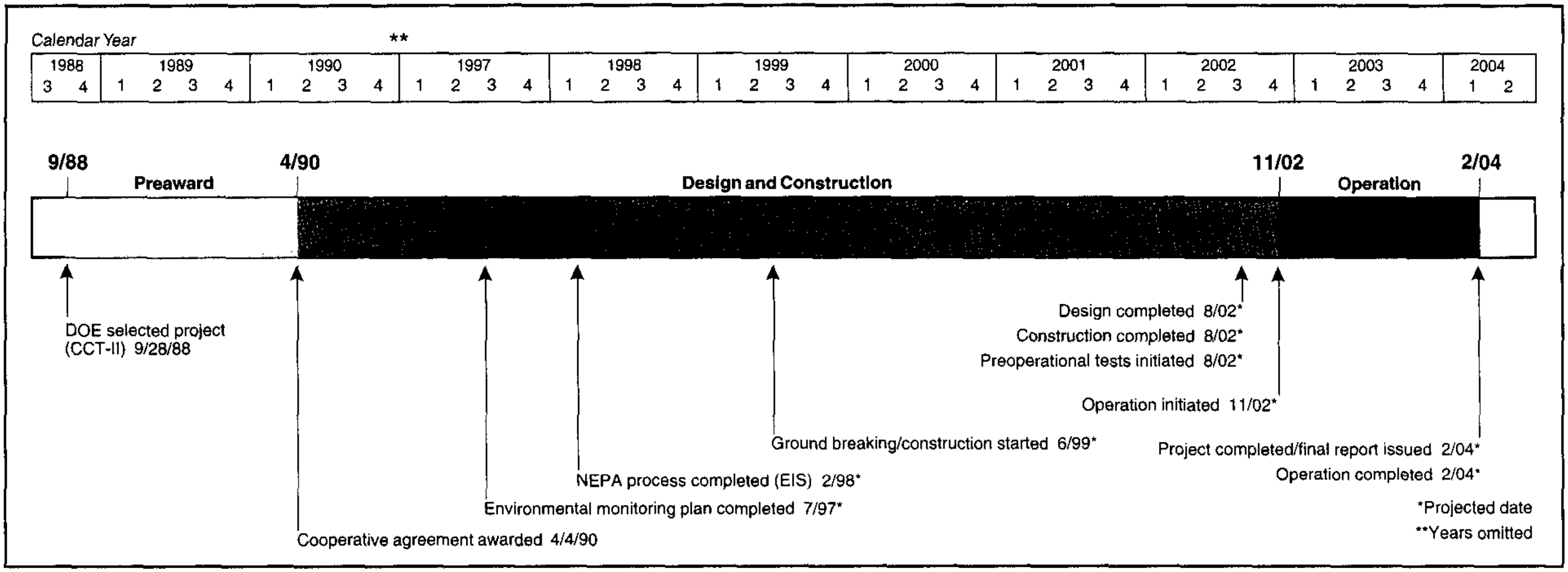


Technology/Project Description:
This project will be a greenfield facility located adjacent to the existing Mountaineer and Sporn plants. The most noticeable aspect of the unit is that the boiler, cyclones, reinjection vessel, and associated hardware are encapsulated in a pressure vessel 60 ft in diameter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

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

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

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



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

Project Status/Accomplishments:

Appalachian Power is evaluating results from various value engineering activities, which were conducted to improve the efficiency and economic viability. The utility and DOE are assessing the merits of continuing the project.

Commercial Applications:

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

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

PCFB Demonstration Project

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

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

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

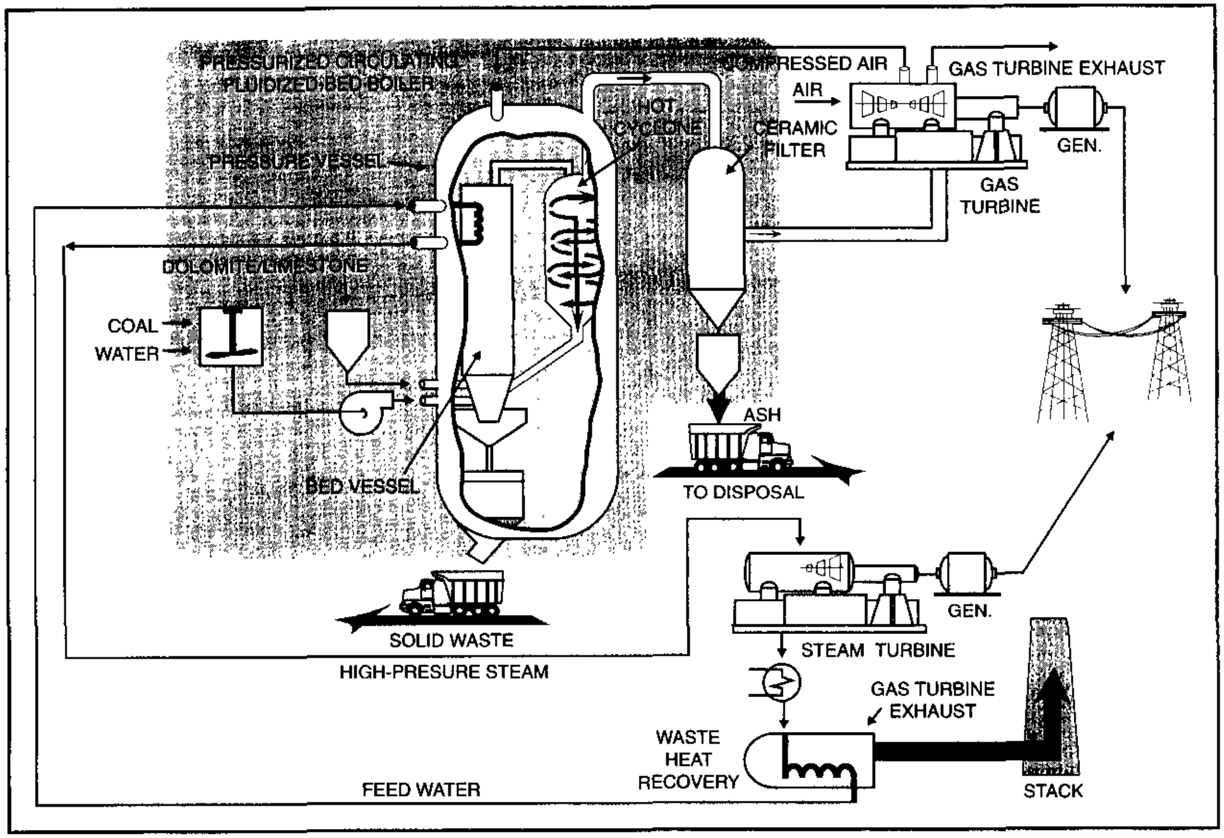
Technology:
Pyropower Corporation's PYROFLOW pressurized circulating fluidized-bed combustion (PCFB) combined-cycle system (advanced electric power generation/fluidized-bed combustion)

Plant Capacity/Production:
80 MWe

Project Funding:

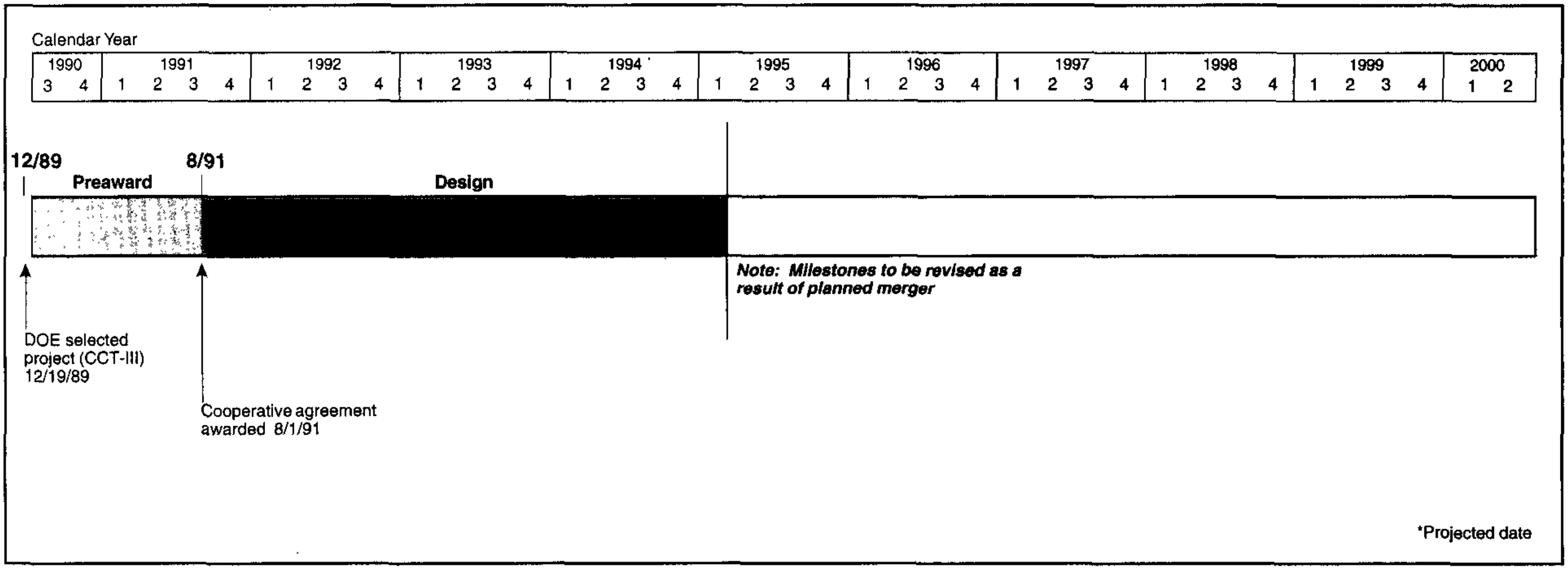
Total project cost	$202,959,000	100%
DOE	93,253,000	46
Participants	109,706,000	54

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



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

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



Project Status/Accomplishments:

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

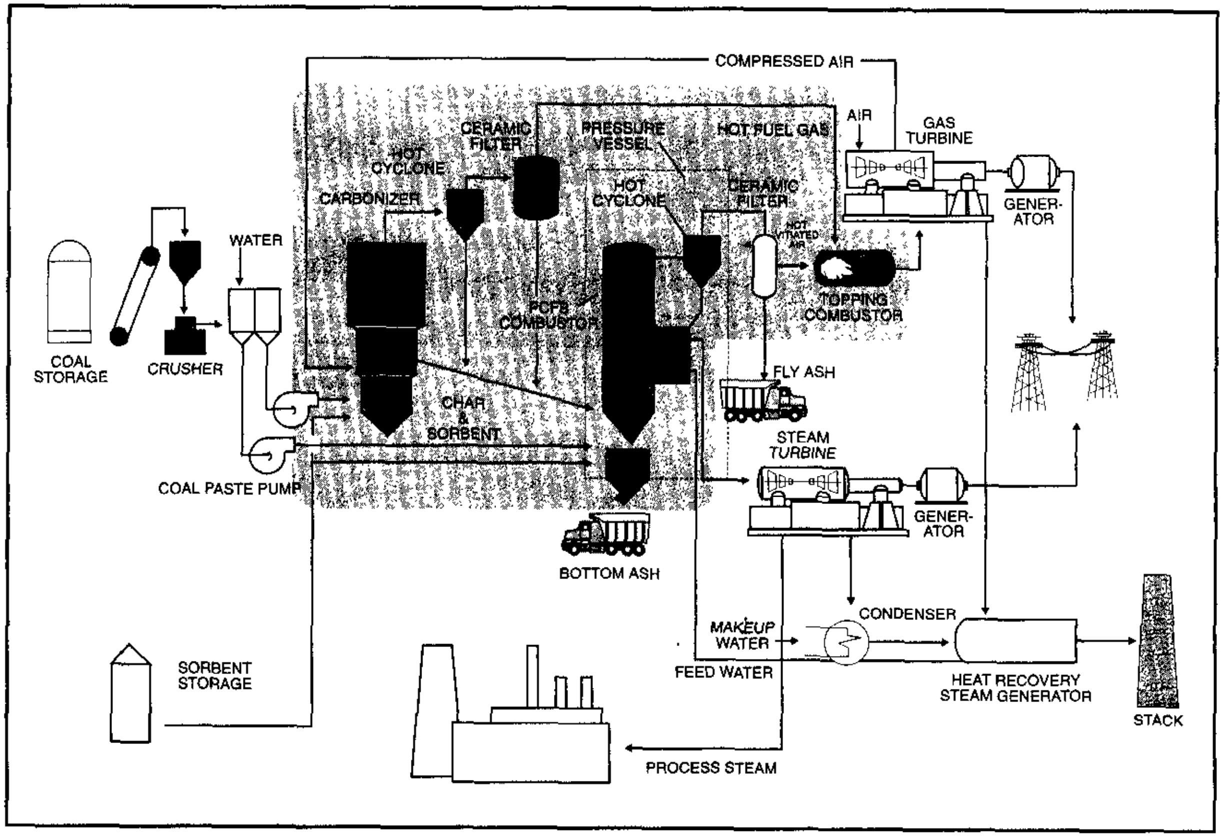
Commercial Applications:

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

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

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

Four Rivers Energy Modernization Project



Participant:

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

Additional Team Members:

Foster Wheeler Energy Corporation—combustor, carbonizer, heat exchanger supplier; engineering

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

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

Location:

Calvert City, Marshall County, KY (adjacent to Air Products and Chemicals' chemicals manufacturing plant)

Technology:

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

Plant Capacity/Production:

95 MWe (equivalent if all steam were converted)

Project Funding:

Total project cost	$360,707,500	100%
DOE	142,460,000	39
Participants	218,247,500	61

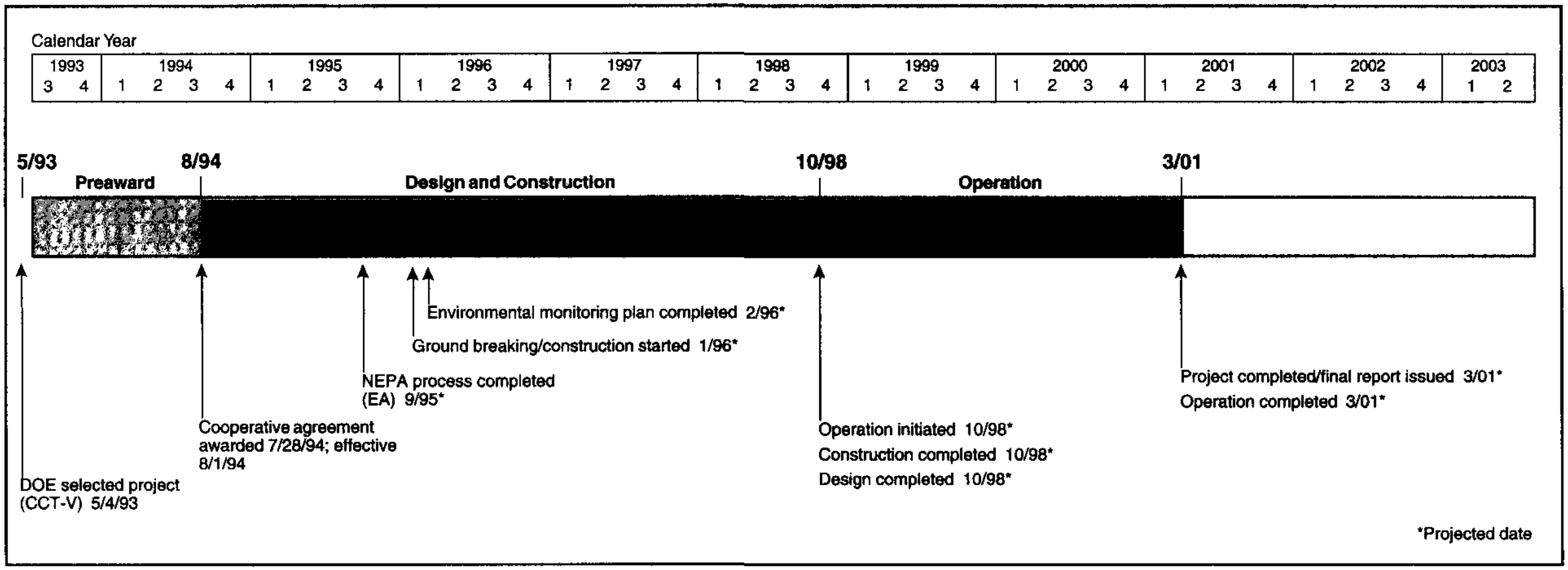
Project Objective:

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

Technology/Project Description:

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

At the Calvert City chemical manufacturing plant, the second-generation PCFB process will replace the steam-generating capacity of two operating industrial process boilers. These two industrial units are spreader-stoker coal-fired units which were installed in the late 1950s. This equipment change will result in significant reductions in the current emissions of pollutants. The facility will use about 870 tons/day of 2.4–3.5% sulfur bituminous coals from western Kentucky and southern Illinois.



Project Status/Accomplishments:

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

Commercial Applications:

This project serves as a stepping stone to move the second-generation PCFB technology to readiness for widespread commercial application. The project is also in line to be one of the first commercial applications of hot-gas cleanup and one of the first to use a nonruggedized gas turbine in a pressurized fluidized-bed application.

In addition to other advanced technology systems, second-generation PCFB technology will compete with bubbling fluidized-bed combustion systems to repower or replace conventional fossil-fueled power plants with a technology capable of using high-sulfur coals in an environmentally sound manner.

PCFB technology appears to be best suited for a wide range of utility and industrial applications beginning at a level of 50 MWe.

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

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

Tidd PFBC Demonstration Project

Participant:
The Ohio Power Company

Additional Team Members:
Amercian Electric Power Service Corporation—designer, constructor, and manager
The Babcock & Wilcox Company—technology supplier
Ohio Coal Development Office—cofunder

Location:
Brilliant, Jefferson County, OH (Ohio Power Company's Tidd Plant, Unit 1)

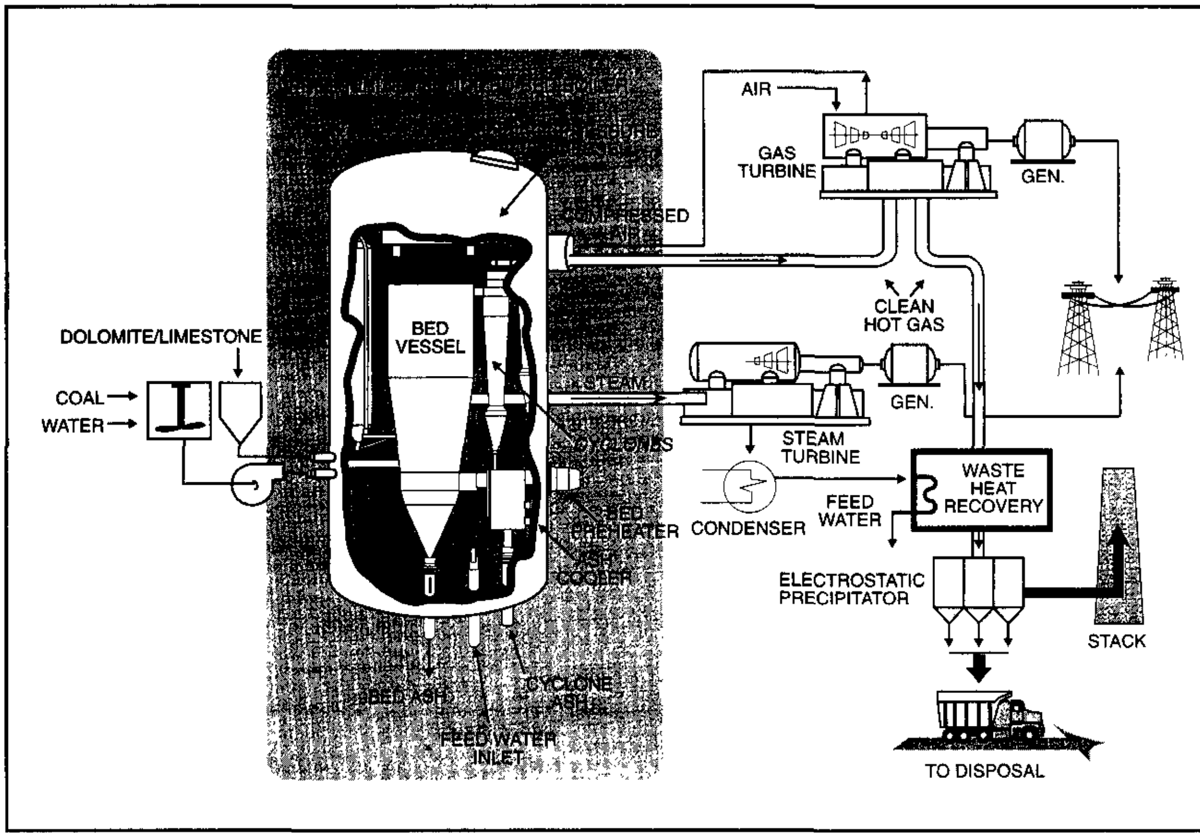
Technology:
The Babcock & Wilcox Company's pressurized fluidized-bed combustion (PFBC) system (under license from ABB Carbon) (advanced electric power generation/ fluidized-bed combustion)

Plant Capacity/Production:
70 MWe

Project Funding:

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

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

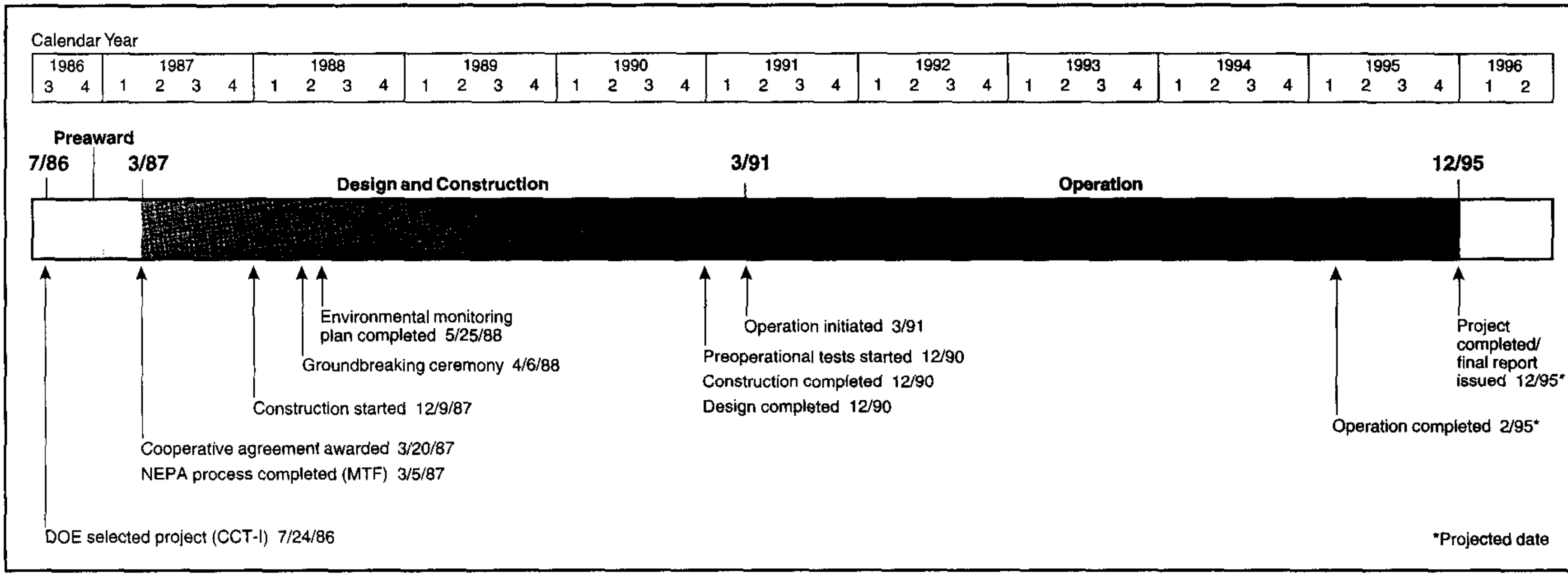


Technology/Project Description:
Tidd is the first large-scale demonstration of PFBC in the United States and one of only five worldwide. The boiler, cyclones, bed reinjection vessels, and associated hardware are encapsulated in a pressure vessel 45 ft in diameter and 70 ft high. The facility was designed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

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

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

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



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

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

Project Status/Accomplishments:

The plant accumulated approximately 4,800 hours of operation during 1994. Overall, coal-fueled operation now totals approximately 10,300 hours, including continuous coal-fired runs of 28, 29, 31, and 45 days. During 1994, Tidd produced 219,011 MWh of gross generation and completed 39 parametric tests. SO_2 emissions reductions above 90% and NO_x emission levels of 0.15–0.18 lb/million Btu were routinely achieved. These levels are well below NSPS requirements.

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

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

Commercial Application:

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

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

Nucla CFB Demonstration Project

Project completed.

Participant:
Tri-State Generation and Transmission Association, Inc. (formerly Colorado-Ute Electric Association, Inc.)

Additional Team Members:
Pyropower Corporation—technology supplier
Technical Advisory Group (potential users)—cofunder
Electric Power Research Institute—technical support

Location:
Nucla, Montrose County, CO (Nucla Station)

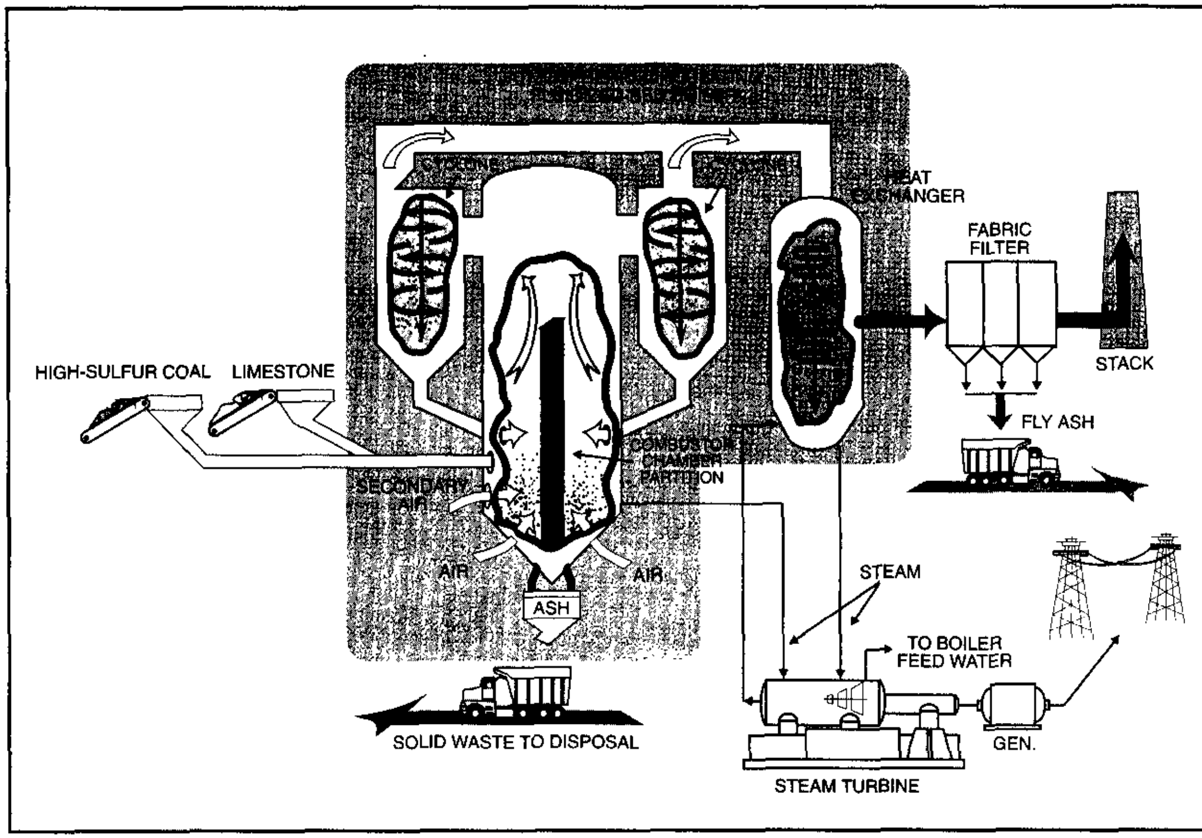
Technology:
Pyropower's atmospheric circulating fluidized-bed combustion (ACFB) system (advanced electric power generation/fluidized-bed combustion)

Plant Capacity/Production:
110 MWe

Project Funding:

Total project cost	$54,087,000	100%
DOE	19,920,000	37
Participants	34,167,000	63

Project Objective:
To demonstrate ACFB at a scale of 110 MWe, representing a 2:1 scaleup from previously demonstrated capacities; to verify expectations of the technology's economic, environmental, and technical performance in a repowering application at a utility site; to accomplish greater than 90% SO_2 removal; to reduce NO_x emissions by 60%; and to achieve an efficiency of 34% in a repowering mode.



Technology/Project Description:
Nucla's circulating fluidized-bed system operates at atmospheric pressure. In the combustion chamber, a stream of air fluidizes and entrains a bed of coal, coal ash, and sorbent (e.g., limestone). Relatively low combustion temperatures limit NO_x formation. Calcium in the sorbent combines with SO_2 gases, and solids exit the combustion chamber and flow into a hot cyclone. The cyclone separates the solids from the gases, and the solids are recycled for combustor temperature control. Continuous circulation of coal and sorbent improves mixing and extends the contact time of solids and gases, thus promoting high utilization of the coal and high sulfur capture efficiency. Heat in the flue gas exiting the hot cyclone is recovered in the economizer. The flue gas passes through a baghouse where the particulate matter is removed. The steam generated in the ACFB is used to generate electric power.

Three small, coal-fired, stoker-type boilers at Nucla Station were replaced with a new 925,000-lbs/hr ACFB steam generator capable of driving a new 74-MWe turbine generator. Extraction steam from this turbine generator powers three existing turbine generators (12 MWe each). Three western coals were tested: Peabody coal (0.4–0.8% sulfur), Dorchester coal (1.5% sulfur), and Salt Creek coal (0.5% suflur).

In 1992, Colorado-Ute Electric Association, Inc., the owner of Nucla Station, was purchased by Tri-State Generation and Transmission Association, Inc.

Project Results/Accomplishments:

Between August 1988 and January 1991, a total of 72 steady-state performance tests were conducted: 22 tests at 50% load, 6 at 75% load, 2 at 90% load, and 42 at full load (110 MWe). Some key results, as reported by the participant, follow:

- Results indicated strong correlations of absolute CO, SO_2, and NO_x emissions levels with combustor operating temperatures. Although NSPS compliance was maintained, a penalty on limestone feed requirements for sulfur retention was realized at the higher operating temperatures. Below 1,620 °F, 70% sulfur retention was achieved with 1.5 Ca/S, and 95% sulfur retention was achieved with 4.0 Ca/S. Around 1,700 °F, Ca/S greater than 5.0 was required to maintain 70% sulfur capture.
- The NO_x emissions for all tests were less than 0.34 lb/million Btu, which was well within the state-regulated emission limit of 0.50 lb/million Btu. The average level of NO_x emissions for all tests was 0.18 lb/million Btu.
- Combustion efficiency, a measure of the quantity of carbon that is fully oxidized to CO_2, ranged from 96.9% to 98.9%. Of the four exit sources of incompletely burned carbon, the largest was carbon contained in the fly ash (93%). The next largest (5%) was carbon contained in the bottom ash stream, and the remaining feed-carbon loss (2%) was incompletely oxidized CO in the flue gas. The fourth possible source, hydrocarbons in the flue gas, was measured and found to be negligible.
- Boiler efficiencies for 68 performance tests varied from 85.6% to 88.6%. The contributions to boiler heat loss were identified as unburned carbon; sensible heat in dry flue gas; fuel and sorbent moisture; latent heat in burning hydrogen; sorbent calcination; radiation, and convection; and bottom ash cooling water. Net plant heat rate decreased with increasing boiler load, from 12,400 Btu/kWh at 50% of full load to 11,600 Btu/kWh at full load. The lowest value achieved during a full-load steady-state test was 10,980 Btu/kWh. These values were affected by the absence of reheat, the presence of the three older 12.5-MWe turbines in the overall steam cycle, the number of unit restarts, and part-load testing.
- Over the range of operating temperatures at which testing was performed at Nucla, bed temperature was found to be the most influential operating parameter. With the possible exception of coal-feed configuration and excess air at elevated temperatures, bed temperature was the only parameter that had a measurable impact on emissions or efficiencies. Emissions of SO_2 and NO_x were found to increase with increasing combustor temperatures while CO emissions decreased with increasing temperature. Combustion efficiency also improved as the temperature was increased.

An economic evaluation indicated that the final capital costs for the Nucla ACFB system were about $112.3 million. This represents a cost of $1,123/net kW. Total power production costs associated with test operations were about $54.7 million, which results in a normalized power production cost of $63.63/MWh. Fixed costs were about 62% of the total, and variable costs were more than 38%. Nucla's power production costs proved competitive with pulverized coal units not limiting emissions as significantly.

Commercial Applications:

ACFB technology has good potential in both industrial and utility sectors for new capacity additions or for repowering existing coal-fired plants. Coal of any sulfur content can be used. Because any type or size of boiler can be repowered by ACFB using the existing plant area, coal- and waste-handling equipment, and steam turbine equipment, the life of the plant can be extended. Benefits of ACFB include 90% SO_2 reduction, 60–80% NO_x reduction, and control of pollutants at lower costs than are offered by existing technologies.

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

Project Schedule:

DOE selected project (CCT-I)	10/7/87
Cooperative agreement awarded	10/3/88
NEPA process completed (MTF)	4/18/88
Environmental monitoring plan completed	2/27/88
Operational testing	8/88–1/91
Project completed	4/92

Final Reports:

Final Technical Report	10/91
Economic Evaluation Report	3/92
Public Design Report	12/90
Performance Test Summary Reports	3/92

York County Energy Partners Cogeneration Project

Participant:
York County Energy Partners, L.P. (a limited partnership which includes Air Products and Chemicals, Inc.)

Additional Team Members:
P.H. Glatfelter Company—site host

Foster Wheeler Energy Corporation —technology supplier

Location:
North Codorus Township, York County, PA (greenfield site)

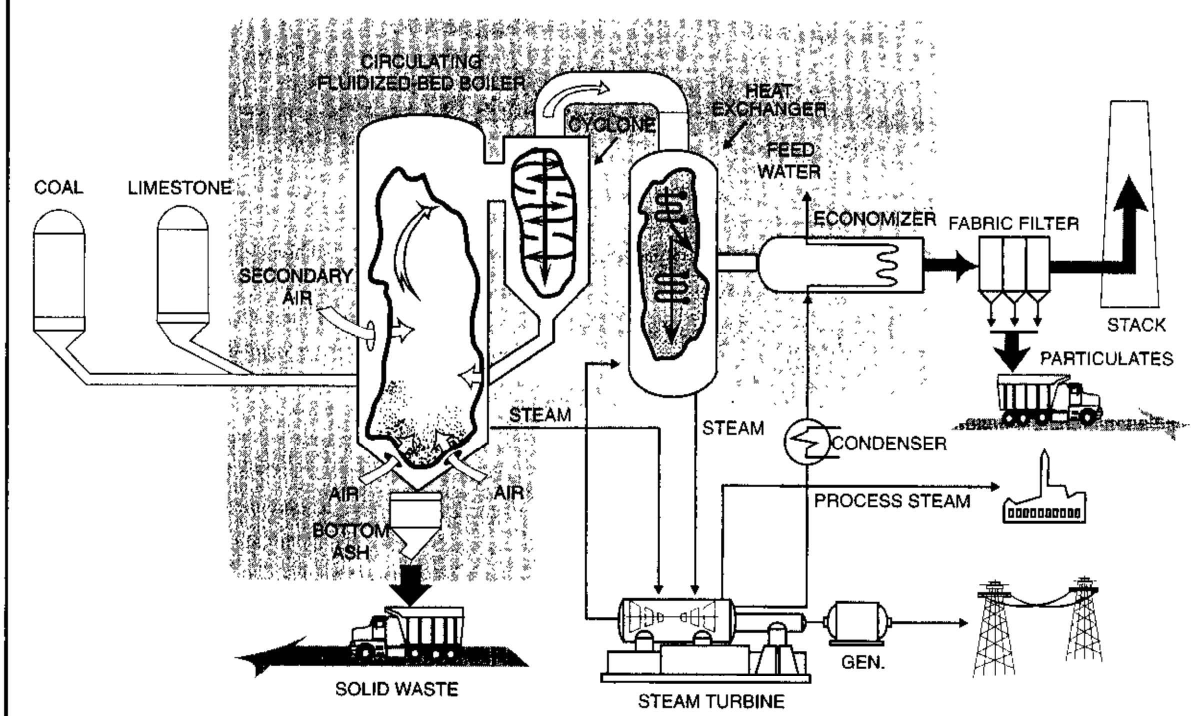
Technology:
Foster Wheeler's atmospheric circulating fluidized-bed (ACFB) combustor (advanced electric power generation/ fluidized-bed combustion)

Plant Capacity/Production:
227 MWe (net) and 400,000 lbs/hr steam

Project Funding:

Total project cost	$379,645,450	100%
DOE	74,733,833	20
Participant	304,911,617	80

Project Objective:
To demonstrate ACFB at 250 MWe, representing a 1.7:1 scaleup from previously constructed facilities; to verify expectations of the technology's economic, environmental, and technical performance in a greenfield cogeneration application; and to provide cogenerators, as well as utility and nonutility power producers, with the data necessary for evaluating a 250-MWe ACFB as a commercial alternative to accomplish greater than 90% SO_2 removal, to reduce NO_x emissions by 60% when compared with conventional technology, and to achieve a steam efficiency of 88%.

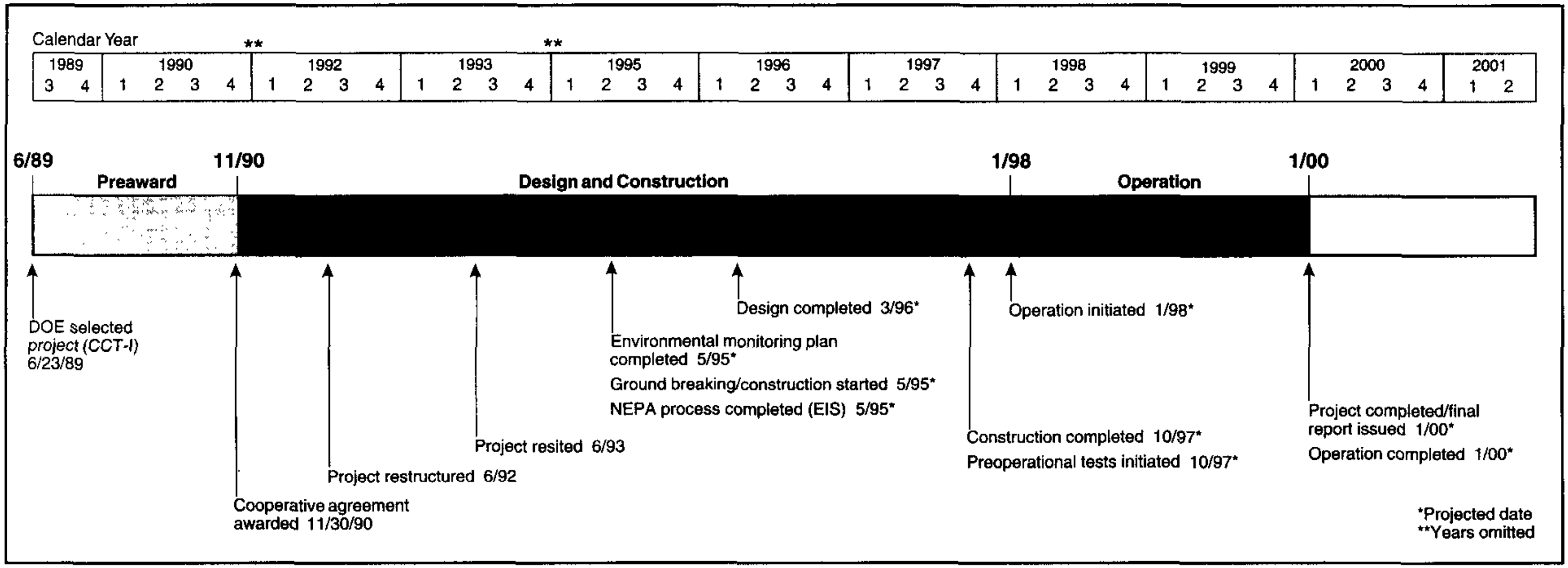


Technology/Project Description:
In this project, the circulating fluidized-bed combustor operates at atmospheric pressure. Coal, primary air, and a solid sorbent, such as limestone, are introduced into the lower portion of the combustor where initial combustion occurs. As coal particles decrease in size due to combustion and breakage, they are carried higher in the combustor to an area where secondary air is introduced. As the coal particles continue to be reduced in size, the coal, along with some of the sorbent, is carried out of the combustor, collected in a particle separator, and recycled to the lower portion of the combustor. The sorbent in the bed removes sulfur during the combustion process, eliminating the need for scrubbers.

Steam is generated in tubes placed along the combustor's walls and superheated in tube bundles placed in the solids-circulating stream and the flue gas stream. The steam is then used to produce power in a conventional steam cycle.

The project will demonstrate ACFB in a 250-MWe greenfield cogeneration application in York County, PA. The participant has an electrical power purchase agreement with Metropolitan Edison Company to supply up to 227 MWe and a steam purchase agreement with the P.H. Glatfelter Company to supply steam to the paper-making facility located adjacent to the project site.

The heat rate for this cogeneration plant is expected to be 9,200 Btu/kWh (37% efficiency). Expected SO_2 emissions from this demonstration plant are below



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

*Bituminous coal (2% sulfur) from western Pennsyl*vania will be used.

Project Status/Accomplishments:

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

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

Commercial Applications:

ACFB technology has good potential for application in both the industrial and utility sectors, whether for use in repowering existing plants or in new facilities. ACFB is attractive for both baseload and dispatchable power applications because it can be efficiently turned down to 25% of full load. Coal of any sulfur content can be used, and any type or size of a coal-fired boiler can be repowered. In repowering applications, an existing plant area is used, and coal- and waste-handling equipment as well as steam turbine equipment are retained, thereby extending the life of a plant.

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

Combustion Engineering IGCC Repowering Project

Participant:

ABB Combustion Engineering, Inc.

Additional Team Members:

City Water, Light and Power—cofunder and host utility

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

Location:

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

Technology:

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

Plant Capacity/Production:

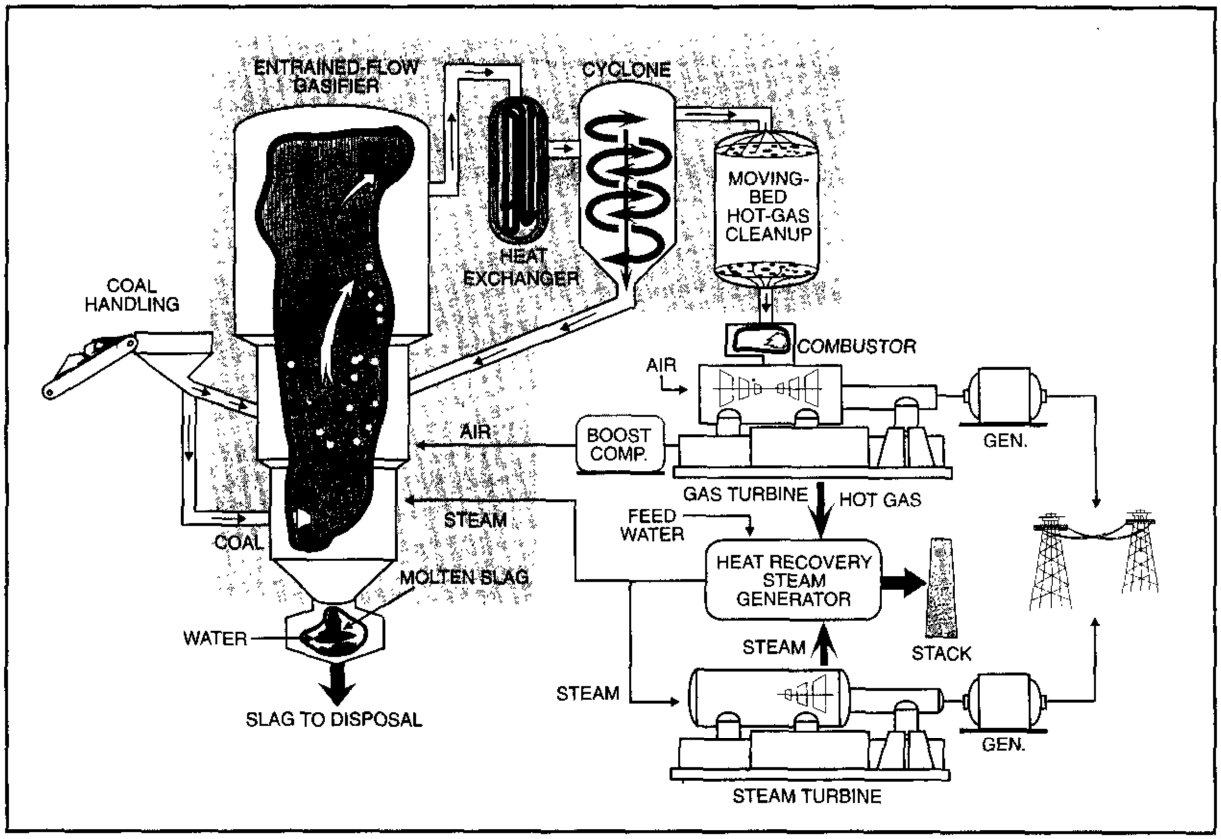
65 MWe (net)

Project Funding:

Total project cost	$270,700,000	100%
DOE	129,357,204	48
Participants	141,342,796	52

Project Objective:

To demonstrate an advanced dry-feed, air-blown, two-stage, entrained-flow coal gasifier with a moving-bed, zinc titanate, hot-gas cleanup system; to assess long-term reliability and maintainability of the system at a sufficient scale to determine commercial potential.



Technology/Project Description:

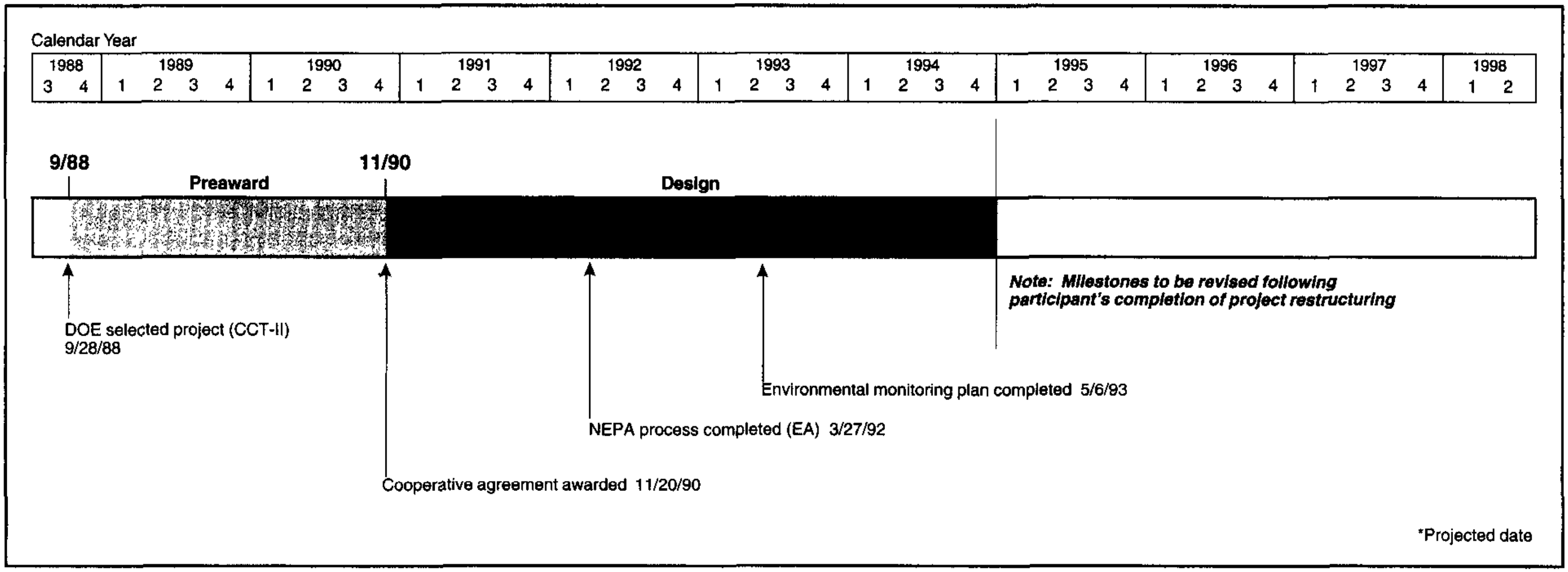
Pressurized pulverized coal is pneumatically transported to the gasifier. The gasifier essentially consists of a bottom combustor section and a top reductor section. Coal is fed into both sections. A slag tap at the bottom of the combustor allows molten slag to flow into a water-filled quench tank.

The raw, low-Btu gas and char leave the gasifier at approximately 2,000 °F and are reduced in temperature to about 1,000 °F in a heat exchanger. Char in the gas stream is captured by a high-efficiency cyclone, as well as by a subsequent fine-particulate removal system, and recycled back to the gasifier.

A newly developed process consisting of a moving bed of zinc titanate sorbent is being used to remove sulfur from the hot gas. Particulate emissions are removed from the coal-handling system and gas stream by a combination of cyclone separators and baghouses, and ahigh percentage of particulates are fed back to the gasifier for more complete reaction and ultimate removal with the slag.

The cleaned low-Btu gas is routed to a combined-cycle system for electric power production. About 40MW e (net) are generated by a gas turbine. Extracted air from the gas turbine is used to meet the high-pressure air requirements of the gasifier and the zinc titanate desulfurization system. Exhaust gases from the gas turbine are used to produce steam which is fed to a bottoming cycle to generate an additional 25 MWe (net).

The demonstration project is converting 600 tons/day of coal into 65 MWe. This is being accomplished



through the installation of an entrained-flow coal gasifier and the integration of a 25-MWe steam turbine with a 40-MWe gas turbine at City Water, Light and Power's Lakeside Station located in Springfield, IL. The anticipated heat rate for the repowered unit is 8,800Btu/kWh (an efficiency of 38.8%). SO_2 emissions are expected to be less than 0.1 lb/million Btu (99% reduction). NO_x emissions are also expected to be less than 0.1 lb/million Btu (90% reduction). Illinois No. 6 bituminous coal containing 2.4% sulfur will be used.

Project Status/Accomplishments:

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

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

Commercial Applications:

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

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

Clean Energy Demonstration Project

Participant:

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

Additional Team Members:

Duke Engineering & Services, Inc.—engineer and constructor

General Electric Company—power island designer and supplier

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

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

Electric Power Research Institute—cofunder

National Rural Electric Cooperative Association—cofunder

Deutsche Aerospace AG—cofunder

Location:

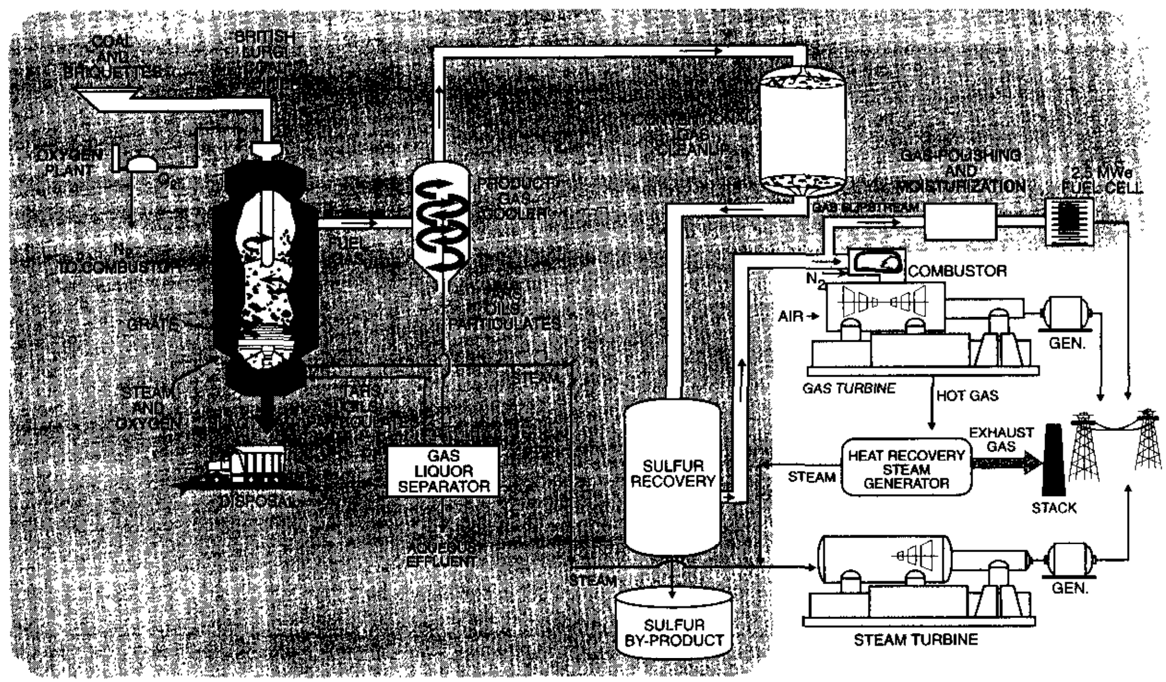
An east coast site

Technology:

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

Plant Capacity/Production:

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



Project Funding:

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

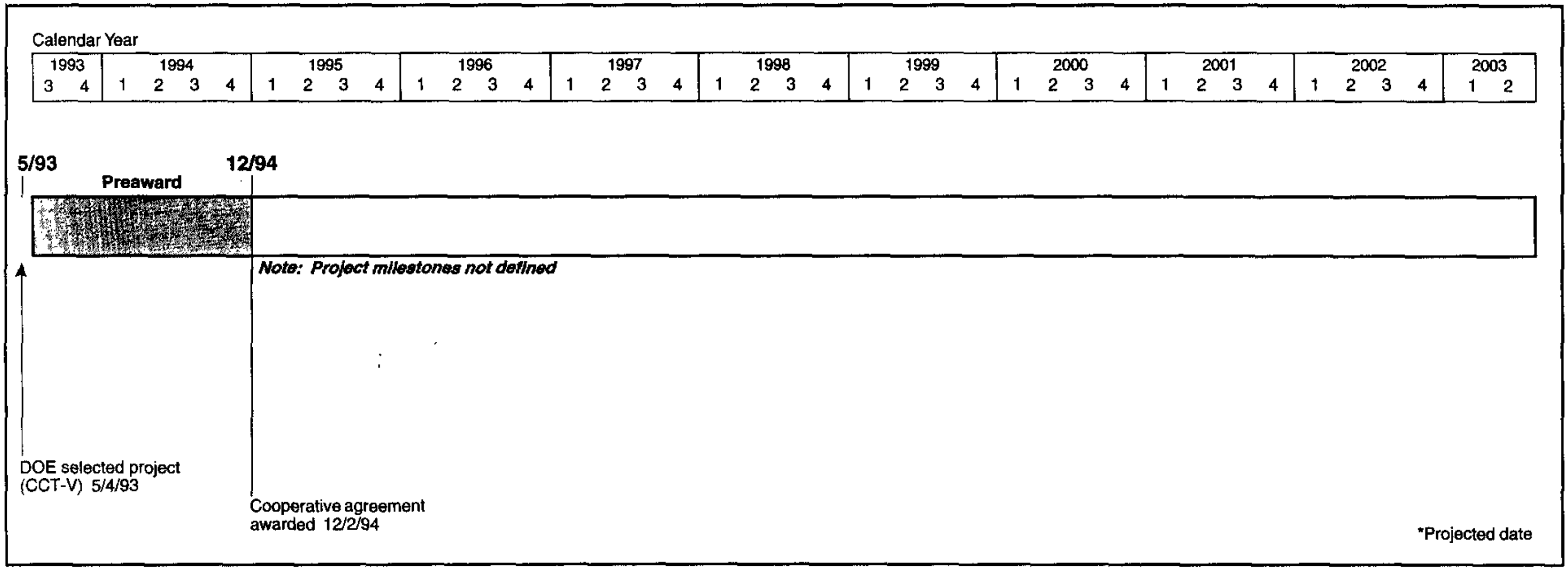
Project Objective:

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

Technology/Project Description:

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

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



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

Project Status/Accomplishments:

The cooperative agreement was awarded December 2, 1994.

Commercial Applications:

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

The heat rate of the IGCC demonstration facility is 8,560 Btu/kWh (40% efficiency) and the commercial embodiment of the system has a projected heat rate of 8,035 Btu/kWh (42.5% efficiency). The commercial version of the molten carbonate fuel cell fueled by a BG/L gasifier is anticipated to have a heat rate of 7,379 Btu/kWh (46.2% efficiency). These efficiencies represent greater than 20% reduction in emissions of CO_2 when compared to a conventional pulverized coal plant equipped with a scrubber. SO_2 emissions from the IGCC system are expected to be less than 0.1 lb/million Btu (99% reduction); NO_x emissions, less than 0.15 lb/million Btu (90% reduction).

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

Piñon Pine IGCC Power Project

Participant:
Sierra Pacific Power Company

Additional Team Members:
Foster Wheeler USA Corporation—architect, engineer, and constructor

The M.W. Kellogg Company—technology supplier

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

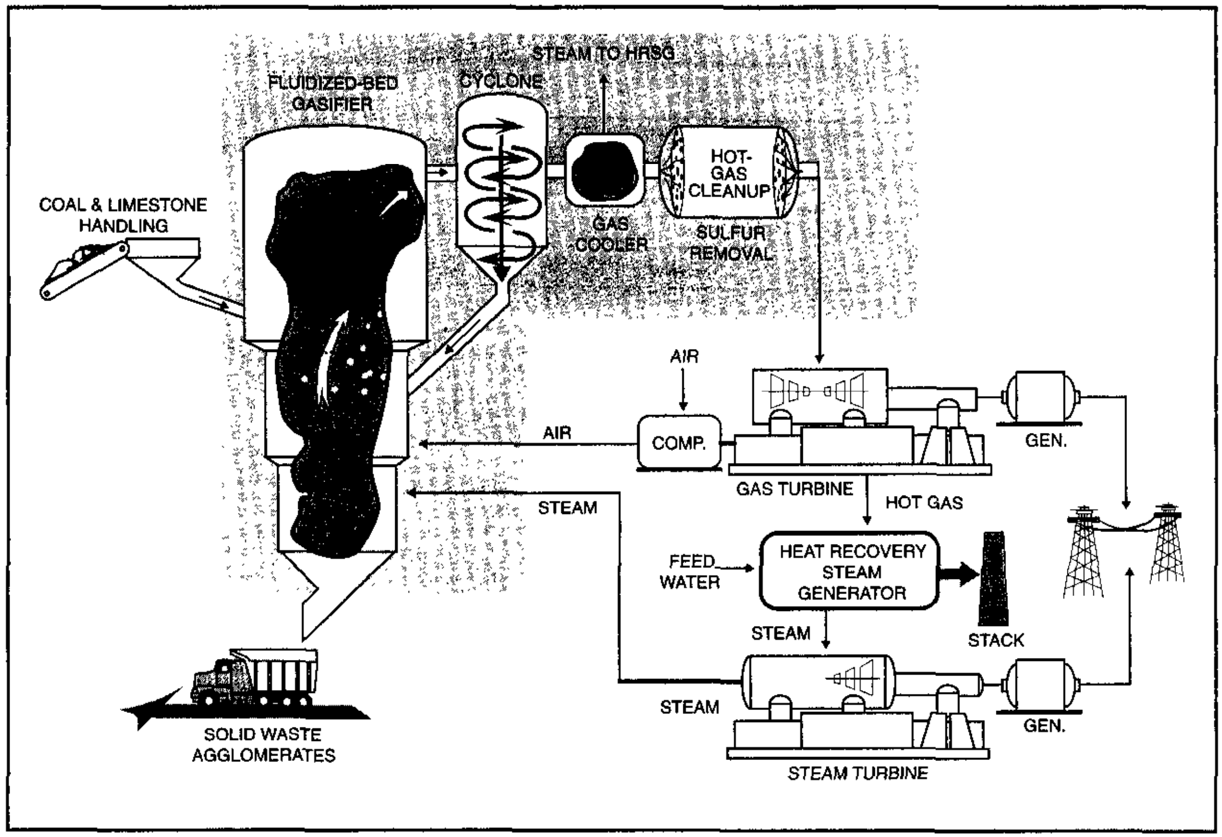
Technology:
Integrated gasification combined-cycle (IGCC) using the KRW air-blown, pressurized, fluidized-bed coal gasification system (advanced electric power generation/ integrated gasification combined cycle)

Plant Capacity/Production:
99 MWe (net)

Project Funding:

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

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



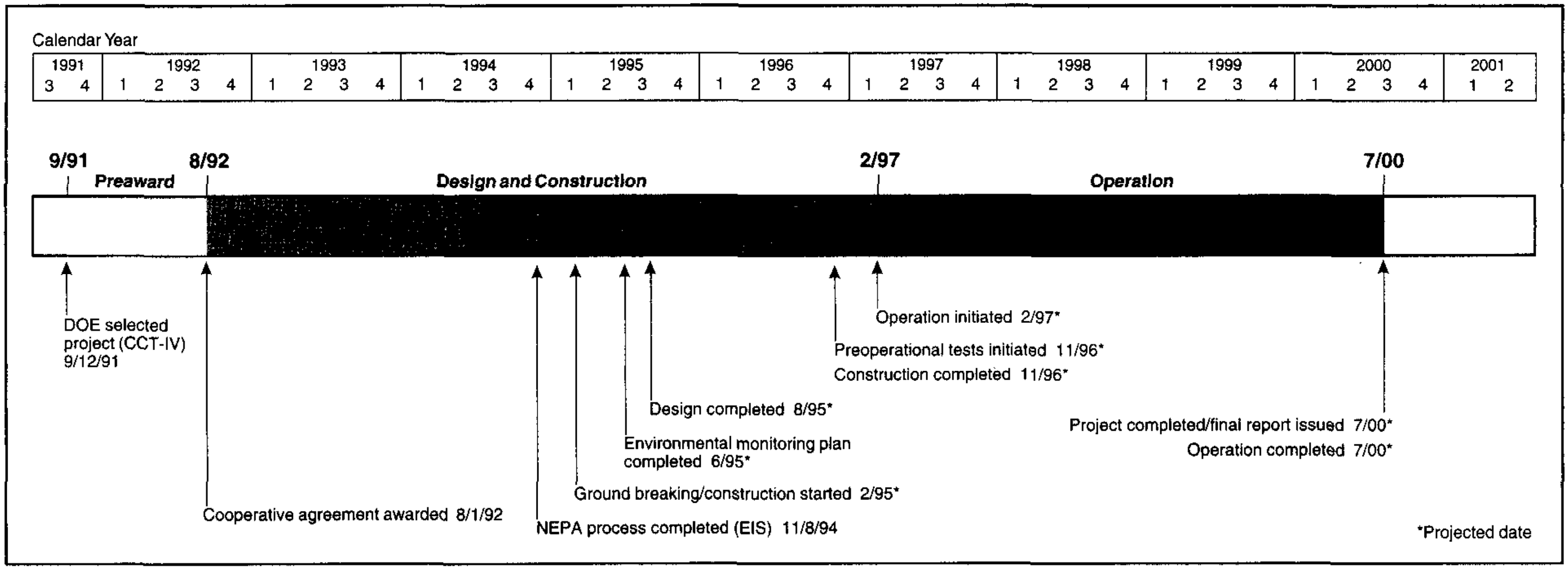
Technology/Project Description:
Dried and crushed coal is introduced into a pressurized, air-blown, fluidized-bed gasifier. Crushed limestone is added to the gasifier to capture a portion of the sulfur and to inhibit conversion of fuel nitrogen to ammonia. The sulfur reacts with the limestone to form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

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

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

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

In the demonstration project, 880 tons/day of coal are converted into 107 MWe (gross), or 99MW e (net), for export to the grid. Western bituminous coal (0.5–0.9% sulfur) from Utah is the design coal; tests



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

Project Status/Accomplishments:

Design and permitting activities continued throughout 1994. A permit to construct the project under the provisions of Nevada's Utilty Environmental Protection Act was issued by the Public Service Commission of Nevada. In June 1994, three public hearings were conducted on the draft EIS. A final EIS was released for public comment on September 30, 1994. DOE issued a record of decision on November 8, 1994. By December 1994, all permits needed for plant construction had been received, and the participant had requested approval from DOE to continue with detailed design and construction of the plant.

Commercial Applications:

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

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

Toms Creek IGCC Demonstration Project

Participant:

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

Additional Team Member:

Institute of Gas Technology—technology developer and consultant

Location:

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

Technology:

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

Plant Capacity/Production:

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

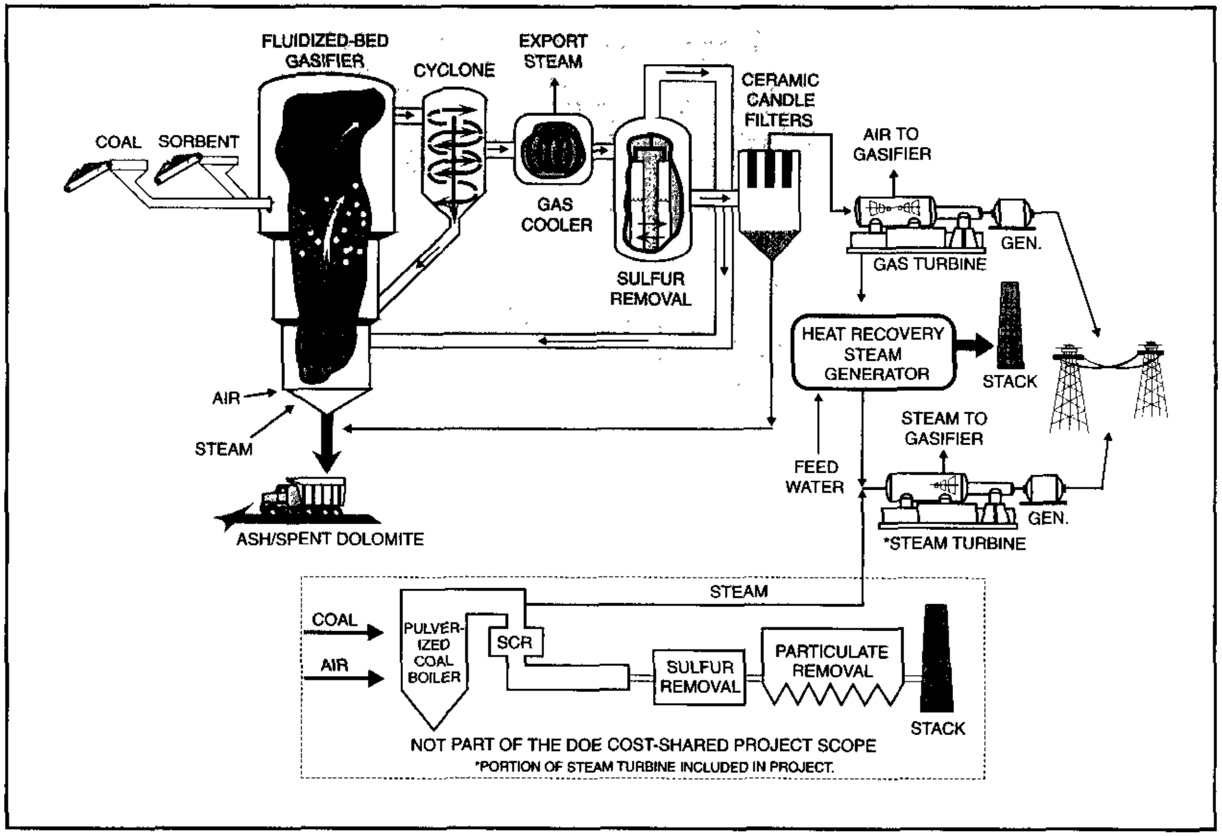
Project Funding:

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

Project Objective:

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

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



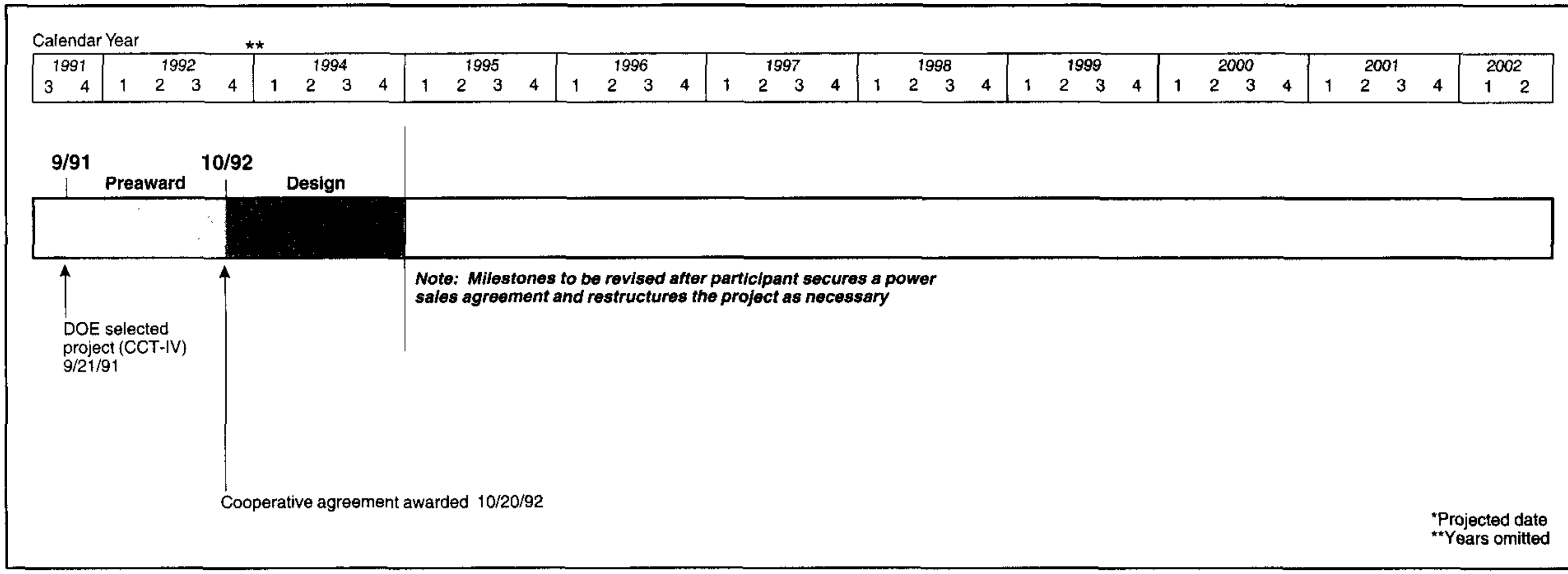
Technology/Project Description:

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

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

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

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



Project Status/Accomplishments:

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

Commercial Applications:

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

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

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

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

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

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

Tampa Electric Integrated Gasification Combined-Cycle Project

Participant:
Tampa Electric Company

Additional Team Members:
Texaco Development Corporation—gasification technology supplier

General Electric Company—combined-cycle technology supplier

GE Environmental Systems, Inc.—hot-gas cleanup technology supplier

TECO Power Services Corporation—project manager and marketer

Bechtel Power Corporation—architect and engineer

Location:
Lakeland, Polk County, FL (Tampa Electric Company's Polk Power Station, Unit 1)

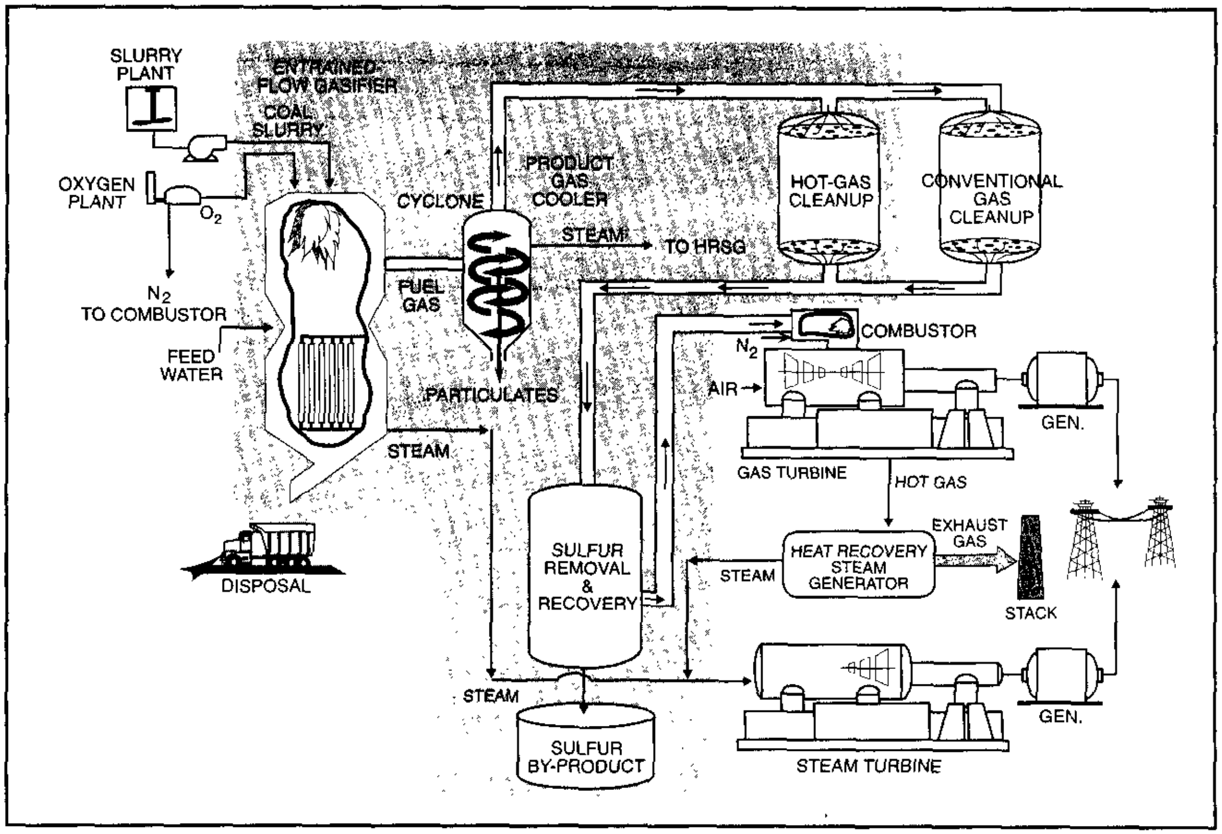
Technology:
Integrated gasification combined-cycle (IGCC) system using Texaco's pressurized, oxygen-blown, entrained-flow gasifier technology and incorporating both conventional, low-temperature acid-gas removal and hot-gas moving-bed desulfurization (advanced electric power generation/integrated gasification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

Plant Capacity/Production:
250 MWe (net)

Project Funding:

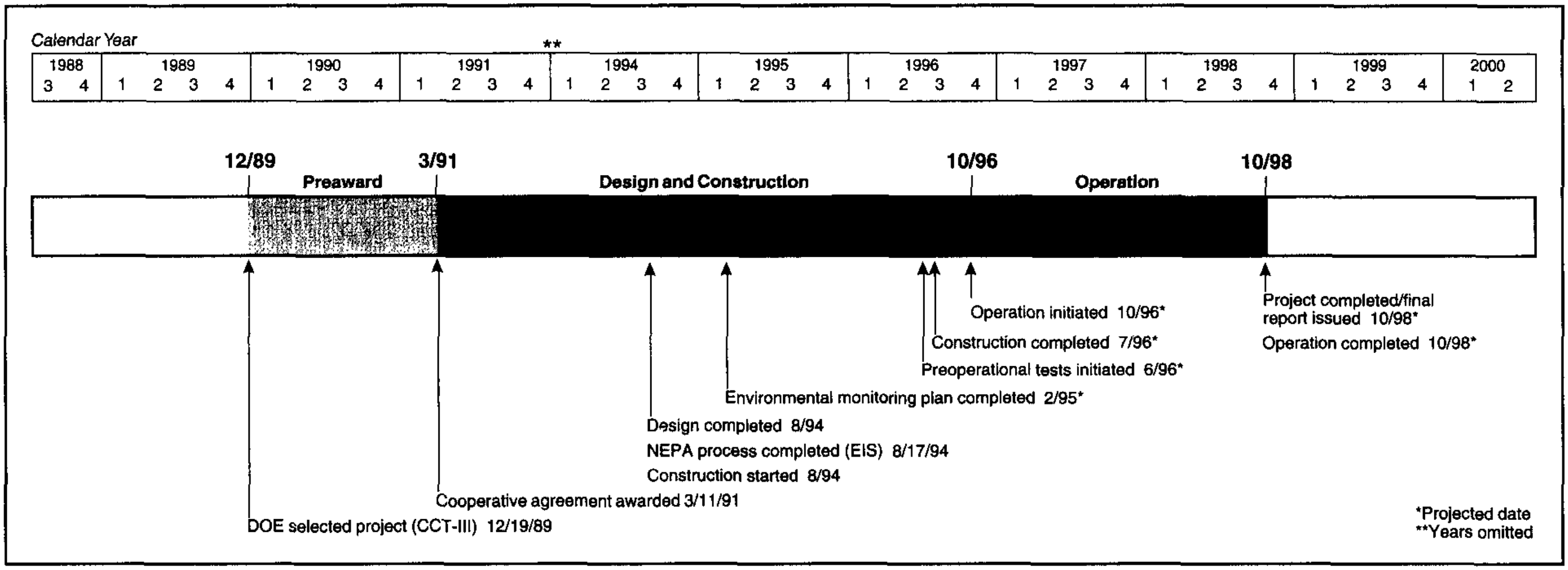
Total project cost	$260,706,446	100%
DOE	130,353,223	50
Participant	130,353,223	50

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



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

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



along with the steam generated in the gasification process, is routed to the steam turbine to generate an additional 120 MWe (gross). The IGCC heat rate for this demonstration is expected to be approximately 8,600 Btu/kWh (40% efficient).

The demonstration project involves only the first 250-MWe (net) portion of the planned 1,150-MWe Polk Power Station. Coals being used in the demonstration are Illinois 6 and Pittsburgh 8 bituminous coals having sulfur contents ranging 2.5–3.5%.

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

Project Status/Accomplishments:

The project is in detailed design and early construction. In January 1994, all state permits for the plant were approved by the governor.

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

Commercial Applications:

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

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

Wabash River Coal Gasification Repowering Project

Participant:

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

Additional Team Members:

PSI Energy, Inc.—host utility

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

Location:

West Terre Haute, Vigo County, IN (PSI Energy's Wabash River Generating Station, Unit 1)

Technology:

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

Plant Capacity/Production:

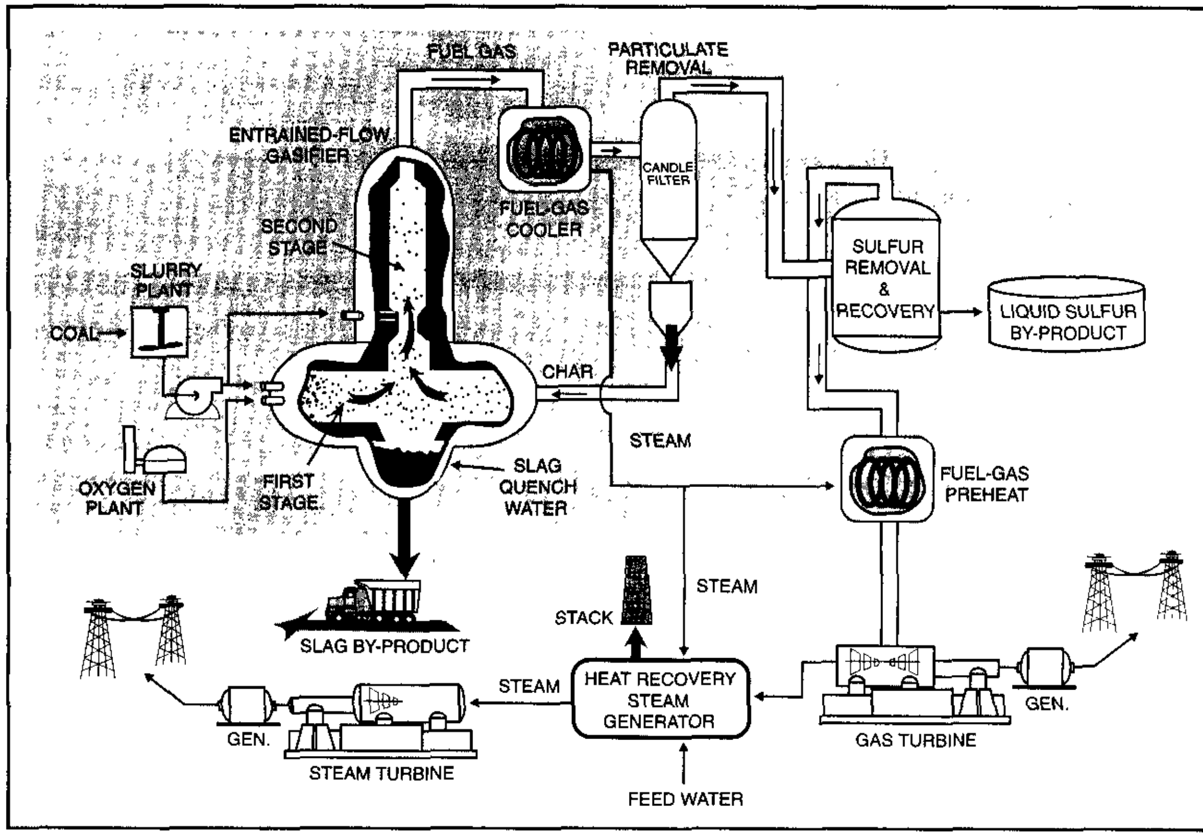
262 MWe (net)

Project Funding:

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

Project Objective:

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

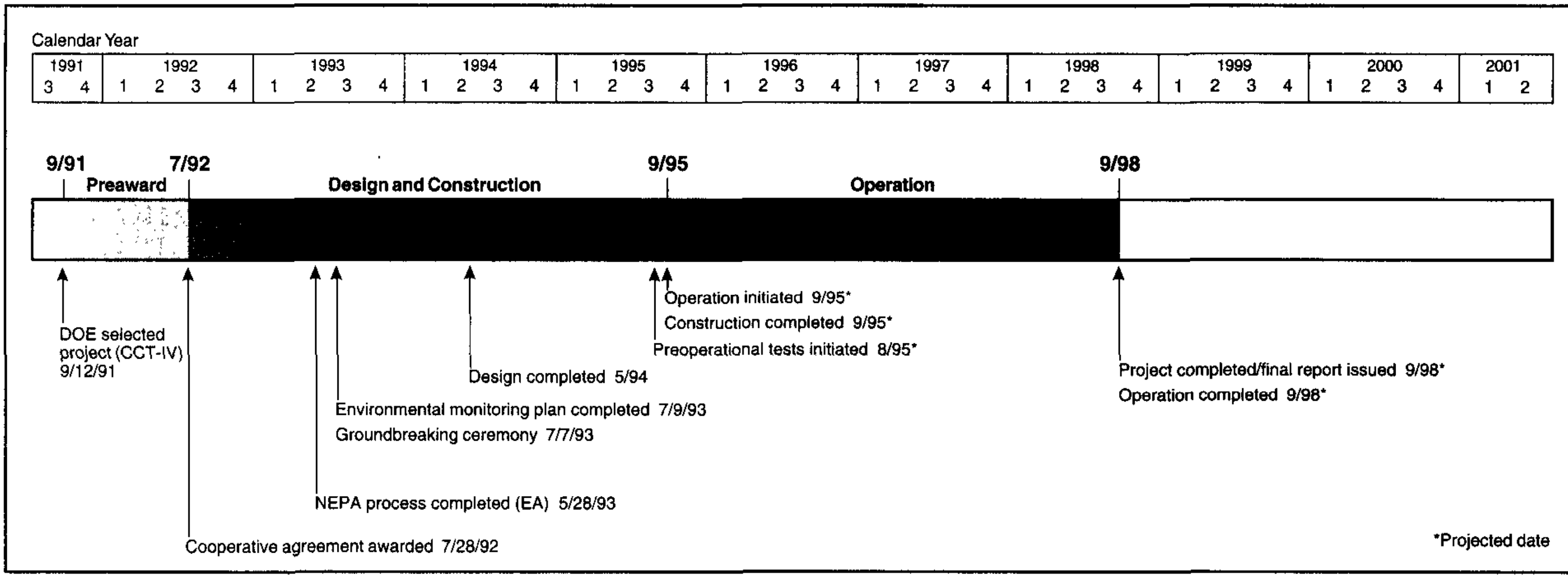


Technology/Project Description:

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

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

One of six units at PSI Energy's Wabash River Generating Station, located in West Terre Haute, IN, is being repowered. The demonstration unit will be designed to generate 262 MWe (net) using 2,544 tons/day of high-sulfur (2.3–5.9% sulfur), Illinois Basin bituminous coal. The anticipated heat rate for the repowered unit is approximately 9,000 Btu/kWh (38% efficiency). Using high-sulfur bituminous coal, SO_2 emissions are expected to be less than 0.1 lb/million Btu (98% reduc-



tion). NO_x emissions are expected to be less than 0.1 lb/million Btu (90% reduction). Upon completion, the project will represent the largest single-train IGCC plant in operation in the United States.

Project Status/Accomplishments:

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

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

Commercial Applications:

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

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

Healy Clean Coal Project

Participant:
Alaska Industrial Development and Export Authority

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

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

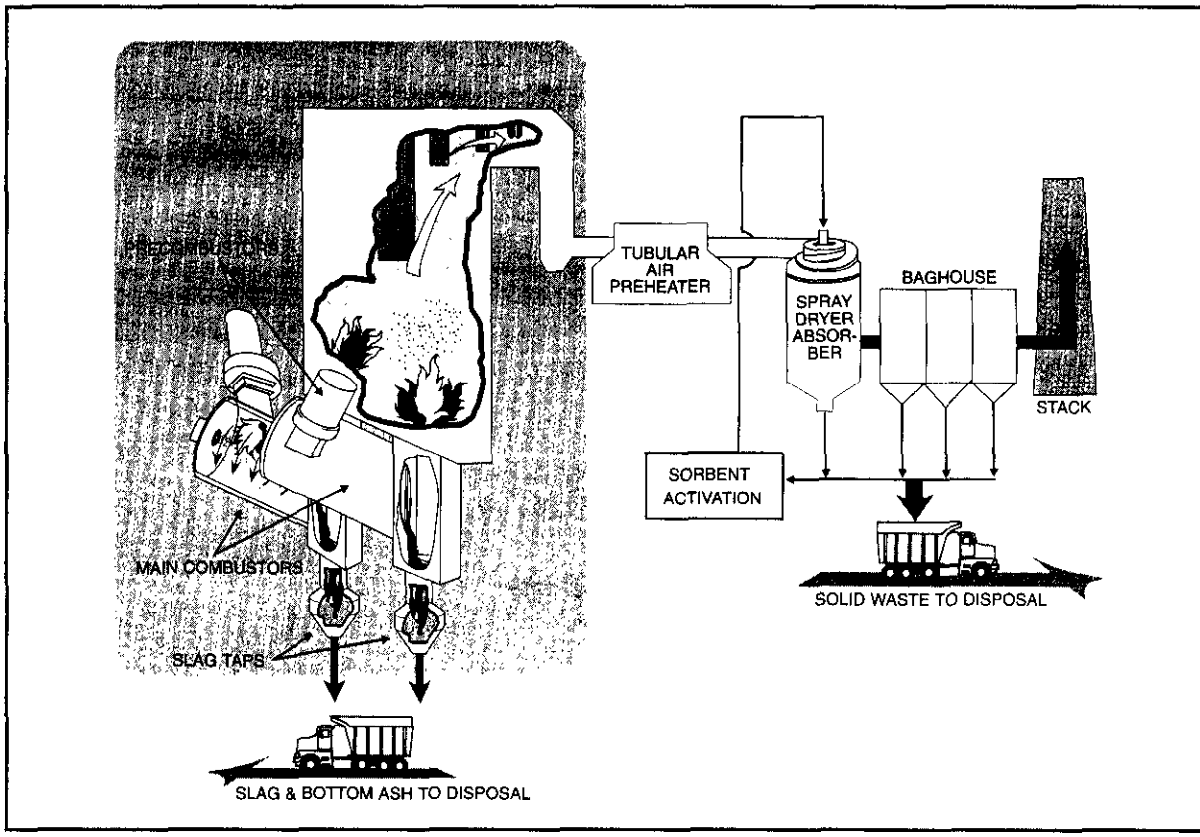
Technology:
TRW's advanced entrained (slagging) combustor
Joy Technologies' spray dryer absorber with sorbent recycle
(advanced electric power generation/advanced combustion/heat engines)

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

Project Funding:

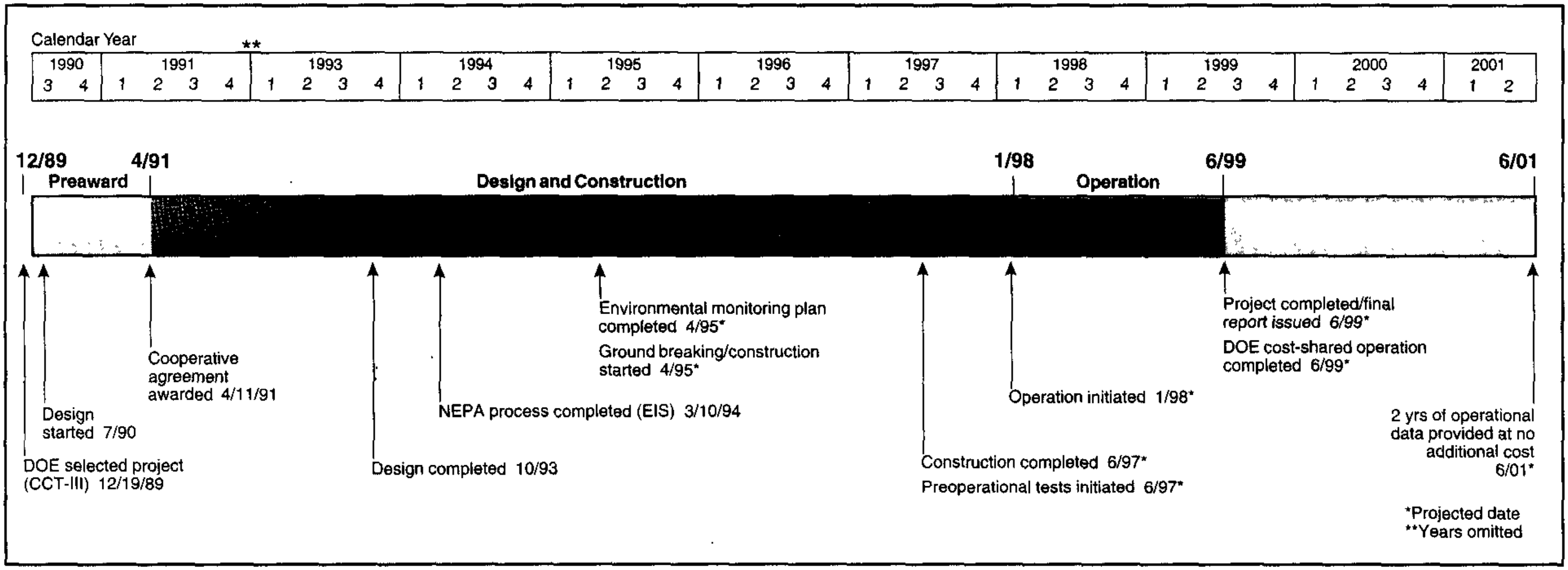
Total project cost	$242,058,000	100%
DOE	117,327,000	48
Participant	124,731,000	52

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



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

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



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

The project site is adjacent to the existing Healy Unit #1 near Healy,AK. Power will go to the Golden Valley Electric Association (GVEA). The plant will use a nominal 900 tons/day of subbituminous coal containing a nominal 0.2% sulfur and waste coal and provide 3 years of data, with 2 years of data being provided at no cost to DOE. A hazardous air pollutant monitoring program will also be implemented.

To address concerns about potential impact to the nearby Denali National Park and Preserve, DOE, the National Park Service, GVEA, and the project participant entered into an agreement to reduce the emissions from Unit #1 reducing the combined emissions from the two units to only slightly greater than those currently emitted from Unit #1 alone. Total site emissons will be further reduced to current levels if necessary to protect the park.

Project Status/Accomplishments:

Test burns using Healy project fuel were completed at TRW's Cleveland facility. Joy/Niro testing of flash-calcined sorbent was completed at the Copenhagen facility. A full-scale precombustor was constructed and test fired at TRW's Capistrano, CA, test facility to verify scale-up designs. The design and engineering is complete; bids for the general construction contract were opened in November 1994; construction is scheduled to start in April 1995.

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

Commercial Applications:

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

Coal Diesel Combined-Cycle Project

Participant:
Arthur D. Little, Inc.

Additional Team Members:
Ohio Coal Development Office—cofunder
The Easton Utilities Commission—host
Cooper Energy Services (Cooper-Bessemer Reciprocating Products Division is a division of Cooper Energy Services which is owned by Cooper Industries.)—engine supplier and commercializer
CQ, Inc.—coal-slurry supplier
PSI—cleanup system designer
AMBAC International—coal-water fuel injection system components supplier

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

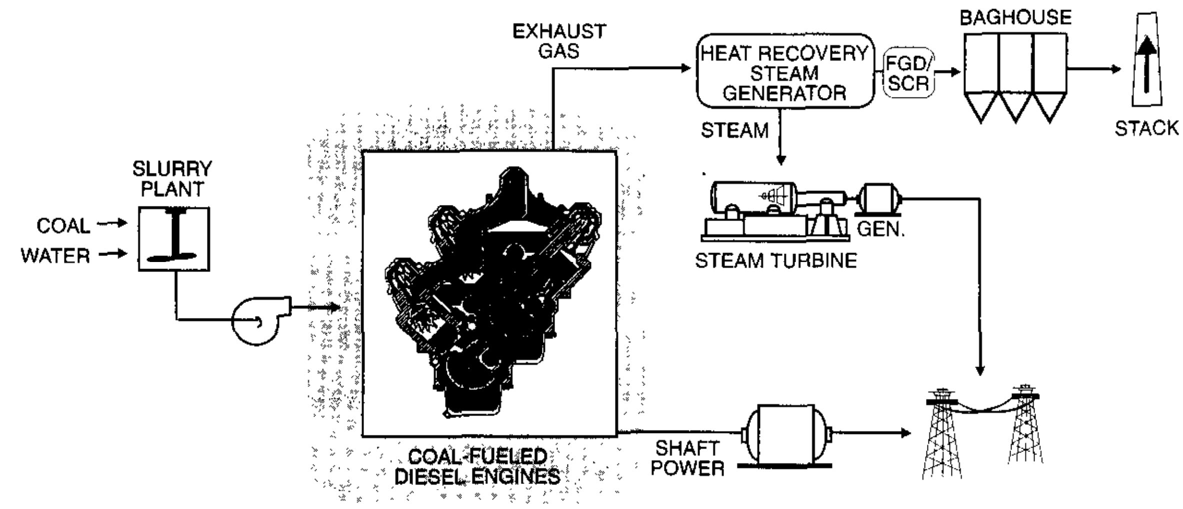
Technology:
Cooper-Bessemer's coal-fueled diesel engine combined-cycle (CDCC) system (advanced electric power generation/advanced combustion/heat engines)

Plant Capacity/Production:
14 MWe (net)

Project Funding:

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

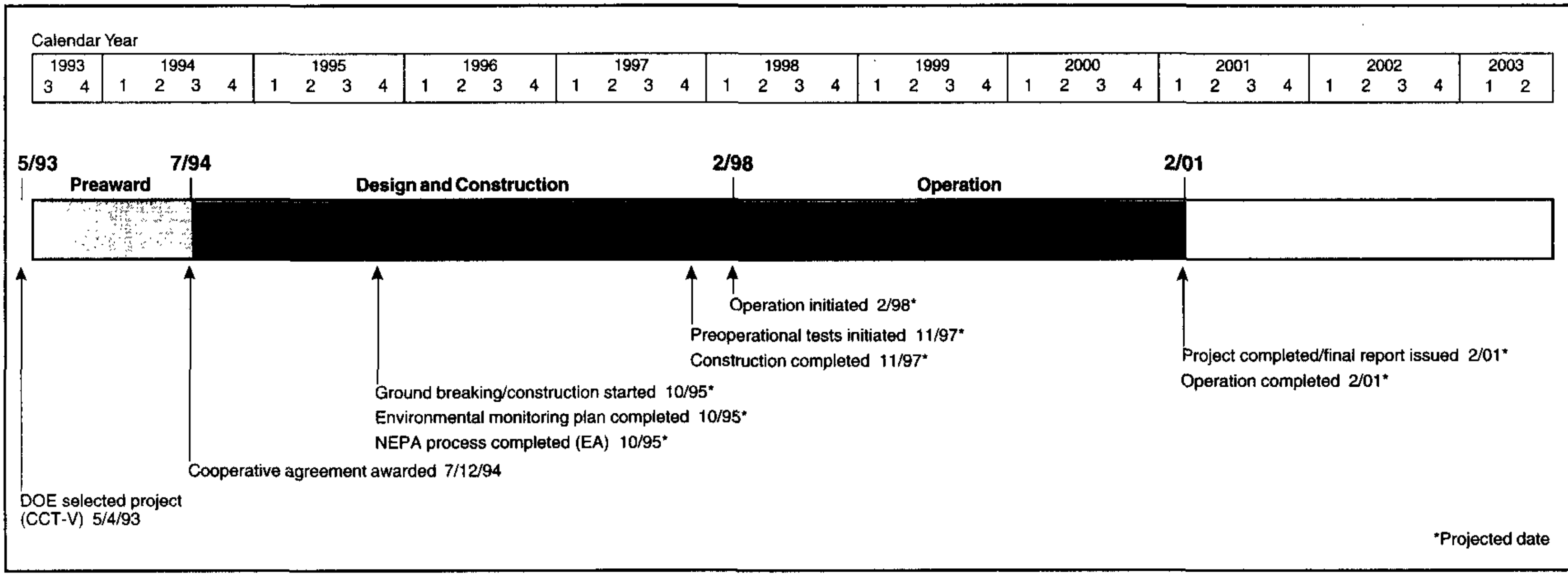
Project Objective:
To demonstrate an advanced, coal-fueled diesel engine combined-cycle system based on Cooper-Bessemer's LSB/LSVB diesel engine series. To provide critical data on the performance, reliability, and wear information of all major subsystems.



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

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

The demonstration site is The Easton Utilities Commission's Plant #2 in Easton, MD. Planned for use in making the coal-water fuel is an Ohio bituminous coal



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

Project Status/Accomplishments:

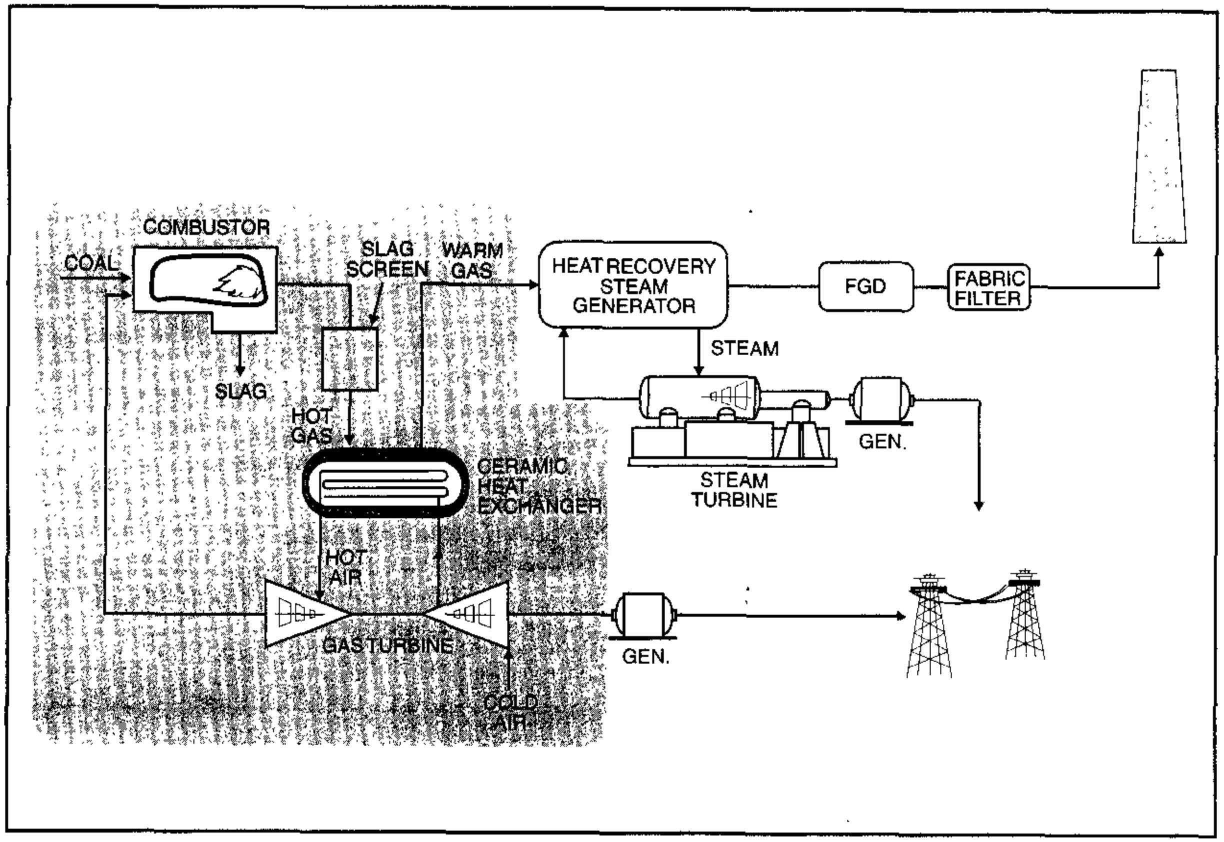
The cooperative agreement was awarded July 12, 1994. Design efforts are in progress. Environmental information is being prepared for use in the NEPA process. The participant has finalized its subcontract arrangements with Cooper-Bessemer and CQ, Inc., as well as its funding agreement with the Ohio Coal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

Commercial Applications:

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

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

Warren Station Externally Fired Combined-Cycle Demonstration Project



Participant:

Pennsylvania Electric Company

Additional Team Members:

Hague International—technology developer and supplier
Black & Veatch—engineer and construction manager

Location:

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

Technology:

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

Plant Capacity/Production:

62.4 MWe (net)

Project Funding:

Total project cost	$146,832,000	100%
DOE	73,416,000	50
Participant	73,416,000	50

Project Objective:

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

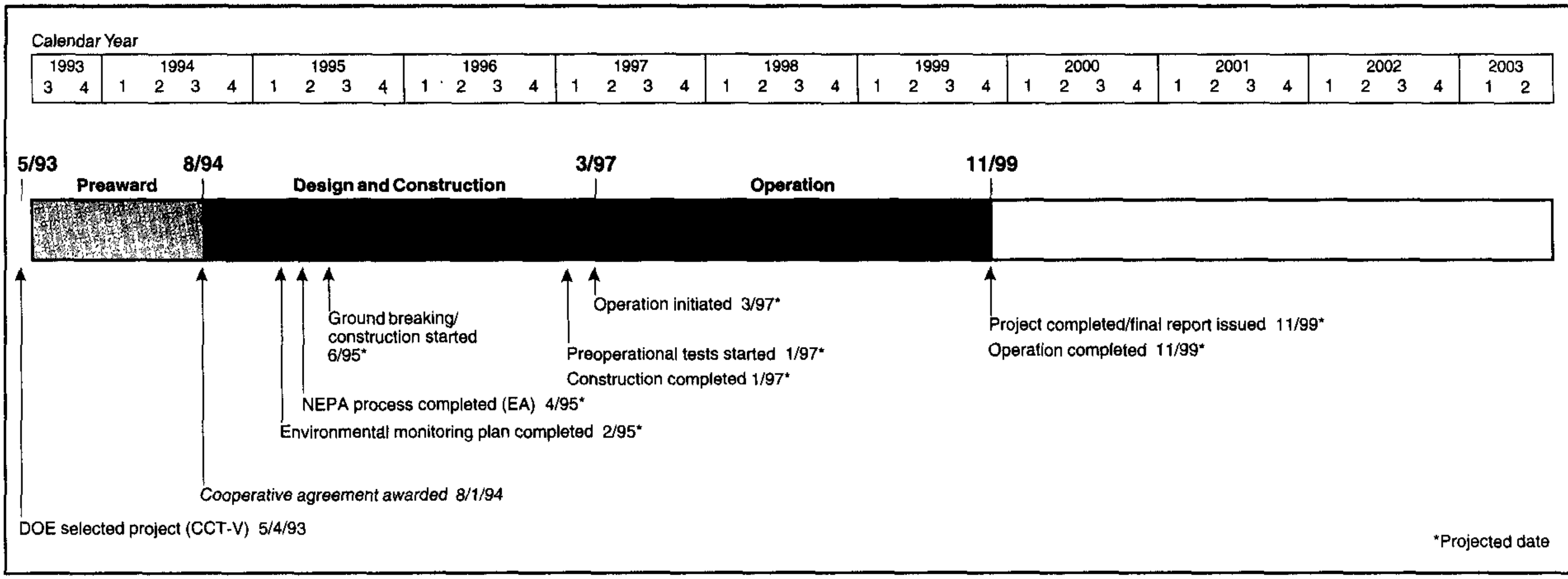
Technology/Project Description:

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

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

The attractiveness of the EFCC lies in its ability to eliminate the need for a hot gas cleanup system to protect the costly gas turbine gas-path components from the corrosive and abrasive elements in the combustion product gas. Instead, the gas turbine operates on indirectly heated clean air and the gas path is never exposed to the corrosive elements in the fuel or product gas. The

CerHx is a registered trademark of Hague International.



CerHx® raises the temperature of the air to the turbine inlet conditions using tube elements that are manufactured from corrosion resistant, toughened, ceramic materials.

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

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

Project Status/Accomplishments:

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

Commercial Applications:

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

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

Environmental Control Devices Fact Sheets

Demonstration of Coal Reburning for Cyclone Boiler NO_x Control

Project completed.

Participant:

The Babcock & Wilcox Company

Additional Team Members:

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

Location:

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

Technology:

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

Plant Capacity/Production:

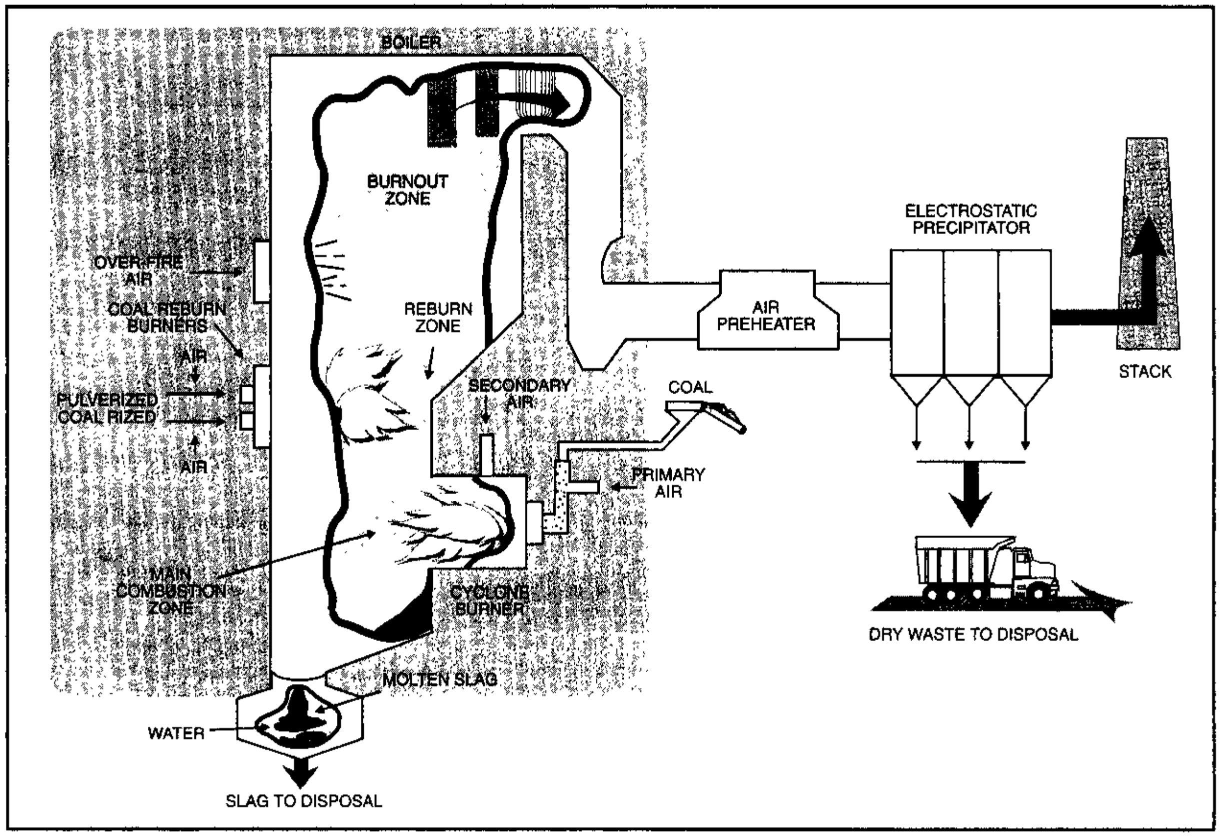
100 MWe

Project Funding:

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

Project Objective:

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



Technology/Project Description:

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

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

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

Project Results/Accomplishments:

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

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

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

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

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

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

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

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

Additional effects of coal reburning on the retrofitted boiler follow:

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

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

Commercial Applications:

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

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

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

Project Schedule:

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

Final Reports:

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

Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit

Project completed.

Participant:
The Babcock & Wilcox Company

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

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

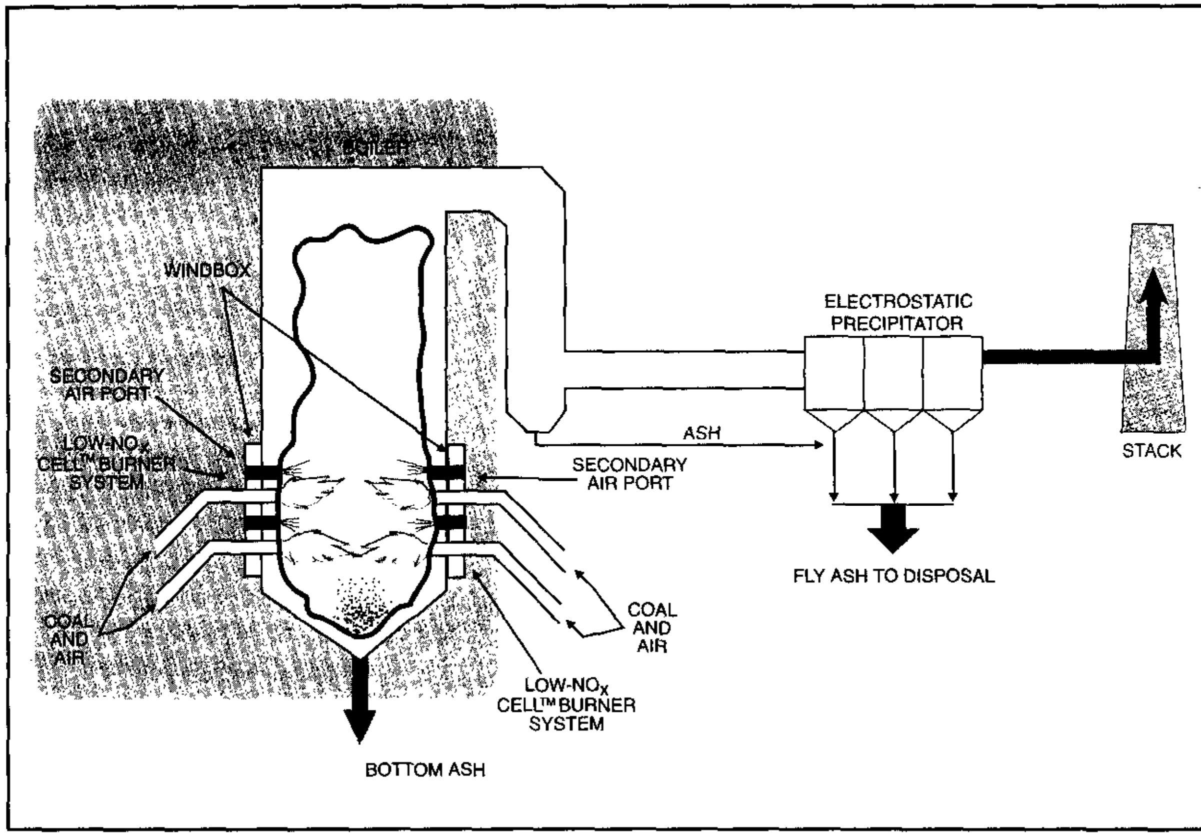
Technology:
The Babcock & Wilcox Company's low-NO_x cell burner (LNCB®) system (environmental control devices/NO_x control technologies)

Plant Capacity/Production:
605 MWe

Project Funding:

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

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



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

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

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

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

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

Project Results/Accomplishments:

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

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

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

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

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

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

Commercial Applications:

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

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

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

Project Schedule:

DOE selected project (CCT-III)	12/19/89
Cooperative agreement awarded	10/11/90
NEPA process completed (MTF)	8/10/90
Environmental monitoring plan completed	8/9/91
Construction	9/91–11/91
Operational testing	12/91–4/93
Project completed*	3/95

Final Reports:

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

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

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

Participant:
Energy and Environmental Research Corporation

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

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

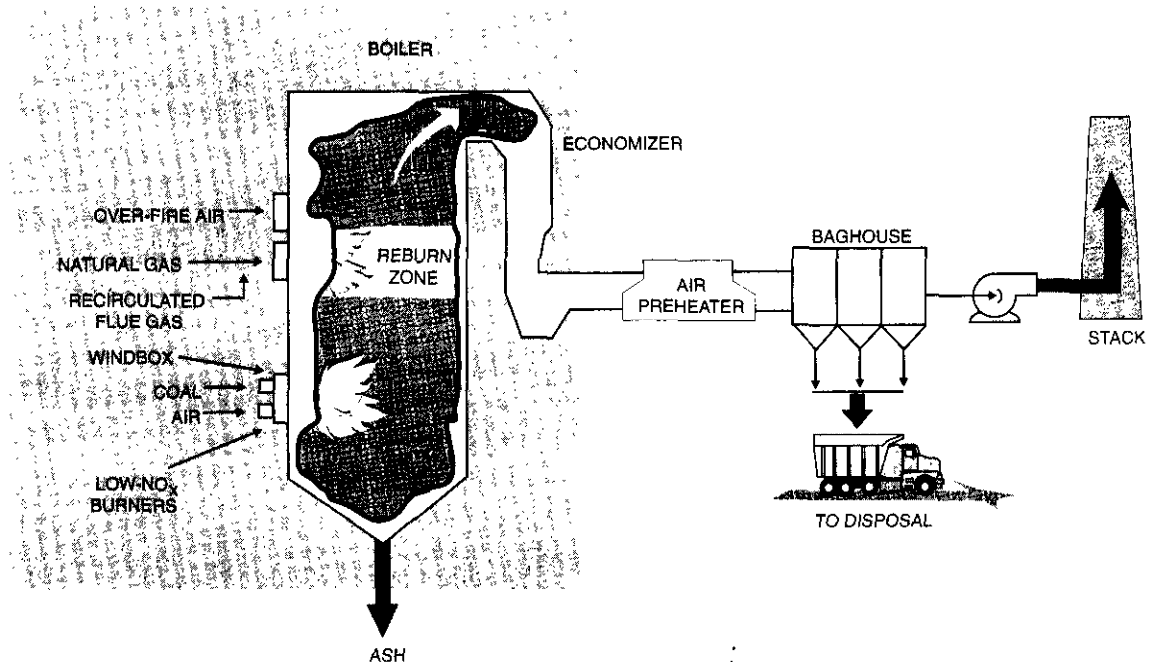
Technology:
Energy and Environmental Research Corporation's gas reburning and low-NO_x burner (GR–LNB) system (environmental control devices/NO_x control technologies)

Plant Capacity/Production:
172 MWe

Project Funding:

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

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



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

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

measure the amount of air through the SOFA system. LNCFS LevelIII utilizes both CCOF A and SOFA.

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

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

Project Results/Accomplishments:

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

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

Commercial Applications:

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

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

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

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

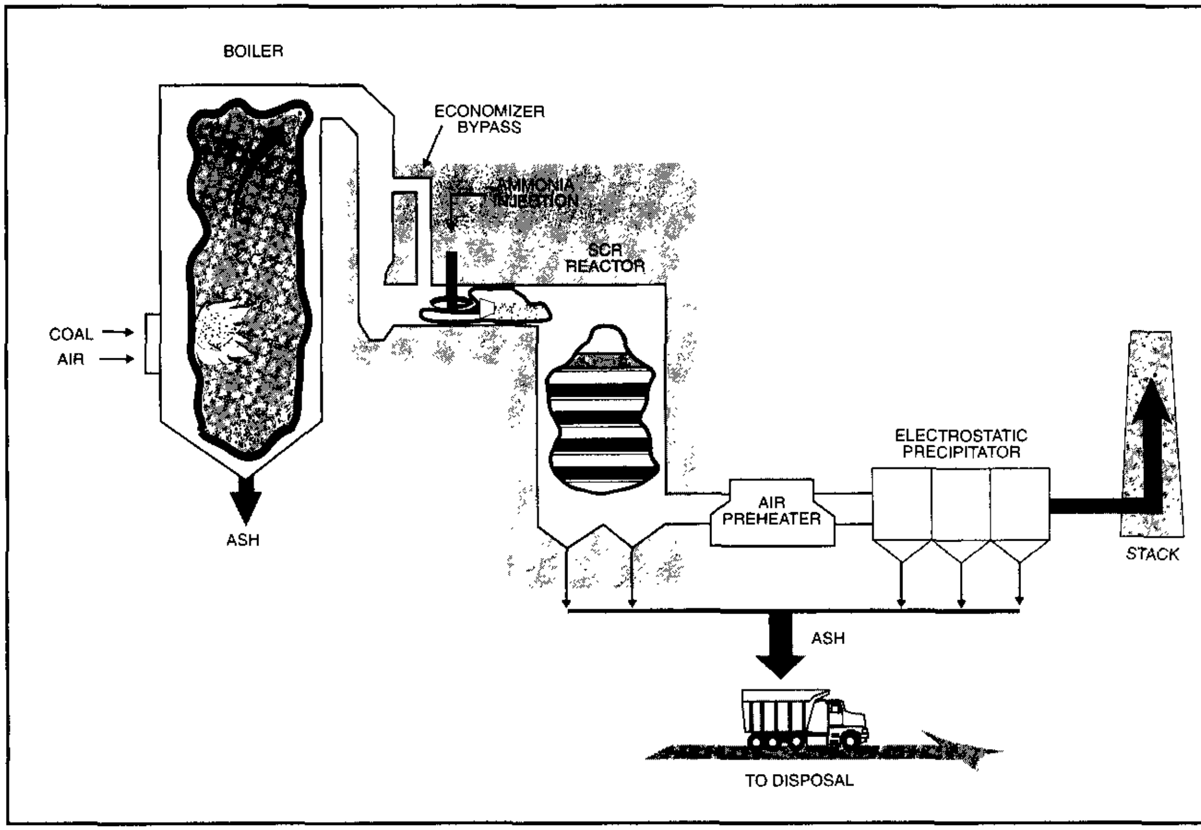
Project Schedule:

DOE selected project (CCT-III)	9/28/88
Cooperative agreement awarded	9/20/90
NEPA process completed (MTF)	7/21/89
Environmental monitoring plan completed	12/27/90
Construction	11/90–5/91
Operational testing	5/91–12/92
Project completed	6/94

Final Reports:

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

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



Participant:
Southern Company Services, Inc.

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

Location:
Pensacola, Escambia County, FL (Gulf Power Company's Plant Crist, Unit 4)

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

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

Project Funding:

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

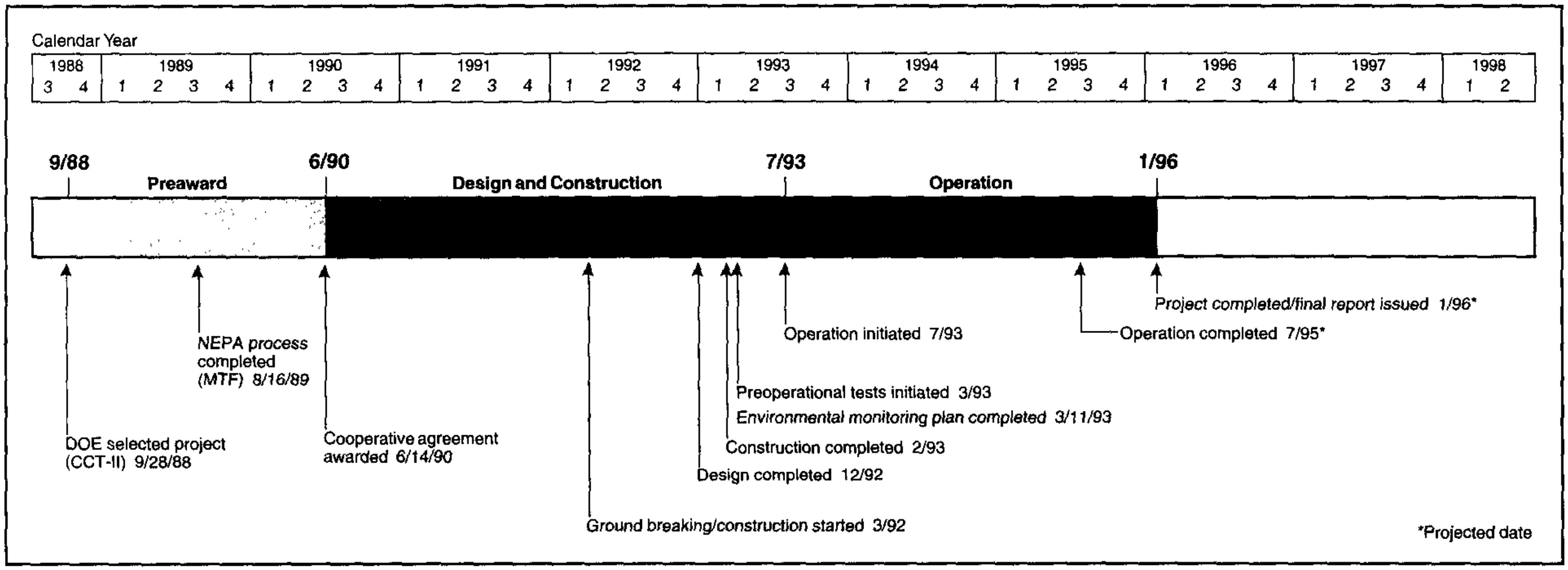
Project Objective:
To evaluate the performance of commercially available SCR catalysts when applied to operating conditions found in U.S. pulverized coal-fired utility boilers using U.S. high-sulfur coal under various operating conditions while achieving as much as 80% NO_x removal.

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

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

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

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



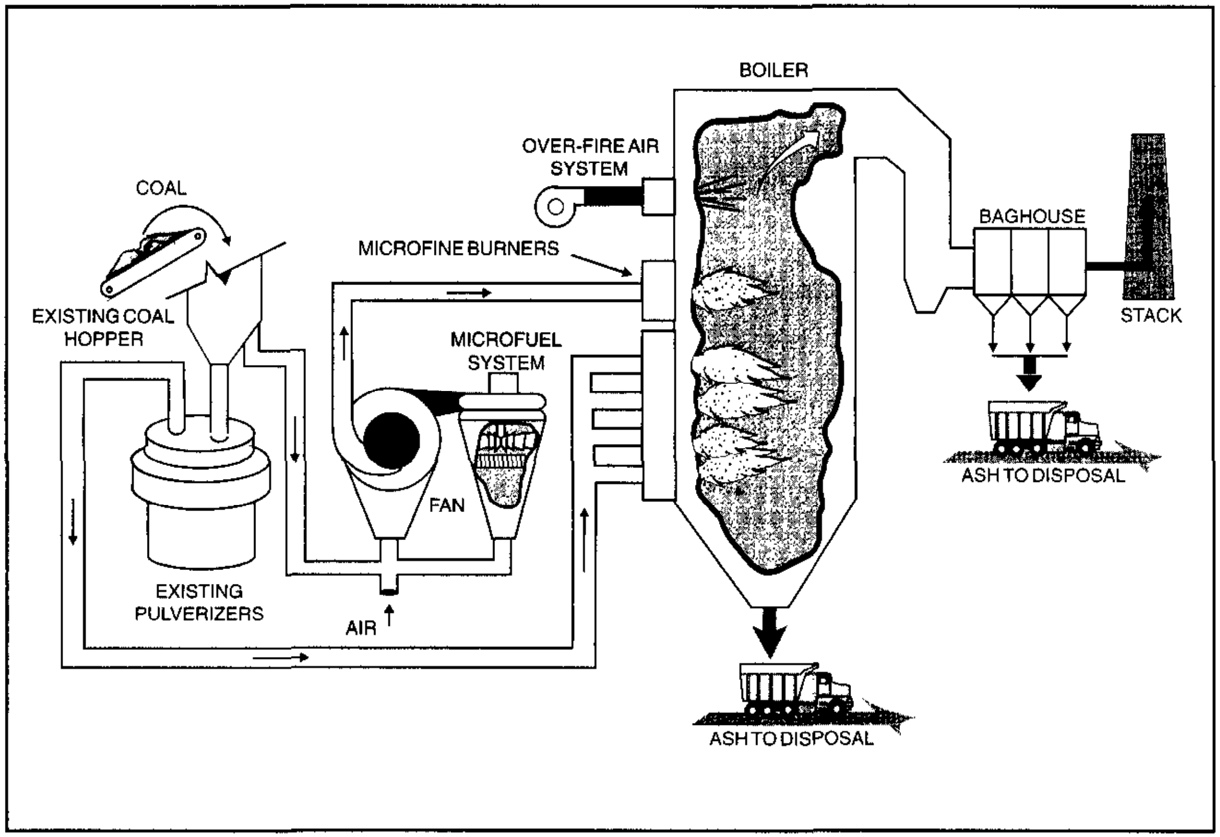
Project Status/Accomplishments:
Preliminary design engineering for the SCR test facility was concluded at the end of February 1991. Construction began in late-March 1992; a dedication ceremony was held on July 1, 1992. Detailed engineering was completed in December 1992. Flue gas was first passed through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

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

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

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

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



Participant:

Tennessee Valley Authority

Additional Team Members:

Duke/Fluor Daniel (partnership between Duke Engineering & Services, Inc., and Fluor Daniel, Inc.)—engineer and constructor

Fuller Company—technology supplier

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

Location:

Negotiations for a new site are under way.

Technology:

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

Plant Capacity/Production:

175 MWe

Project Funding:

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

Project Objective:

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

Technology/Project Description:

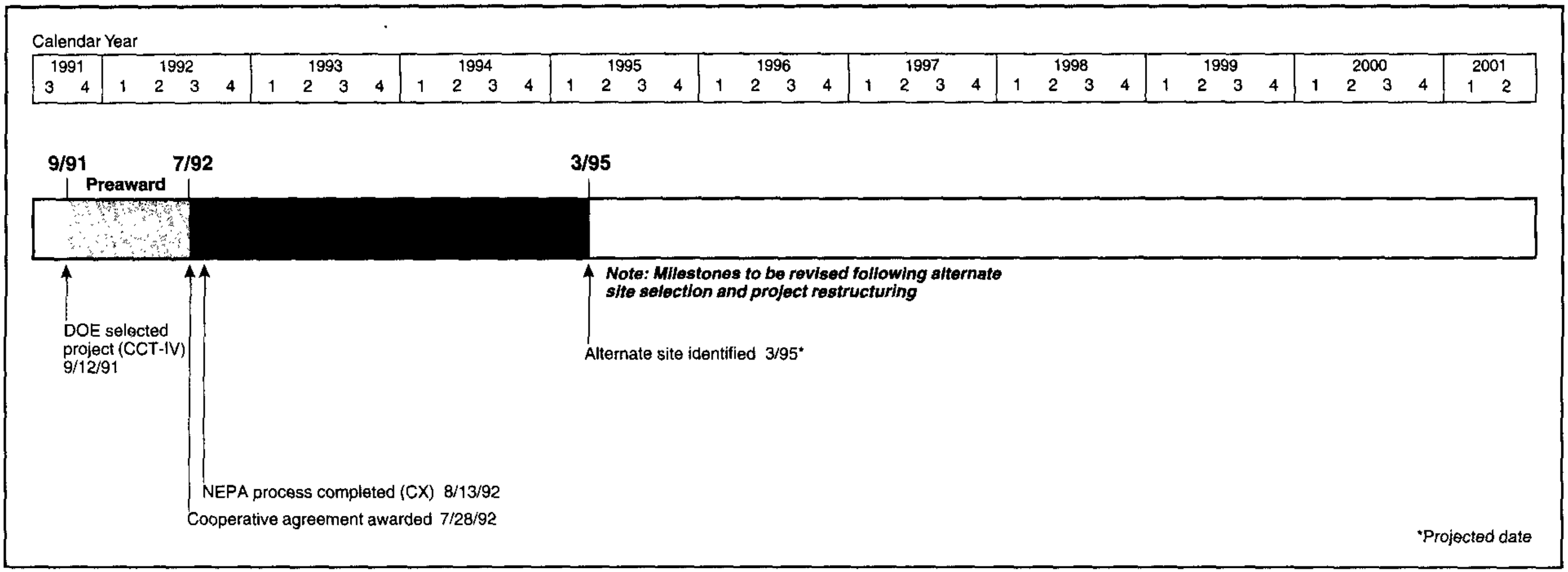
The technology will be applied to a pulverized coal furnace. The coal to be used to fire the furnace will be a low-sulfur bituminous coal. This same coal will be used as the reburning fuel. The reburning coal, which can comprise up to 30% of the total fuel, is micronized (80% below 325 mesh) and injected into the furnace above the main burner, the region where NO_x formation occurs.

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

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

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

MicroMill is a trademark of the Fuller Company.



Project Status/Accomplishments:

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

Commercial Applications:

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

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

10-MWe Demonstration of Gas Suspension Absorption

Project completed.

Participant:
AirPol, Inc.

Additional Team Members:
FLS miljo a/s (parent company of AirPol, Inc.)—technology owner
Tennessee Valley Authority—cofunder and site owner

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

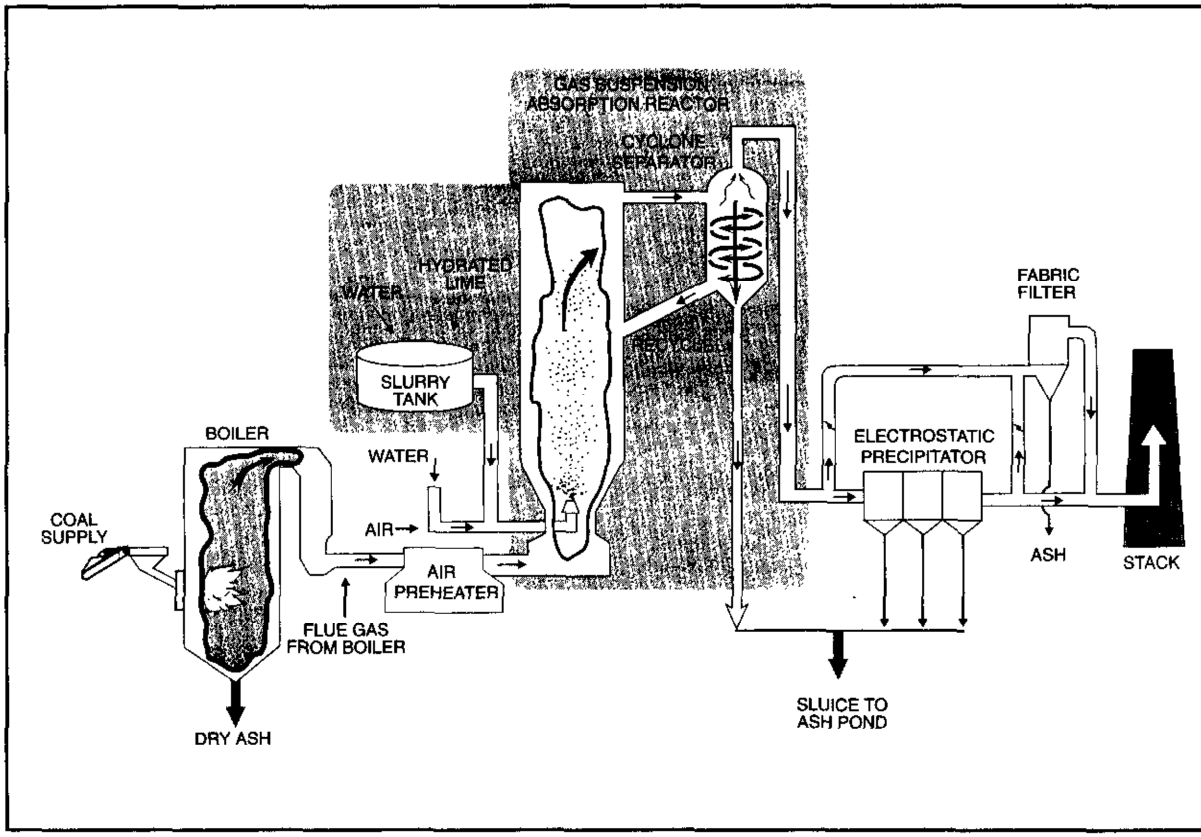
Technology:
FLS miljo a/s' Gas Suspension Absorption (GSA) system for flue gas desulfurization (FGD) (environmental control devices/SO_2 control technologies)

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

Project Funding:

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

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



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

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

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

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

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

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

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

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

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

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

Commercial Applications:

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

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

In addition, FLS miljo has been awarded a major project in Sweden for a high-performance GSA system to remove sulfur from the flue gas of a 4-million-ton/year iron ore sinter plant. Sweden's stringent standards require an SO_2 removal efficiency of 90–95%.

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

Project Schedule:

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

Final Reports:

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

Confined Zone Dispersion Flue Gas Desulfurization Demonstration

Project completed.

Participant:
Bechtel Corporation

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

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

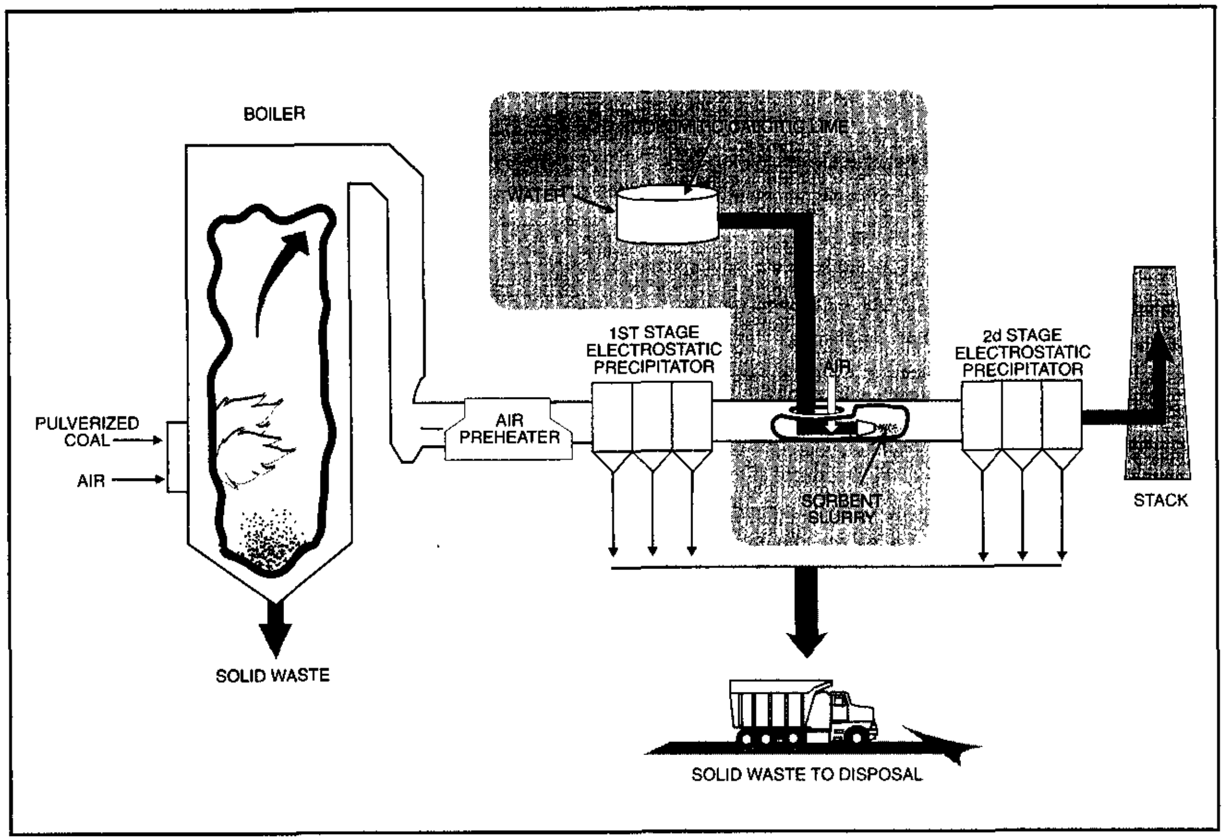
Technology:
Bechtel Corporation's in-duct, confined zone dispersion flue gas desulfurization (CZD/FGD) process (environmental control devices/SO_2 control technologies)

Plant Capacity/Production:
73.5 MWe

Project Funding:

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

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



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

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

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

Project Results/Accomplishments:

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

In summary, the demonstration showed the following:

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

Bechtel notified DOE on June 30, 1993, that it was discontinuing the demonstration project effective July 1, 1993.

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

Commercial Applications:

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

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

Project Schedule:

DOE selected project (CCT-III)	12/19/89
Cooperative agreement awarded	10/13/90
NEPA process completed (MTF)	9/25/90
Environmental monitoring plan completed	6/12/91
Construction	3/91–6/91
Operational testing	7/91–6/93
Project completed	6/95

Final Reports:

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

LIFAC Sorbent Injection Desulfurization Demonstration Project

Project completed.

Participant:

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

Additional Team Members:

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

Location:

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

Technology:

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

Plant Capacity/Production:

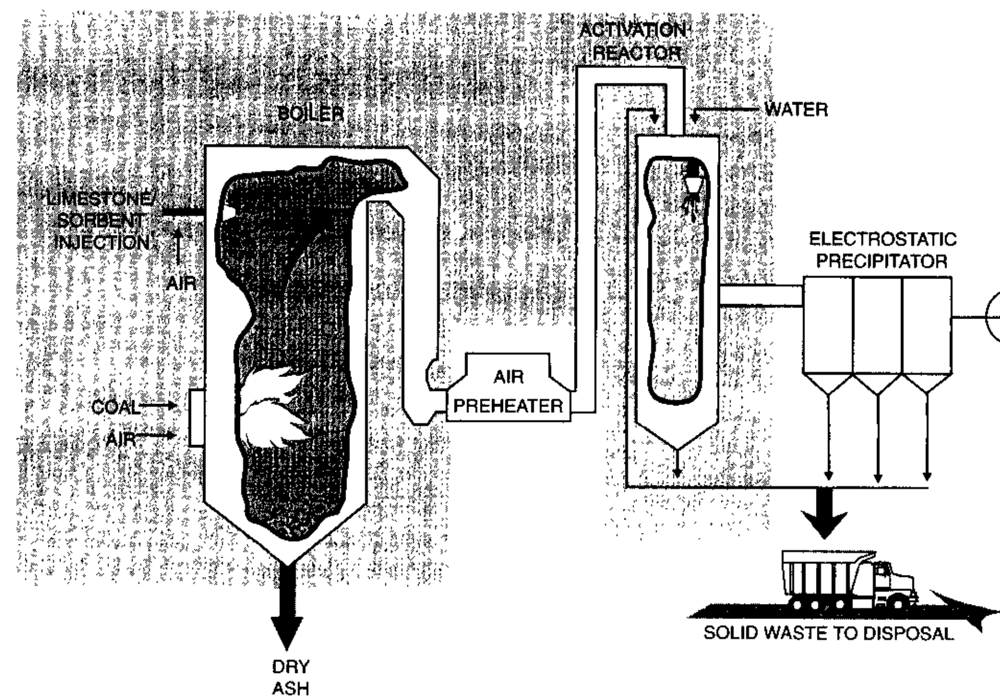
60 MWe

Project Funding:

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

Project Objective:

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



Technology/Project Description:

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

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

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

Project Results/Accomplishments:

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

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

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

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

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

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

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

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

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

Commercial Applications:

This process is suitable for application to all coal-fired utility or industrial boilers, especially those with tight space limitations. The LIFAC process is less expensive to install than conventional wet flue gas desulfurization processes, uses dry limestone instead of more costly lime, is relatively simple to operate, produces a dry, readily disposable waste, and can handle all types of coal.

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

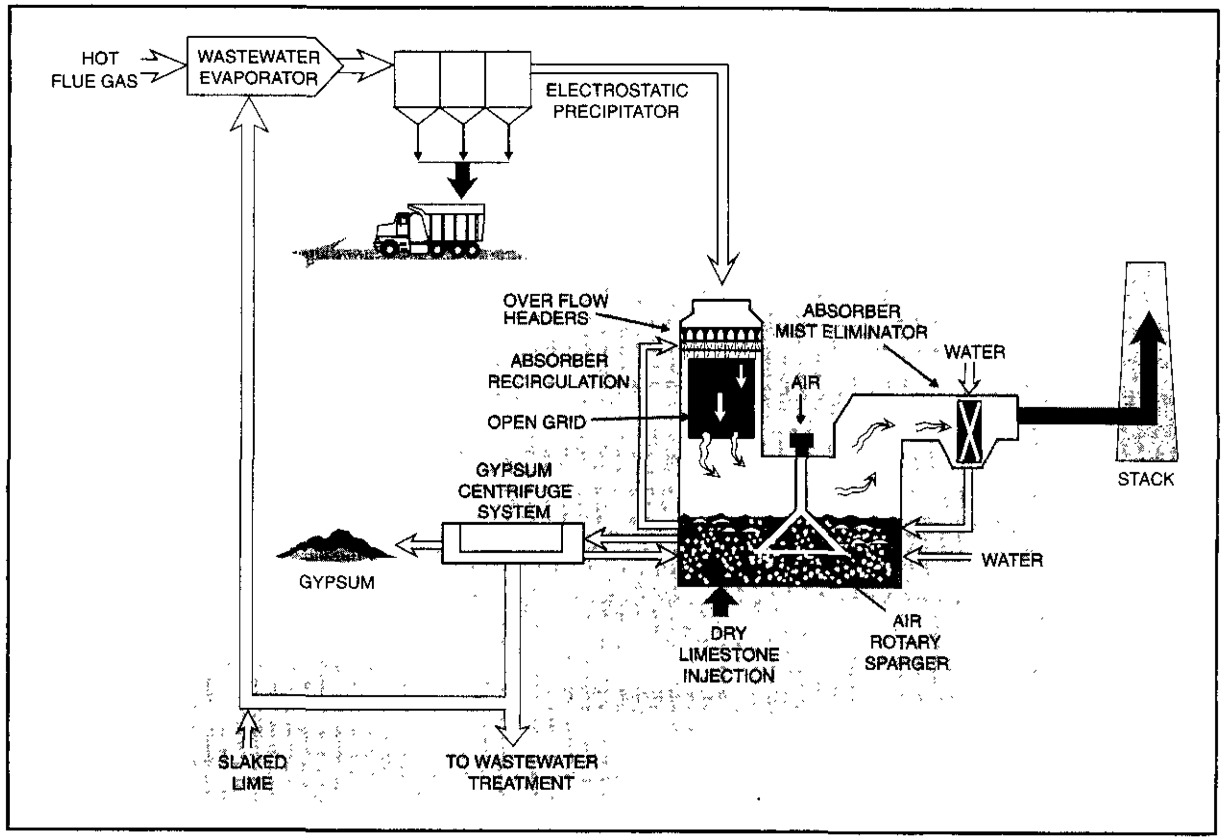
Project Schedule:

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

Final Reports:

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

Advanced Flue Gas Desulfurization Demonstration Project



Participant:

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

Additonal Team Members:

Northern Indiana Public Service Company—cofunder and host utility

Mitsubishi Heavy Industries, Ltd.—process designer

United Engineers and Constructors (Stearns-Roger Division)—facility designer

Air Products and Chemicals, Inc.—constructor and operator

Location:

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

Technology:

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

Plant Capacity/Production:

528 MWe

Project Funding:

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

Project Objective:

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

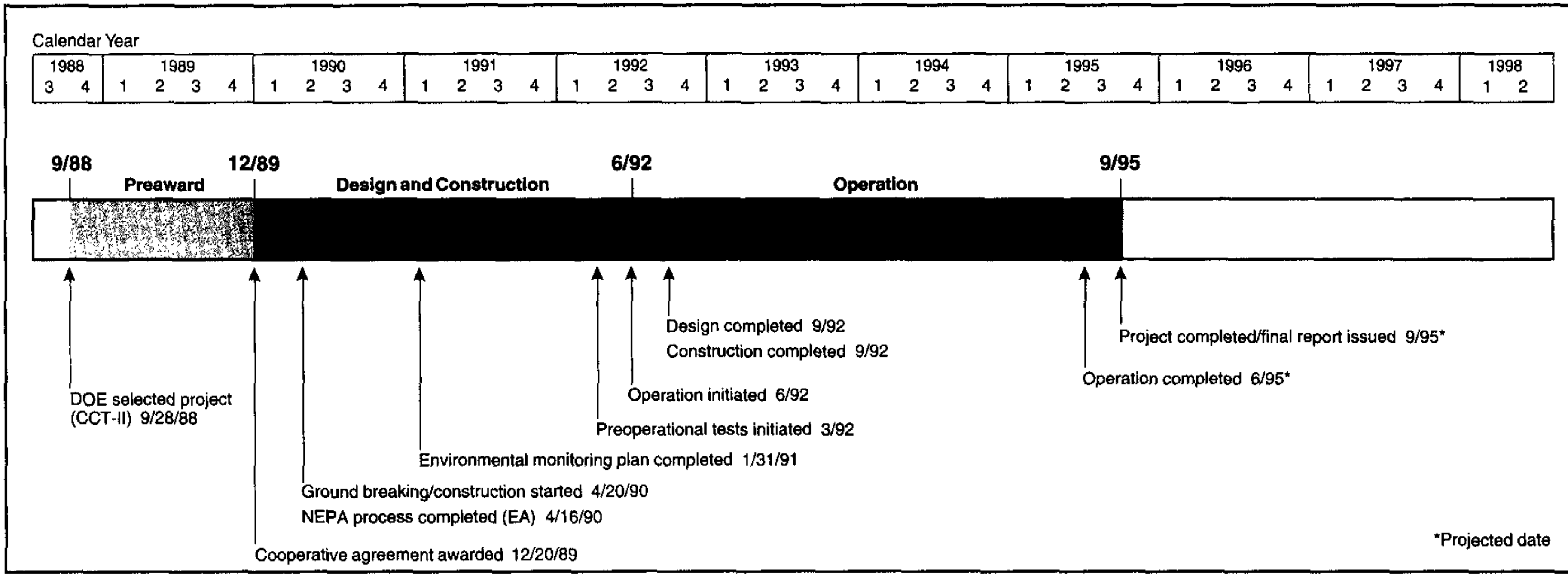
Technology/Project Description:

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

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

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

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



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

The project also seeks to demonstrate a novel business concept whereby Pure Air owns and operates the AFGD facility. Thus, Pure Air expects to specialize in pollution control activities, relieving the electric utility of the operation of the AFGD unit. After the 3-year demonstration period, Pure Air will continue to own the AFGD facility and to operate it as a contracted service to the utility for an additional 17-year period. The demonstration is located at Northern Indiana Public Service Company's 528-MWe Bailly Generating Station near Chesterton, IN, and testing bituminous coals containing 2–4.5% sulfur.

Project Status/Accomplishments:

Operational testing continued through 1994. Tests on the utility's standard coal (3–3.5% sulfur) were completed in 1992. During 1993, tests were conducted on coals with 3.5–4% sulfur and 2.5–3% sulfur. In 1994, tests were completed on coals with 4–4.5% sulfur and 2-2.5% sulfur. The scrubber is achieving SO_2 removals in excess of 95% while producing a commercial gypsum by-product with an average purity level of 97%. Smooth operation continues, and performance continues to be very good.

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

Commercial Applications:

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

The AFGD facility will reduce SO_2 emissions at the Bailly Station by approximately 75,000 tons/yr. Further, the gypsum by-product and wastewater evaporation will demonstrate that SO_2 control can occur without increased solid waste or wastewater production.

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

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

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

Participant:
Southern Company Services, Inc.

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

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

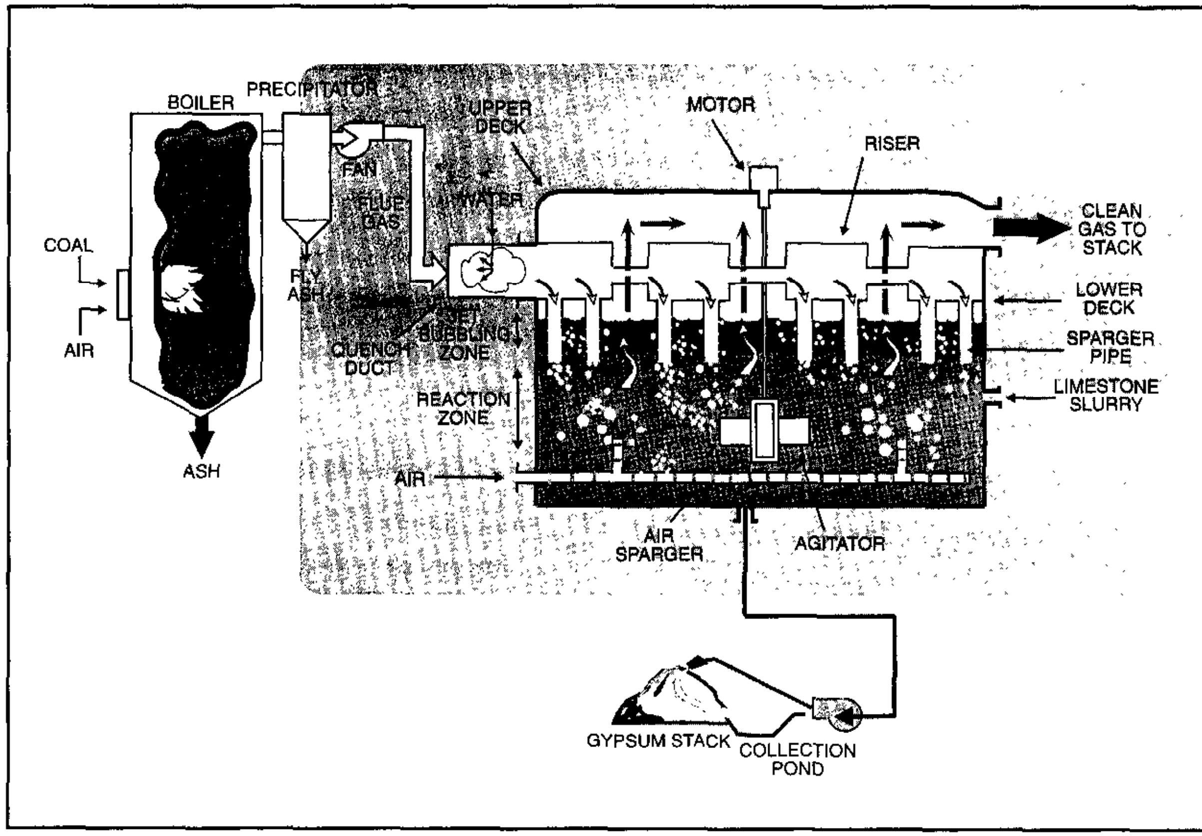
Technology:
Chiyoda Corporation's Chiyoda Thoroughbred-121 (CT-121) advanced flue gas desulfurization (FGD) process (environmental control devices/SO_2 control technologies)

Plant Capacity/Production:
100 MWe

Project Funding:

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

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



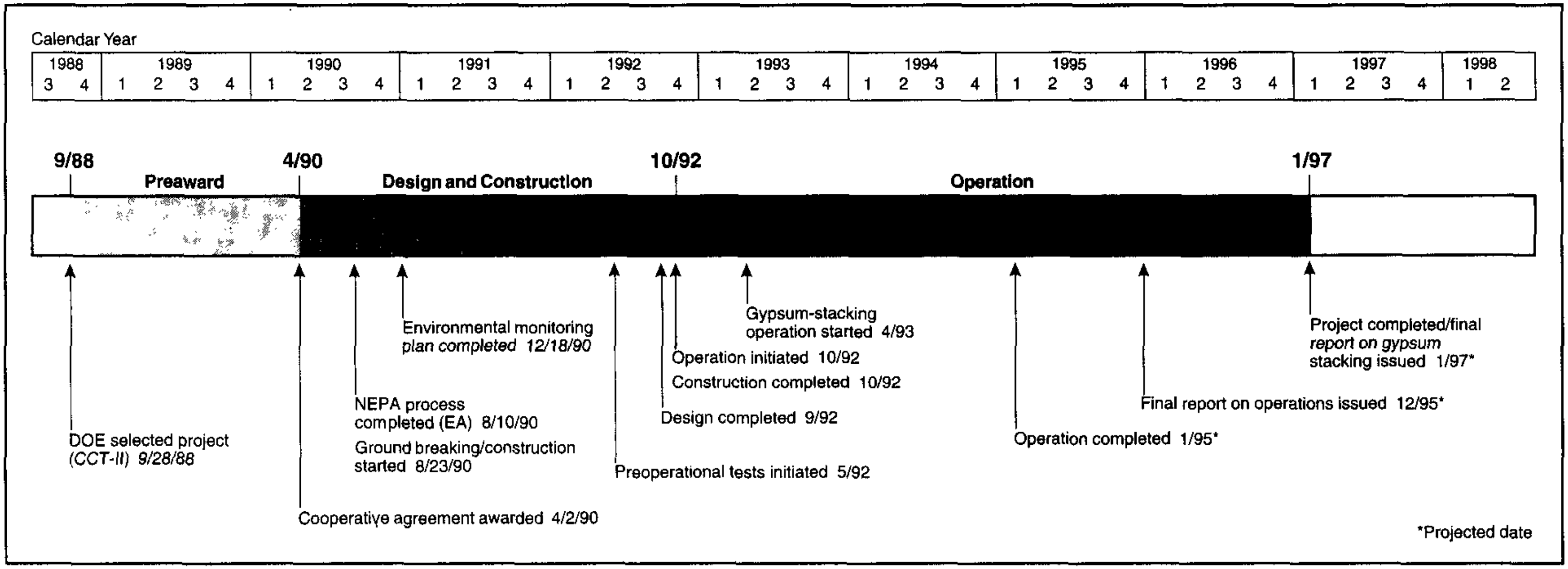
Technology/Project Description:
The project is demonstrating the CT-121 FGD process, which uses a unique absorber design known as the jet-bubbling reactor (JBR). The process combines limestone FGD reaction, forced oxidation, and gypsum crystallization in one process vessel. The process is mechanically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

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

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

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

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



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

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

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

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

The project received two awards in 1994: *Power Magazine's* 1994 Powerplant Award and an Outstanding Achievement Award from the Georgia chapter of the Air and Waste Management Association for the use of an innovative technology for air quality control. In 1993, Plant Yates received an environmental award from the Georgia Chamber of Commerce, based on the success of the CT-121 scrubber.

Commercial Applications:

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

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

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

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

SNOX™ Flue Gas Cleaning Demonstration Project

Project completed.

Participant:
ABB Environmental Systems

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

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

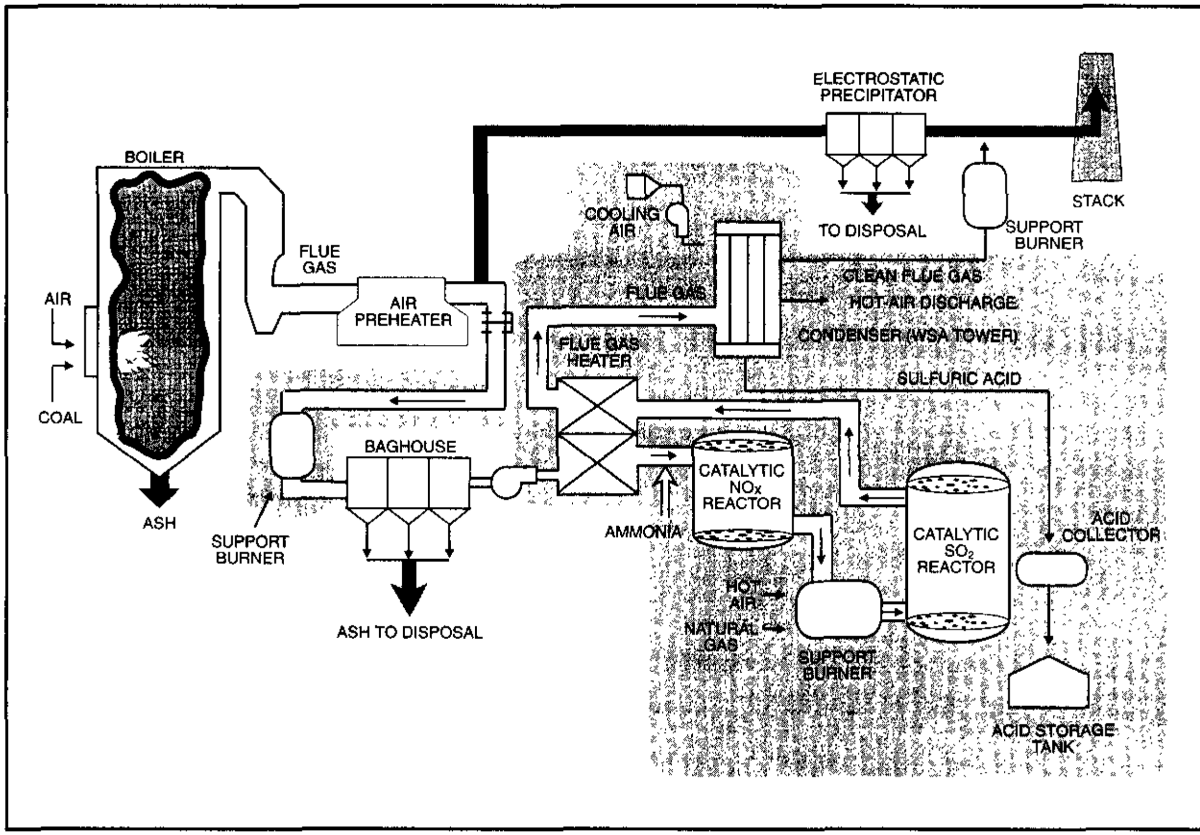
Technology:
Haldor Topsoe's SNOX™ catalytic advanced flue gas cleanup system (environmental control devices/combined SO_2/NO_x control technologies)

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

Project Funding:

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

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



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

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

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

Project Results/Accomplishments:

Operational testing was initiated in March 1992 and completed in December 1994. The system has operated for over 7,800 hours and produced more than 5,400 tons of commercial-grade sulfuric acid. The facility has routinely operated at full capacity, achieving removal efficiencies of 96% for SO_2, 94% for NO_x, and 99.9% for particulates.

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

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

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

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

Commercial Applications:

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

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

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

Project Schedule:

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

Final Reports:

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

LIMB Demonstration Project Extension and Coolside Demonstration

Project completed.

Participant:

The Babcock & Wilcox Company

Additional Team Members:

Ohio Coal Development Office—cofunder

Consolidation Coal Company—cofunder and technology supplier

Ohio Edison Company—host utility

Location:

Lorain, OH (Ohio Edison's Edgewater Station, Unit 4)

Technology:

The Babcock & Wilcox Company's limestone injection multistage burner (LIMB) system; Babcock & Wilcox DRB-XCL® low-NO_x burners

Consolidation Coal Company's Coolside duct injection of lime sorbents

(environmental control devices/combined SO_2/NO_x control technologies)

Plant Capacity/Production:

105 MWe

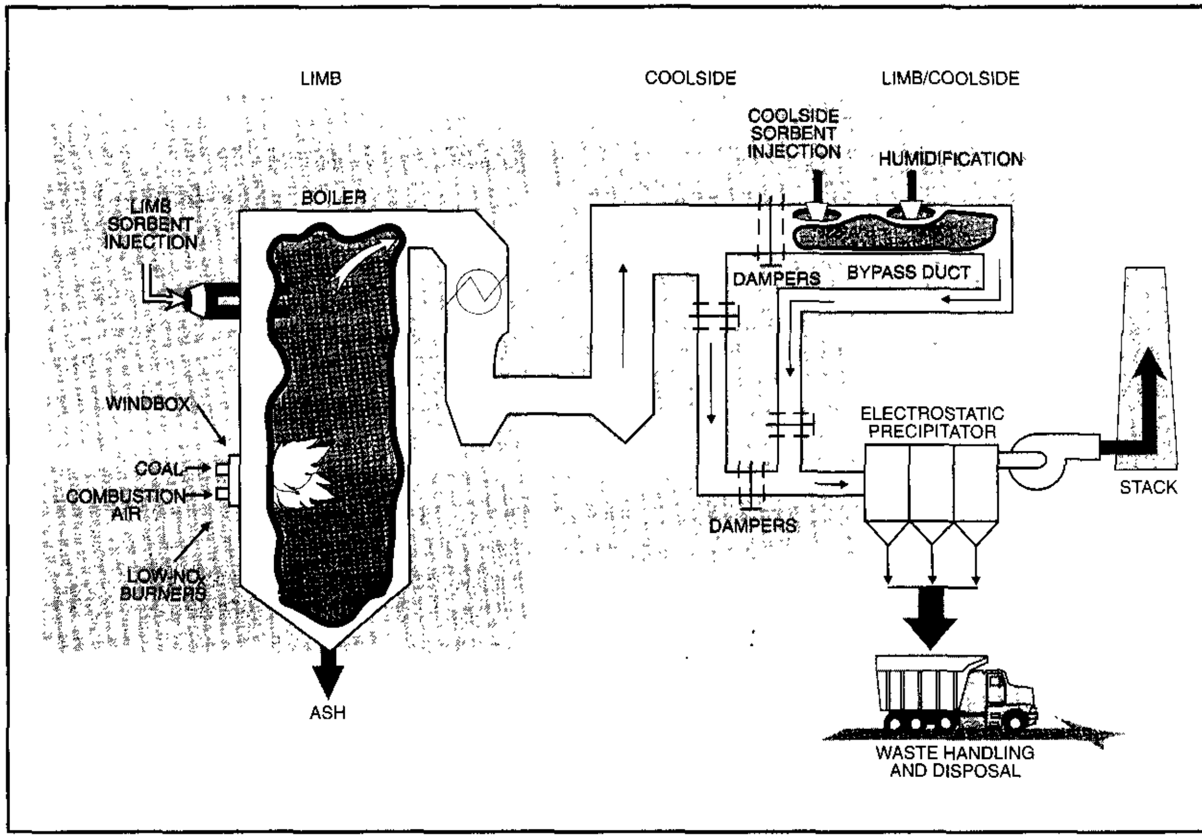
Project Funding:

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

Project Objective:

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

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



Technology/Project Description:

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

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

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

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

Project Results/Accomplishments:

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

- The coal's sulfur content, as reflected in the SO_2 concentration in the flue gas, affected SO_2 removal efficiency—the higher the sulfur content, the greater the SO_2 removal for a given sorbent at a comparable stoichiometry. A 5–7% increase in removal occurred when switching to 3.8% from 1.6% sulfur coal and injecting at a stoichiometry of 2.0.

- The highest sulfur removal efficiencies, without humidification to close approach, were attained using the ligno lime—61% SO_2 removal was achieved while burning 3.8% sulfur coal. All sorbents tested were capable of removing SO_2 although calcium utilization of even finely pulverized limestone was not nearly as high as those of the limes.

- While injecting commercial limestone with 80% of the particles less than 44 microns in size, removal efficiencies of about 22% were obtained at a stoichiometry of 2.0 while burning 1.6% sulfur coal. However, removal efficiencies of about 32% were achieved at a stoichiometry of 2.0 when using a limestone with all particles less than 44 microns. For a third limestone with essentially all particles less than 10 microns, the removal efficiency was about 5–7% higher than that obtained at similar conditions for limestone with all particles less than 44 microns.

- Sorbent injection at the 181-ft plant elevation level inside the boiler, just above the boiler's nose, yielded the highest SO_2 removal rates. Here, the sorbent was injected at close to the optimum furnace temperature of 2,300 °F.

- SO_2 removal efficiencies were enhanced by about 10% over the range of stoichiometries tested when humidification down to a 20 °F approach to saturation was used.

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

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

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

Commercial Applications:

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

Project Schedule:

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

Final Reports:

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

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

Project completed.

Participant:
The Babcock & Wilcox Company

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

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

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

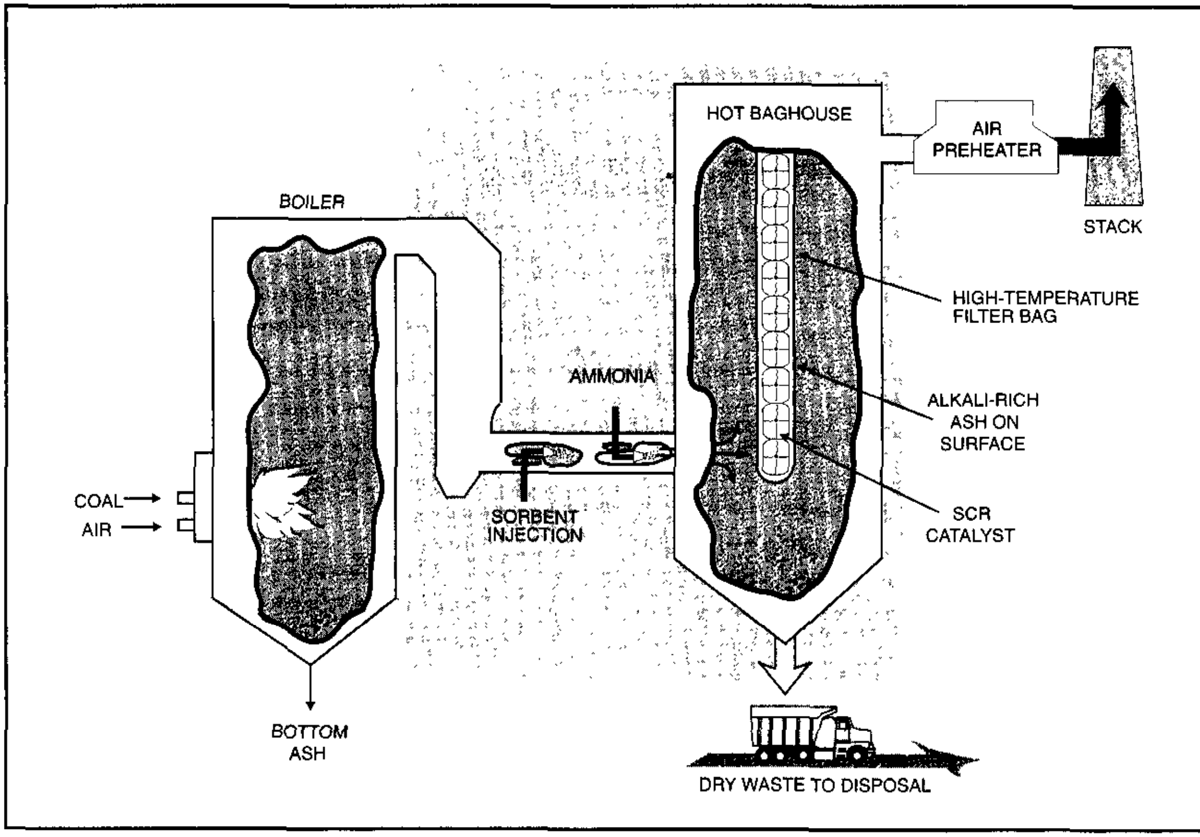
Plant Capacity/Production:
5-MWe equivalent slipstream from a 156-MWe boiler

Project Funding:

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

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

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.Bur ger Plant, Unit No. 5, in Dilles Bottom, OH. Bituminous coal with an average sulfur content of 3.4% was burned at this site during the demonstration.

Project Results/Accomplishments:

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

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

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

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

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

Commercial Applications:

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

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

Project Schedule:

DOE selected project (CCT-II)	9/28/88
NEPA process completed (MTF)	9/22/89
Cooperative agreement awarded	12/20/89
Construction	5/91–12/91
Environmental monitoring plan completed	12/31/91
Operational testing	5/92–5/93
Project completed	5/95

Final Reports:

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

Enhancing the Use of Coals by Gas Reburning and Sorbent Injection

Project completed.

Participant:

Energy and Environmental Research Corporation

Additional Team Members:

Gas Research Institute—cofunder

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

Illinois Power Company—host utility

City Water, Light and Power—host utility

Locations:

Hennepin, Putnam County, IL (Illinois Power Company's, Hennepin Plant, Unit 1)

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

Technology:

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

Plant Capacity/Production:

Hennepin: tangential-fired 80 MWe (gross), 71 MWe (net)

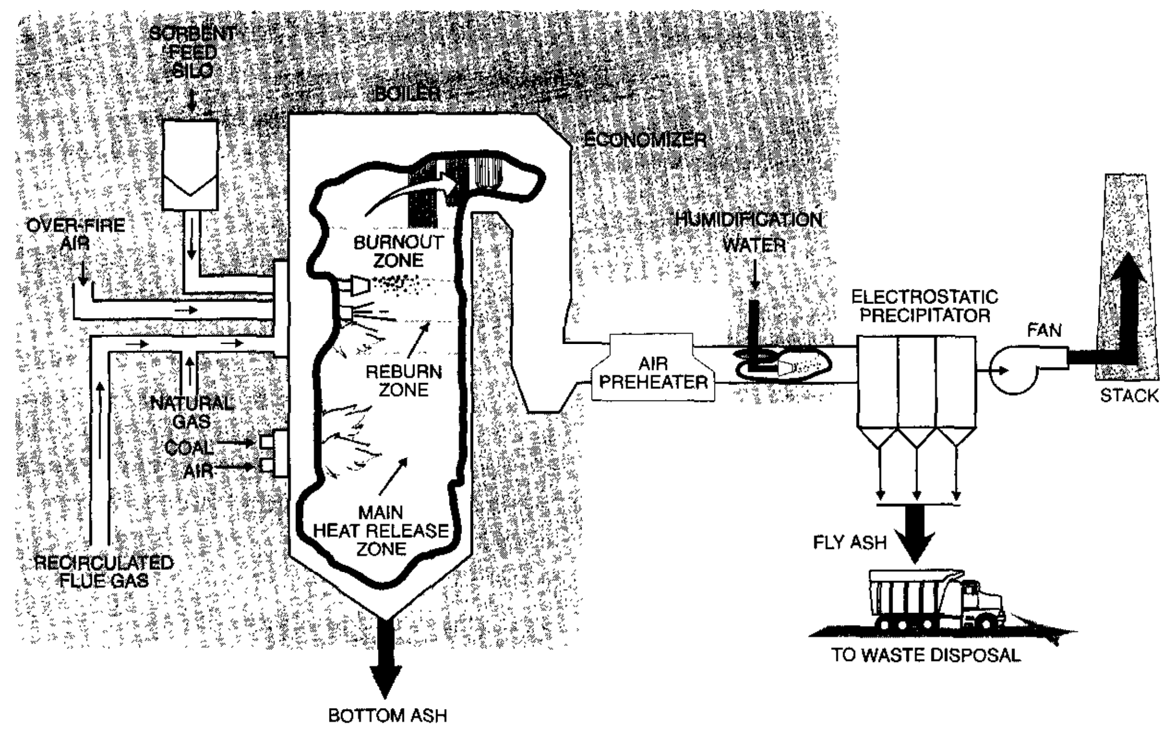
Lakeside: cyclone-fired 40 MWe (gross), 33 MWe (net)

Project Funding:

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

Project Objective:

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



Technology/Project Description:

In this process, 80–85% of the fuel is coal and is supplied to the main combustion zone. The remaining 15–20% of the fuel, generally natural gas or a hydrocarbon, bypasses the main combustion zone and is injected above the main burners to form a reducing zone in which NO_x is converted to nitrogen. A calcium compound (sorbent) is injected in the form of dry, fine particulates above the reburning zone in the boiler or even further downstream. The calcium compound tested is $Ca(OH)_2$ (lime). The goal was to achieve at least 60% NO_x reduction and at least 50% SO_2 reduction on different boiler configurations at power plants burning high-sulfur midwestern coal. This project demonstrated the gas reburning and sorbent injection GR–SI process on two separate boilers representing two different firing configurations—a tangentially fired, 80-MWe (gross) boiler at Illinois Power Company's Hennepin Plant in Hennepin, IL, and a cyclone-fired, 40-MWe (gross) boiler at City Water, Light and Power's Lakeside Station in Springfield, IL. Illinois bituminous coal containing 3% sulfur was the test coal for both Hennepin and Lakeside.

Project Results/Accomplishments:

A matrix of 32 gas reburn tests were completed on the tangentially fired boiler at the Hennepin Plant. NO_x *reductions of up to 77% were achieved, with 65% being* routine—exceeding the project objective of 60%. Evaluation of 20 over-fire air tests indicated substantial NO_x reduction was achievable at low power generation loads, with lesser reductions as load increased. Sorbent injection reduced SO_2 emissions as much as 62%, with 52%

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

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

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

The system installed at Hennepin operated for more than 2,100 hours, of which about 400 hours were gas reburning; 115 hours, sorbent injection; and nearly 760 hours, combined operation (the remainder was baseline testing).

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

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

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

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

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

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

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

Commercial Applications:

Gas reburning and sorbent injection is the unique combination of two separate technologies. The commercial applications for these technologies, both separately and combined, extend to both utility companies and industry in the United States and abroad. In the United States alone, these two technologies can be applied to over 900 pre-NSPS utility boilers; the technologies also can be applied to new utility boilers. With NO_x and SO_2 removal exceeding 60% and 50%, respectively, these technologies have the potential to extend the life of a boiler or power plant and also provide a way to use higher sulfur coals.

Project Schedule:

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

Final Reports:

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

Milliken Clean Coal Technology Demonstration Project

Participant:
New York State Electric & Gas Corporation

Additional Team Members:
New York State Energy Research and Development Administration—cofunder

Empire State Electric Energy Research Corporation—cofunder

Consolidation Coal Company—technical consultant

Saarberg-Hölter-Umwelttechnik, GmbH—technology supplier

The Stebbins Engineering and Manufacturing Company—technology supplier

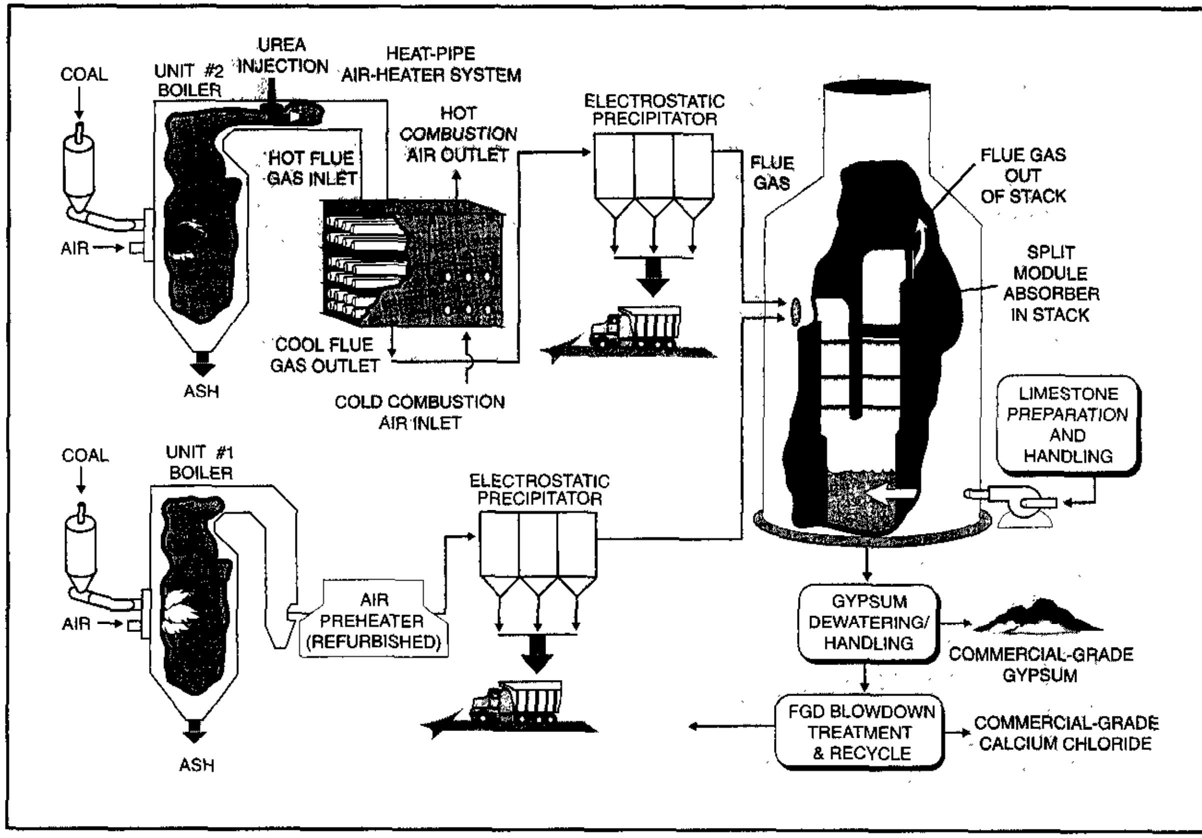
NALCO Fuel Tech—technology supplier

ABB Air Preheater, Inc.—technology supplier

DHR Technologies, Inc.—operator advisor system

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

Technology:
Flue gas cleanup using Saarberg-Hölter-Umwelttechnik's (S-H-U) formic-acid-enhanced, wet limestone scrubber technology; ABB Combustion Engineering's Low-NO_x Concentric Firing System (LNCFS) Level III; NALCO Fuel Tech's NO_xOUT urea injection system; Stebbins' tile-lined split-module absorber; and ABB Air Preheater's heat-pipe air-heater system (environmental control devices/combined SO_2/NO_x control technologies)



Plant Capacity/Production:
300 MWe

Project Funding:

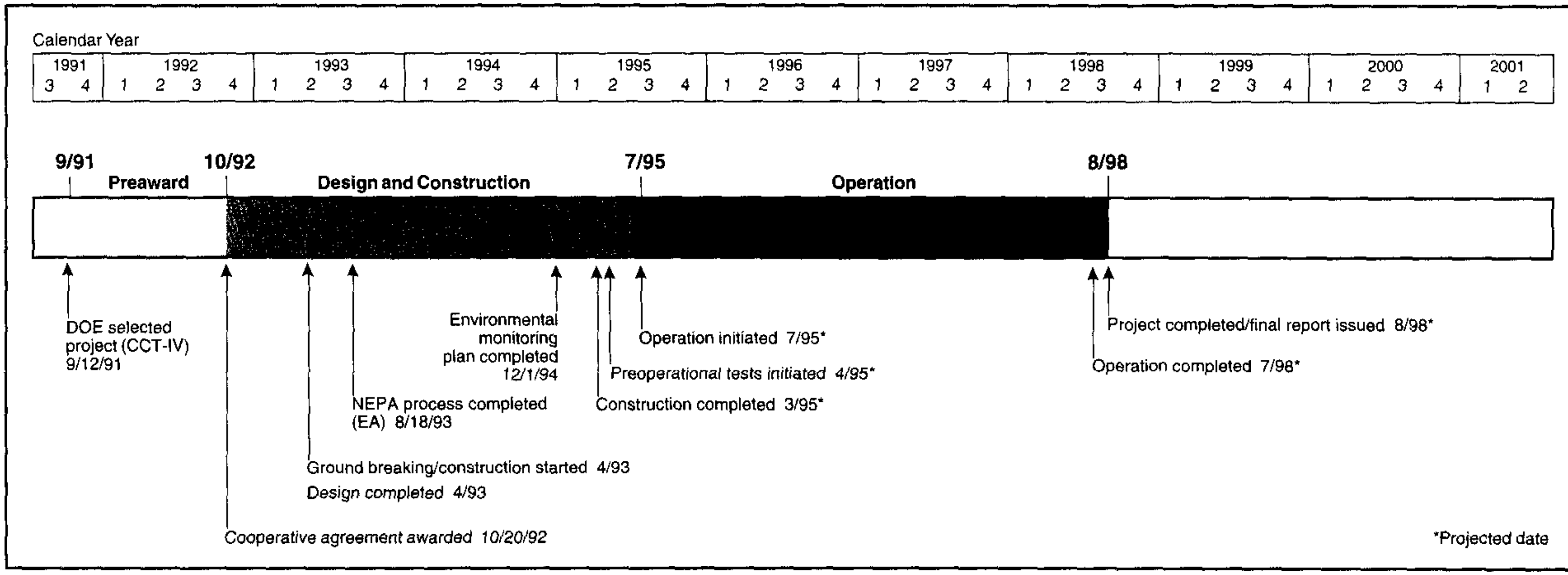
Total Project Cost	$158,607,807	100%
DOE	45,000,000	28
Participant	113,607,807	72

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

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

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

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



III (low-NO_x burner system), will reduce NO_x emissions and produce marketable fly ash.

A heat-pipe air-heater system by ABB Air Preheater, Inc., will be used with advanced temperature controls to reduce both air leakage and the air heater's flue gas exit temperature. DHR Technologies, Inc., will provide a state-of-the-art boiler and plant artificial-intelligence-based control system. Ultimate emissions reductions with increased boiler efficiencies will result.

The project is designed for "total environmental and energy management," a concept encompassing low emissions, low energy consumption, improved combustion, upgraded boiler controls, and reduced solid waste. The system is being designed to achieve at least a 95% SO_2 removal efficiency (or up to 98%) using limestone while burning high-sulfur coal. NO_x reductions will be achieved using selective non-catalytic reduction technology and separate combustion modifications. NO_x emissions have been reduced from 0.65 to 0.40 lb/million Btu (23%) by retrofitting the two boilers with low-NO_x burners. NO_xOUT is expected to reduce NO_x emissions from Unit 2 by an additional 15–20%. The system has zero wastewater discharge and produces marketable by-products (e.g., commercial-grade gypsum, calcium chloride, and fly ash), minimizing solid waste.

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

Project Status/Accomplishments:

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

Commercial Applications:

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

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

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

Participant:
NOXSO Corporation

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

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

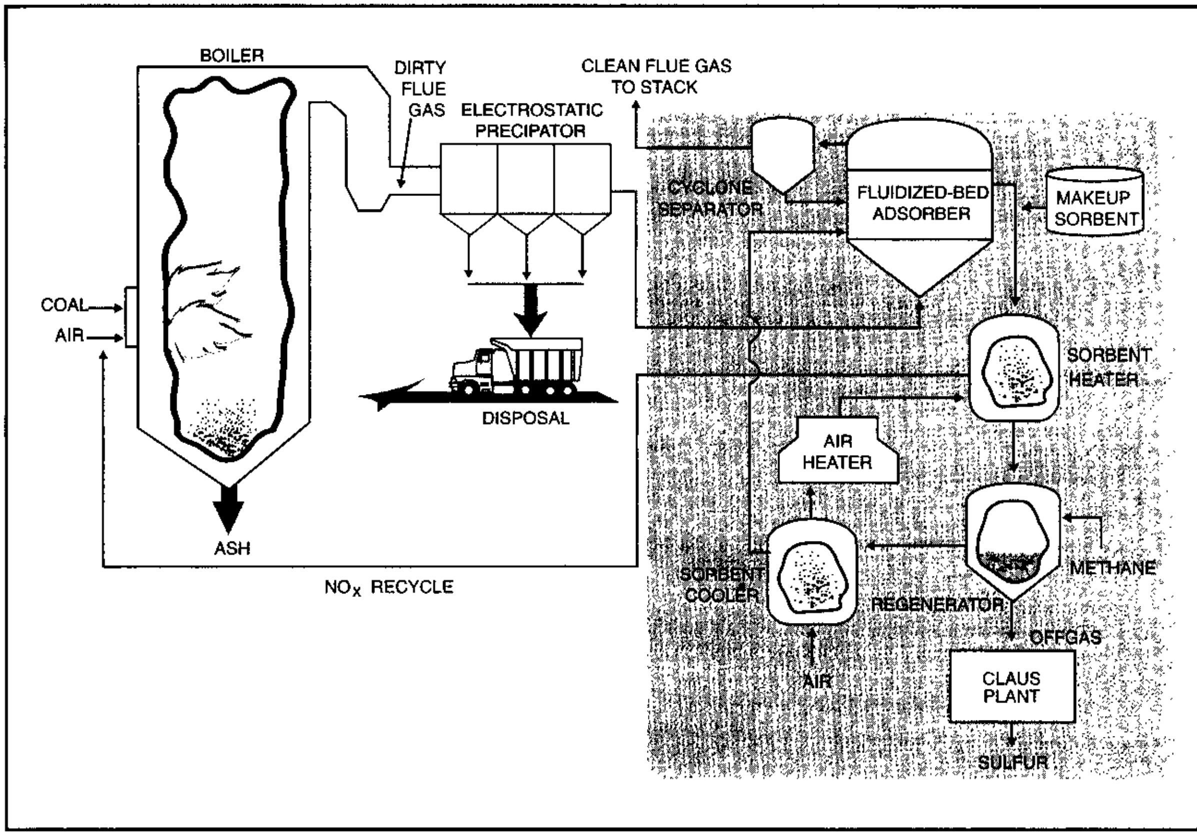
Technology:
NOXSO Corporation's dry, regenerable flue gas cleanup process (environmental control devices/combined SO_2/NO_x control technologies)

Plant Capacity/Production:
144 MWe (net)

Project Funding:

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

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

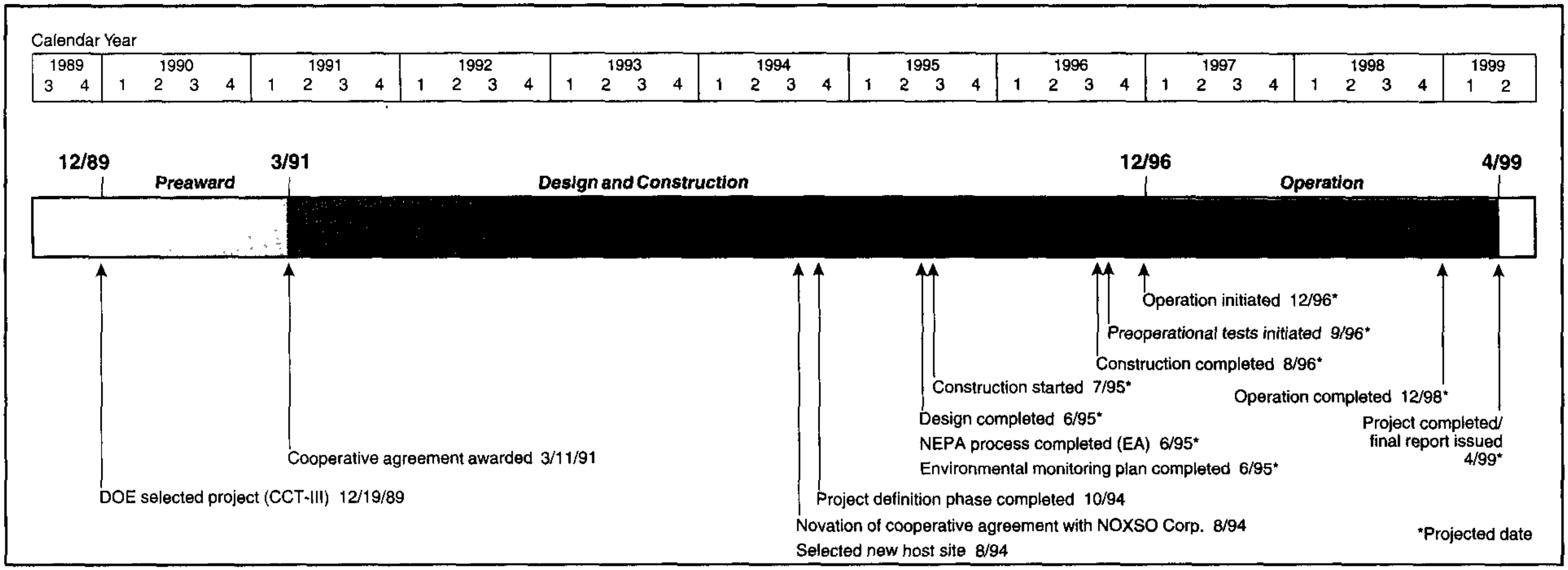


Technology/Project Description:
The NOXSO process is a dry, regenerable system capable of removing both SO_2 and NO_x in flue gas from coal-fired utility boilers burning medium- to high-sulfur coals. In the basic process, the flue gas passes through a fluidized-bed adsorber located downstream of the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

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

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

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



Project Status/Accomplishments:

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

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

Commercial Applications:

The NOXSO process is applicable for retrofit or new facilities. The process is suitable for utility and industrial coal-fired boilers of 75 MWe or larger. A high-sulfur coal is being used in the demonstration; however, the process is adaptable to coals with any sulfur content.

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

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

Integrated Dry NO_x/SO_2 Emissions Control System

Participant:
Public Service Company of Colorado

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

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

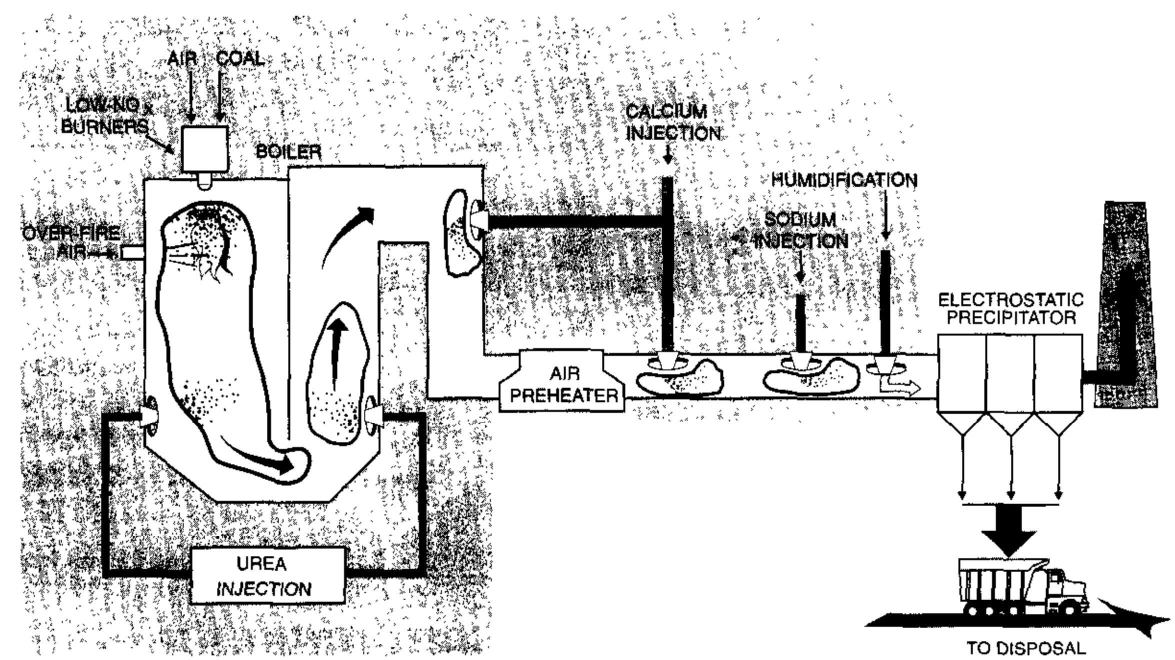
Technology:
The Babcock & Wilcox Company's DRB-XCL® low-NO_x burners, in-duct sorbent injection, and furnace (urea) injection (environmental control devices/combined SO_2/NO_x control technologies)

Plant Capacity/Production:
100 MWe

Project Funding:

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

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

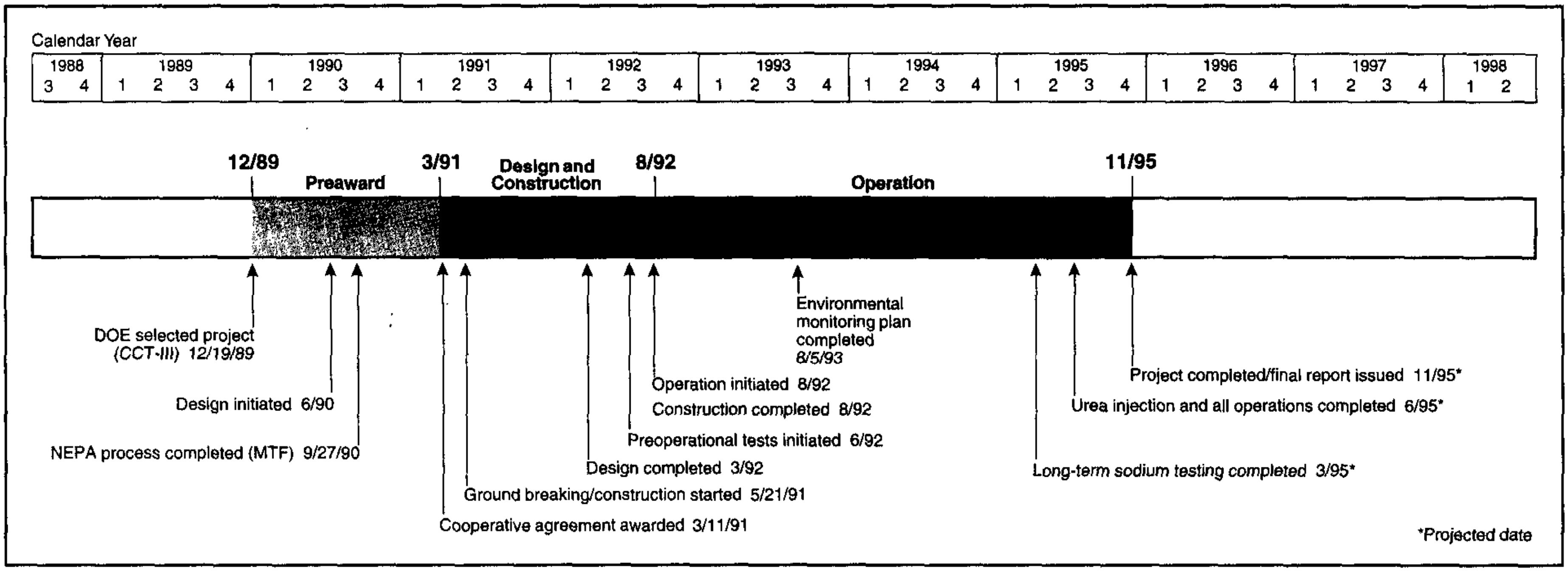


Technology/Project Description:
All of the testing is using Babcock & Wilcox's low-NO_x DRB-XCL® down-fired burners with over-fire air. These burners control NO_x by injecting the coal and the combustion air in an oxygen-deficient environment. Additional air is introduced via over-fire air ports to complete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

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

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

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



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

Project Status/Accomplishments:

Operational testing of the boiler with low-NO_x burners and over-fire air started in early August 1992. Testing of the combustion modifications was completed in late October 1992. While firing western bituminous coal, NO_x was reduced from an original baseline of 1.15 lbs/million Btu to about 0.4 lb/million Btu—a 65% reduction—with no operating problems. In-furnace urea injection testing began in January 1993 and continued for 3 months. At full load, 44% NO_x reduction was achieved with a 10-ppm ammonia slip. Duct sorbent-injection testing began in August 1993 and was completed in May 1994. Sodium-bicarbonate injection achieved over 70% SO_2 removal at a stoichiometric ratio of approximately 1.0. Sodium sesquicarbonate injection after the air heater also obtained a 70% SO_2 removal but at a stoichiometric ratio of approximately 1.8. Calcium-based dry reagent injection achieved a maximum of 40% SO_2 removal and caused some operational concerns. Pre-economizer calcium-based injection achieved only 10% SO_2 removal, significantly less than expected. Testing of the integration of sodium and urea injection began in June 1994 and will be completed in mid-1995. Overall NO_x reduction of 80% has been demonstrated at full load.

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

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

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

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

Commercial Applications:

Either the entire integrated dry NO_x/SO_2 emissions control system or the individual technologies are applicable to most utility and industrial coal-fired units. They provide a lower capital-cost alternative to conventional wet flue gas desulfurization processes. They can be retrofitted with modest capital investment and downtime, and their space requirements are substantially less. They can be applied to any unit size but are mostly applicable to the older, small- to mid-size units.

Coal Processing for Clean Fuels Fact Sheets

Development of the Coal Quality Expert

Participants:

ABB Combustion Engineering, Inc.
CQ, Inc.

Additional Team Members:

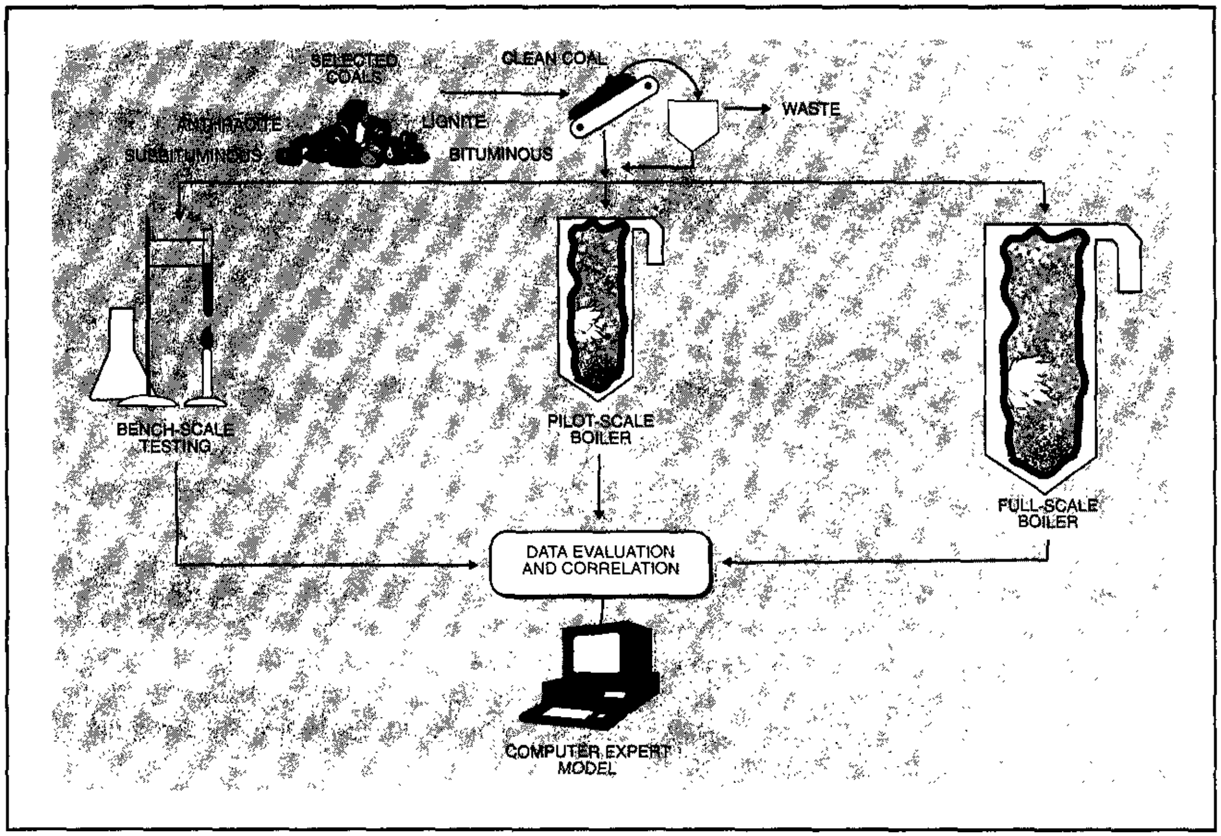
Black and Veatch—cofunder and expert system developer
Electric Power Research Institute—cofunder
The Babcock & Wilcox Company—cofunder and pilot-scale testing
Guild Products, Inc.—expert system architecture developer
Electric Power Technologies, Inc.—field testing
University of North Dakota, Energy and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

Locations:

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

Technology:

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



Plant Capacity/Production:

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

Project Funding:

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

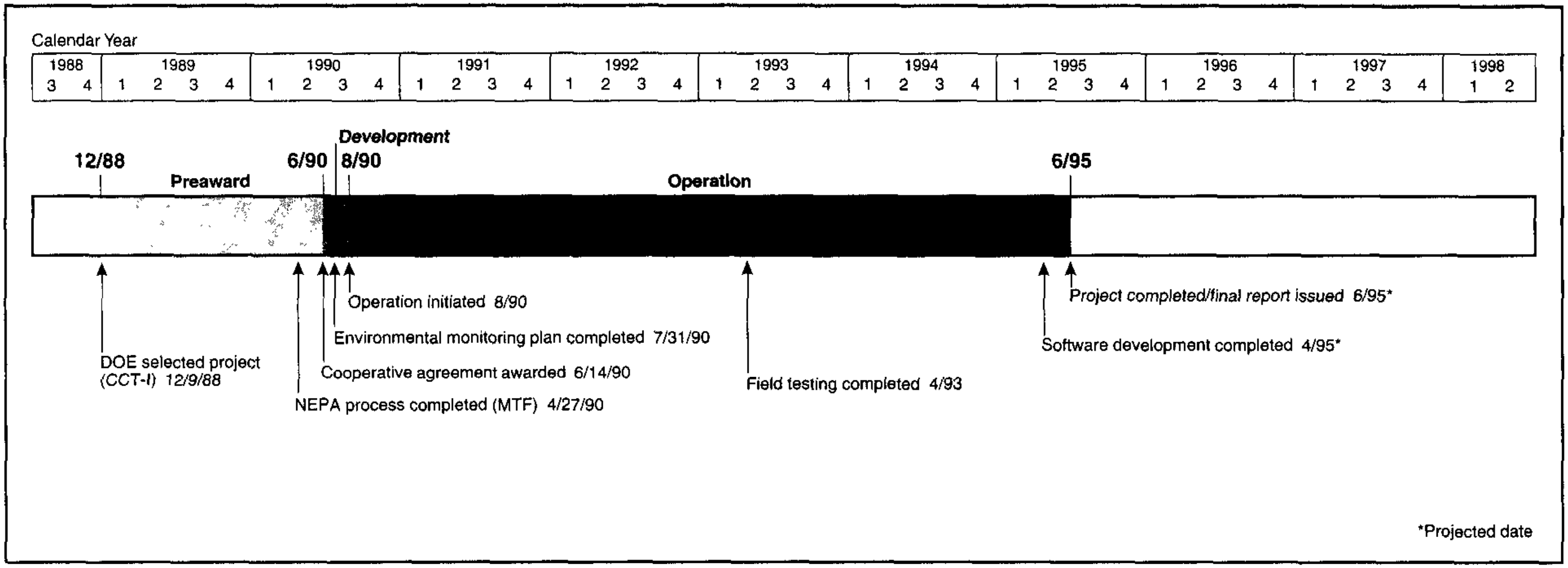
Project Objective:

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

Technology/Project Description:

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

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



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

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

Project Status/Accomplishments:

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

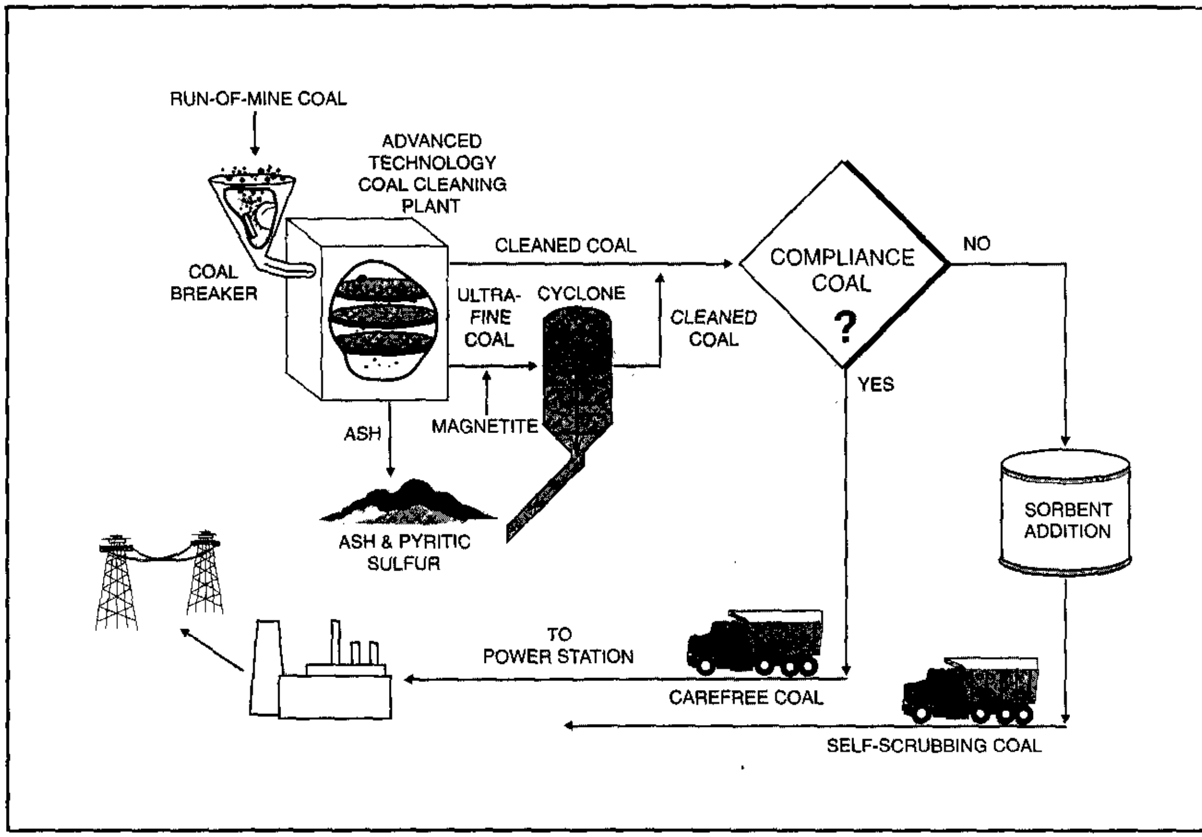
Commercial Applications:

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

The CQE system is applicable to all electric power plants and industrial/institutional boilers that burn coal. The system will predict the operational and emission reduction benefits of using cleaned coal. A commercial sale of the CQE Acid Rain Advisor software package was made in March 1993.

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

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



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

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

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

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

Plant Capacity/Production:
500 tons/hr

Project Funding:

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

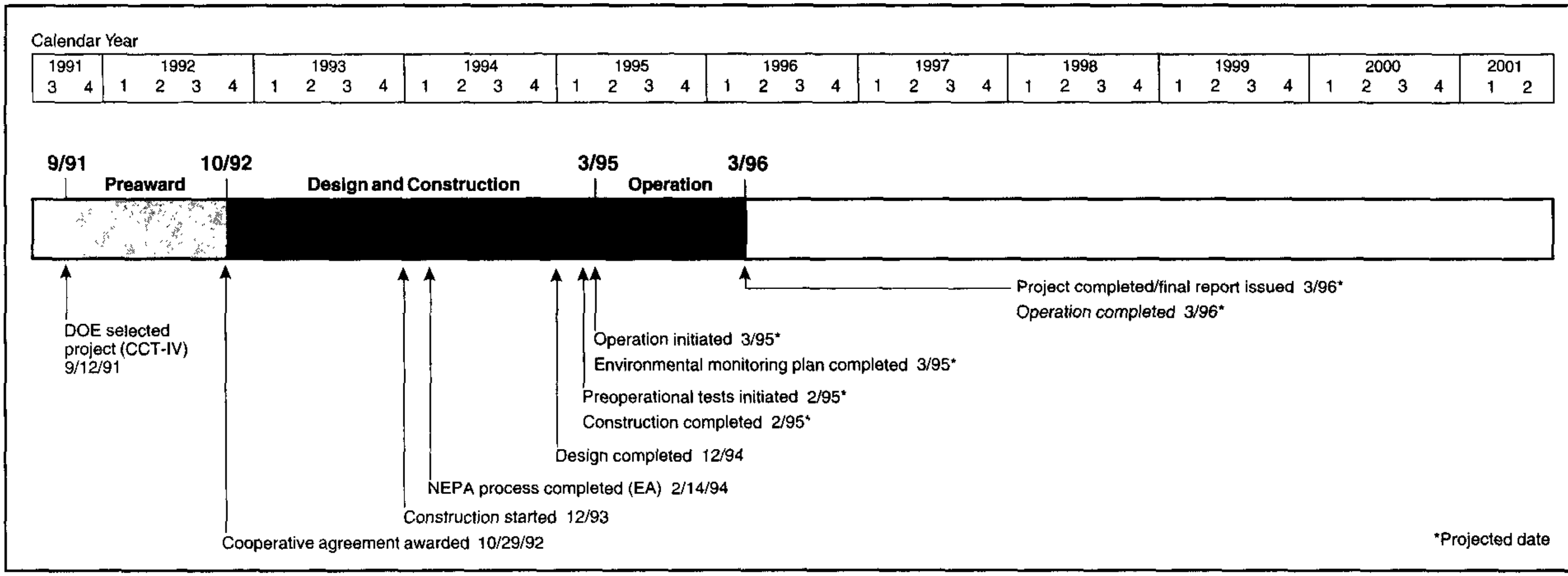
Self-Scrubbing Coal and Carefree Coal are trademarks of Custom Coals International.

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

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

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

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



ash specifications of the boiler or overloading the electrostatic precipitator.

A 500-ton/hr advanced coal-cleaning plant is being designed and constructed at a site near Central City, PA. The advanced coal-cleaning plant will manufacture Self-Scrubbing Coal™ and Carefree Coal™. Two medium- to high-sulfur coals—Illinois No. 5 (2.7% sulfur) from Wabash County, IL, and Lower Freeport seam coal (3.9% sulfur) from Belmont County, OH—will be used to produce Self-Scrubbing Coal™. Carefree Coal™ will be made using Sewickley coal (4.8% sulfur) from Greene County, PA. The Sewickley coal will be combustion tested at Duquesne Light Company's Cheswick Power Station located in Springdale, PA; the Illinois No. 5 coal will be tested at Richmond Power & Light's Whitewater Valley Generating Station Unit No. 2 located in Richmond, IN; and the Lower Freeport seam coal will be tested at Centerior Energy's Ashtabula C Power Plant near Ashtabula, OH.

Project Status/Accomplishments:

Construction has moved at a rapid pace since beginning in December 1993. Structural steel erection is complete. Over 99% of the equipment has been installed. Raw coal burn testing to provide baseline data to determine the cleaning effect is scheduled to begin in early 1995.

DOE approved a finding of no significant impact for an environmental assessment on February 14, 1994.

Commercial Applications:

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

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

In August 1994, a U.S.-led consortium with Custom Coals Corporation as the principal partner signed a cooperative agreement with the People's Republic of China to build a coal-cleaning plant, a 500-mile underground slurry pipeline, and port facility. The pipeline will bring coal from the Shanxi province in northwest China to the coastal province of Shandong. The work included under the agreement is valued at $888.6 million.

Advanced Coal Conversion Process Demonstration

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

Additional Team Member:
None

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

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

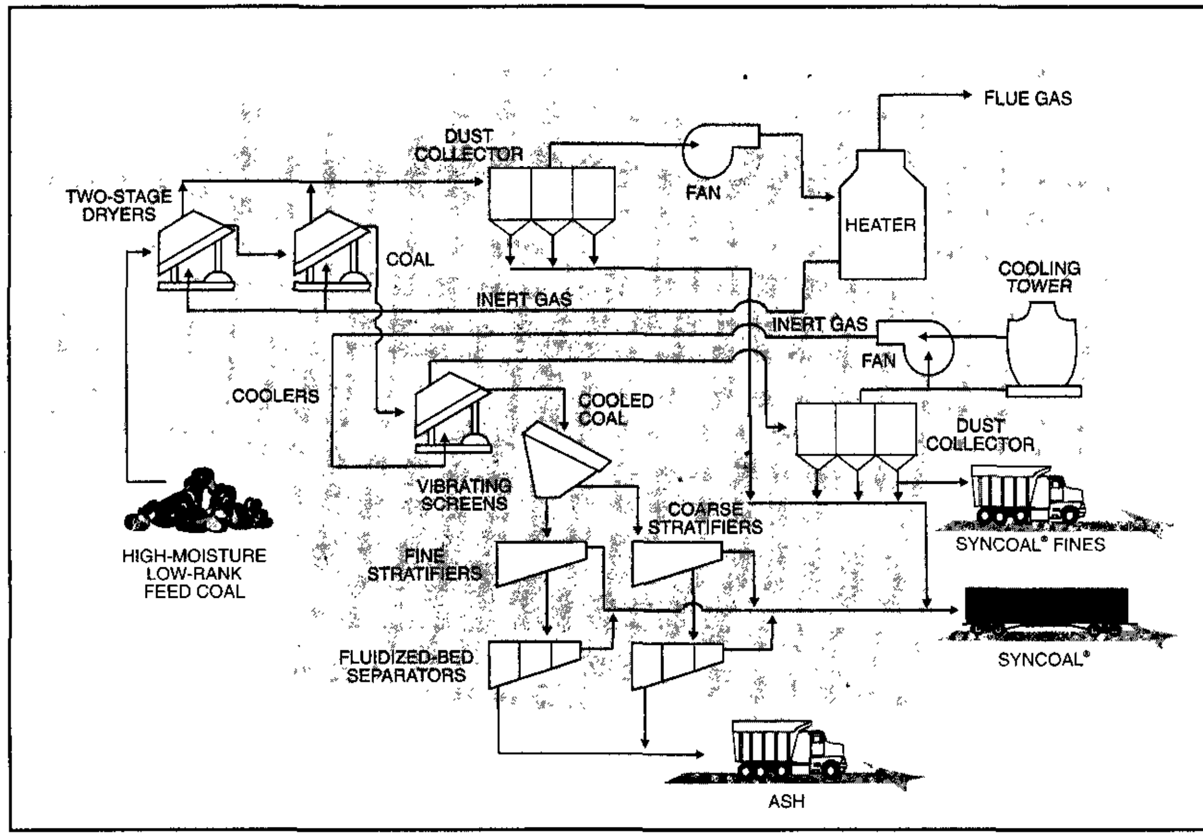
Plant Capacity/Production:
45 tons/hr of SynCoal® product (300,000 tons/yr)

Project Funding:

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

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

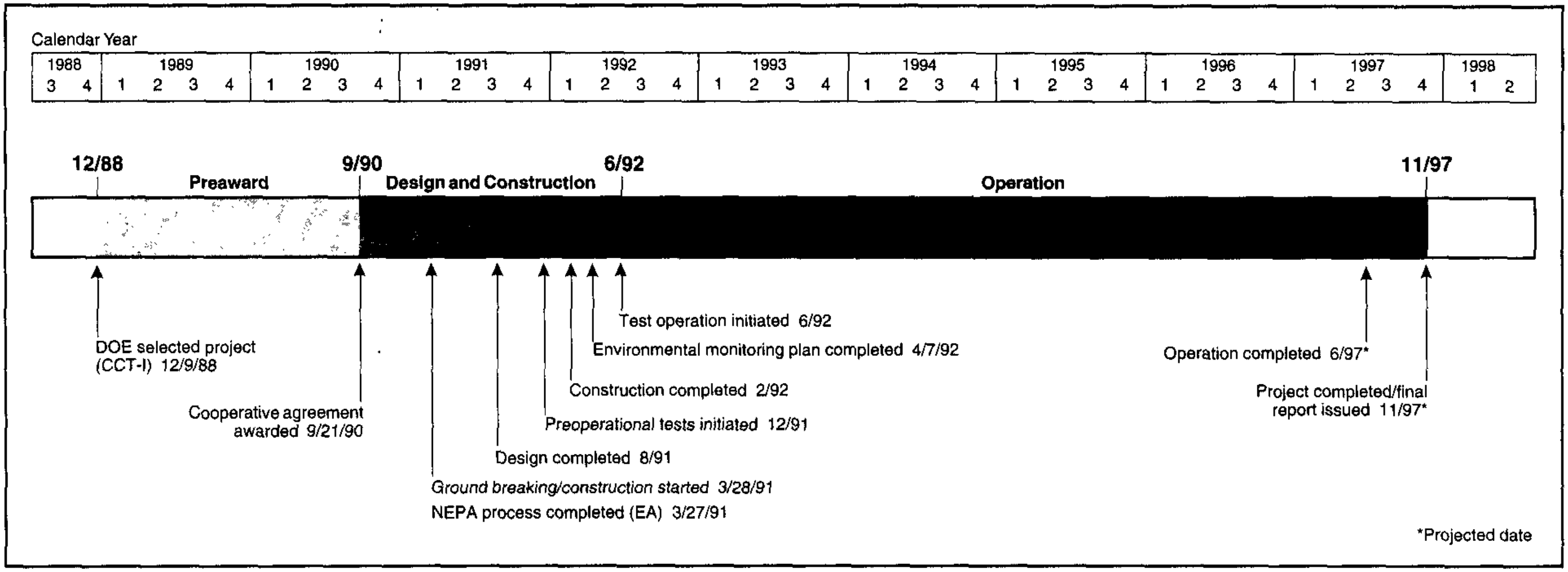
SynCoal is a registered trademark of the Rosebud SynCoal Partnership.



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

The technology enhances low-rank western coals, usually with a moisture content of 25–40%, sulfur content of 0.5–1.5%, and heating value of 5,500–9,000 Btu/lb, by producing an upgraded SynCoal® product with a moisture content as low as 1%, sulfur content as low as 0.3%, and heating value up to 12,000 Btu/lb.

The 45-ton/hr unit is located adjacent to a unit train loadout facility at Western Energy Company's Rosebud coal mine in Colstrip, MT. The demonstration plant is one-tenth the size of a commercial facility. However, the process equipment is at 1/3–1/2 commercial scale because a full-sized commercial plant will have multiple process trains.



Project Status/Accomplishments:
Ground was broken on March 28, 1991. Initial "turn-over" of equipment started in December 1991, and final construction was completed in February 1992. Initial "hot" operations began in March 1992. On December 6, 1993, the plant exceeded its 68-ton/hr design capacity by processing 70 tons/hr.

In March 1994 a 50/50 SynCoal® blend test was completed at Montana Power Company's J.E. Corette Plant. Wyoming subbituminous feedstock was tested at the SynCoal® demonstration plant in May 1994. This plant demonstrated a 75% availability factor and 98% capacity factor for the first 6 months of 1994.

A scheduled maintenance and plant improvement outage was completed in September 1994. A follow-up test burn using a 50/50 SynCoal® blend was conducted at the J.E. Corette Plant following chemical cleaning of the boiler. Testing at the power plant continues at the main utility test burn site. A total of 5,412 tons have been delivered to the utility. In addition, 5,757 tons have been delivered to Ash Grove Cement, Bentonite Corporation, and Empire Sand and Gravel.

Commercial Applications:
Rosebud SynCoal's advanced coal conversion process has the potential to enhance the use of low-rank western subbituminous and lignite coals. Many of the power plants located throughout the upper Midwest have cyclone boilers, which burn low-ash-fusion-temperature coals. Presently, most of these plants burn Illinois Basin high-sulfur coal. SynCoal® is an ideal low-sulfur coal substitute for these and other plants because it allows operation under more restrictive emissions guidelines without requiring derating of the units or the addition of costly flue gas desulfurization systems. The advanced coal conversion process produces SynCoal® which has a consistently low moisture content, a low sulfur content, a high heating value, and a high volatile content. Because of these characteristics, SynCoal® could have significant impact on SO_2 reduction and provide an economical clean alternative fuel to many regional industrial facilities and small utilities being forced to use fuel oil and natural gas. Rosebud Syncoal's process, therefore, will be attractive to industry and utilities because the upgraded fuel will be less costly to use than would the construction and use of flue gas desulfurization equipment. This will allow plants that would otherwise be closed to remain in operation.

On December 20, 1993, Rosebud SynCoal Partnership announced the signing of a letter of intent with Minnkota Power Cooperative to prepare a $2-million study to examine the merits of applying the coal processing technology to a commercial plant integrated into an existing power plant site. The study's results have been positive, but market commitments are still necessary.

ENCOAL Mild Coal Gasification Project

Participant:

ENCOAL Corporation (a subsidiary of SMC Mining Company)

Additional Team Members:

SMC Mining Company—cofunder

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

SGI International—technology developer

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

The M.W. Kellogg Company—engineer and constructor

Location:

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

Technology:

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

Plant Capacity/Production:

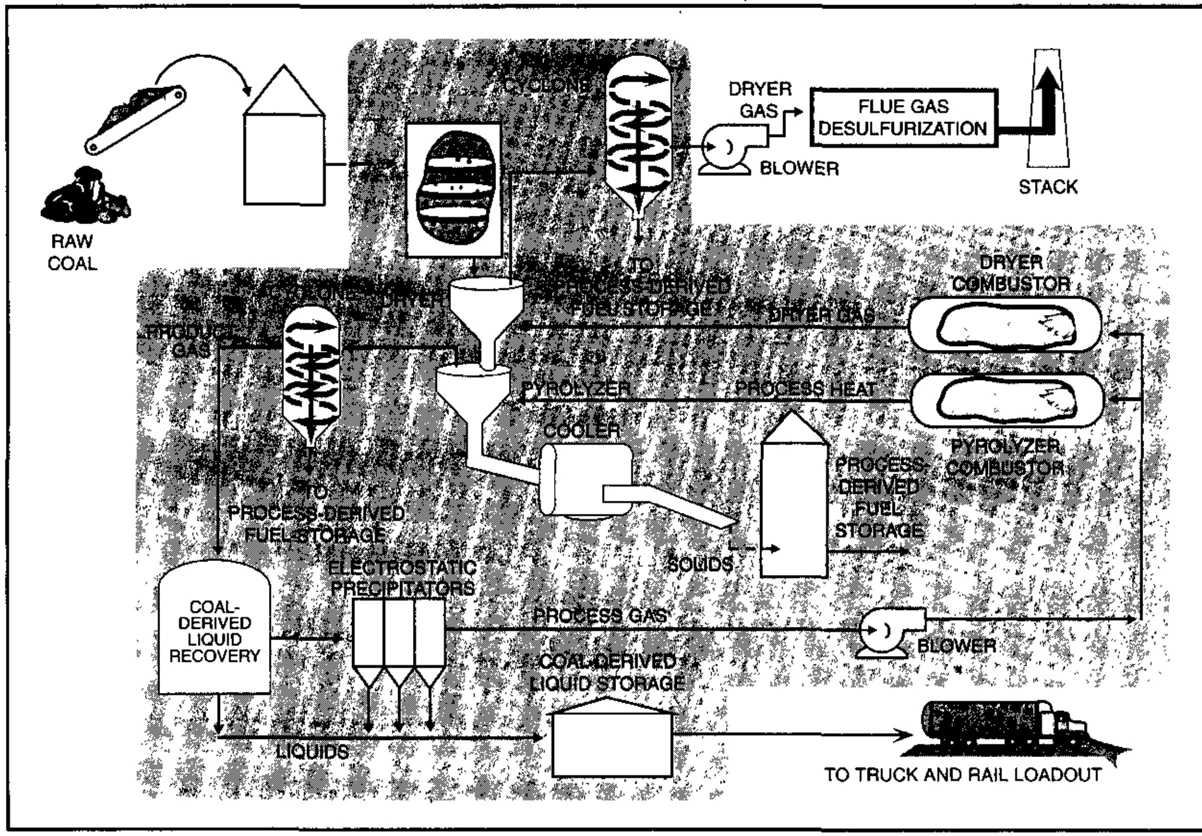
1,000 tons/day of subbituminous coal feed

Project Funding:

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

Project Objective:

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



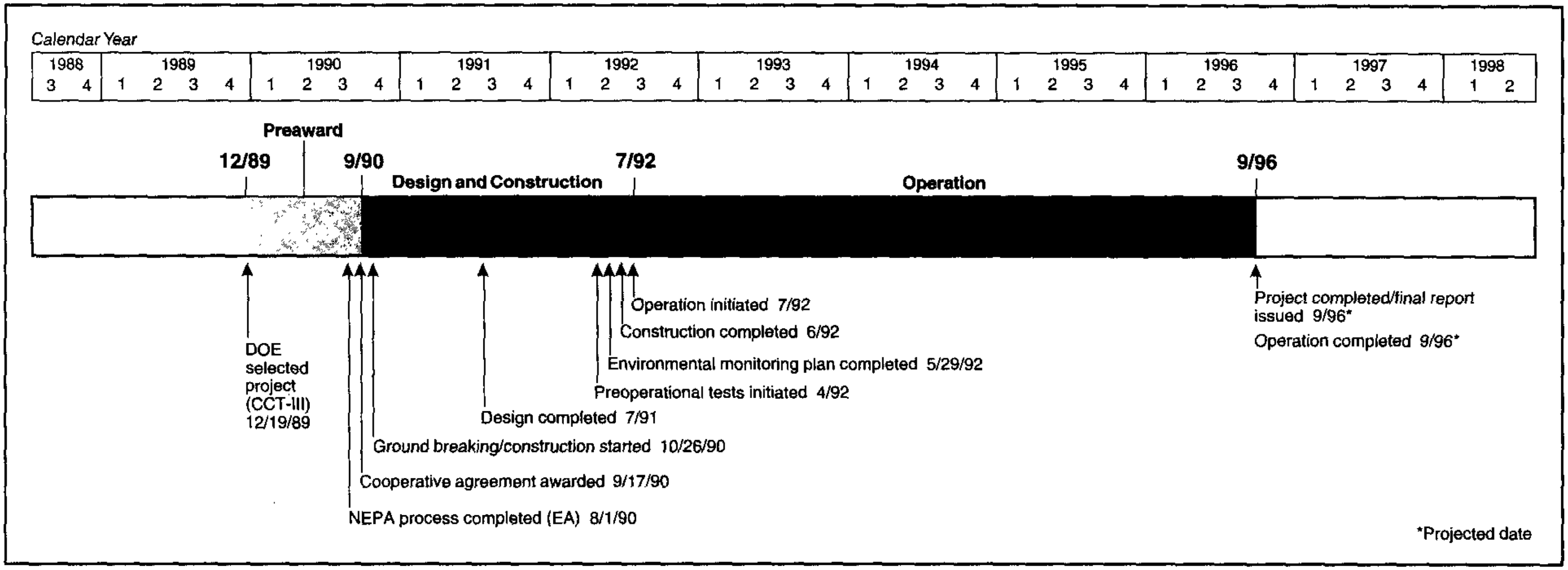
Technology/Project Description:

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

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

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

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



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

Project Status/Accomplishments:

The plant officially entered the production mode in June 1994; operation has been at a coal feed rate of 500 tons/day. By year-end 1994, 22 test runs were completed, representing more than 5,000 hours of operation on coal. Solid and liquid products being produced by the plant are being shipped to industrial and utility customers. In September 1994, approximately 8,000 tons of solid product were shipped as 15–35% blends with Powder River Basin coal for use in electricity generation at the Western Farmers Cooperative's Hugo plant in Oklahoma. This rural electric cooperative used the product successfully in its boilers. ENCOAL also has contracted with Wisconsin Power & Light for the sale of 30,000 tons of solid product. A contract to sell blends of up to 92% solid product was signed with Muscatine Power and Water of Muscatine, IA. Other major utility companies have expressed interest in purchasing solid product. Tank cars of liquid product are being shipped on a regular basis to several customers in the Midwest for use in industrial boilers. The Dakota Gasification Company tested the liquid product in 1992 and in 1994 purchased an additional 800,000 gallons for use in its synfuel plant in Beulah, ND.

The project has been extended for 2 years in order to resolve problems with the in-process stabilization of the solid product and to conduct and analyze utility test burns of solid product.

Commercial Applications:

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

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

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

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

Participant:

Air Products Liquid Phase Conversion Company, L.P. (a limited partnership between Air Products and Chemicals, Inc., the general partner, and Eastman Chemical Company)

Additional Team Members:

Air Products and Chemicals, Inc.—technology supplier and cofunder

Eastman Chemical Company—host; synthesis gas and services provider

Acurex Environmental Corporation—fuel methanol testing and cofunder

Electric Power Research Institute—fuel methanol testing and cofunder

Location:

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

Technology:

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

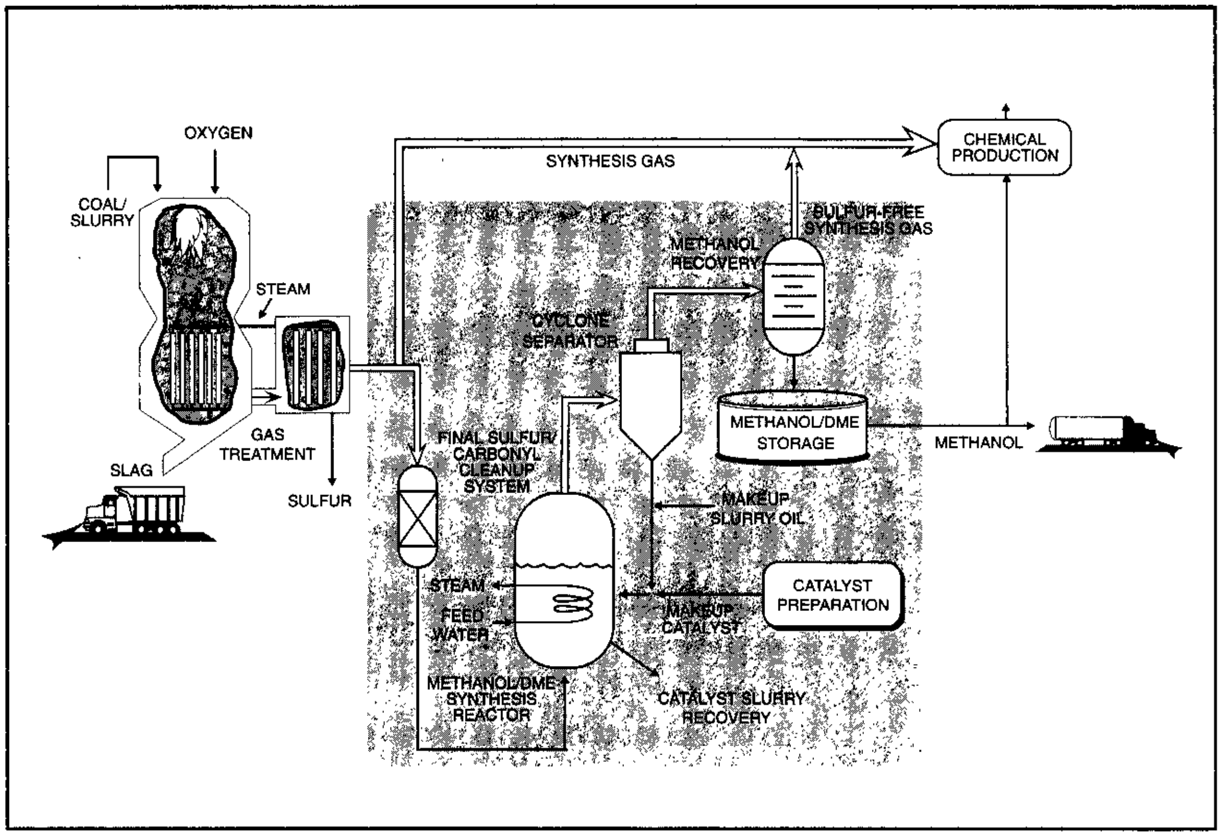
Plant Capacity/Production:

260 tons/day of methanol (nominal)

Project Funding:

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

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



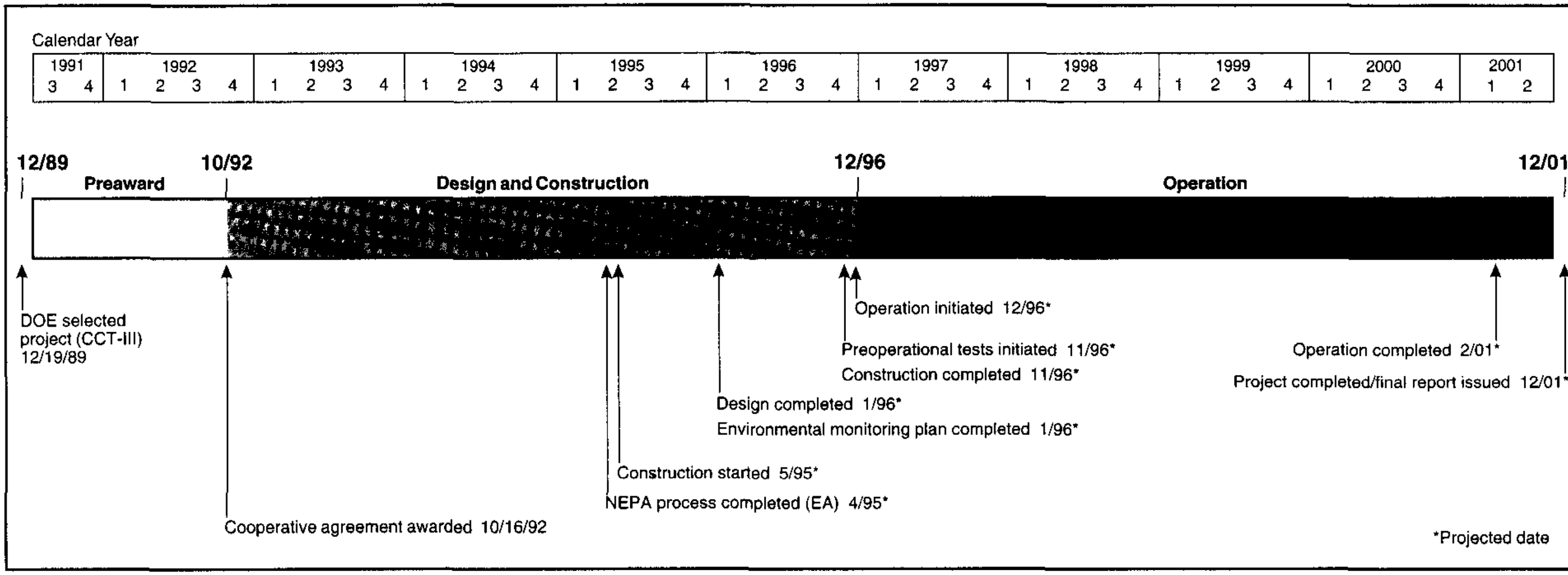
Project Objective:

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

Technology/Project Description:

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

The Eastman Chemical Company's integrated coal gasification facility at Kingsport, TN, has operated commercially since 1983. At this site, it will be possible to ramp up and down to demonstrate the unique load-following flexibility of the LPMEOH™ unit for application to coal-based electric power generation facilities. Methanol fuel testing will be conducted in off-site stationary and mobile applications, such as boilers, fuel cells, buses, and van pools. Design verification testing for the production of DME as a mixed coproduct with methanol for use as a storable fuel is planned, and a decision to



demonstrate will be made. Eastern high-sulfur bituminous coal (Mason seam) containing 3% sulfur (5% maximum) and 10% ash will be used.

Project Status/Accomplishments:

To provide a contractual basis to manage and execute the LPMEOH™ *demonstration project, Air Products and* Chemicals and the Eastman Chemicals Company have formed the limited partnership, Air Products Liquid Phase Conversion Company. Project definition activities were completed in September 1994 and design was initiated. Relevant environmental information for the NEPA process is being updated; an environmental assessment is in progress. Construction is expected to start in May 1995.

Commercial Applications:

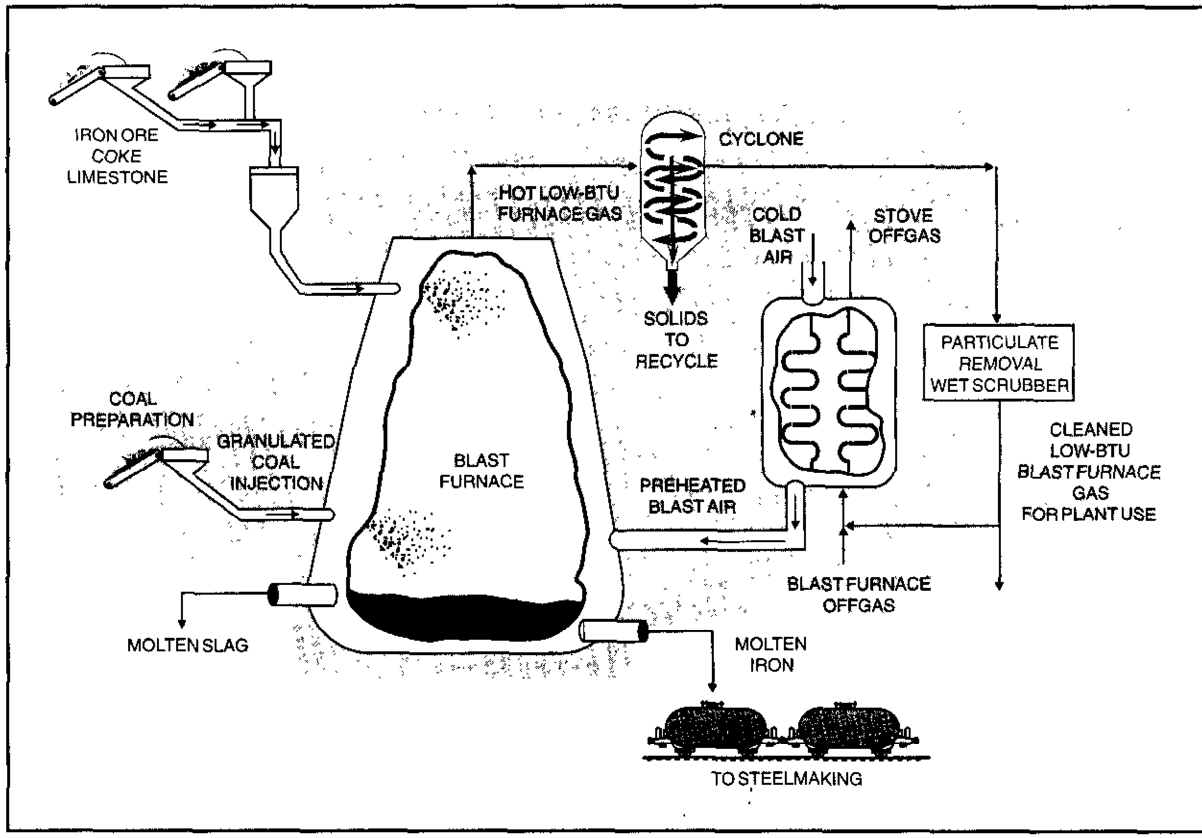
The LPMEOH™ process has been developed to enhance integrated gasification combined-cycle (IGCC) power generation by producing a clean burning, storable liquid fuel—methanol—from the clean coal-derived gas. Methanol also has a broad range of commercial applications, can be substituted for conventional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

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

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

Industrial Applications Fact Sheets

Blast Furnace Granulated-Coal Injection System Demonstration Project



Participant:
Bethlehem Steel Corporation

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

Simon-Macawber, Ltd.—equipment supplier

Fluor Daniel, Inc.—architect and engineer

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

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

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

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

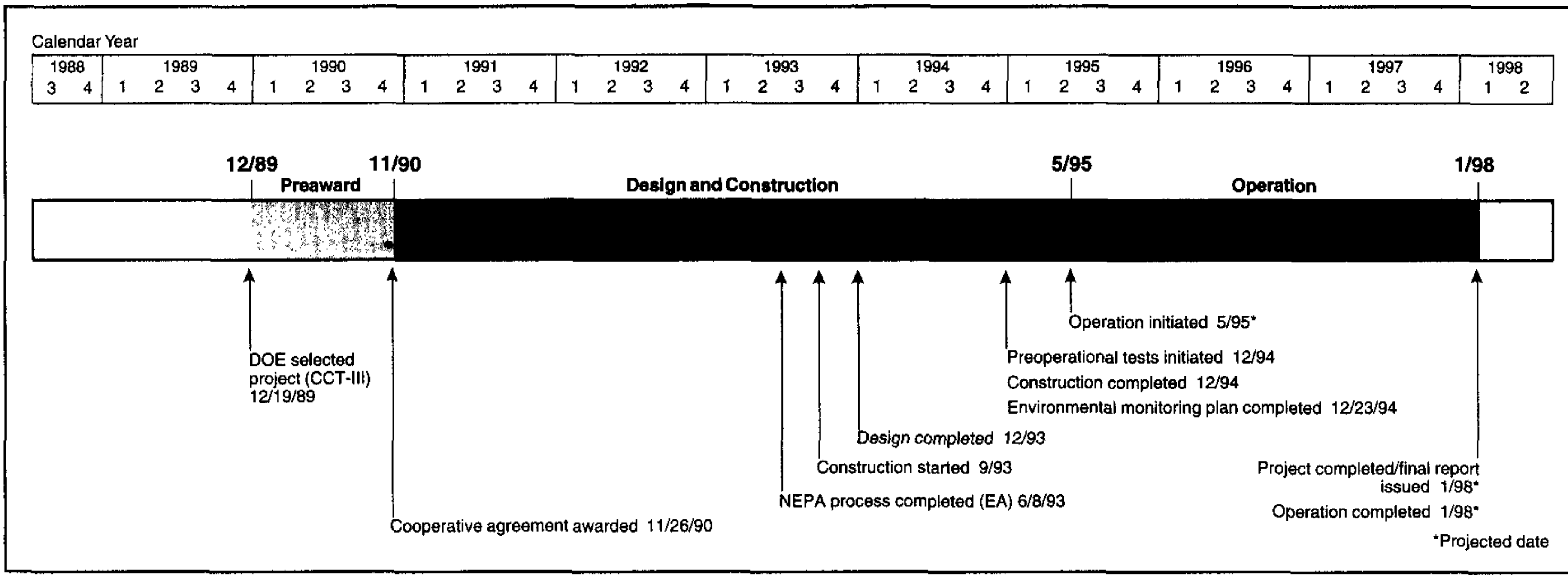
Project Funding:

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

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

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

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



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

Project Status/Accomplishments:

Construction has been completed, and preoperational tests have been initiated. Facilities constructed include those needed to prepare the coal, to deliver the prepared coal to the two blast furnaces, and to inject it into the furnaces. In addition, the blast furnaces were modified to accept the prepared coal. The necessary modifications to furnace D were made on-the-fly through a series of short outages on the operating furnace. Furnace C was modified during a reline in late 1994.

Bethlehem Steel expects to submit a public design report in January 1995.

Commercial Applications:

BFGCI technology can be applied to essentially all U.S. blast furnaces. The technology should be applicable to any rank coal commercially available in the United States that has a moisture content no higher than 12%. The environmental impacts of commercial application are primarily indirect and consist of a significant reduction of emissions resulting from diminished coke-making requirements.

Innovative Coke Oven Gas Cleaning System for Retrofit Applications

Participant:
Bethlehem Steel Corporation

Additional Team Member:
Thyssen Still/Otto Technical Services—technology developer

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

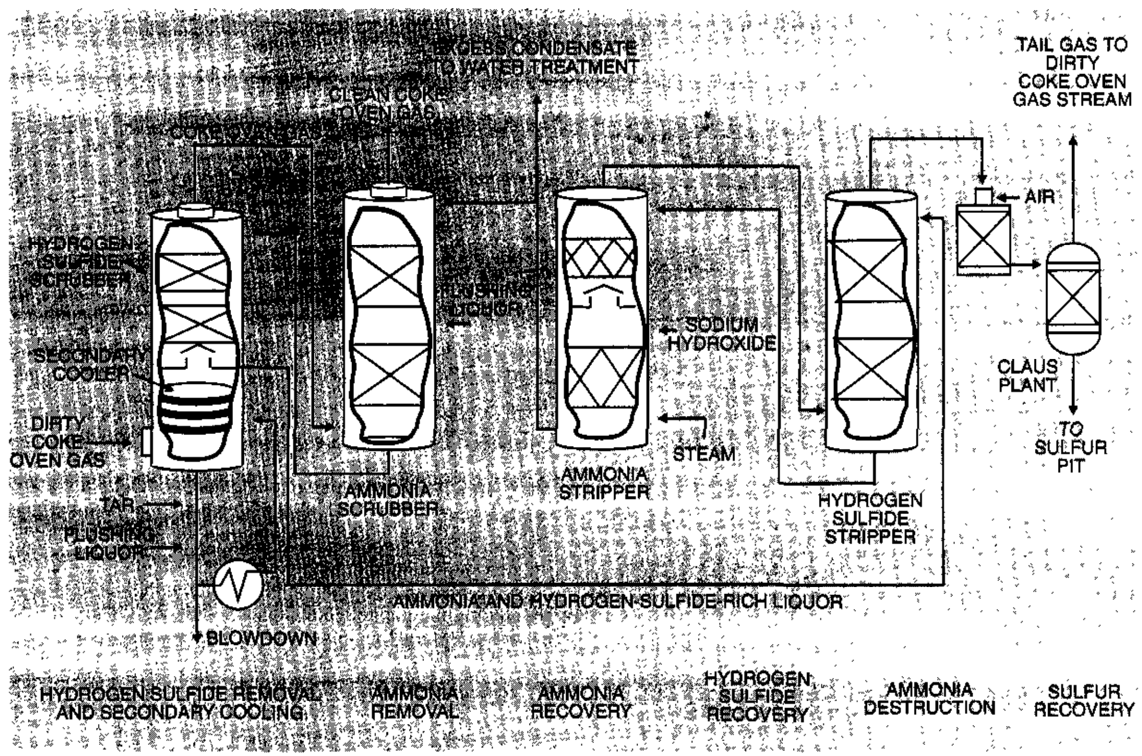
Technology:
Thyssen Still/Otto's process for precombustion cleaning of coke oven gas (COG) (industrial applications)

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

Project Funding:

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

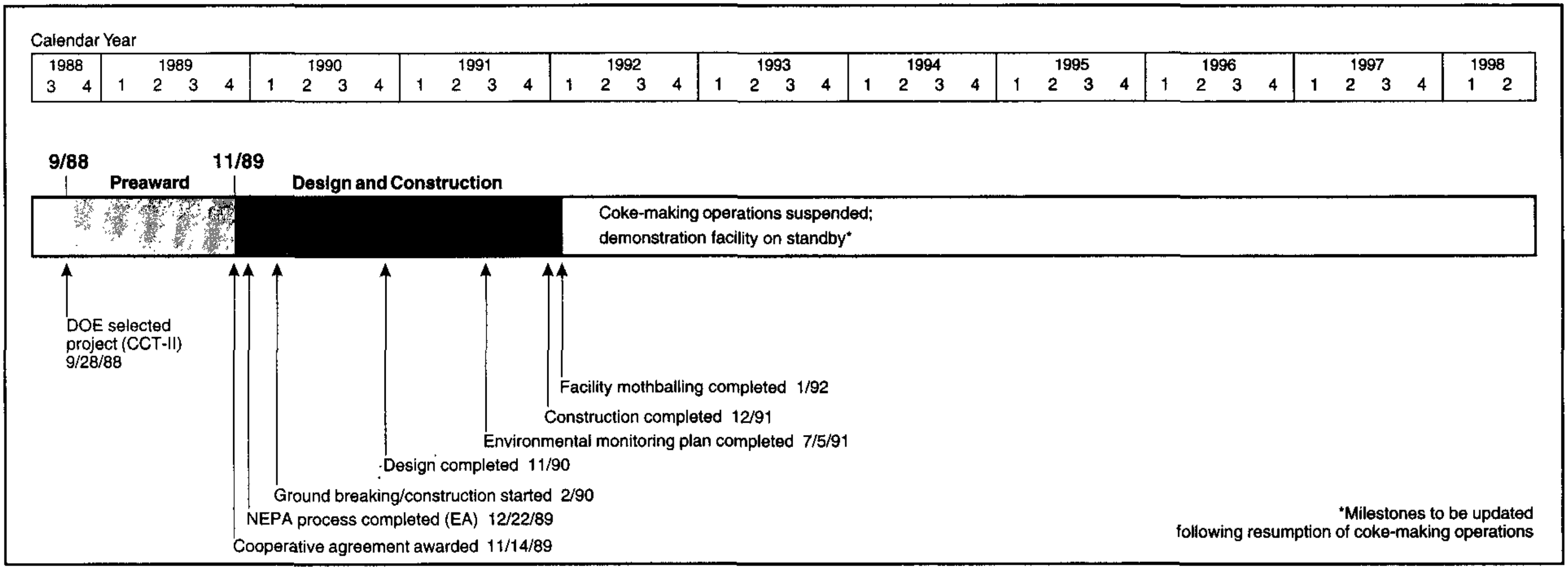
Project Objective:
To demonstrate a first-of-a-kind novel integration of commercially available process steps for simultaneous removal of hydrogen sulfide and ammonia from COG, recovery of hydrogen sulfide and ammonia, destruction of ammonia, and recovery of sulfur in a commercial-sized application; 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 Thyssen Still/Otto for removing hydrogen sulfide and ammonia from COG. The process uses contaminated water produced in the coke oven batteries to absorb the hydrogen sulfide and ammonia contained in the COG. Both hydrogen sulfide and ammonia are steam stripped from the absorption liquor. The ammonia is destroyed in a catalytic reactor; hydrogen sulfide is converted to elemental sulfur in a conventional Claus plant, and sulfur is recovered as a salable by-product.

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

This project involves the modification of the COG processing units at Bethlehem Steel's Sparrows Point Plant in Baltimore County, MD. The demonstration facility is designed to process the entire COG stream from Coke Oven Batteries A, 11, and 12, which amounts to 74millionstdft ^{3}/day. These coke oven batteries have the capability to produce up to 1.2 million tons/yr of coke from a blend of Pennsylvania and Virginia coals having sulfur contents ranging from 0.8% to 1.37%. The raw COG has a hydrogen sulfide content of 175–340 grains/100 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 December 5, 1991, Bethlehem Steel Corporation suspended all coke production at its Sparrows Point facility for a period of at least 2 years. This decision was made due to the rapid deterioration of the coke ovens. During this period, an evaluation will be made to explore *alternatives for resumption of coke production.* Bethlehem Steel's interest is for long-term coke independence at this facility.

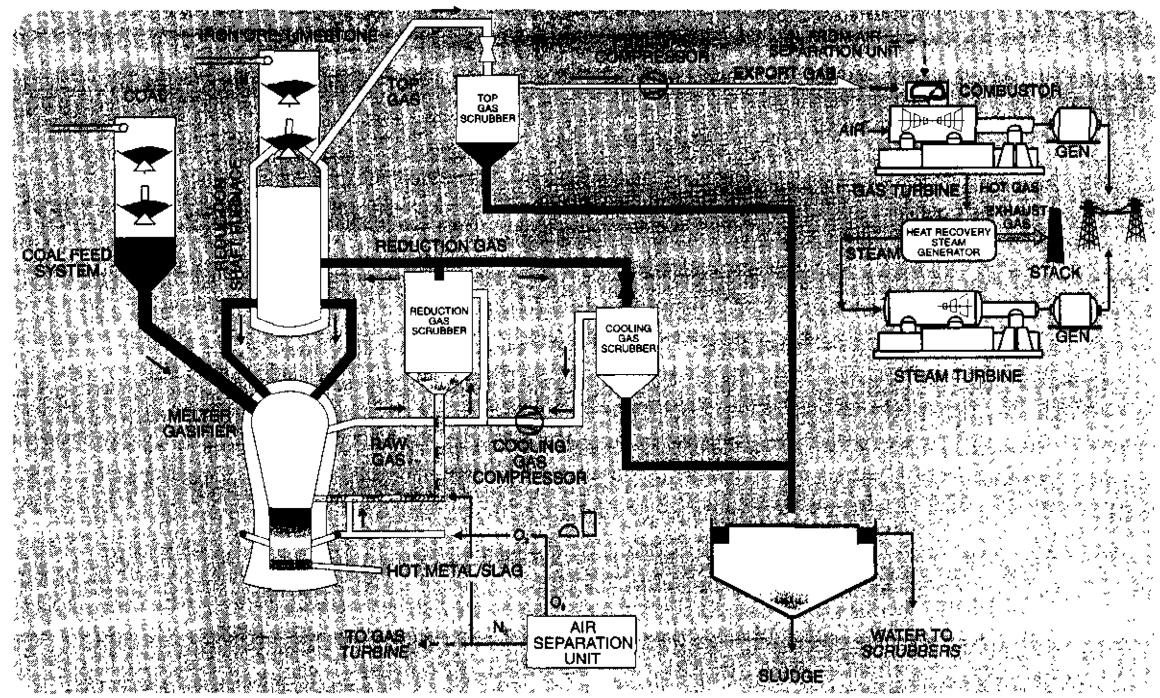
Construction of the coke oven gas cleaning demonstration facility is complete, and the unit has been mothballed to maintain it in good shape so that hot commissioning, start-up, and operation can be accomplished successfully when coke-making operations are resumed.

Commercial Applications:

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

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

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



Participant:

Centerior Energy Corporation

Additional Team Members:

Geneva Steel Company—site owner; constructor and operator of COREX® unit

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

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

Electric Power Research Institute—cofunder

Location:

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

Technology:

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

Plant Capacity/Production:

195 MWe (net) and 3,300 tons/day of hot metal (liquid iron)

Project Funding:

Total project cost	$825,092,000	100%
DOE	150,002,000	18
Participants	675,090,000	82

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

Project Objective:

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

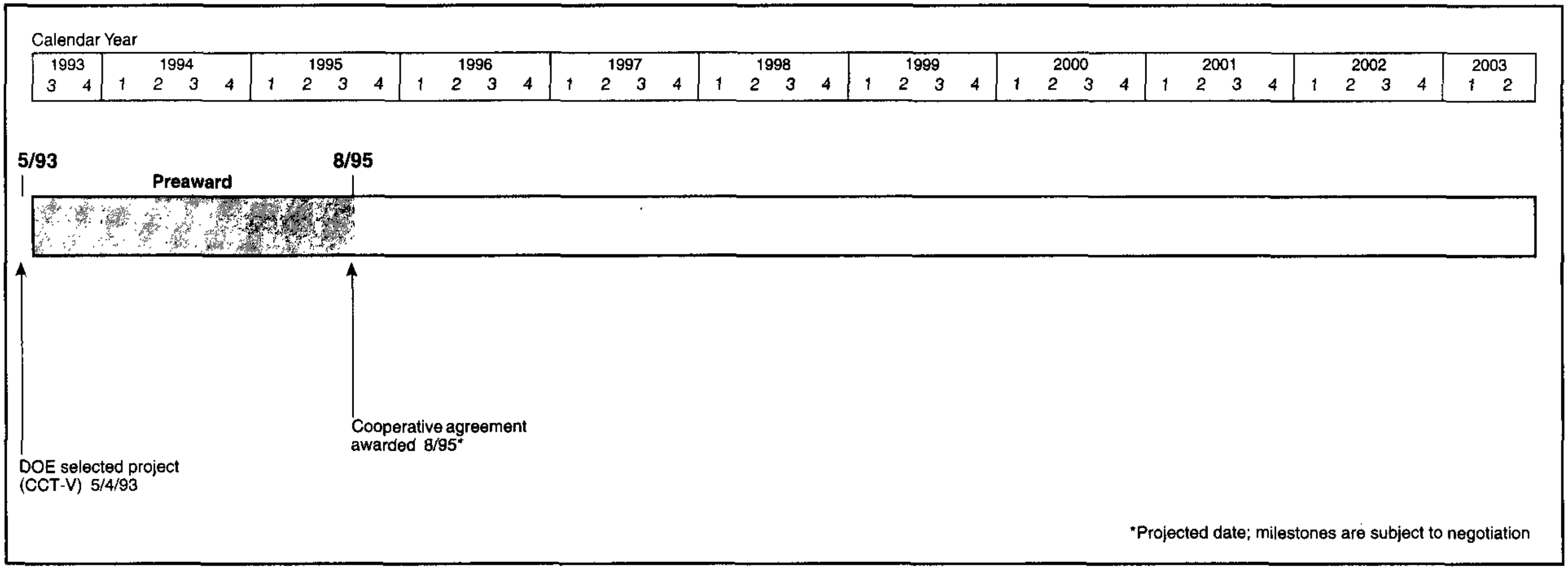
Technology/Project Description:

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

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

During the demonstration, about 3,400 tons/day of a bituminous coal blend containing about 0.5% sulfur will be utilized. The project will produce 3,300 tons/day of hot metal and 195 MWe for sale.

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



CPICOR™ technology is less complex and environmentally superior than competing iron-making and power-generating technologies. Criteria air pollutants are reduced substantially largely due to (1) the inherent desulfurizing capability of the COREX® process wherein the limestone fed to the reduction furnace captures the sulfur present in the coal and (2) the efficient control systems within the combined-cycle power generation process. Because coke is not used, coke plants and their associated pollutants can be eliminated.

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

Project Status/Accomplishments:

The project is in negotiation. In April 1994, LTV Steel elected to withdraw from the proposed project. In July 1994, Air Products and Chemicals, Centerior Energy, and Geneva Steel Company signed an agreement to develop and site the project at Geneva Steel's mill in Vineyard, UT (near Orem).

Commercial Applications:

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

The total emissions of NO_x from a future commercial plant are expected to be 0.012 lb/million Btu of coal, which is a reduction of more than 97% from the combination of a comparably sized blast furnace, associated coke-making facilities, and a comparably sized pulverized coal power plant with flue gas desulfurization. Similarly, the total emissions of SO_2 from the commercial facility are expected to be 0.024 lb/million Btu, a reduction of more than 90%. The net electrical generating efficiency of the commercial facility is estimated to be 47% (a net effective heat rate of 7,262 Btu/kWh on an LHV basis). This compares to a net efficiency of 32% for comparably sized conventional facilities.

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

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

Project completed.

Participant:
Coal Tech Corporation

Additional Team Members:
Commonwealth of Pennsylvania Energy Development Authority—cofunder
Pennsylvania Power and Light Company—supplier of test coals
Tampella Power Corporation—host site

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

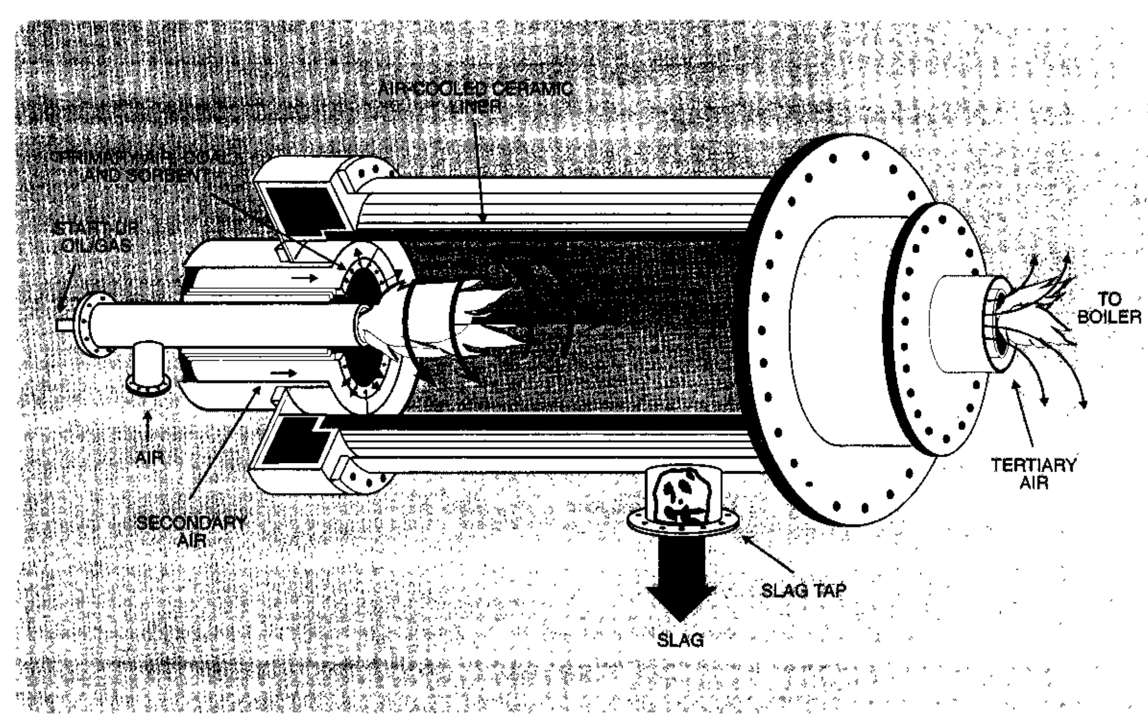
Technology:
Coal Tech's advanced, air-cooled, slagging combustor (industrial applications)

Plant Capacity/Production:
23 million Btu/hr

Project Funding:

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

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



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

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

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

Project Results/Accomplishments:

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

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

Coal Tech reported the following test results:

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

Commercial Applications:

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

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

Project Schedule:

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

Final Reports:

Final Technical Report	8/91
DOE Assessment	5/93

Cement Kiln Flue Gas Recovery Scrubber

Project completed.

Participant:
Passamaquoddy Tribe

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

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

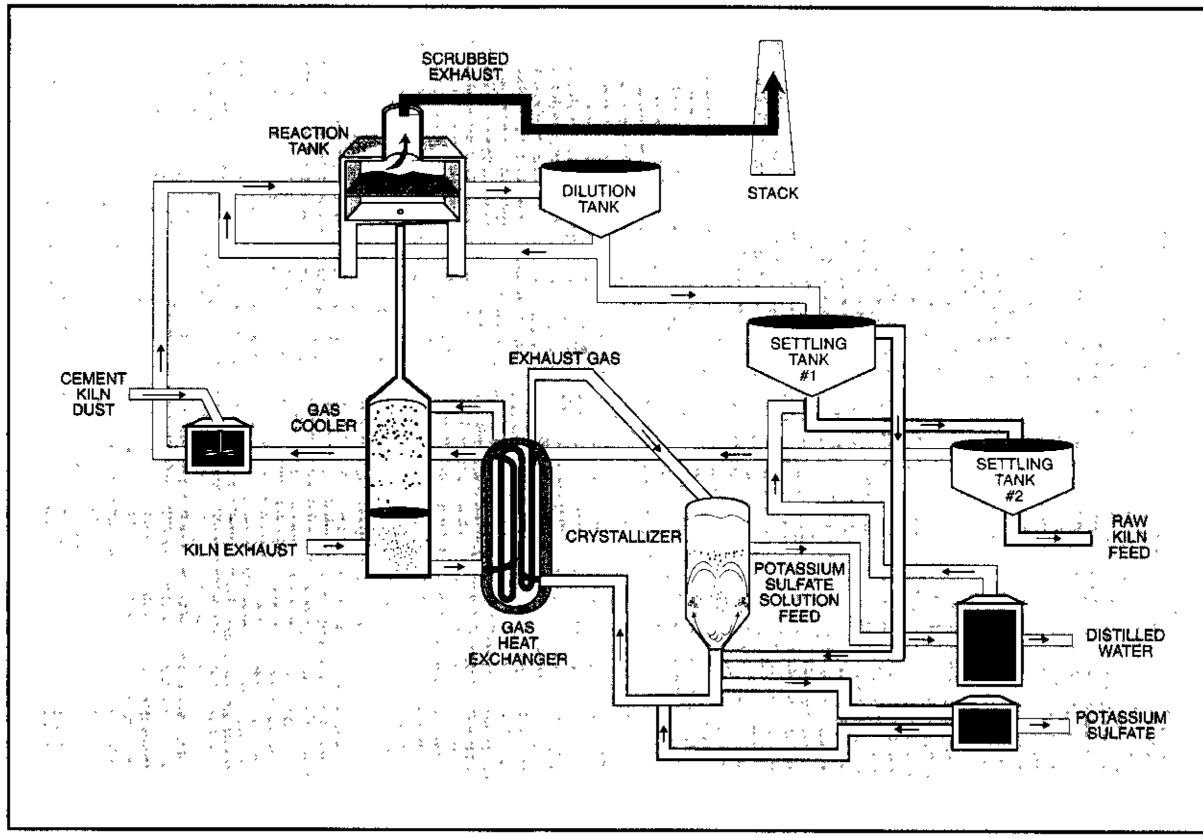
Technology:
Passamaquoddy Technology Recovery Scrubber™ (industrial applications)

Plant Capacity/Production:
1,450 tons/day of cement; 250,000 std ft³/min of kiln gas; and up to 274 tons/day of coal

Project Funding:

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

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



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

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

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

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

Project Results/Accomplishments:

The recovery scrubber began operations in August 1991 and has continued operations with several temporary shutdowns for normal kiln repairs and maintenance and a more lengthy shutdown from January to May 1992 due to poor economic conditions in the area. In a 5-month period from May to September 1992, the plant produced approximately 140,000 tons of cement while the scrubber removed 70 tons of SO_2 and treated 6,000tons of kiln dust for return to the kiln as raw feed. Initial testing of the scrubbing system achieved the project objective of 90–95% SO_2 emission reduction, with a maximum reduction of 98%. The effect on NO_x emissions also was determined during the demonstration. NO_x emissions were reduced 5–15%. Operations have totaled 5,316 hours. Capital costs are approximately $10 million for a 450,000-ton/yr plant, with a simple payback in about 3–4 years. Project operations continued through September 1993 when the scrubber became a permanent part of the Dragon Products facility.

Commercial Applications:

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

There are over 250 cement kiln installations in the United States and along the St. Lawrence River in Canada emitting approximately 230,000 tons/yr of SO_2. Based upon the characteristics of the technology, the applicable market would include approximately 75% of these installations. If the technology were installed in the applicable market facilities, SO_2 emissions could be reduced by approximately 150,000 tons/yr. Commercialization of the technology may be spurred on when EPA issues emissions limits on cement kilns under the CAAA of 1990. The technology may also have broader applications in paper production and municipal waste incineration in the United States and abroad.

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

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

In 1994 a Taiwanese cement company engaged Passamaquoddy Technologies, L.P., to do a preliminary study for the installation of the Passamaquoddy Technology Recovery Scrubber™ on a new cement plant in Taiwan.

Project Schedule:

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

Final Reports:

Final Technical Report (including economic assessment)	2/94
Topical Report	3/92
Public Design Report	10/93

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

Participant:
ThermoChem, Inc.

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

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

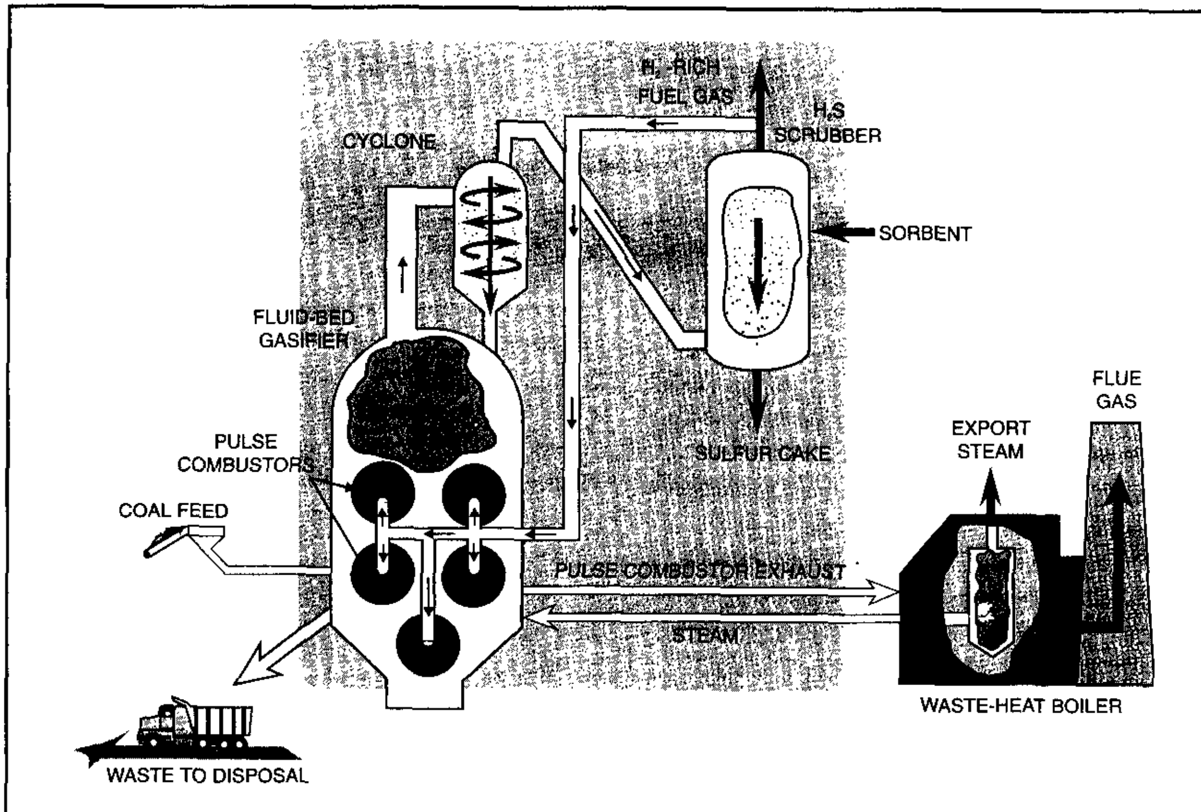
Technology:
Advanced combustion using Manufacturing and Technology Conversion International's (MTCI) pulse combustor/gasifier (industrial applications)

Plant Capacity/Production:
161 million Btu/hr of 325 Btu/std ft^3 medium-Btu fuel gas plus 40,0001b/hr of export steam

Project Funding:

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

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

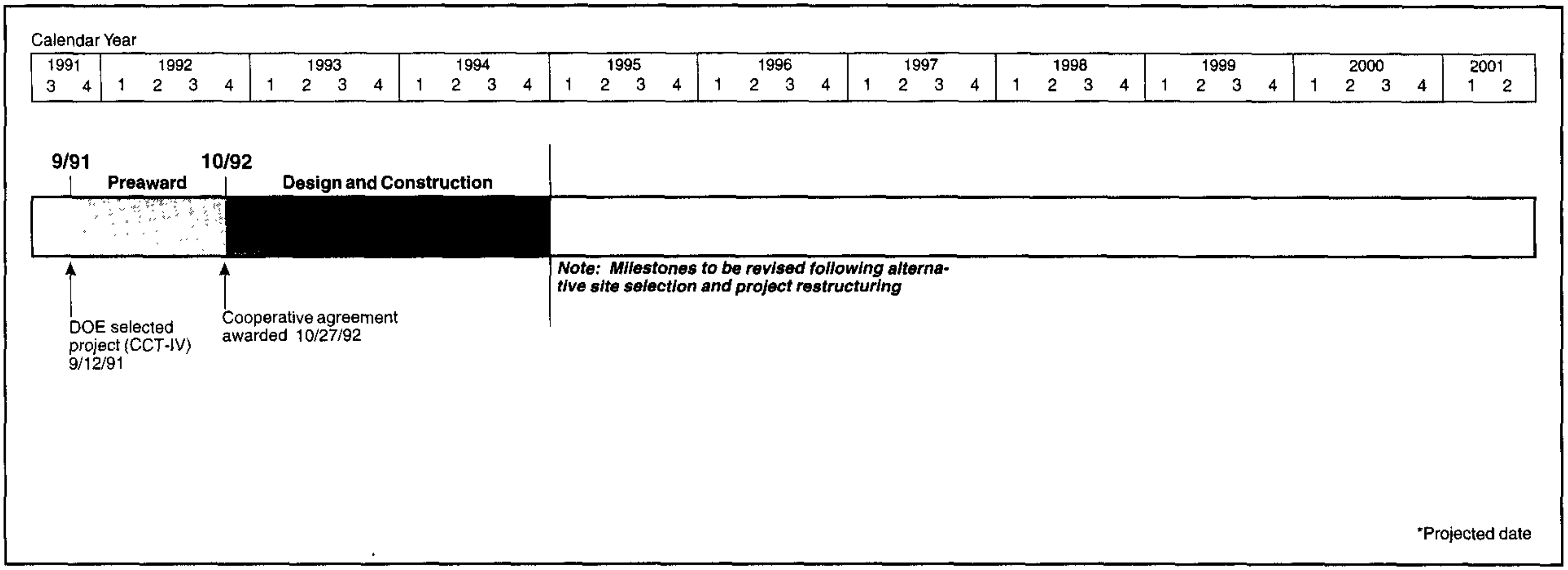


Technology/Project Description:
The MTCI fluidized-bed gasifier incorporates an innovative indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean, medium-Btu fuel gas without the need for an oxygen plant. The indirect heat transfer is provided by MTCI's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

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

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

The demonstration facility will be built at the Caballo Rojo Mine in conjunction with a new facility to demonstrate the K-Fuel coal-upgrading process. Water required to gasify the subbituminous coal will be produced by the K-Fuel process and the steam produced in the gasification demonstration facility will be used in the K-Fuel facility. The product gas will be burned in a gas turbine to generate electricity to operate both facilities. Subbituminous coal (0.3% sulfur) will be used.



Project Status/Accomplishments:

The cooperative agreement was awarded on October 27, 1992. Design verification tests at MTCI's Baltimore facility are continuing. The design tests include the construction and test firing of one full-size pulse combustor tube bundle. Fabrication of the design-verification–scale 252-tube pulse combustor has been completed. On October 26, 1994, ThermoChem, Inc., requested that DOE consider relocating the project to an alternative host site. A detailed planning conference on changing sites was held in December 1994.

Commercial Applications:

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

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

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

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

Appendix E: CCT Project Contacts

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

Advanced Electric Power Generation/ Fluidized-Bed Combustion

PFBC Utility Demonstration Project

Participant:
The Appalachian Power Company

Contacts:
Mario Marrocco, Manager, PFBC Programs
(614) 223-1740
(614) 223-2466 (fax)

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

Jeffrey Summers, DOE/HQ, (301) 903-4412
Larry K. Carpenter, METC, (304) 285-4161

PCFB Demonstration Project

Participant:
DMEC-1 Limited Partnership

Contacts:
Gary E. Kruempel, Project Manager
(515) 281-2459
(515) 281-2355 (fax)

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

John Geffken, DOE/HQ, (301) 903-9430
Larry K. Carpenter, METC, (304) 285-4161

Four Rivers Energy Modernization Project

Participant:
Four Rivers Energy Partners, L.P.

Contacts:
Edward Holley, Senior Project Manager
(610) 481-8568
(610) 481-3228 (fax)

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

William Fernald, DOE/HQ, (301) 903-9448
Larry K. Carpenter, METC, (304) 285-4161

Tidd PFBC Demonstration Project

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

Contacts:
Mario Marrocco, Manager, PFBC Programs
(614) 223-1740
(614) 223-2466 (fax)

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

Jeffrey Summers, DOE/HQ, (301) 903-4412
Larry K. Carpenter, METC, (304) 285-4161

Nucla CFB Demonstration Project

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

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

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

John Geffken, DOE/HQ, (301) 903-9430
Nelson F. Rekos, METC, (304) 285-4066

York County Energy Partners Cogeneration Project

Participant:
York County Energy Partners, L.P.

Contacts:
Bradley F. Hahn, Project Manager
(610) 481-3955
(610) 481-2393 (fax)

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

John Geffken, DOE/HQ, (301) 903-9430
Nelson F. Rekos, METC, (304) 285-4066

Advanced Electric Power Generation/ Integrated Gasification Combined Cycle

Combustion Engineering IGCC Repowering Project

Participant:
ABB Combustion Engineering, Inc.

Contacts:
Henry H. Vroom, Project Director
(203) 285-9085
(203) 285-3861 (fax)

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

Lawrence Saroff, DOE/HQ, (301) 903-9483
Gary A. Nelkin, METC, (304) 285-4216

Clean Energy Demonstration Project

Participant:
Clean Energy Partners Limited Partnership

Contacts:
Victor Shellhorse, Vice President
(704) 373-2474
(704) 382-9325 (fax)

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

Stanley Roberts, DOE/HQ, (301) 903-9431
Donald W. Geiling, METC, (304) 285-4784

Piñon Pine IGCC Power Project

Participant:
Sierra Pacific Power Company

Contacts:
John W. (Jack) Motter, Project Manager
(702) 689-4013
(702) 689-3047 (fax)

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

Lawrence Saroff, DOE/HQ, (301) 903-9483
Douglas M. Jewell, METC, (304) 285-4720

Toms Creek IGCC Demonstration Project

Participant:
TAMCO Power Partners

Contacts:
J.G. Patel, Project Director
(404) 859-2621
(404) 984-2441 (fax)

Tampella Power Corporation
2300 Windy Ridge Parkway
Suite 1125
Atlanta, GA 30339

John Geffken, DOE/HQ, (301) 903-9430
Gary A. Nelkin, METC, (304) 285-4216

Tampa Electric Integrated Gasification Combined-Cycle Project

Participant:
Tampa Electric Company

Contacts:
Donald E. Pless, Director, Advanced Technology
(813) 228-1332
(813) 228-1308 (fax)

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

William Fernald, DOE/HQ, (301) 903-9448
Nelson F. Rekos, METC, (304) 285-4066

Wabash River Coal Gasification Repowering Project

Participant:
Wabash River Coal Gasification Repowering Project Joint Venture

Contacts:
Michel R. Woodruff
(713) 735-4131
(713) 735-4169 (fax)

Destec Energy, Inc.
2500 City West Boulevard, Suite 1500
Houston, TX 77042

Jeffrey Summers, DOE/HQ, (301) 903-4412
Gary A. Nelkin, METC, (304) 285-4216

Advanced Electric Power Generation/ Advanced Combustion/Heat Engines

Healy Clean Coal Project

Participant:
Alaska Industrial Development and Export Authority

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

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

Stanley Roberts, DOE/HQ, (301) 903-9431
Robert M. Kornosky, PETC, (412) 892-4521

Coal Diesel Combined-Cycle Project

Participant:
Arthur D. Little, Inc.

Contacts:
Robert P. Wilson, Vice President
(617) 498-5806
(617) 498-7206 (fax)

Arthur D. Little, Inc.
200 Acorn Park
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Environmental Control Devices/NO_x Control Technologies

Demonstration of Coal Reburning for Cyclone Boiler NO_x Control

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Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit

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

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Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler

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

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

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

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Environmental Control Devices/SO_2 Control Technologies

10-MWe Demonstration of Gas Suspension Absorption

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Confined Zone Dispersion Flue Gas Desulfurization Demonstration

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Advanced Flue Gas Desulfurization Demonstration Project

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

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Environmental Control Devices/Combined SO_2/NO_x Control Technologies

SNOX™ Flue Gas Cleaning Demonstration Project

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LIMB Demonstration Project Extension and Coolside Demonstration

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