CLEAN COAL TECHNOLOGY

DOE/FE-0247P

Clean Coal Technology Demonstration Program

Program Update 1991

(As of December 31, 1991)

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

February 1992

CCT-I
Project Fact Sheets

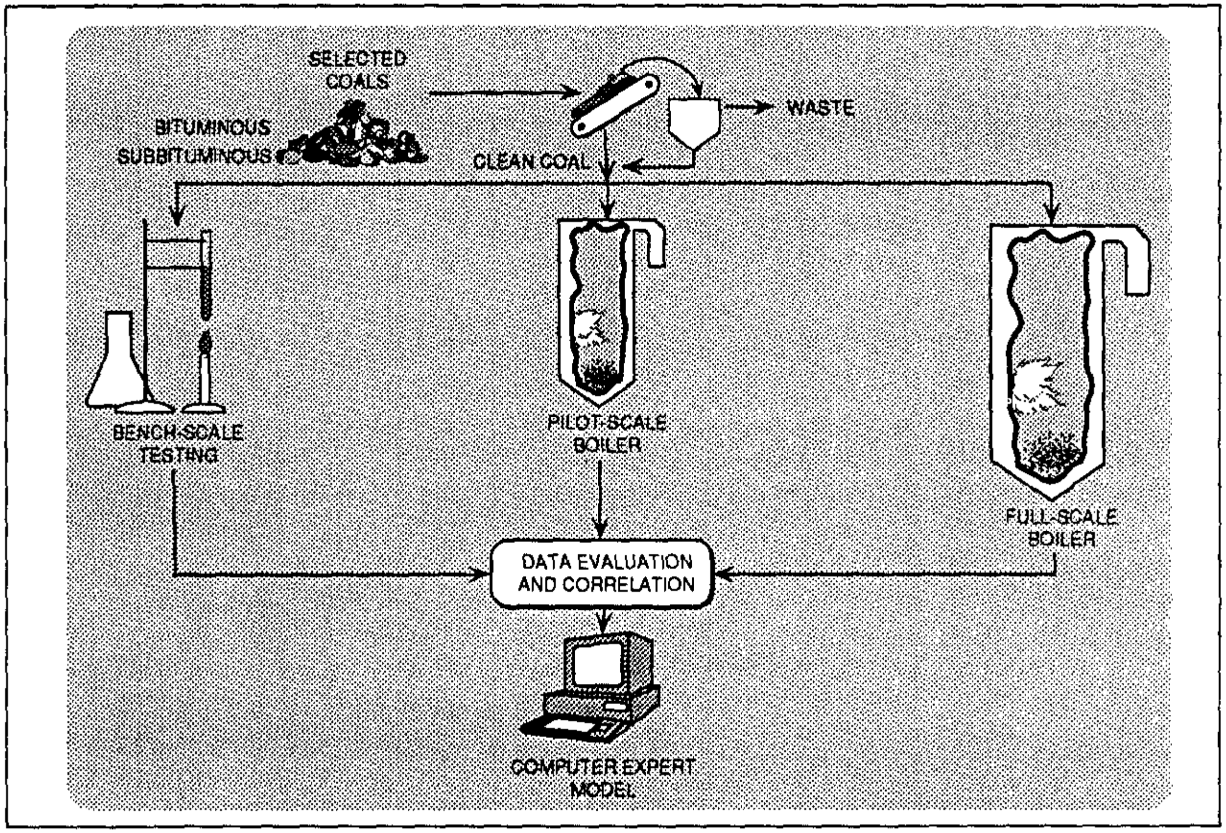
Development of the Coal Quality Expert

Sponsor:
ABB Combustion Engineering, Inc., and 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
Expert-EASE Systems Inc.—expert system architecture developer
Electric Power Technologies, Inc.—field testing
University of North Dakota, Energy and Minerals Research Center—bench-scale testing
Alabama Power Company—host utility
Duquesne Light Company—host utility
Mississippi Power Company—host utility
Northern States Power Company—host utility
Pennsylvania Electric Company and New York State Electric & Gas Corporation—host utilities
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)
Springdale, Westmoreland County, PA (Cheswick Station)
Gulfport, Harrison County, MS (Watson, Unit 4)
Bayport, Washington County, MN (King Station)
Homer City, Indiana County, PA (Homer City, Unit 2)
Oologah, Rogers County, OK (Northeastern, Unit 4)

Technology:
CQ, Inc.'s EPRI coal quality expert (CQE) computer model



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

Project Funding:

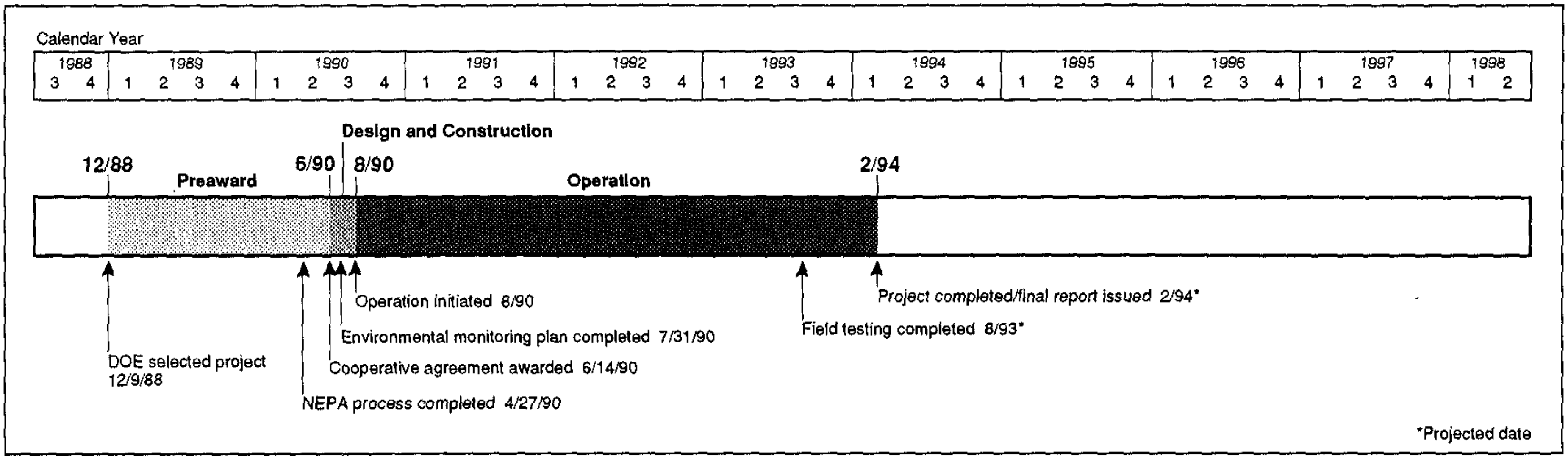
Total project cost	$17,382,258	100%
DOE	8,691,129	50
Participants	8,691,129	50

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 and environmental emissions.

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

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

The baseline and alternate coals for each test site also are burned in bench- and pilot-scale facilities under



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

Bench-scale testing will be performed at the University of North Dakota's Energy and Mineral Research Center in Grand Forks, ND; pilot-scale testing will be done at ABB Combustion Engineering's facilities in Windsor, CT, and Alliance, OH. The six field test sites are: Gatson, Unit 5 (880 MWe), Wilsonville, AL; Cheswick Station (500 MWe), Springdale, PA; Watson, Unit 4 (250 MWe), Gulfport, MS; King Station (560 MWe), Bayport, MN; Homer City, Unit 2 (600 MWe), Homer City, PA; and Northeastern, Unit 4 (445 MWe), Oologah, OK.

Project Status/Accomplishments:

Several field tests are complete, such as those conducted at Public Service of Oklahoma's Northeastern Unit 4, Mississippi Power Company's Watson Unit 4, and Northern States Power Company's King Station. Coals tested include Wyoming, blends of Wyoming/Oklahoma, Illinois, and western Kentucky, and a blend of Wyoming/Montana/petroleum coke. Tests at Alabama Power Company's Gatson Unit 5 will be resumed in the spring or summer of 1992. The CQE "Acid Rain Advisor" software package will be commercially released in January 1992. Pilot and bench coal tests are continuing.

Environmental Considerations:

NEPA compliance has been satisfied by a memo-to-file approved on April 27, 1990. An environmental monitoring plan has been prepared.

It is projected that by using the CQE model, SO_2 and NO_x emissions can be significantly reduced on a national basis relative to the no-action alternative considered in the PEIS. The expert system will enable coal-fired utilities to select the optimum quality coals for their specific boilers to reduce SO_2 and NO_x emissions.

Commercial Application:

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

LIMB Demonstration Project Extension and Coolside Demonstration

Sponsor:
The Babcock & Wilcox Company

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

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

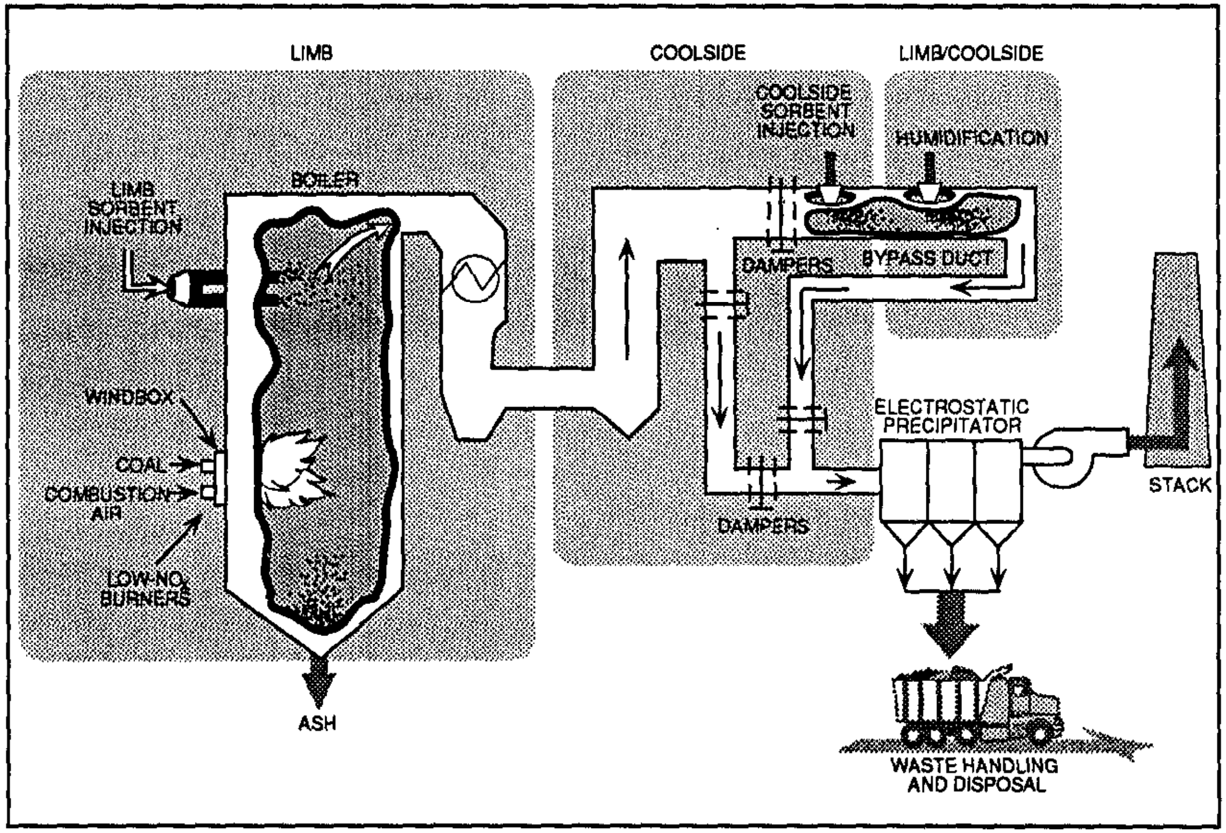
Technology:
The Babcock & Wilcox Company's limestone injection multistage burner (LIMB) system
Consolidation Coal Company's Coolside duct injection of lime sorbents

Plant Capacity/Production:
105 MWe

Project Funding:

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

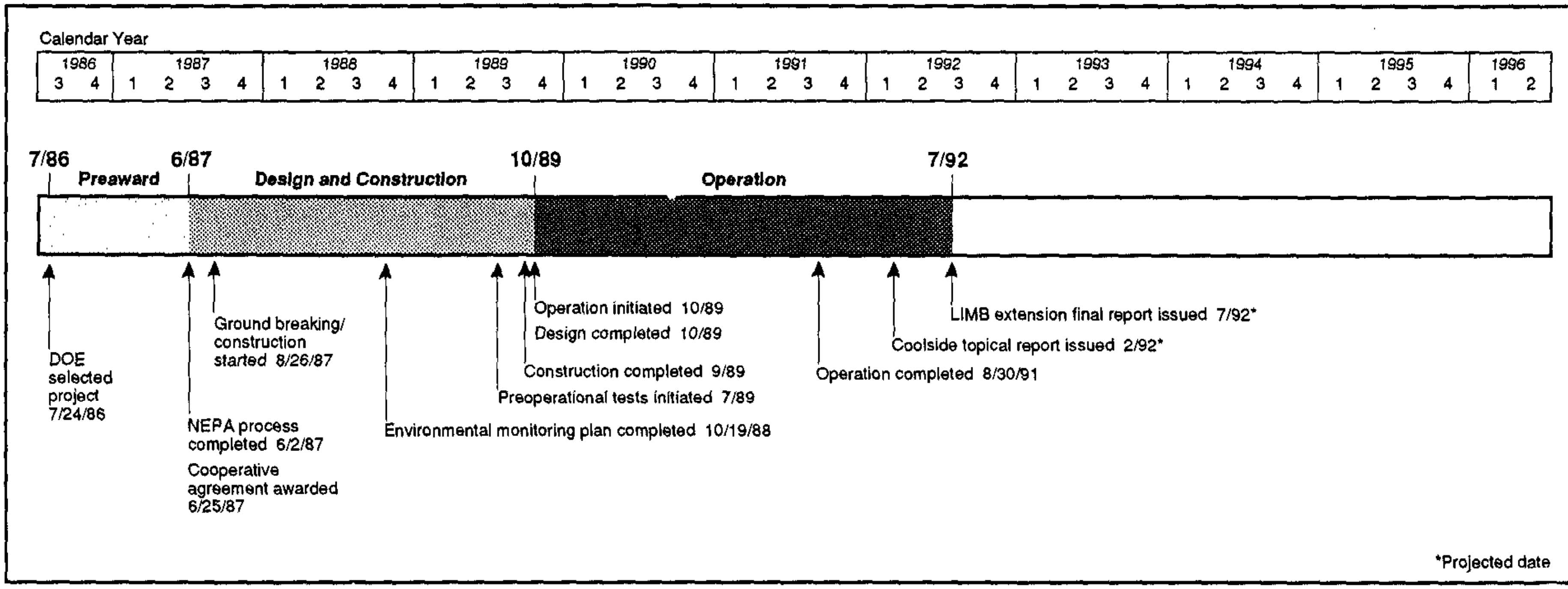
Project Objective:
To demonstrate, with a variety of coals and sorbents, the limestone injection multistage burner (LIMB) process as a retrofit system for simultaneous control of sulfur and nitrogen oxides in the combustion process, and that LIMB can achieve up to 60% NO_x and SO_2 reductions; to test alternate sorbent and coal combinations , using the Coolside duct injection process, to demonstrate in-duct sorbent injection, upstream of the humidifier and precipitator; and to show SO_2 removal of up to 80%.



Technology/Project Description:
The LIMB process is expected to reduce SO_2 by 50–60% 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 the existing particulate removal equipment, either an electrostatic precipitator (ESP) or a baghouse. Humidification of the flue gas before it enters an ESP is necessary to maintain normal ESP operation and to enhance SO_2 removal. This project will test combinations of three coals, each with a different sulfur content (1.6%, 3.0%, and 3.8%), and four sorbents. The tests are expected to provide commercial-scale operating and maintenance data on a variety of coal/sorbent combinations with diverse SO_2 removals and costs. Both limestone and hydrated lime (calcitic and dolomitic) sorbents will be tested.

In the Coolside process, dry sorbent is injected into the flue gas after the boiler and before the ESP. The gas is humidified in this process to enhance both ESP performance and SO_2 absorption. Also, a chemical additive can be dissolved in the humidification water to improve SO_2 absorption. Because of these benefits, it is expected that humidification equipment will be part of most, if not all, commercial Coolside applications. The spent sorbent is also collected with the fly ash as in the LIMB process. Reduction of SO_2 by 50–80% is expected.

Both demonstrations used the same low-NO_x burners, which control NO_x by injecting the coal and part of the combustion air simultaneously so that the first of the



combustion reactions takes place in an oxygen-deficient environment. The balance of the combustion air is introduced in a second stage to complete the combustion process. Staged combustion has been found to reduce NO_x emissions by 50–60%.

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 Status/Accomplishments:

The project has completed testing of the Coolside and LIMB processes.

Coolside test results indicate that this process can remove up to 70% of the SO_2 when using 3.0% sulfur coal at a 2:1 calcium-to-sulfur molar ratio using a commercially available hydrated lime, a 20 °F approach to adiabatic saturation, and an additive to the humidification water at a 0.2:1 sodium-to-calcium ratio. SO_2 removal rates up to 70% were routinely achieved with two different commercially available hydrated limes at a calcium-to-sulfur ratio of 2:1. Sodium hydroxide addition and higher sorbent rates achieved higher SO_2 removal, and sorbent recycle significantly increased sorbent utilization. When Coolside testing was concluded in February 1990, the system had operated for over 1,700 hrs, including 265 hrs of uninterrupted operation. The full-scale tests favorably confirmed the previous pilot-scale testing.

LIMB extension testing also demonstrated up to 70% SO_2 removal using various coal-sorbent combinations. Sorbents tested included lignosulfonated lime, ground limestone, hydrated calcitic lime, and locally available hydrated dolomitic lime. Three coals with nominal sulfur contents of 1.5–3.0% were selected for testing. NO_x removal was in the 40–50% range throughout both Coolside and LIMB testing.

Final reports describing Coolside and LIMB extension testing are being prepared.

Environmental Considerations:

NEPA compliance was satisfied with a memo-to-file signed on June 2, 1987.

Because of wide market application, SO_2 and NO_x reductions of 30% and 11% respectively by 2010 are projected on a national basis, assuming maximum commercialization of the technology. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

Sorbent injection is applicable to most utility and industrial coal-fired units and can be retrofitted with modest capital investment and downtime.

The LIMB and Coolside processes both provide an alternative to conventional wet flue gas desulfurization (FGD) processes. Both are expected to be substantially less expensive than wet FGD, and their space requirements are also substantially less. These factors are important in retrofit applications.

Arvah B. Hopkins Circulating Fluidized-Bed Repowering Project

Sponsor:

The City of Tallahassee

Additional Team Members:

Foster Wheeler Energy Corporation — technology supplier

Bechtel Power Corporation — engineer and constructor

Location:

An alternate site is being considered.

Technology:

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

Plant Capacity/Production:

250 MWe

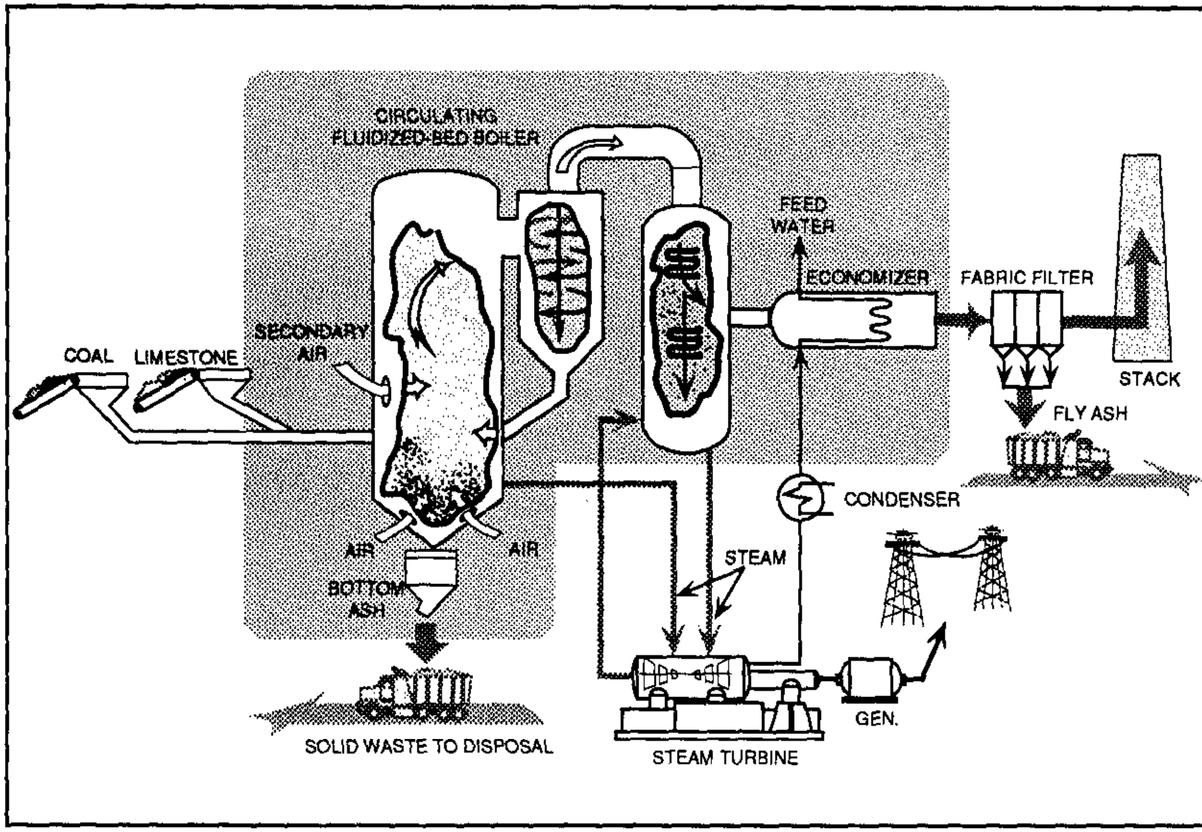
Project Funding:

Total project cost	$276,791,974	100%
DOE	74,733,833	27
Participant	202,058,141	73

(Funding is subject to project restructuring after alternate site is selected.)

Project Objective:

To demonstrate ACFB at 250 MWe, representing a 1.7:1 scale-up from previously constructed facilities; to verify expectations of the technology's economic, environmental, and technical performance in the repowering of an existing oil-/natural-gas-fired boiler at a utility site; and to provide the utility industry 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%.

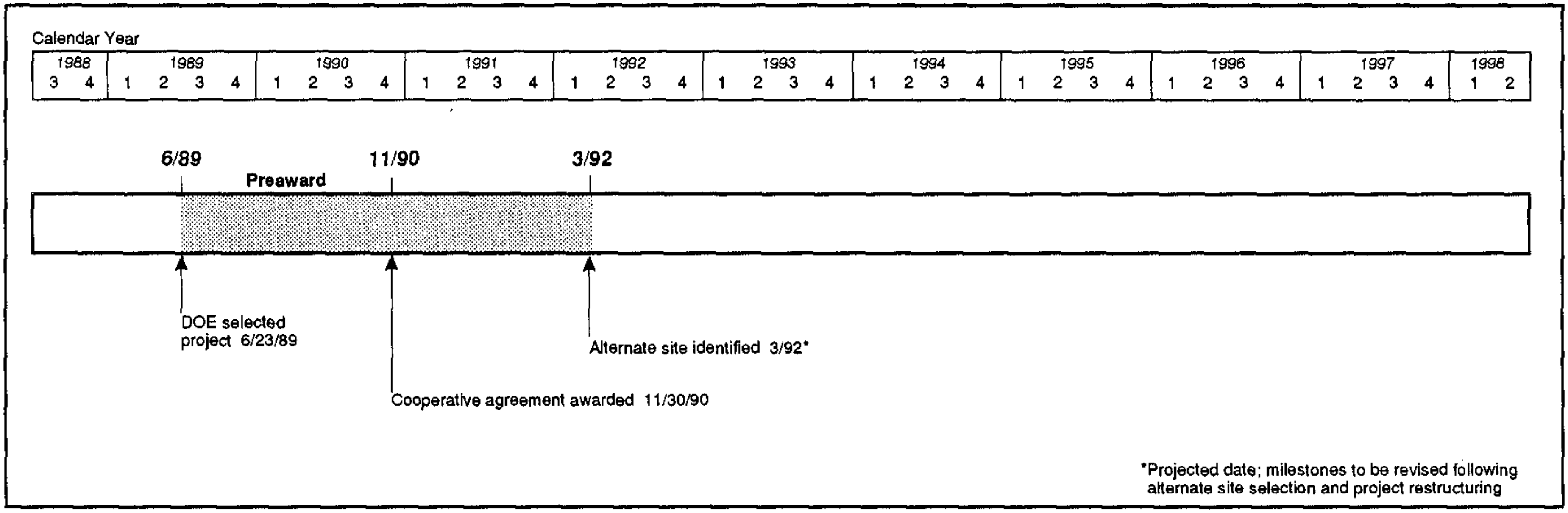


Technology/Project Description:

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 a water-wall combustor where initial combustion occurs. Combustion takes place at relatively low temperatures of 1,500–1,600 °F. 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.

Heat is removed by the water walls as well as by the steam-cooled cyclone and the solids recycle heat exchanger located within the circulating loop encompassing the combustor, particle separator, and solids recycle leg. Combustion gases that leave the particle separator are cooled in a convective back pass containing additional superheaters, water walls, and an economizer. The steam produced is sent to the steam turbine to generate power. Sulfur is absorbed by the sorbent and removed with the ash.

This project involves repowering an existing steam electric power plant by using a scaled-up ACFB boiler. A coal-fired ACFB steam-generating system will replace the existing oil-/gas-fired steam-generating system used to drive a steam turbine. The existing turbine generator and the balance of the equipment are being retained.



Project Status/Accomplishments:

The City of Tallahassee has elected not to proceed with the project at the Arvah B. Hopkins Station site. The decision was based on results from an updated economic study which compared costs of the proposed repowering project and continued operation of the current 23-yr-old plant using natural gas. Lower than expected natural gas prices in the near-term and environmental controls more stringent than required by law caused cost increases for the CCT project that indicated it was no longer the least-cost option. However, the City is still interested in CFB technology and, with DOE concurrence, has authorized Foster Wheeler to locate an alternate host site. Work on the project has ceased pending identification of a new site. It is estimated that an alternate site will be identified and approved in early 1992. At that time, new project milestone dates and revised project costs will be determined.

Environmental Considerations:

The following are projected impacts from maximum commercialization of ACFB technology on a national basis by 2010 relative to a no-action alternative:

- SO_2 reduction—44%
- NO_x reduction—17%
- Solid waste increase, but in a dry, granular form amenable to some by-product markets
- CO_2 reduction—5%

(Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

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. Coal of any sulfur content can be used, and any type or size of a coal-fired boiler can be repowered. Because an existing plant area is used, and coal- and waste-handling equipment as well as steam turbine equipment are retained, the life of a plant can be extended.

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
- Dry, granular solid waste

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

Sponsor:
Coal Tech Corporation

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

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

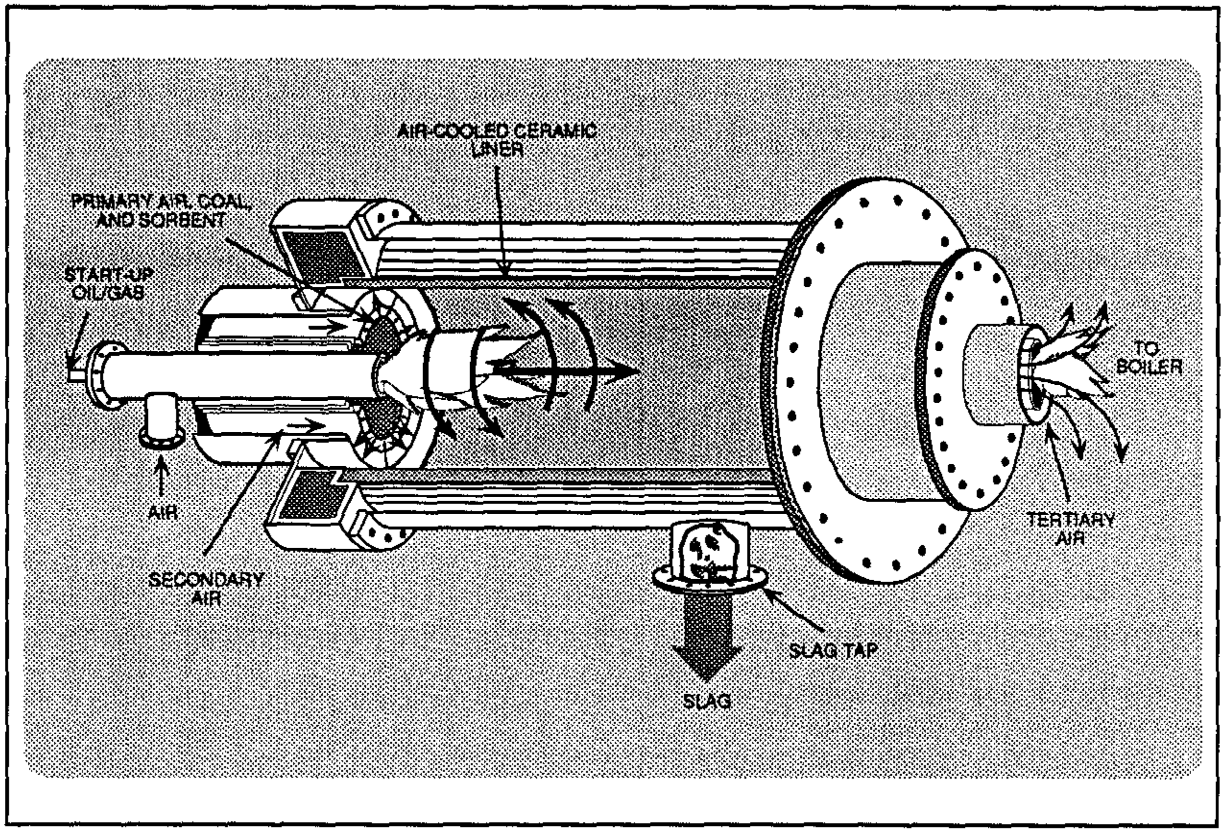
Technology:
Coal Tech's advanced, air-cooled, slagging combustor

Plant Capacity/Production:
23 million Btu/hr

Project Funding:

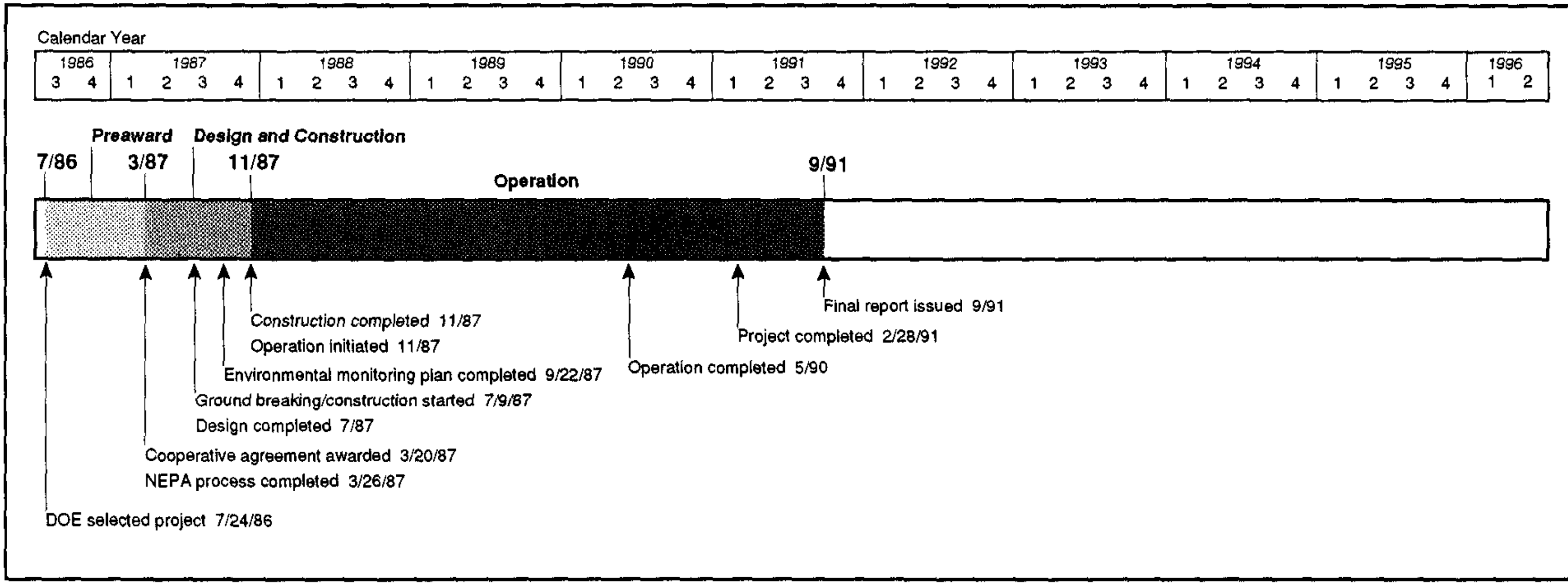
Total project cost	$984,394	100%
DOE	490,149	50
Participants	494,245	50

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 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 combustor. The 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 90% 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.

The project features combustion of dry pulverized coal in an advanced, air-cooled, cyclone coal combustor retrofitted on a 23-million-Btu/hr, oil-designed package boiler located at the Tampella Keeler plant in Williamsport, PA. Pennsylvania bituminous coals containing from 1% to approximately 3.3% sulfur were tested to demonstrate that this combustor is capable of burning most U.S. coals in an environmentally acceptable manner.



Project Status/Accomplishments:

Coal Tech completed design, construction, and operation by mid-1990. The project was completed on February 28, 1991. The final report is entitled *The Demonstration of Advanced Cyclone Coal Combustor, with Internal Sulfur, Nitrogen and Ash Control for the Conversion of a 23 MM Btu/hr Oil Fired Boiler to Pulverized Coal; Volume 1—Final Technical Report; Volume 2—Appendices I, II, III, IV, and V; Volume 3—Appendix VI.* The report is available from NTIS as DE 9200-2587 Volume 1, and DE 9200-2588-T7 Appendices.

The Coal Tech combustor was operated for approximately 1,000 hrs under varying loads and conditions simulating industrial applications. Results indicate that Coal Tech has achieved most of the objectives that were set forth in the cooperative agreement during the 30-month test period. The test results indicate that Coal Tech's air-cooled, coal-fired, slagging combustor can successfully (1) be retrofitted to and operate efficiently over a wide stoichiometric range on previously oil- or gas-fired boilers, (2) reduce coal-derived NO_x emissions by approximately 75%, (3) remove up to 90% of the coal slag at the combustor slag tap upstream of the boiler, and (4) capture and remove with the slag about 10% of the sulfur contained in the coal. Coal Tech also has test results indicating that over 80% sulfur removal can be achieved through a combination of sorbent injection at and downstream of the combustor. Coal Tech has concluded that this novel air-cooled combustor design concept is sound and that sufficient design and operational information has been obtained from this CCT demonstration to scale up to 100 million Btu/hr.

Environmental Considerations:

NEPA compliance was satisfied by a memo-to-file approved on March 26, 1987.

The advanced cyclone combustor is expected to reduce emissions nationally as follows:

- SO_2 reduction—45%
- NO_x reduction—18%

The SO_2 emissions are reduced through sorbent injection. (Source: CCT Programmatic Environmental impact Statement)

Commercial Application:

Coal Tech's advanced, air-cooled, slagging combustor permits the combustion of a wide range of U.S. coals, including high-sulfur coals. This combustor can be used to retrofit small utility and industrial boilers that currently operate with oil or gas firing, due to the combustor's ability to effectively eliminate coal solids upstream of the boiler and to control NO_x and SO_2 emissions.

Nucla CFB Demonstration Project

Sponsor:
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)

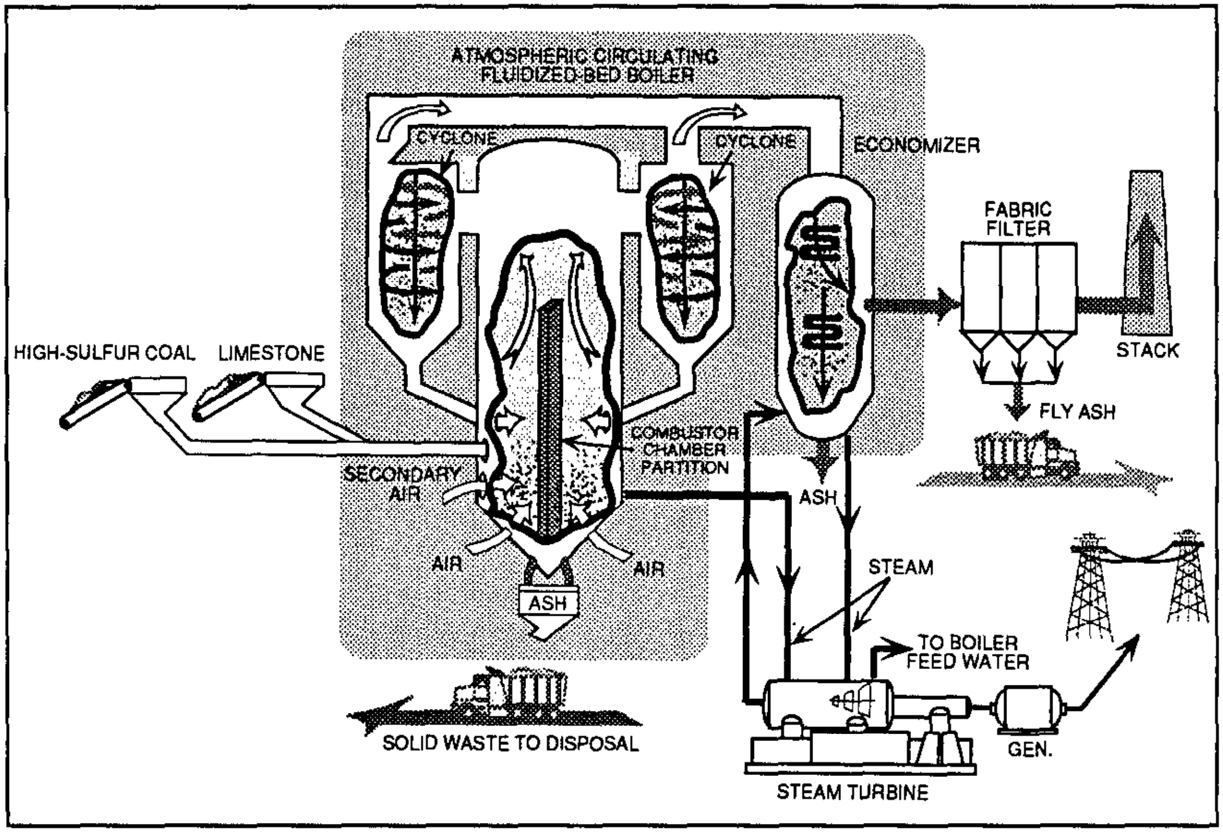
Technology:
Pyropower's atmospheric circulating fluidized-bed combustion (ACFB) system

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 scale-up 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:
The Nucla circulating fluidized-bed system operates at atmospheric pressure. In the combustion chamber, a stream of air fluidizes and entrains the bed material, which includes coal, coal ash, and a sulfur sorbent such as limestone. Combustion takes place at relatively low temperatures that 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 power.

Three small, coal-fired, stoker-type boilers at the Colorado-Ute Nucla Station were replaced with a single ACFB steam generator capable of driving a new 74-MWe turbine generator. Extraction steam from this turbine generator will power the three existing turbine generators of 12 MWe each. The majority of other existing plant equipment is being used to minimize costs and to demonstrate the suitability of ACFB technology for repowering and life extension of existing units.

Wabash River Coal Gasification Repowering Project

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

Additional Team Members:
PSI Energy, Inc.—host utility
Destec Energy, Inc.—engineer, gas plant operator, and technology supplier
Electric Power Research Institute—cofunder

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

Technology:
Integrated gasification combined-cycle (IGCC) using Destec's two-stage, entrained-flow gasification system

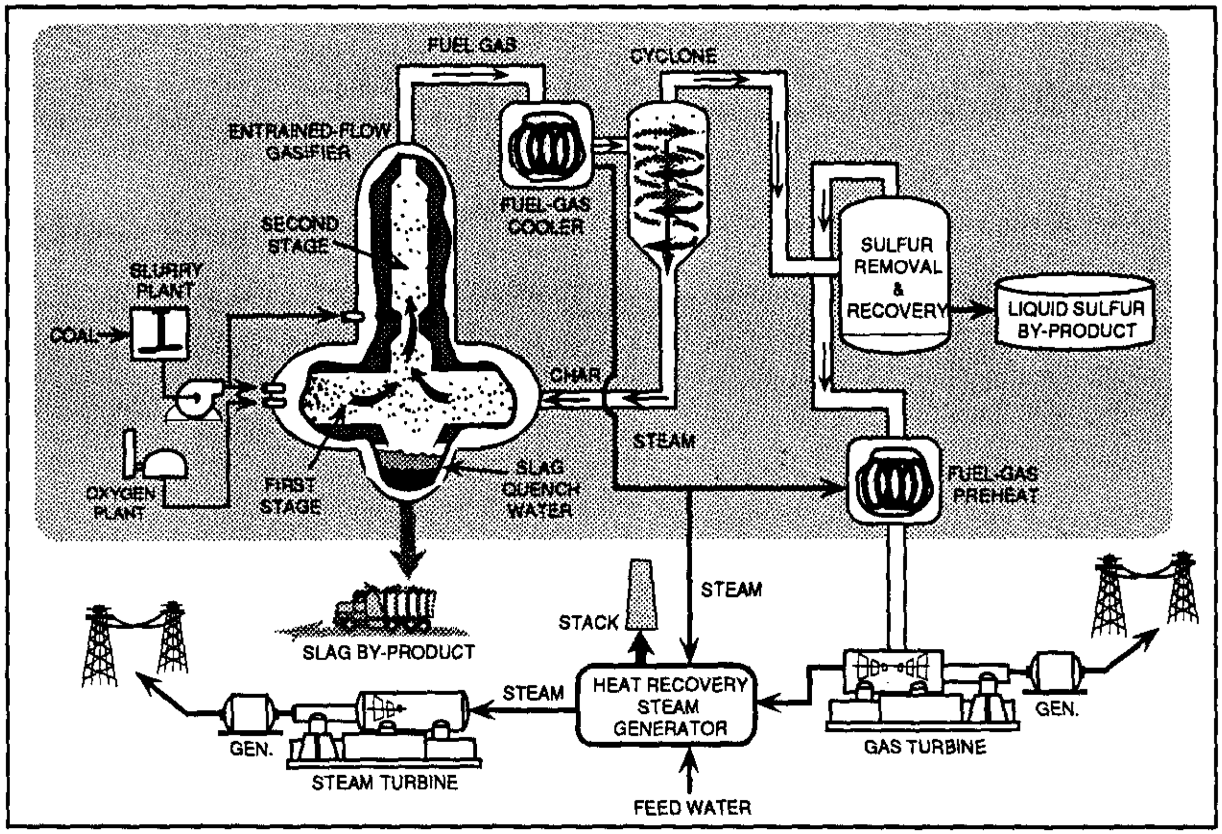
Plant Capacity/Production:
265 MWe

Project Funding:

Total Project cost	$591,927,376	100%
DOE	244,585,837	41
Participant	347,341,539	59

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

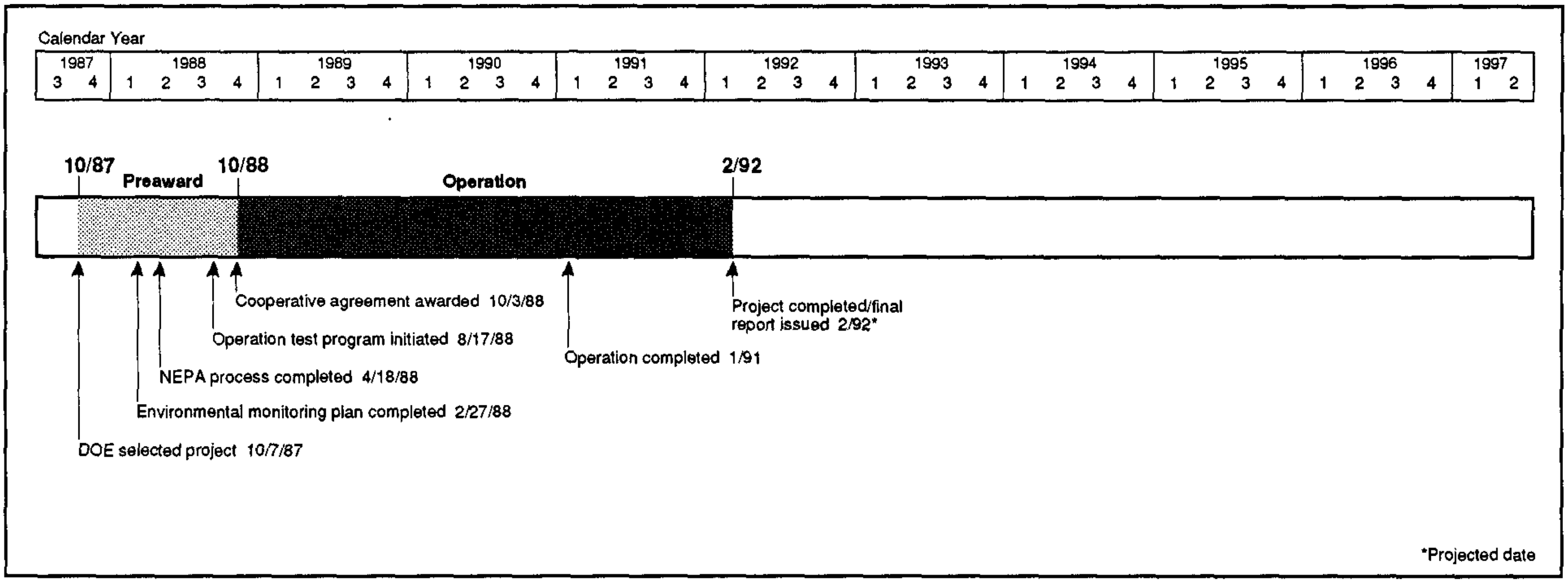
Project Objective:
To demonstrate utility repowering with a two-stage, oxygen-blown IGCC system, including advancements in the technology relevant to the use of high-sulfur bituminous coal, and to assess long-term reliability, availability, and maintainability of the system at a fully commercial scale.



Technology/Project Description:
Coal is ground, slurried with water, and gasified in a pressurized, two-stage (entrained flow slagging first stage and non-slagging second stage), oxygen-blown, entrained-flow gasifier. The product gas is cooled through heat exchangers and passed through a conventional cold gas cleanup system which removes particulates, ammonia, and sulfur. The clean, medium-Btu gas is then reheated and burned in an advanced 192-MWe 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 110-MWe steam turbine.

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

One of six units at PSI Energy's Wabash River Generating Station, located in West Terre Haute, IN, is being repowered. The demonstration unit will be designed to generate 265 MWe net using 2,544 tons/day of high-sulfur, Illinois Basin bituminous coal. Upon completion, the project will represent the largest single-train IGCC plant in operation in the United States.



Project Status/Accomplishments:

The project was initially scheduled to be completed in August 1990 following a 2-yr operational test program. Although some 15,700 hrs of testing were accomplished, the test program could not be completed within the original schedule because of numerous plant outages for repairs and plant modifications that were mostly unrelated to the ACFB technology. Therefore, testing was extended to complete the program and determine the optimum operating conditions and performance.

To date, Nucla has met all NSPS requirements with better than 90% sulfur capture, has typically achieved NO_x emissions less than 0.18 lb/million Btu, and has removed 99.96% of the particulates. Cost information is promising, with capital cost of approximately $1,021/gross kW and operating cost at $20/MW. This is competitive with pulverized coal units that are not limiting emissions as significantly as Nucla. Net heat rates have averaged about 11,900 Btu/kWh. A 200-MWe facility is projected to operate at heat rates of approximately 10,000 Btu/kWh.

To complete project reporting requirements, the project has been extended to February 29, 1992.

Environmental Considerations:

NEPA compliance was satisfied April 18, 1988, with a memo-to-file. The performance to date of the demonstration has met or exceeded the improved environmental performance projections for the ACFB.

The following impacts are projected from maximum commercialization of the ACFB technology on a national basis by 2010 relative to a no-action alternative:

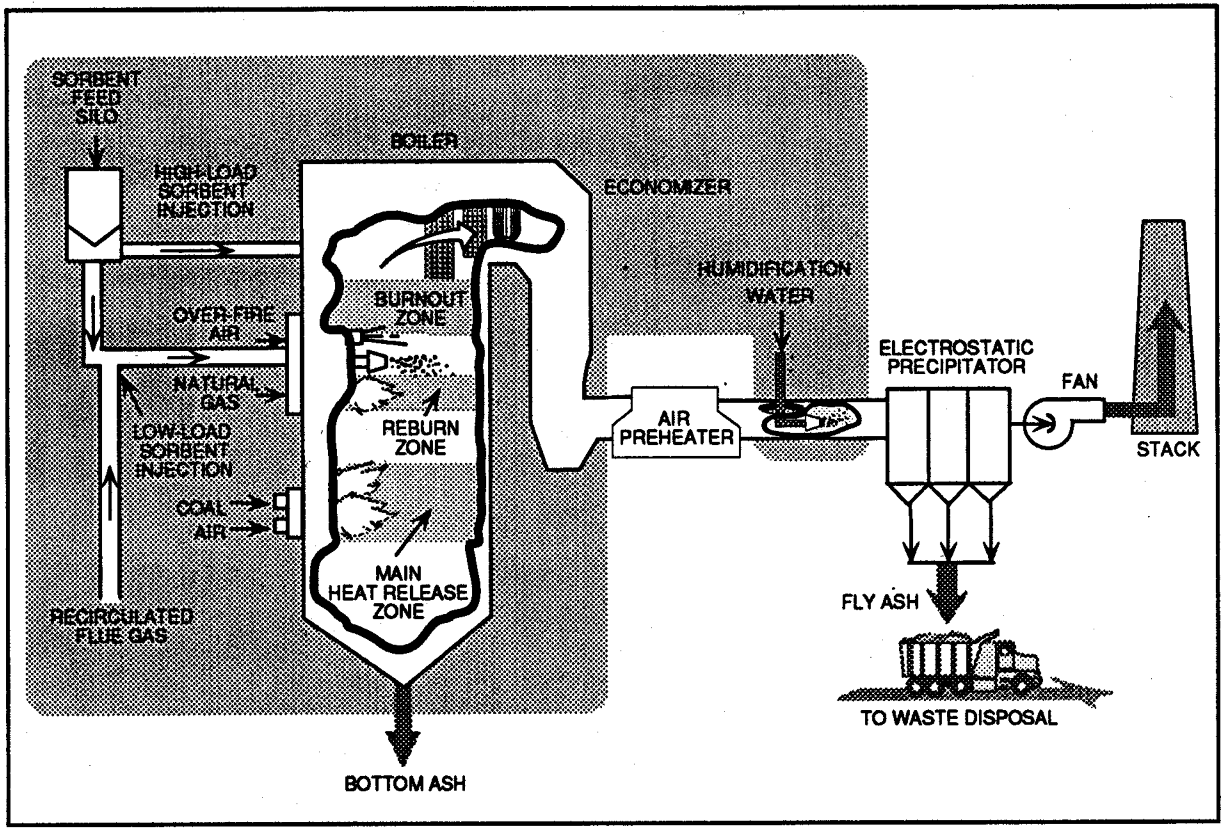
- SO_2 reduction— 44%
- NO_x reduction—17%
- CO_2 reduction—5%

Although solid waste is expected to increase, it would be in a dry, granular form more amenable to alternative uses, such as construction aggregate, and requiring less land area for disposal than conventional scrubber sludge. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

ACFBs have good potential for both industrial and utility sectors in repowering existing coal-fired plants or new facilities. In repowering applications, ACFB can increase capacity by an increment of about 15%. 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.

Enhancing the Use of Coals by Gas Reburning and Sorbent Injection



Sponsor:
Energy and Environmental Research Corporation

Additional Team Members:
Gas Research Institute—cofunder
State of Illinois, Department of Energy and Natural Resources—cofunder
Illinois Power Company—host utility
City Water, Light and Power—host utility

Locations:
Hennepin, Putnam County, IL (Illinois Power Company, Hennepin Plant)
Springfield, Sangamon County, IL (City Water, Light and Power, Lakeside Station)

Technology:
Energy and Environmental Research Corporation's gas reburning and sorbent injection process

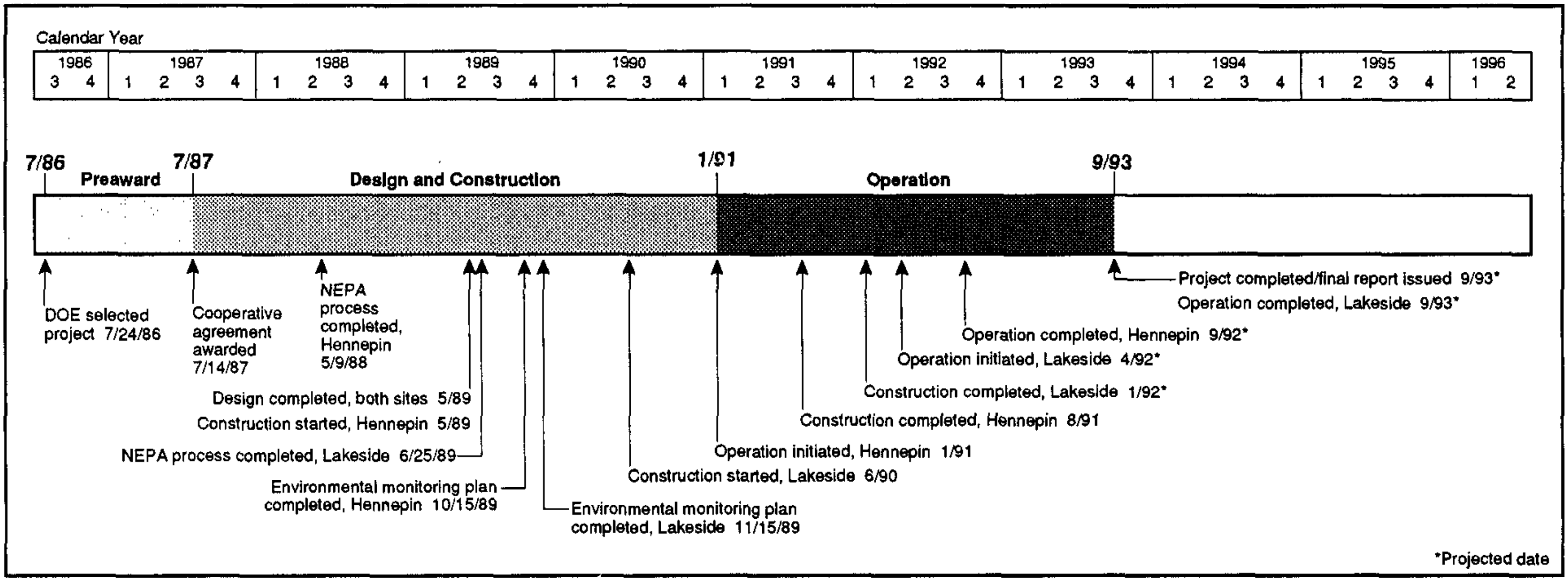
Plant Capacity/Production:
Hennepin: tangentially fired 80 MWe (nominal)
Lakeside: cyclone-fired 40 MWe (nominal)

Project Funding:

Total project cost	$29,998,253	100%
DOE	14,998,253	50
Participants	15,000,000	50

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

Technology/Project Description:
Gas reburning is a postcombustion technology that is being developed primarily for the removal of NO_x. In this process, 80–85% of the fuel is coal and is supplied to the main combustion zone. The remaining 15–20% of the fuel, generally natural gas or a hydrocarbon, bypasses the main combustion zone and is injected above the main burners to form a reducing zone in which NO_x is converted to nitrogen. A calcium compound (sorbent) is injected in the form of dry, fine particulates above the reburning zone in the boiler or even further downstream. The calcium compounds to be tested will be $CaCO_3$ (calcium carbonate) and $Ca(OH)_2$ (lime). The process is expected to achieve 60% NO_x reduction and 50% SO_2 reduction on different boiler configurations at power plants burning high-sulfur midwestern coal. This project will demonstrate the gas reburning and sorbent injection process on two separate boilers representing two different firing configurations—a tangentially fired 80-MWe boiler at Illinois Power's Hennepin Plant in Hennepin, IL, and a cyclone-fired 40-MWe boiler at City Water, Light and Power's Lakeside Station in Springfield, IL.



Project Status/Accomplishments:

Permitting and engineering design efforts were completed for the 3 original project sites. In 1990, plans to use the third site (Bartonville, IL) were suspended.

Construction is complete and operation activities have begun at the tangentially fired boiler at Hennepin. A matrix of 32 gas reburn tests have been completed, achieving NO_x reduction rates of 60–65%. In one short-term test, a 77% reduction in NO_x was achieved. Evaluation of 20 over-fire air tests indicated substantial NO_x reduction was achieved at low loads with lesser reductions as load increased. Combined operational testing of gas reburning and sorbent injection began in August 1991 with SO_2 reduction in the range of 50–55%. Operations at Hennepin should be completed by September 1992.

At Lakeside, construction is scheduled for completion in January 1992, at which time start-up activities will begin. Frozen conditions at this site in early 1991 delayed civil construction work and made it necessary to reschedule the completion of construction and start-up.

Environmental Considerations:

NEPA compliance was satisfied for Hennepin with a memo-to-file approved on May 9, 1988, and for Lakeside with an environmental assessment and finding of no significant impact approved June 25, 1989.

Assuming maximum commercialization, significant SO_2 and NO_x reductions (38% and 11% respectively) are projected to be achievable nationally by 2010 with enhancement of the use of coals by gas reburning and sorbent injection relative to a no-action alternative. Gas reburning will reduce emissions of NO_x, and sorbent injection will reduce emissions of SO_2. The gas reburning and sorbent injection process has wide applicability as it can be retrofitted to many coal-fired boilers. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

Gas reburning and sorbent injection is the unique combination of two separate technologies. The commercial application for these technologies, both separately and combined, extends 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; additionally the technologies can be applied to new utility boilers. With 60% NO_x removal and 50% SO_2 removal, 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 without exceeding emission limits for NO_x and SO_2.

Tidd PFBC Demonstration Project

Sponsor:
The Ohio Power Company

Additional Team Members:
American Electric Power Service Corporation—design, construction, and management

ABB Carbon and Babcock & Wilcox—technology supplier

Ohio Coal Development Office—cofunder

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

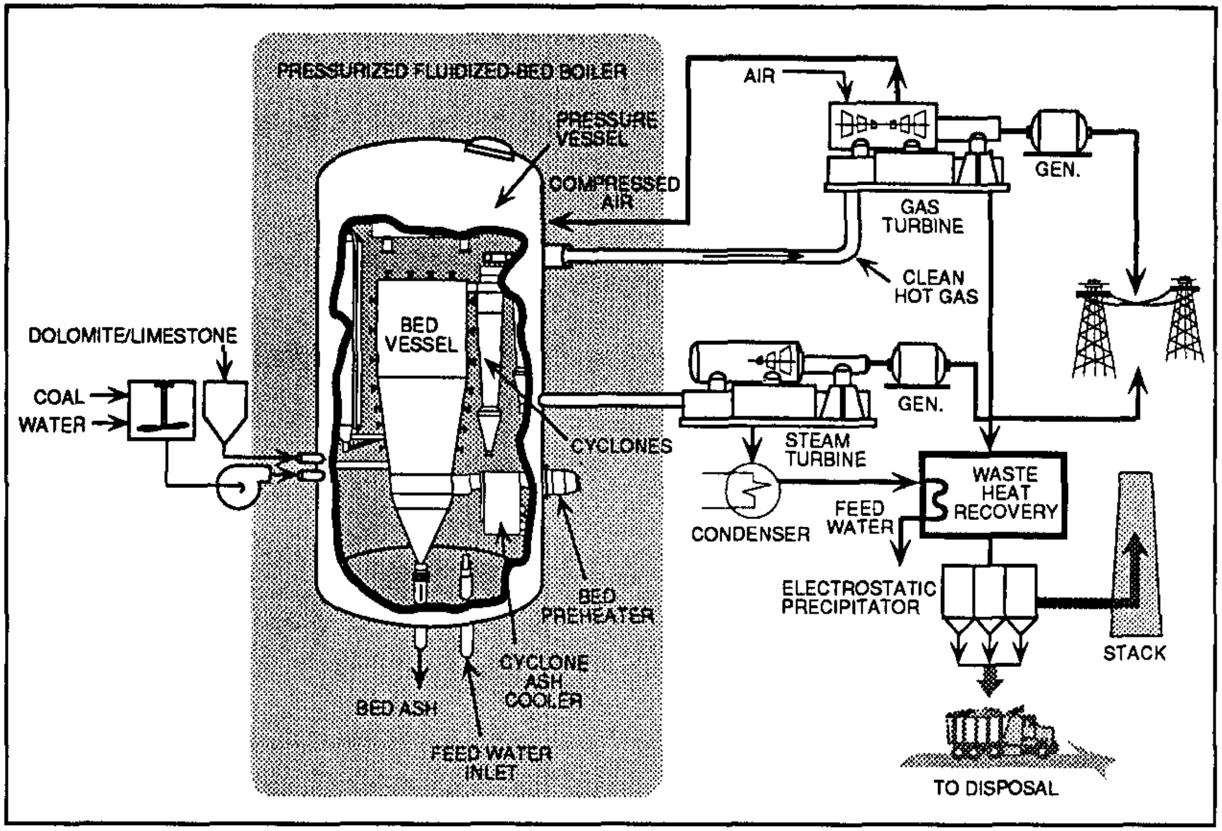
Technology:
ABB Carbon and Babcock & Wilcox's pressurized fluidized-bed combustion (PFBC) system

Plant Capacity/Production:
70 MWe

Project Funding:

Total project cost	$167,500,000	100%
DOE	60,200,000	36
Participants	107,300,000	64

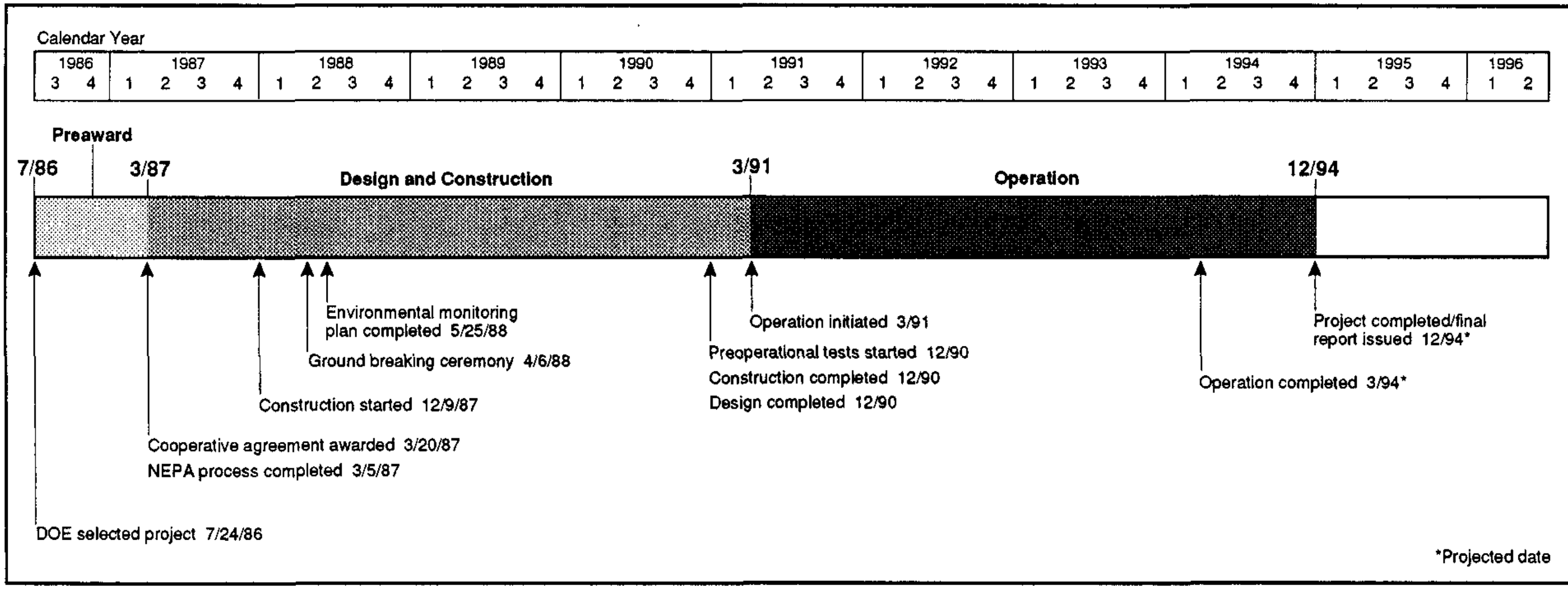
Project Objective:
To demonstrate PFBC at a 70-MWe scale, representing a 13:1 scale-up from the pilot plant facility; to verify expectations of the technology's economic, environmental, and technical performance in a combined-cycle repowering application at a utility site; and to accomplish greater than 90% SO_2 removal, NO_x emission level of 0.2 lb/million Btu, and an efficiency of 38% in a repowering mode using the existing steam system.



Technology/Project Description:
This PFBC technology uses a pressurized bubbling fluidized-bed operating at 175 lb/in^2 atm. Pressurized combustion air is supplied by the gas turbine compressor. In PFBC, the air fluidizes the bed material, which consists of fuel (a coal-water paste), coal ash, and dolomite sorbent. The hot combustion gases exiting the bed vessel with entrained ash particles pass through cyclones to remove 98% of the particles. The gas exits the pressure vessel and is expanded in a gas turbine to produce 16 MWe. The gas exiting the turbine is cooled in a waste heat recovery step and cleaned further in an electrostatic precipitator prior to discharge into the atmosphere. Pressurized boiler feed water is converted to superheated steam in the tubes in the boiler zone of the pressure vessel. The steam exits at 1,305 lb/in^2 atm and 925 °F and passes through a steam turbine to produce 58 MWe. The dolomite in the bed reacts with the sulfur to form calcium sulfate, a dry, granular material, which is discharged with the ash for disposal or by-product recovery. The maximum bed temperature of 1,600 °F reduces the formation of NO_x.

The Unit 1 boiler at the Tidd facility is being replaced with the PFBC system and the addition of the gas cycle. The existing steam turbine and condensate and feed water systems are being refurbished.

Project Status/Accomplishments:
Electricity was successfully generated for the first time on December 6, 1990, with the plant operating in a combined-cycle mode. Start-up proceeded through February 1991 with operation starting in March 1991.



The unit achieved full-bed height operation of 127 inches on April 21, 1991. By year-end 1991, over 900 hrs of coal-fired operation had been logged, including one continuous run exceeding 110 hrs. Preliminary testing conducted at port load indicated that SO_2 and NO_x emissions are below NSPS requirements. On July 17, 1991, *Power Magazine* presented the Tidd Plant its 1991 Power Plant Award. Following a planned outage for maintenance, repairs, and rework, testing resumed during the first week of December 1991.

Environmental Considerations:

NEPA compliance has been satisfied with a memo-to-file approved March 5, 1987. The environmental monitoring plan has been prepared.

Assuming maximum commercialization of the PFBC technology on a national basis by 2010, relative to a no-action alternative, the following impacts are projected:

- SO_2 reduction—48%
- NO_x reduction—17%
- Solid waste increase, but in a dry, granular form more amenable to alternative uses, such as construction aggregate, and requiring less land area for disposal than conventional scrubber sludge

(Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

Combined-cycle PFBC permits use of a wide range of coals, including high-sulfur coals. It can be used to repower oil- and gas-fired boiler units, to repower coal-fired power plants, and to build new PFBC units. Combined-cycle PFBC technology appears to be best suited for electric utility plants greater than 100 MWe. Capable of being constructed modularly, PFBC generating plants will permit utilities to add increments of capacity economically to match load growth and to reduce utility financing requirements. Plant life can be extended by repowering with PFBC using the existing plant area, coal- and waste-handling equipment, and steam turbine equipment.

The performance potential of PFBC technology in its commercial configuration is characterized below:

- SO_2 reduction—95%
- NO_x reduction—80%
- Plant efficiency—up to 45%
- Incremental power increase—40%
- Fuel flexibility—permits use of wide range of coals
- Compactness—high process efficiency reduces space requirements per unit of energy generated

Advanced Coal Conversion Process Demonstration

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

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

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

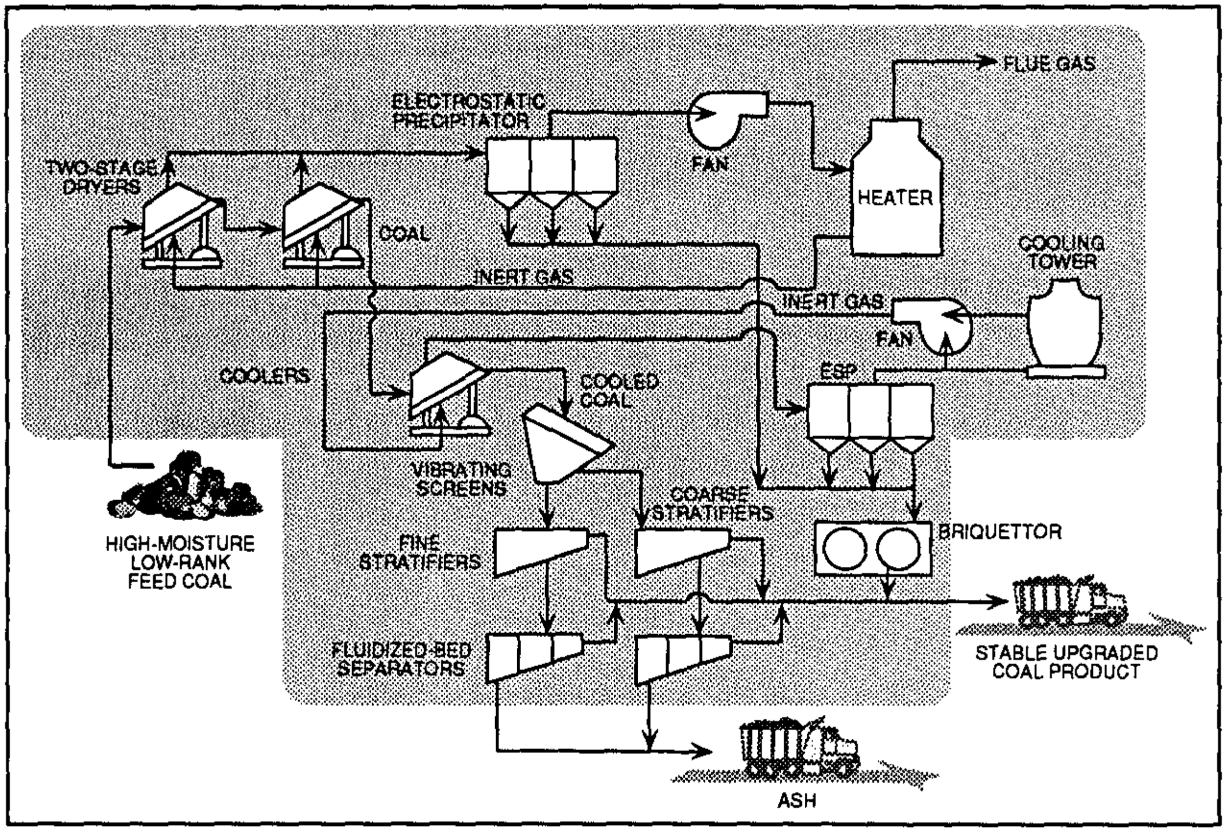
Technology:
Western Energy Company's advanced coal conversion process for upgrading low-rank subbituminous and lignite coals

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

Project Funding:

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

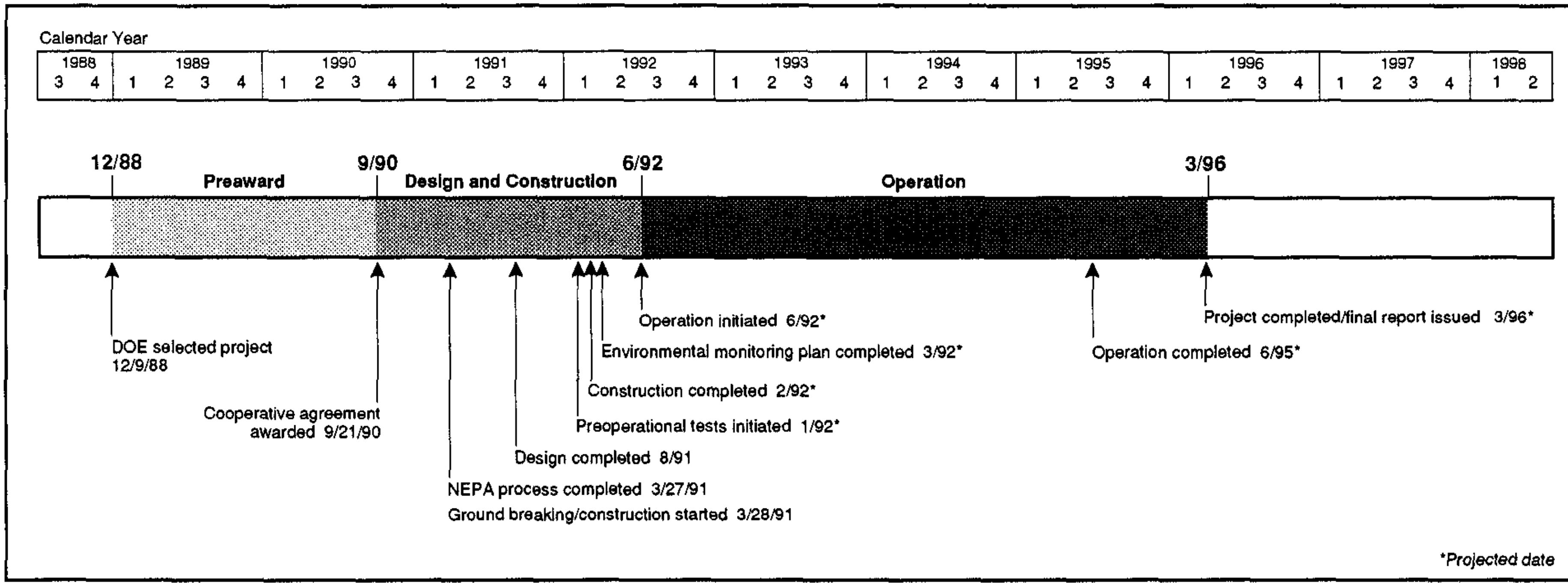
Project Objective:
To demonstrate Western Energy's advanced coal conversion process to produce a stable coal product having a moisture content as low as 1%, sulfur content as low as 0.3%, and heating value up to 12,000 Btu/lb.



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

The technology, if successfully demonstrated, enhances low-rank western coals, usually with a moisture content of 25–55%, sulfur content of 0.5–1.5%, and heating value of 5,500–9,000 Btu/lb, by producing a stable, upgraded coal 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 being located adjacent to a unit train loadout facility at Western Energy Company's Rosebud coal mine in Colstrip, MT. Although the demonstration plant is one-tenth the size of a commercial facility, the process equipment is at commercial scale because a full-sized commercial plant has multiple process trains.



Project Status/Accomplishments:

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

Ground was broken on March 28, 1991, and by June, pieces of major equipment were arriving on site. The construction of two 6,000-ton product storage silos and all foundation work was completed by July. The main process facility structure and the control/administration building were completed by November. Initial "turn-over" of equipment started in December and final construction will be completed in January 1992. Plant shakedown activities are under way with full operations scheduled for the second quarter of 1992.

Environmental Considerations:

An environmental assessment and finding of no significant impact was approved by DOE on March 27, 1991.

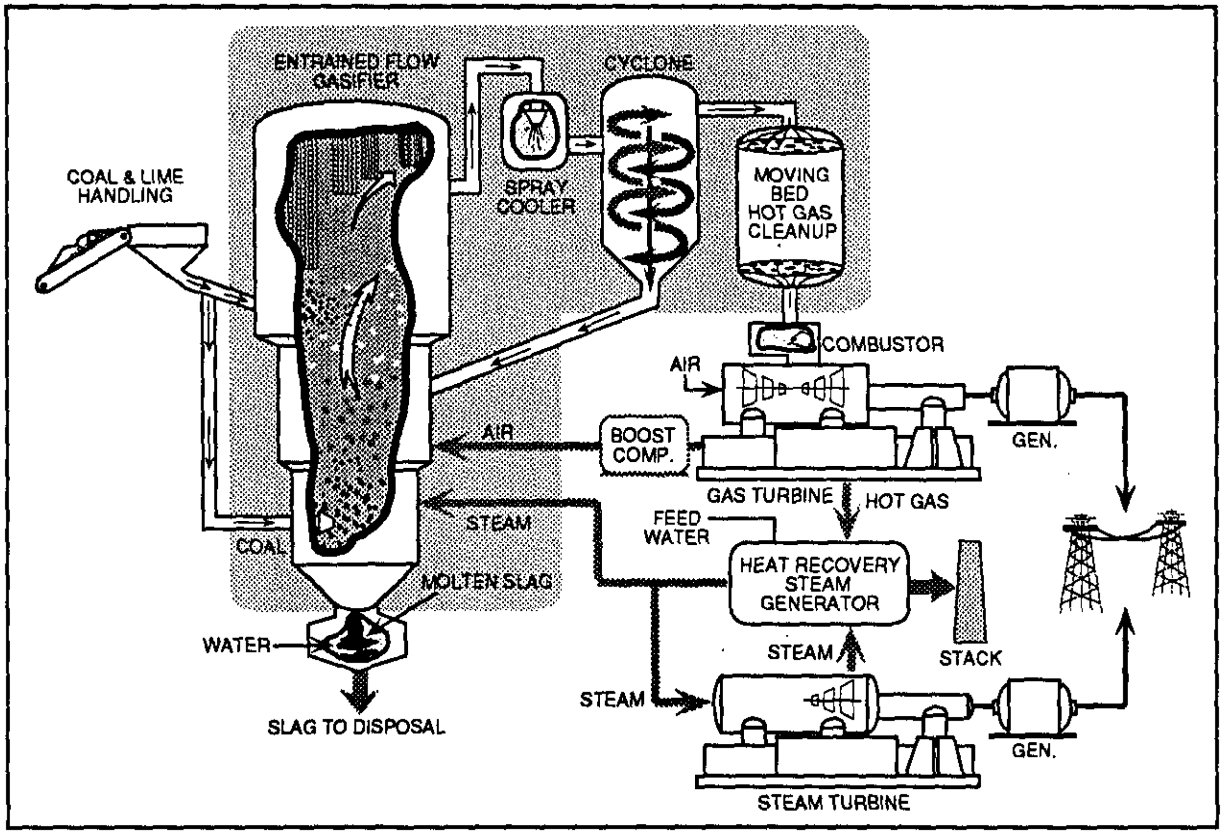
Because the advanced coal conversion process will produce SynCoal which has a very low sulfur content, high heating value, and stable physical/chemical characteristics, it could have significant impact on SO_2 reduction relative to the no-action alternative considered in the PEIS.

Commercial Application:

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

CCT-II
Project Fact Sheets

Combustion Engineering IGCC Repowering Project



Sponsor:

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—funding

Location:

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

Technology:

ABB Combustion Engineering's integrated gasification combined-cycle (IGCC) system

Plant Capacity/Production:

65 MWe

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 limestone injection and the moving-bed, zinc ferrite, hot-gas cleanup system; to evaluate a kinetic coal extruder; and to assess long-term reliability, availability, and maintainability at sufficient scale to determine commercial potential.

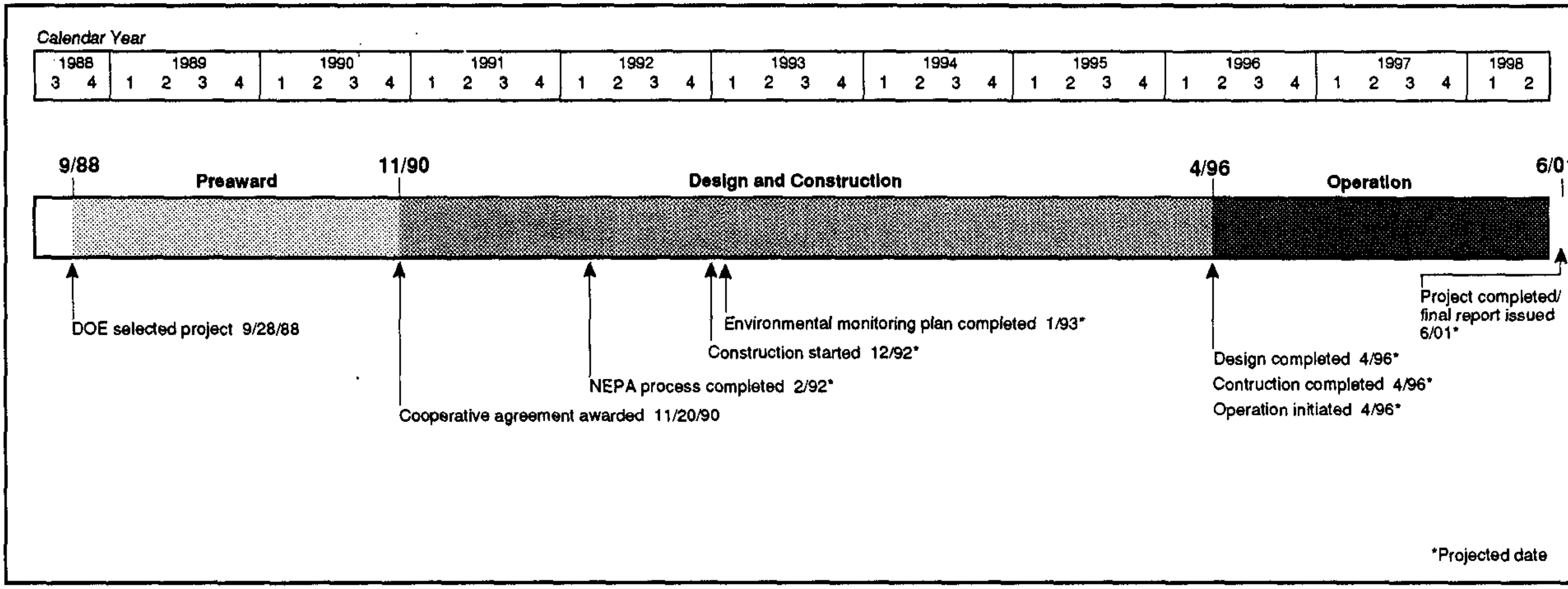
Technology/Project Description:

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 by various heat exchange surfaces and by water spray prior to gas cleanup. Char in the gas stream is captured by a high-efficiency cyclone, as well as by subsequent fine particulate removal systems, and recycled back to the gasifier.

A newly developed process is being used to remove sulfur from the hot gas: a moving bed of zinc ferrite sorbent and a limestone sorbent injection system provide in-bed desulfurization. Particulate emissions are removed from the coal-handling system and gas stream by a combination of cyclone separators and baghouses, and a high 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. Approximately 40 MWe 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 ferrite 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.



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.

Project Status/Accomplishments:

The preliminary design package and plant cost estimates are complete. ABB Combustion Engineering held technical exchange discussions with the Japanese regarding the 200-ton/day entrained-flow gasification pilot plant in Japan. At the meetings, ABB Combustion Engineering obtained operational data for this plant for use in the CCT project.

Environmental Considerations:

The DOE review of the environmental assessment resulted in a finding of no significant impact. The NEPA process will be completed in early 1992.

Assuming maximum commercialization of the IGCC technology on a national basis by the year 2010, relative to a no-action alternative, the following impacts are projected:

- SO_2 reduction—37%
- NO_x reduction—17%
- Solid waste reduction—5%
- CO_2 reduction—6%

(Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

In recent years, IGCC has become a rapidly emerging alternative for new electricity generating plants. IGCC plants require 15% less land area than pulverized coal plants with flue gas desulfurization. IGCC technology also can be used in repowering, where a gasifier, gas stream cleanup unit, gas turbine, and waste heat recovery boiler are added to replace the existing coal boiler. The remaining equipment is left in place, including the steam turbine and electrical generator.

The performance potential of IGCC technology in its commercial configuration is characterized as follows:

- SO_2 reduction—99%
- NO_x reduction—95%
- Plant efficiency—up to 48%
- Incremental power increase—230%
- Fuel flexibility—permits use of wide range of coals
- Compactness—high process efficiency reduces space requirements per unit of energy generated
- Modular construction—lends itself to economic addition of capacity increments to match load growth

SNOX Flue Gas Cleaning Demonstration Project

Sponsor:
ABB Combustion Engineering, Inc.

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

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

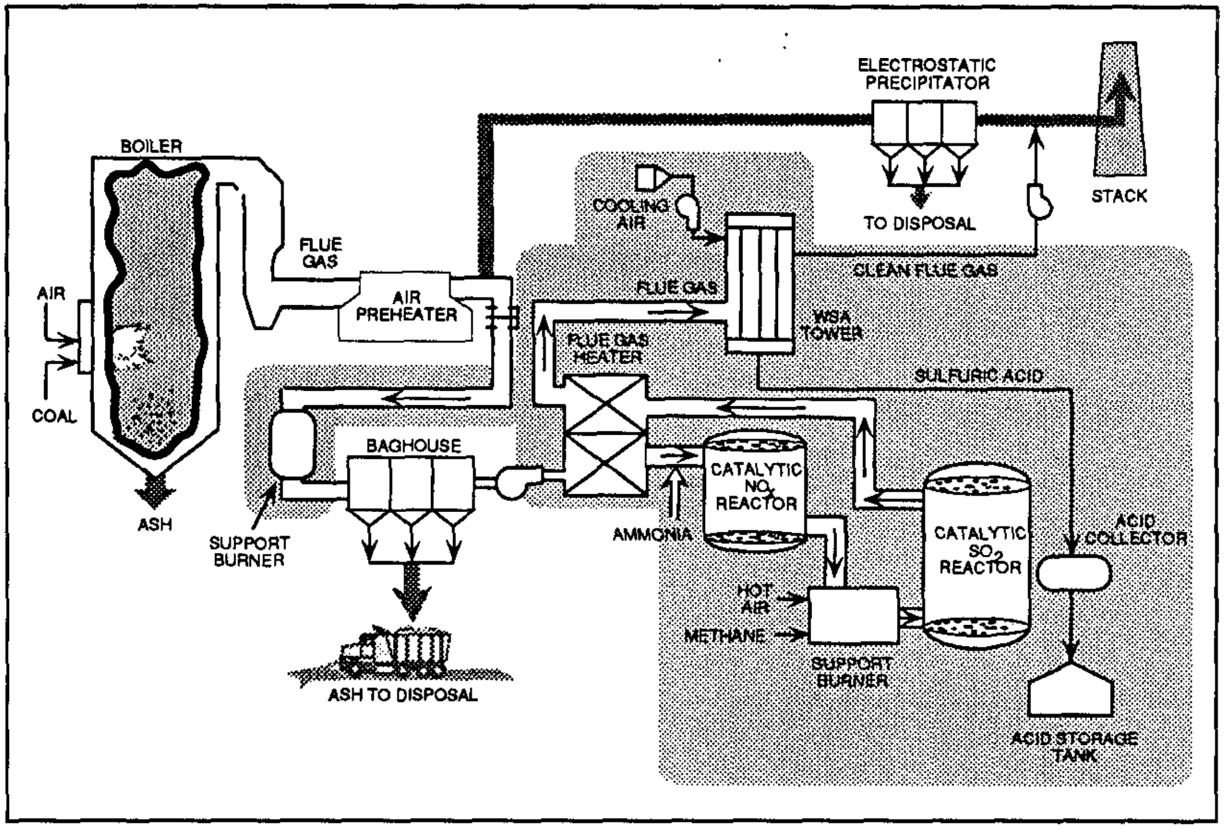
Technology:
Haldor Topsoe's SNOX catalytic advanced flue gas cleanup system

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

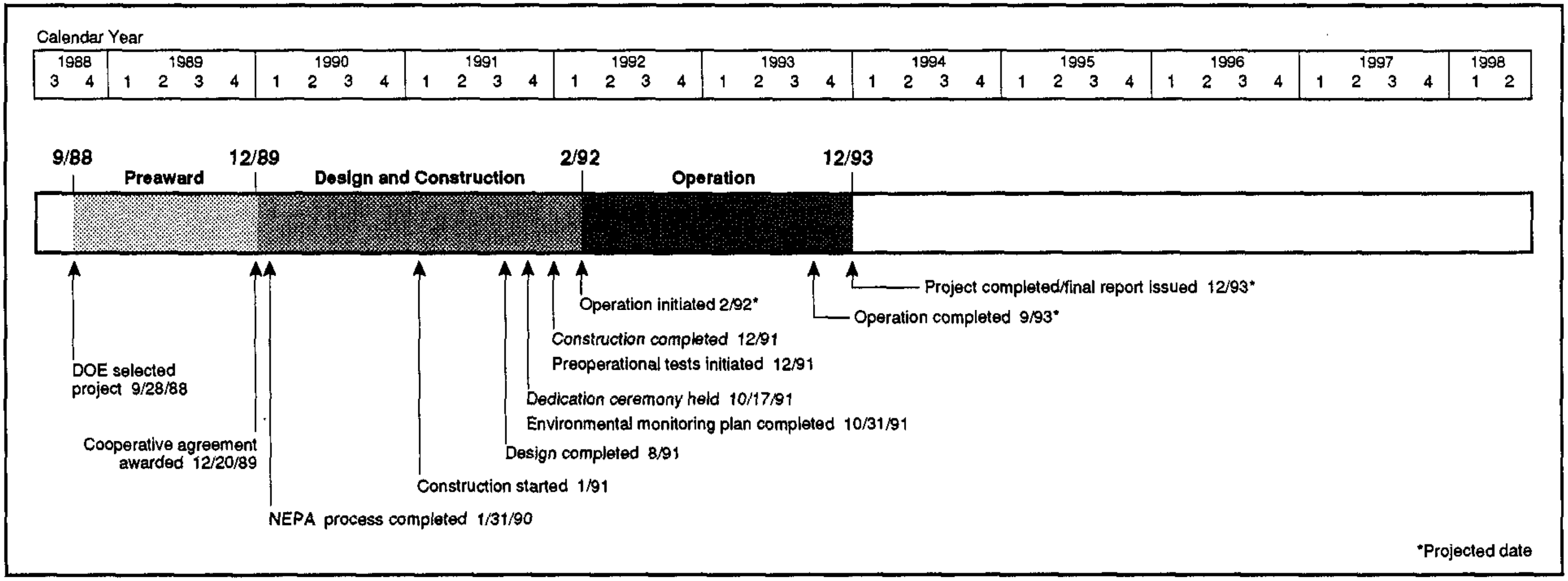
Project Objective:
To demonstrate on U.S. coals at an electric power plant that SNOX technology will catalytically remove 95% of SO_2 and more than 90% of NO_x from flue gas and produce a salable by-product of concentrated sulfuric acid.



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 in a novel glass-tube condenser which allows SO_3 to hydrolyze to concentrated sulfuric acid.

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

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



Project Status/Accomplishments:
Design is complete; all major equipment has been procured and proprietary condenser installed. A formal dedication ceremony was held October 17, 1991. Construction was completed in December 1991 and operation commences in February 1992.

Environmental Considerations:
NEPA compliance has been satisfied by a memo-to-file approved on January 31, 1990. An environmental monitoring plan was completed October 31, 1991.

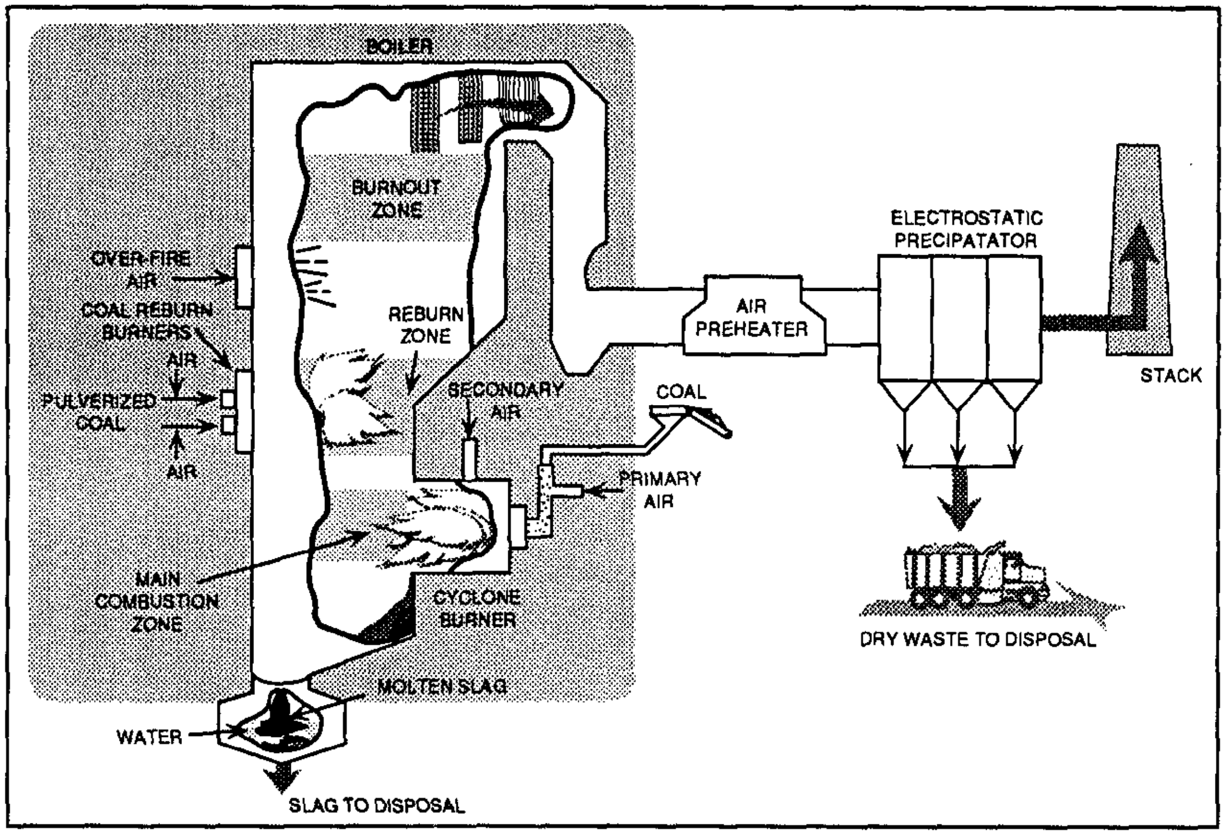
Assuming maximum commercialization on a national basis by 2010 for the SNOX process relative to a no-action alternative, the following impacts are projected:

- SO_2 reduction—38%
- NO_x reduction—15%

The significant reductions of SO_2 and NO_X are projected to be achievable nationally due to the 95% removal of SO_2 and more than 90% NO_x emissions from coal-fired boilers with the SNOX process and the wide applicability of the process. Moreover, the sulfuric acid produced is a salable by-product. No change in solid waste is anticipated; although the plant produces ash, the SNOX technology itself produces no solid waste by-product. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:
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.

Demonstration of Coal Reburning for Cyclone Boiler NO_x Control



Sponsor:
The Babcock & Wilcox Company

Additional Team Members:
Wisconsin Power and Light Company—cofunder and host utility
Sargent and Lundy—engineer for coal handling
Electric Power Research Institute — cofunder
State of Illinois, Department of Energy and Natural Resources—cofunder
Utility companies (10 cyclone boiler operators)—cofunders

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

Technology:
The Babcock & Wilcox Company's coal reburning system

Plant Capacity/Production:
100 MWe

Project Funding:

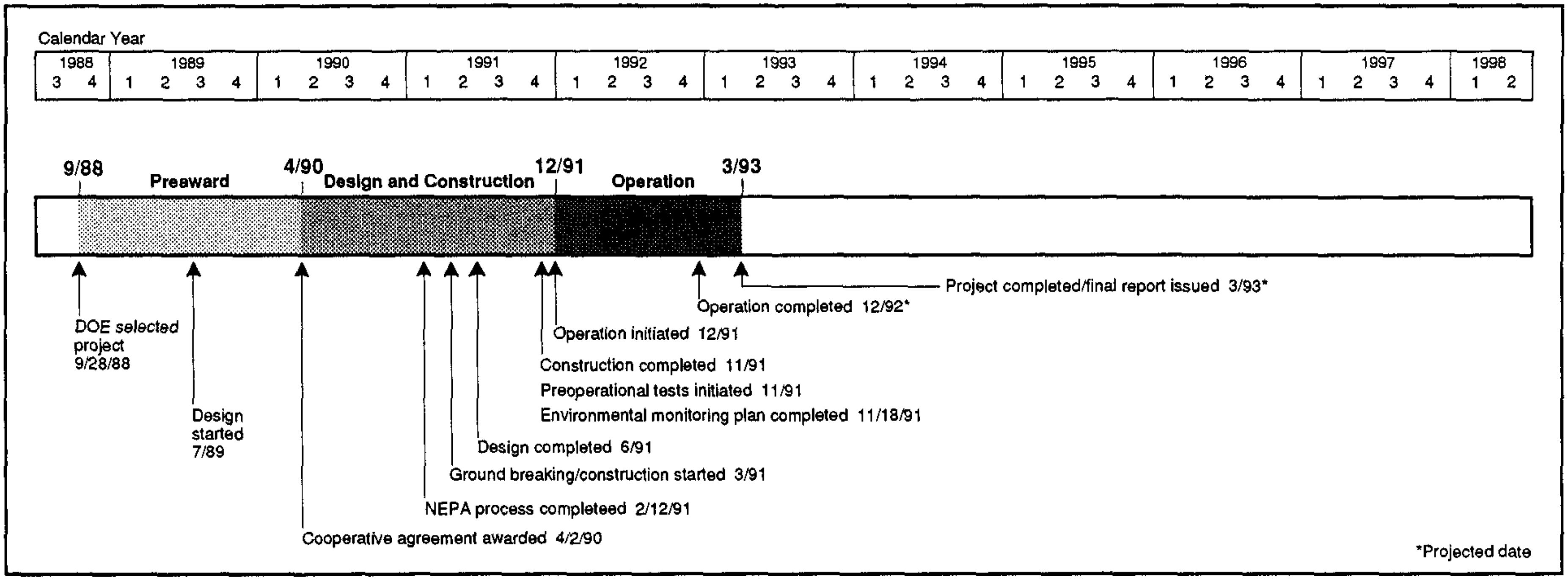
Total project cost	$13,071,559	100%
DOE	6,213,929	48
Participants	6,857,630	52

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 main 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 boiler above the cyclones in the reburning zone to create an oxygen-deficient condition. The NO_x formed in the cyclone burners reacts with the resultant reducing flue gas to be converted into nitrogen and water 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 constant.

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

This project involves retrofitting an existing 100-MWe cyclone boiler that is representative of a large population of cyclone units. The cyclone boiler being retrofitted is presently in commercial operation at



Wisconsin Power and Light's Nelson Dewey Station in Cassville, WI.

Project Status/Accomplishments:

Design work is complete. Short- and long-term boiler baseline characterization testing and performance modeling both with and without the proposed reburn retrofit is complete. Boiler performance results have been analyzed and incorporated into both physical and numerical models of the boiler. The modeling has demonstrated the need for a change from 3 to 4 reburners and over-*fire air ports to assure adequate* NO_x *reduction.*

Installation of the coal reburn system equipment was completed during a scheduled boiler outage in September and October 1991. Check out and shakedown of the newly installed reburn system, including reburn burners, over-fire air ports, pulverizer, ducting, coal feed system, and control systems, began in November 1991. Initial NO_x reduction measurements will be made in January 1992. Testing will continue through 1992.

Environmental Considerations:

An environmental assessment was completed and a finding of no significant impact was approved on February 12, 1991. The environmental monitoring plan was completed November 18, 1991.

Significant reductions of NO_x (11%) are projected *to be achievable nationally by 2010 due to the capability* of the cyclone coal-reburning process to remove 50% of NO_x emissions from coal-fired boilers and the wide potential applicability of the process. Negligible changes in effluents are anticipated. The technology produces no change in solid waste production. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

Currently, no proven retrofit combustion technology exists for reducing NO_x emissions from cyclone boilers. Coal reburning for cyclone boilers is expected to be a viable option as a retrofit combustion technology for NO_x control at reasonable capital and operating costs.

All of the approximately 26,000 MWe of currently installed cyclone boilers are expected to require NO_x control to comply with the CAAA of 1990.

SOX-NOX-ROX Box Flue Gas Cleanup Demonstration Project

Sponsor:
The Babcock & Wilcox Company

Additional Team Members:
Ohio Edison Company—cofunder and host utility
Ohio Coal Development Office—cofunder
Electric Power Research Institute—cofunder
Norton Company—cofunder and SCR catalyst supplier
Minneapolis Mining and Manufacturing Company—cofunder and filter bag supplier

Location:
Dilles Bottom, Belmont County, OH (R. E. Burger Plant, Unit No. 5)

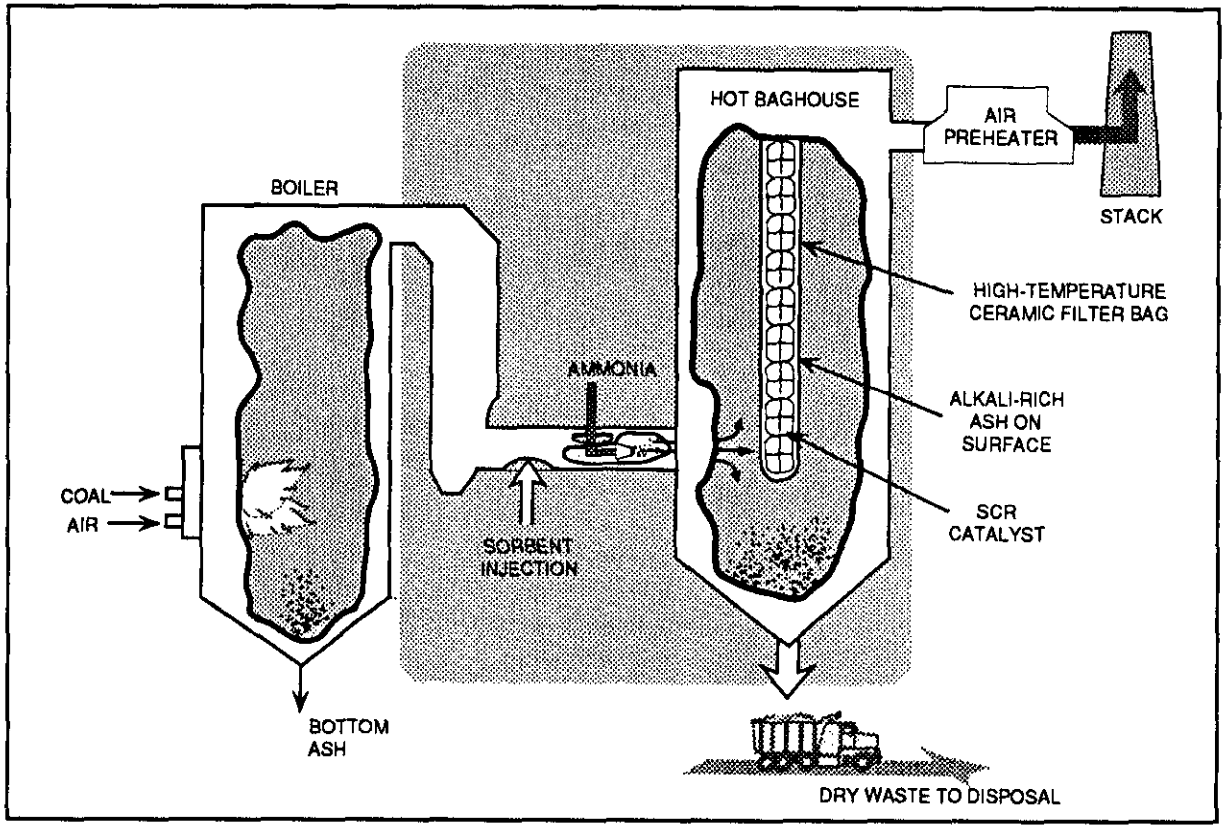
Technology:
The Babcock & Wilcox Company's SOX-NOX-ROX box (SNRB) process

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

Project Funding:

Total project cost	$11,419,087	100%
DOE	5,229,942	46
Participants	6,189,145	54

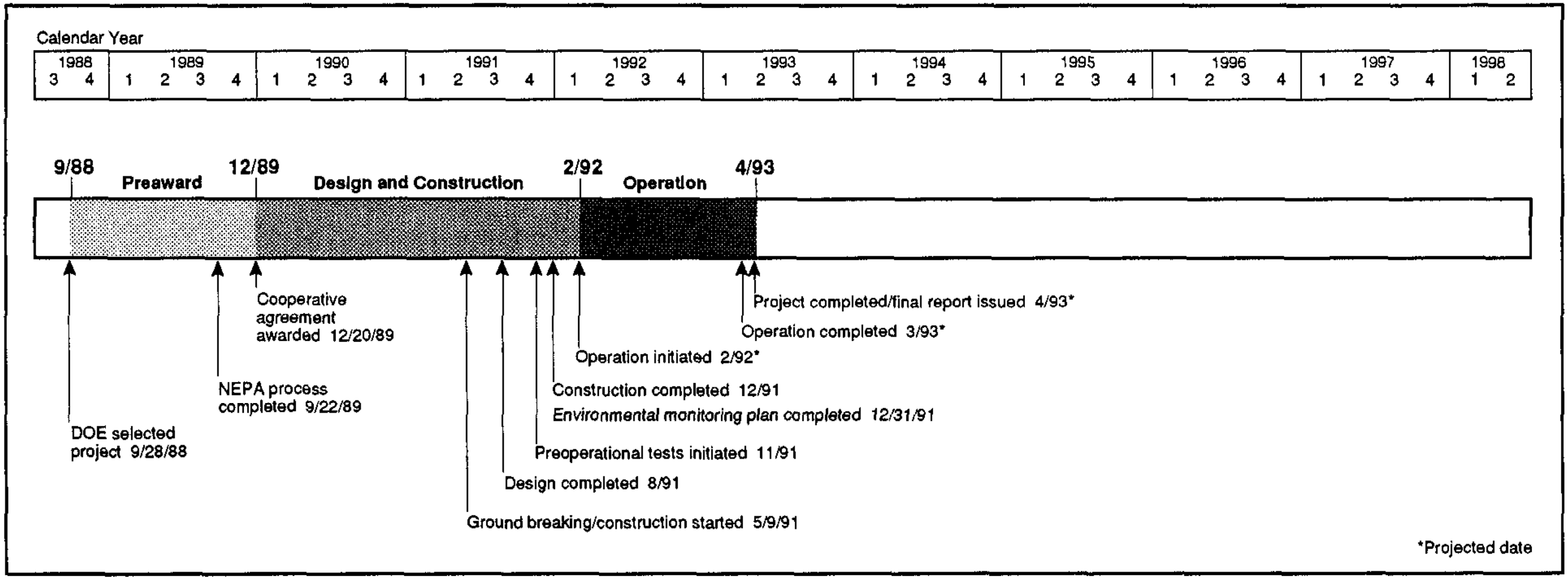
Project Objective:
To demonstrate that the SOX-NOX-ROX box process, used in retrofitting a high-sulfur-coal-fired power plant, can remove high levels of all pollutants using a single processing unit for treating flue gas, thereby lessening on-site space requirements and capital costs.



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 ceramic fiber bag filters.

The SNRB demonstration unit is sized at 5 MWe and is large enough to demonstrate a commercial-scale baghouse module while minimizing the demonstration cost. Additionally, at this scale, the flue gas temperature can readily be controlled to determine the optimum temperature for maximum SO_2 and NO_x reductions.

The project will demonstrate the technical and economic feasibility of achieving 70–90% SO_2 removal, up to 90% NO_x removal, and 99% particulate removal at lower capital, operating, and maintenance costs than other conventional systems. The demonstration will be conducted at Ohio Edison's R. E. Burger Plant, Unit No. 5, in Dilles Bottom, OH.



Project Status/Accomplishments:

Design work is complete. Testing of commercial-sized bags in the pilot baghouse unit is complete, with NO_x capture rates above 90% and SO_2 capture rates approaching 80%.

Construction work was completed in December 1991. Fiber fabric development test facility construction is complete. Three different vendors' bags are being tested over the next 13 months.

Environmental Considerations:

NEPA compliance has been satisfied by a memo-to-file approved on September 22, 1989. The environmental monitoring plan was completed December 31, 1991.

Assuming maximum commercialization, the following impacts are projected on a national basis by 2010 for the SNRB process relative to a no-action alternative:

- SO_2 reduction—38%
- NO_x reduction—15%
- Solid waste increase—8%

The significant reductions of SO_2 and NO_x are projected to be achievable nationally due to the 70–90% removal of SO_2 and NO_x emissions from coal-fired boilers with the SNRB process and the wide applicability of the process. Negligible changes in liquid effluents are anticipated. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

The SNRB process, upon being commercially demonstrated, offers removal of up to 90% of the SO_2 and NO_x and at least 99% of the particulates in a single unit with lower capital and operating costs and smaller space requirements than conventional flue gas cleanup technology. In addition, SNRB offers the potential for increasing boiler efficiency. The SNRB process can be used to retrofit a wide range of utility and industrial coal-fired boilers that are without scrubbing systems in order to achieve a high level of emissions control at favorable capital and operating costs.

Innovative Coke Oven Gas Cleaning System for Retrofit Applications

Sponsor:
Bethlehem Steel Corporation

Additional Team Member:
Davy/Still-Otto—technology developer

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

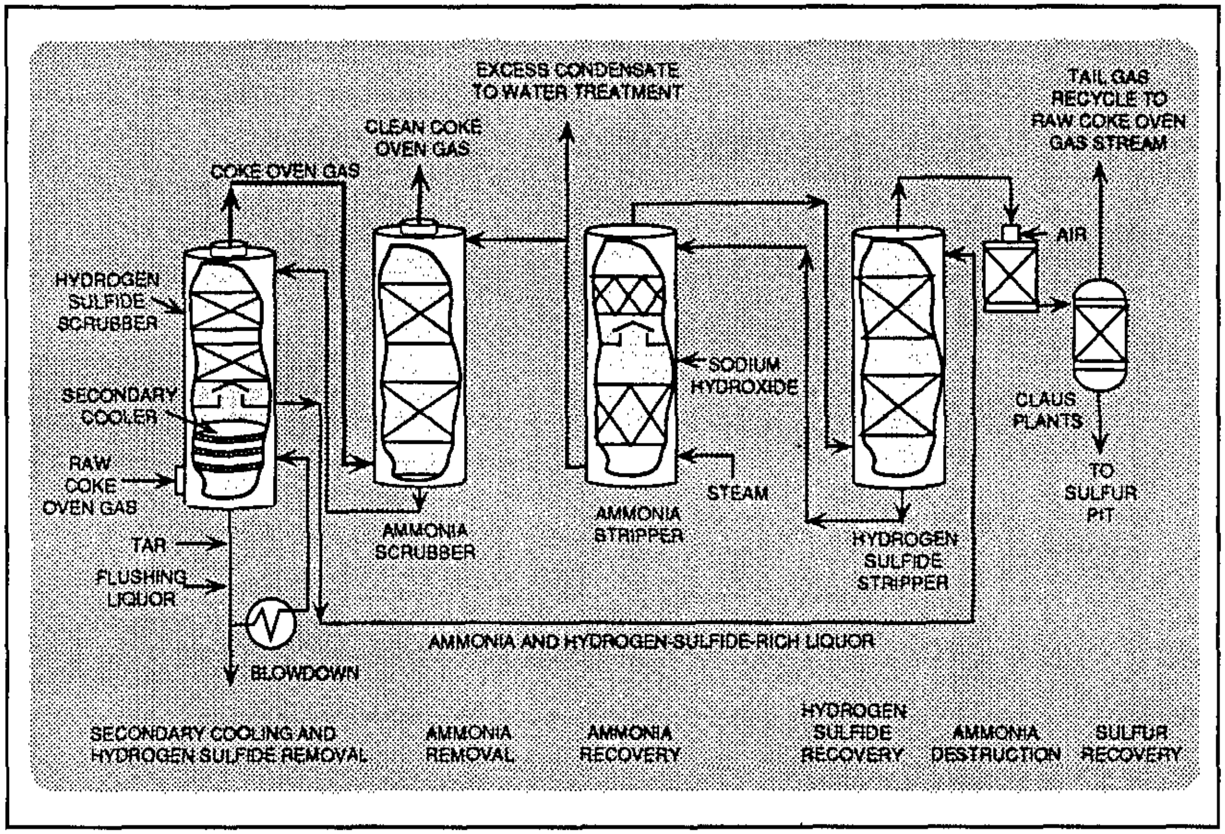
Technology:
Davy/Still-Otto's process for precombustion cleaning of coke oven gas (COG)

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.

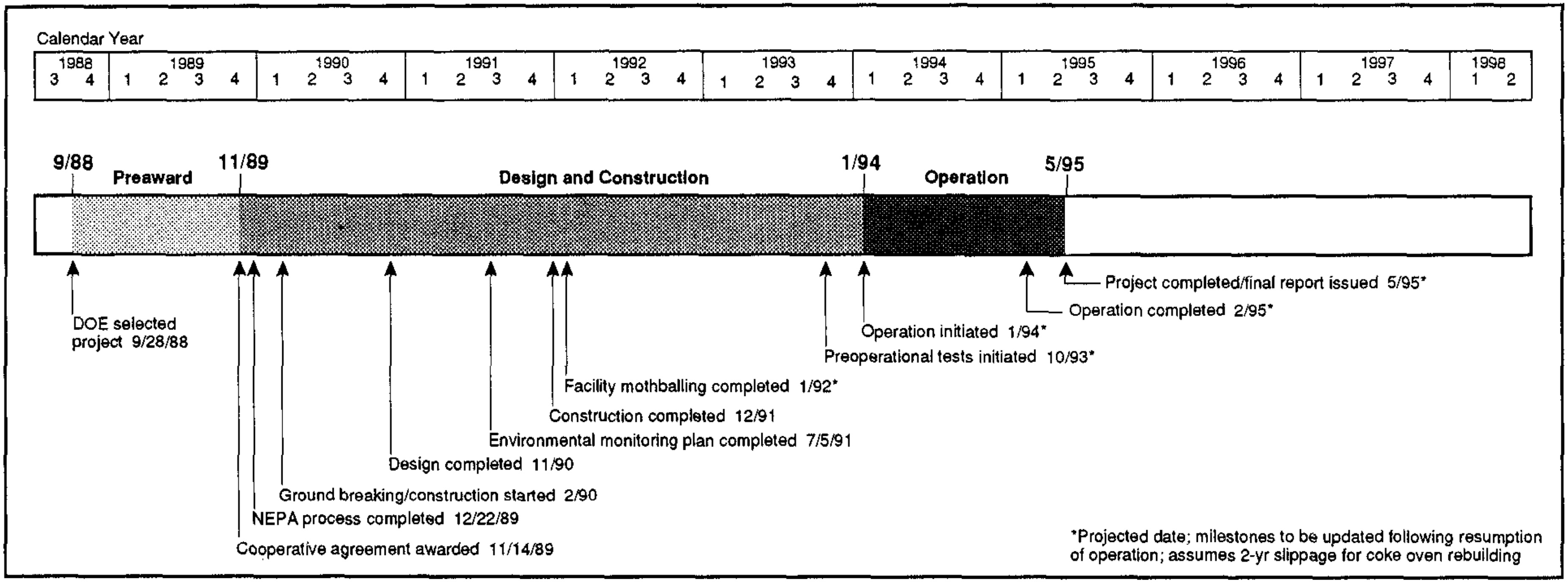


Technology/Project Description:
This project is demonstrating an innovative technology developed by Davy/Still-Otto for removing hydrogen sulfide and ammonia from COG. The process uses contaminated water produced in the coke oven batteries to absorb the hydrogen sulfide and ammonia contained in the COG.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

The technology is expected to reduce the hydrogen sulfide concentration in the cleaned COG by 84% 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 will process the entire COG stream from Coke Oven Batteries A, 11, and 12, which amounts to 74 million std ft^3/day. Currently, only 60% of this COG stream is desulfurized. The remaining 40% is used directly for under-firing the coke ovens.

Project Status/Accomplishments:
On September 16, 1991, Bethlehem Steel Corporation announced that all coke production will be suspended at its Sparrows Point facility for at least 2 yrs. This



decision was made due to the rapid deterioriation of the coke ovens. During this period, an evaluation will be made to explore alternatives for resumption of coke production. Bethlehem Steel's intent is for long-term coke independence at the facility.

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

Environmental Considerations:

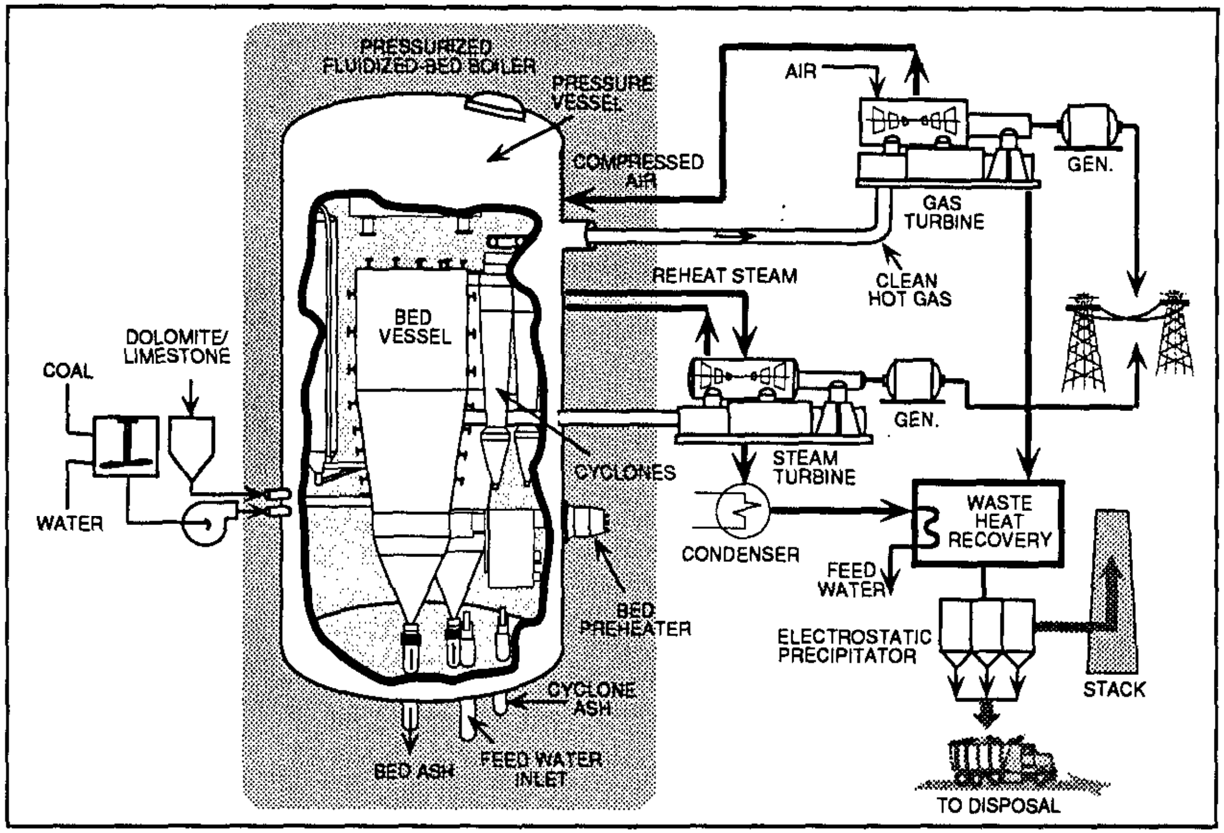
The environmental assessment with a finding of no significant impact was approved by DOE on December 22, 1989. Background environmental sampling has begun. The environmental monitoring plan has been prepared.

The expected performance characteristics and applicable market of the proposed COG cleaning system were used to estimate the environmental impacts that may occur if this technology reaches full commercialization. The existing 30 coke oven plants in the United States 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 yrs, 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.

Commercial Application:

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 yrs, 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 scale-up involved and without significant downtime.

PFBC Utility Demonstration Project



Sponsors:

The Ohio Power Company—cosponsor
The Appalachian Power Company—cosponsor

Additional Team Members:

American Electric Power Service Corporation—design, construction, and management
ABB Carbon and Babcock & Wilcox—technology supplier

Location:

New Haven, Mason County, WV (Ohio Power's and Appalachian Power's Philip Sporn Plant, Units 3 and 4) (An alternate WV greenfield site is being considered.)

Technology:

ABB Carbon and Babcock & Wilcox's pressurized fluidized-bed combustion (PFBC) system

Plant Capacity/Production:

330 MWe

Project Funding:

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

Project Objective:

To demonstrate PFBC at 330 MWe, a large utility scale representing a four-fold scale-up 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; and to achieve 95% SO_2 reduction, at least 70% NO_x reduction, and an efficiency of 39% in a repowering mode using the existing steam system.

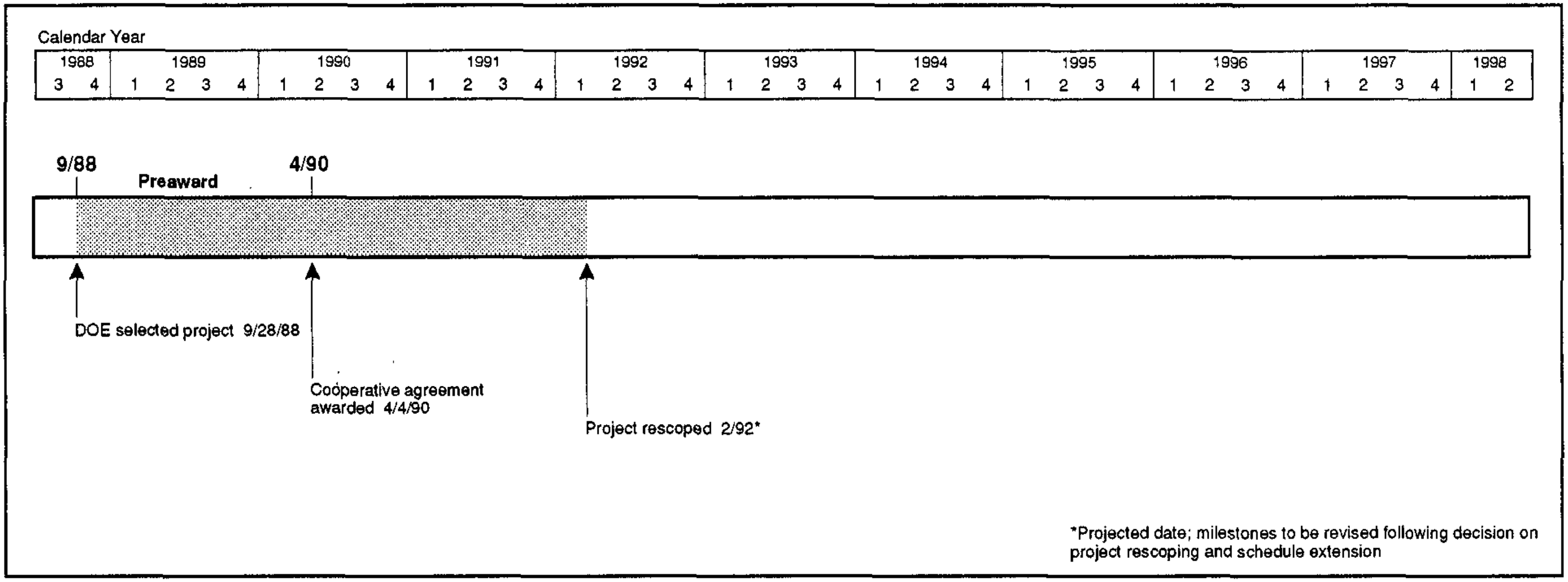
Technology/Project Description:

This PFBC technology uses a bubbling fluidized-bed boiler enclosed in a pressure vessel operated at 16 atm to produce combustion gases with sufficient energy to drive a gas turbine. The gas turbine exhaust is used to preheat boiler water, and the fluidized-bed boiler develops steam for the steam turbine. Because pressure in the boiler enhances combustion and heat transfer, the size of the vessel needed is reduced. Pressure also enhances sulfur capture by the sorbent. Sorbent (limestone or dolomite) is injected into the boiler and reacts with SO_2 to form unreactive calcium sulfate, a dry, granular material.

As originally proposed, the project entails replacement of two 150-MWe units, Units 3 and 4 at the Philip Sporn Plant, with a single 330-MWe unit. Nearly one-fourth of the power from the plant is to be produced through a new gas turbine with the balance generated through the existing steam turbines. However, based on the results of engineering and cost studies, AEP is also evaluating a greenfield plant as an alternative.

Project Status/Accomplishments:

Preliminary engineering analysis and cost estimates were completed to compare a new PFBC plant with both a repowered PFBC unit and a conventional power plant with scrubbers. On the basis of these studies, AEP has decided that a greenfield PFBC plant is the most favorable option for its grid system. Additionally, current load growth projections indicate that there is no need for power until after 2000. Revision of the



originally planned schedule is currently under DOE review. AEP proposes to conduct a 4-yr effort that would include a 2-yr value engineering effort to optimize the design and a 2-yr engineering study to develop a reduced cost basis for a greenfield plant. DOE is evaluating the impact of the proposed slippage and the merits of continuing the project.

Environmental Considerations:

Environmental information is being prepared for the NEPA compliance process.

Assuming maximum commercialization of the PFBC technology on a national basis by 2010 relative to a no-action alternative, the following impacts are projected:

- SO_2 reduction — 48%
- NO_x reduction — 17%
- Solid waste increase, but in dry, granular form, which has more amenable alternative uses, such as construction aggregate, and requires less land area for disposal than conventional scrubber sludge

(Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

Combined-cycle PFBC allows for the combustion of a wide range of coals, including high-sulfur coals. It can be used to repower oil- and gas-fired boiler units while switching them to high-sulfur coal, to repower coal-fired power plants, and to build new PFBC units. Combined-cycle PFBC technology appears to be best suited for electric utility applications for medium (100-400 MWe) and large (> 400 MWe) plants. In fact, because of modular construction capability, PFBC generating plants will enable utilities to add increments of capacity economically to match load growth and to reduce utility financing requirements. Plant life can be extended by repowering with PFBC using the existing plant area, coal and waste handling equipment, and steam turbine equipment.

The performance potential of PFBC technology in its commercial configuration is characterized as follows:

- SO_2 reduction—95%
- NO_x reduction—80%
- Plant efficiency—up to 45%
- Incremental power increase — 40%
- Fuel flexibility—permits use of wide range of coals
- Compactness—high process efficiency reduces space requirements per unit of energy generated
- Modular construction—lends itself to economic additions of capacity increments to match load growth

Cement Kiln Flue Gas Recovery Scrubber

Sponsor:

Passamaquoddy Tribe

Additional Team Members:

Dragon Products Company—project manager and host

E. C. Jordan Company—engineer for overall scrubber system

HPD, Incorporated—designer and fabricator of tanks and heat exchanger

Cianbro Corporation—constructor

Location:

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

Technology:

Passamaquoddy Tribe's cement kiln flue gas recovery scrubber

Plant Capacity/Production:

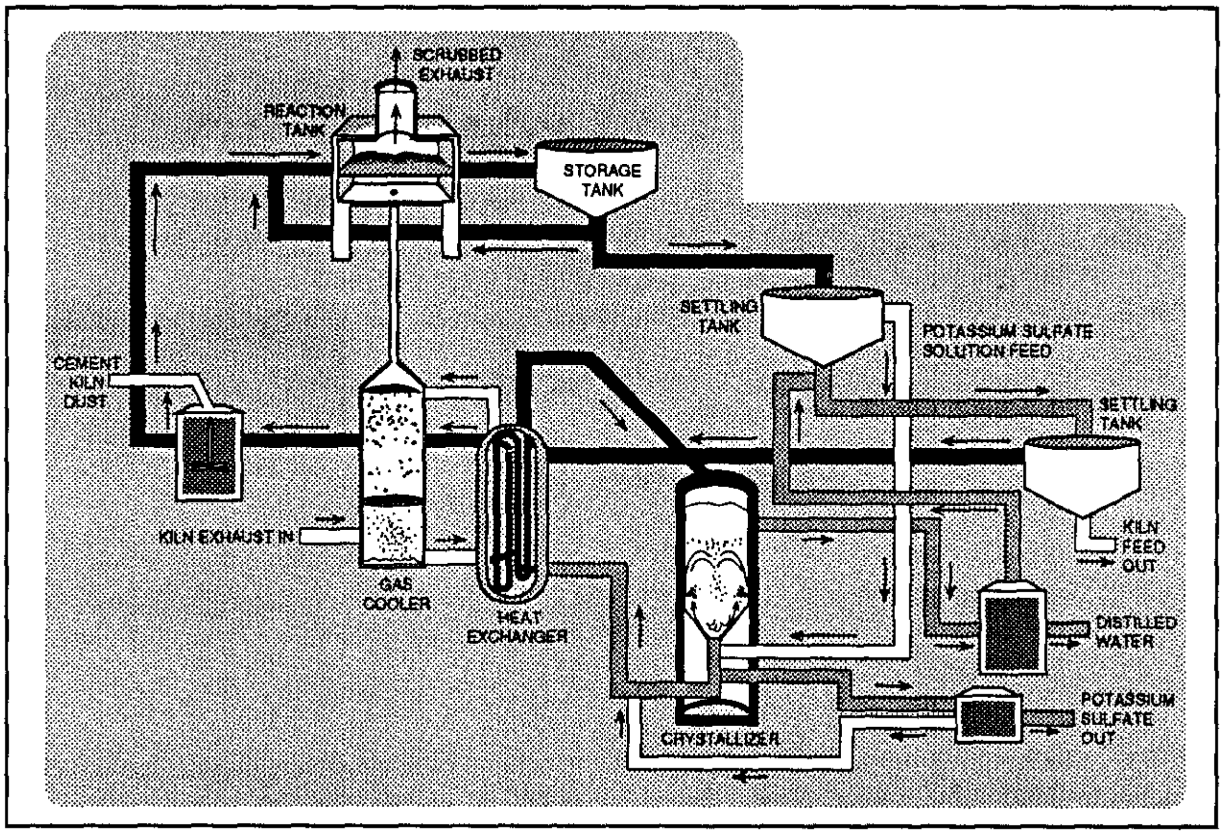
1,450 tons/day of cement; 250,000 std ft^3/min of kiln gas; and up to 274 tons/day of coal

Project Funding:

Total project cost	$12,538,648	100%
DOE	5,903,195	47
Participants	6,635,453	53

Project Objective:

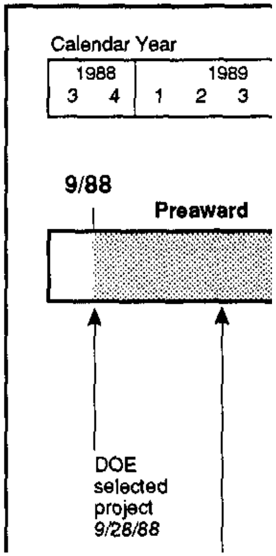
To retrofit and demonstrate a full-scale industrial scrubber and waste recovery system for a coal-burning wet process cement kiln using waste dust as the reagent to accomplish 90–95% SO_2 reduction using high-sulfur eastern coals and to produce a commercial by-product, potassium-based fertilizer.



Technology/Project Description:

The recovery scrubber technology 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 is being 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.


Calendar Year
1988
3
4
1989
1
2
3
9/88
Preaward
DOE
selected
project
9/28/88

Advanced Flue Gas Desulfurization Demonstration Project

Sponsor:

Pure Air on the Lake, L.P. (a project company of Pure Air, which is a 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. (parent company)—process designer

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

Air Products and Chemicals, Inc.—constructor and operator

Location:

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

Technology:

Pure Air's advanced flue gas desulfurization (AFGD) process

Plant Capacity/Production:

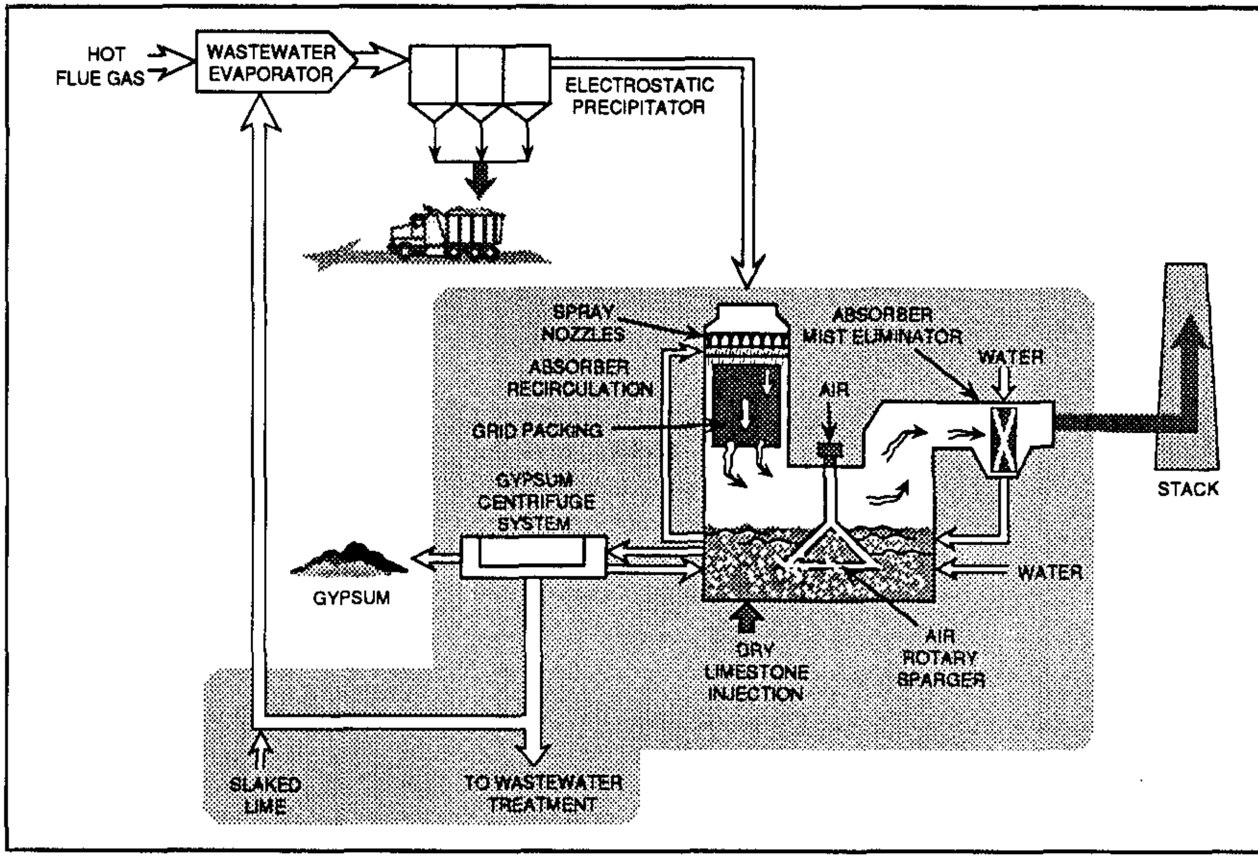
528 MWe

Project Funding:

Total project cost	$150,497,000	100%
DOE	63,434,000	42
Participants	87,063,000	58

Project Objective:

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



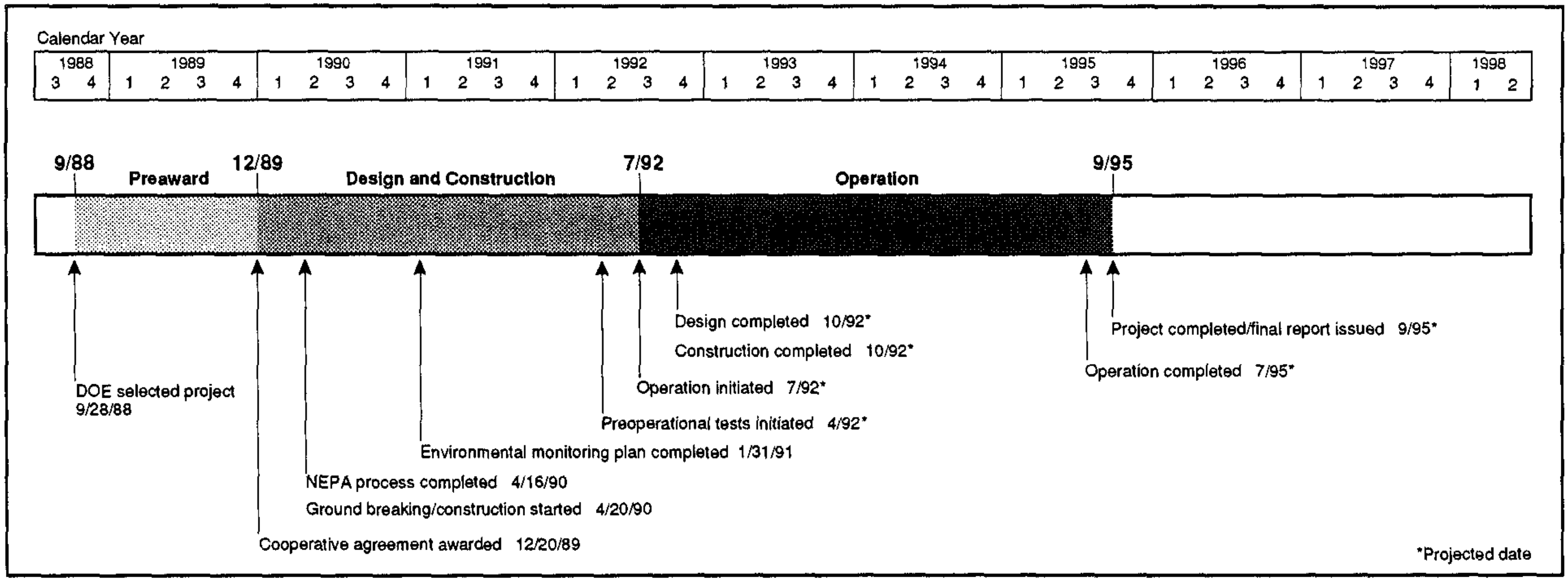
Technology/Project Description:

In this project, Pure Air is building a single SO_2 absorber for a 528-MWe power plant. Although this is expected to be the largest capacity absorber module in the United States, it has relatively modest space requirements because no spare or backup absorber modules are being installed. 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 stirring and air distribution into one piece of equipment to facilitate the oxidation of sludge to gypsum.

The AFGD process being demonstrated is expected simultaneously to remove 90–95% or more of the SO_2, provide a commercial gypsum by-product, and evaporate wastewater.

The project also seeks to demonstrate a novel business concept whereby Pure Air owns and operates the AFGD facility. Thus, Pure Air expects to specialize in pollution control activities, relieving the electric



utility of the operation of the AFGD unit. Assuming that the 3-yr demonstration is successful, Pure Air will continue to own the AFGD facility and to operate it as a contracted service to the utility for an additional 17-yr period. The demonstration is located at Northern Indiana Power Service Company's 528-MWe Bailly Generating Station near Chesterton, IN.

Project Status/Accomplishments:

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

Construction is 85% complete despite the occurrence of a ground subsidence event at the Bailly station on July 2, 1991. The SO_2 absorber is structurally complete and has been resin-lined. A new 480-ft stack has been built and brick-lined. All major equipment has been installed. Work is now focused on instrumentation and utilities (e.g., water, electric). Shakedown activities are expected to begin shortly, with operations scheduled to commence in mid-1992.

Environmental Considerations:

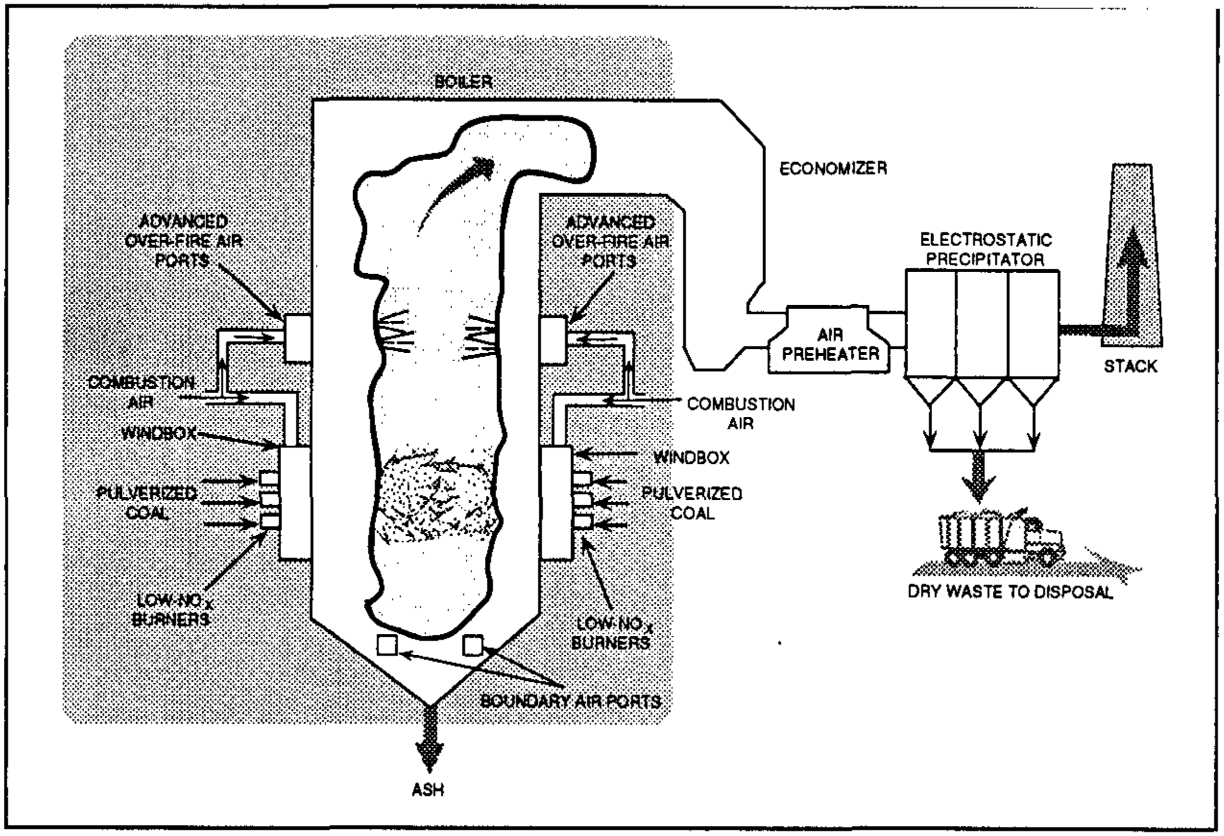
NEPA compliance has been satisfied by an environmental assessment, with a finding of no significant impact approved by DOE on April 16, 1990. The environmental monitoring plan was completed in January 1991.

Assuming maximum commercialization of the AFGD process, a 48% reduction of SO_2 could be achieved on a national basis by 2010, relative to a no-action alternative. The significant reductions of SO_2 are projected to be achievable nationally due to the 90–95% SO_2 removal capability forecasted for the AFGD process and its wide potential applicability. Although the process potentially would increase solid waste by 9%, the gypsum by-product could be sold, depending on the local market conditions, thereby eliminating the need to dispose of it as a waste product. If there is no market for the gypsum by-product, it is readily disposable in a landfill. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

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

Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler



Sponsor:

Southern Company Services, Inc.

Additional Team Members:

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

Location:

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

Technology:

Foster Wheeler's low-NO_x burner (LNB) with advanced over-fire air (AOFA)

Plant Capacity/Production:

500 MWe

Project Funding:

Total project cost	$11,711,229	100%
DOE	5,242,917	45
Participants	6,468,312	55

Project Objective:

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

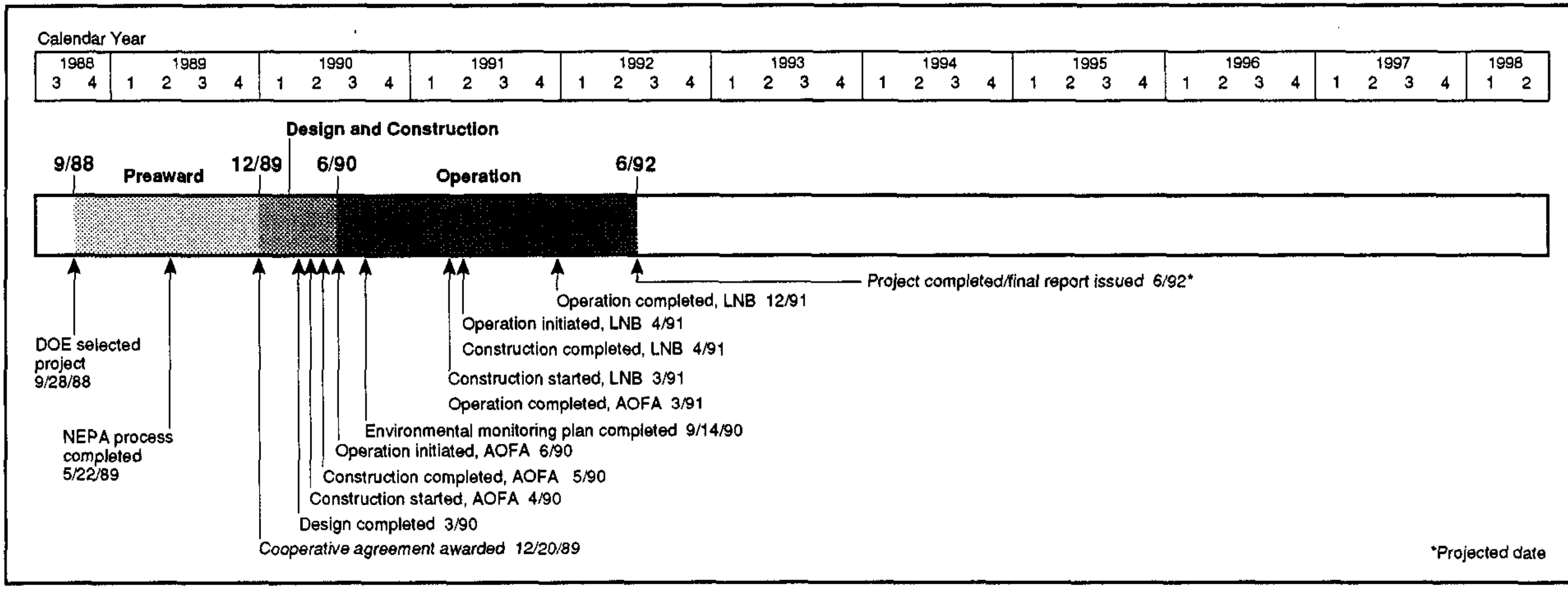
Technology/Project Description:

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

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

Based on earlier experience, the use of AOFA in conjunction with LNB can reduce NO_x emissions by as much as 60% compared with conventional burners.

The demonstration is located at the Georgia Power Company's Hammond Plant, Unit No. 4. The boiler is a nominal 500-MWe pulverized coal, wall-fired unit, which is representative of most of the existing pre-NSPS wall-fired utility boilers in the United States.



Project Status/Accomplishments:

Design and construction activities are complete. AOFA diagnostic and performance testing is complete, and long-term AOFA testing, which began in October 1991, is complete. Analysis of more than 80 days of operating data has provided statistically reliable results indicating that, depending upon load, NO_x reduction of 24% is achievable under normal long-term operation.

The 24 new controlled-flow, split-flame LNBs were installed and first fired on May 1, 1991. Optimization testing for LNB operation without the AOFA system was completed in late-June. The balance of coal fineness and LNB diagnostic and performance tests were completed in December 1991. Preliminary data analysis for both short-parametric and long-term tests indicates NO_x reductions of 47% under full-load conditions.

For both AOFA and LNB, preliminary analysis indicated significant increases of flyash loss or ignition values as compared to the baseline values. Results also show that post-LNB retrofit precipitator particulate mass loading and gas flow rates are substantially above baseline values.

Combined AOFA/LNB tests will be conducted in 1992. Completion of the final analysis of project data and issuance of the final report are scheduled for mid-1992.

Environmental Considerations:

NEPA compliance has been satisfied with a memo-to-file approved May 22, 1989. The environmental monitoring plan has been prepared.

Significant reductions of NO_x (11%) are projected nationally by 2010 from maximum commercialization of the technology due to the 60% removal capability forecasted and the wide applicability of the process. No changes in liquid effluents or solid wastes are anticipated. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

The technology is applicable for retrofitting the 422 pre-NSPS wall-fired boilers existing in the United States.

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

- Reduced short-term NO_x emissions by up to 60%
- Competitive capital and operating costs
- Relatively easy retrofit
- Little or no derating of the boiler
- Use of commercially available components

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

Sponsor:
Southern Company Services, Inc.

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

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

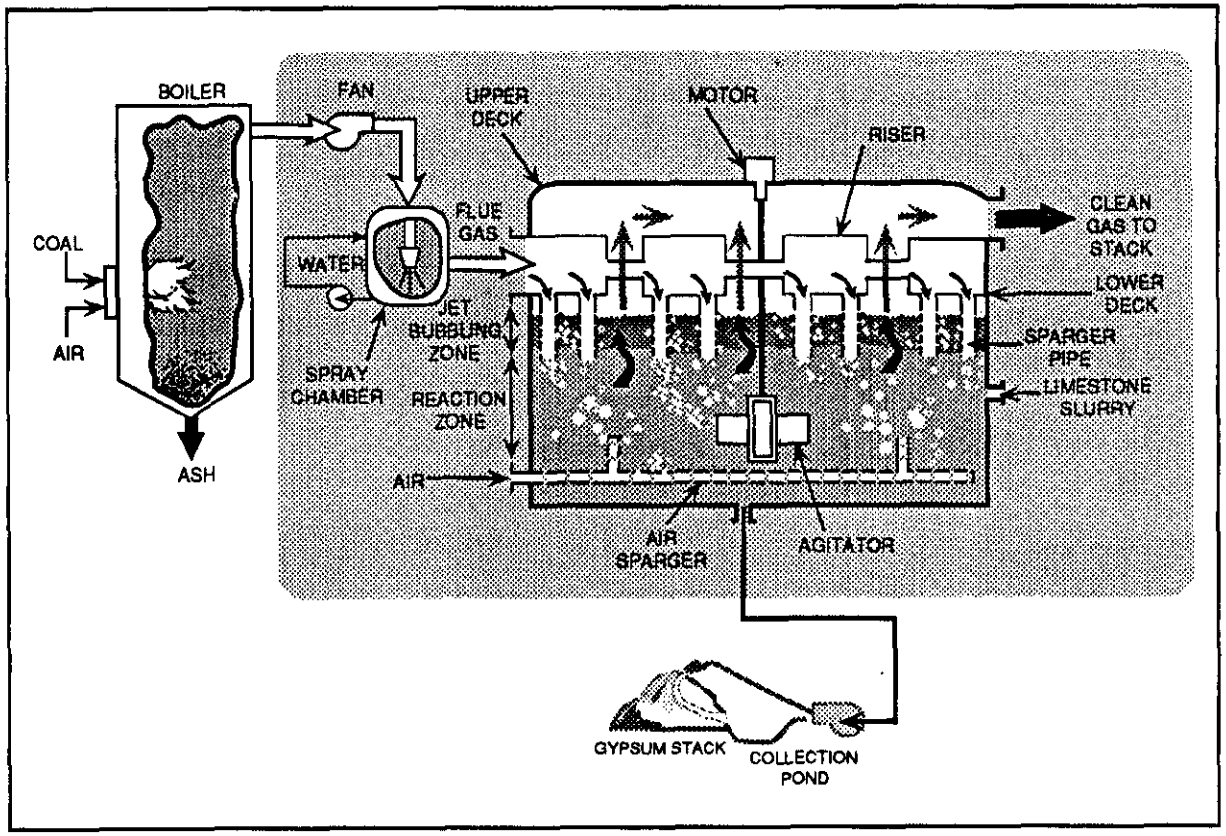
Technology:
Chiyoda Corporation's Chiyoda Thoroughbred-121 (CT-121) advanced flue gas desulfurization (FGD) process

Plant Capacity/Production:
100 MWe

Project Funding:

Total project cost	\$35,843,678	100%
DOE	17,546,646	49
Participants	18,297,032	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.



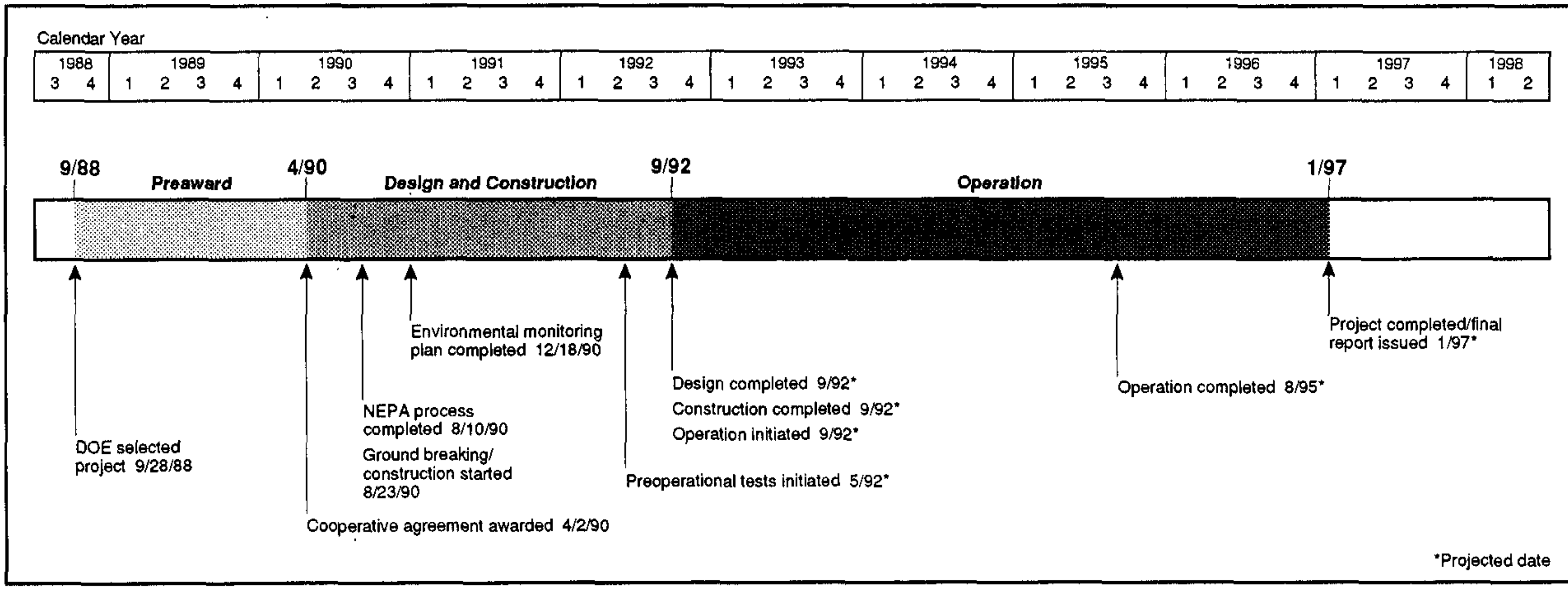
Technology/Project Description:
The project will demonstrate the CT-121 FGD process. This process uses a unique absorber design known as the jet-bubbling reactor (JBR), which combines limestone FGD reaction, forced oxidation, and gypsum crystallization in a one-process vessel. As a result, the process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

In this process, the flue gas enters the scrubbing solution on 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. The stacking technique involves filling a dyked area with gypsum slurry. Gypsum solids settle in the dyked area, and clear water overflows to a retention pond. The clear water from the pond is returned to the process.

As part of the project, innovations to the process will be evaluated to determine whether costs can be reduced further by using fiberglass-reinforced plastic absorbers, eliminating flue gas reheat and spare absorber module, and stacking gypsum to reduce waste management costs. The ability of this technology simultaneously to capture SO_2 and particulates will also be evaluated.

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

Georgia Power Company's 100-MWe Plant Yates, Unit 1, near Newnan, GA (about 40 miles from Atlanta), is being retrofitted with the Chiyoda scrubber.



Project Status/Accomplishments:

On-site spinning of the fiberglass JBR, limestone slurry tank shells, chimney, and duct work are complete. The JBR inlet and outlet flanges, deck and sparger grid beams, lower deck ledge, and dome top have been installed. Pump foundations and slurry sumps are complete, as is the main power bus duct in the turbine room. Hydrostatic and acoustical testing of the JBR is complete, while testing on the limestone slurry tank is under way.

Environmental Considerations:

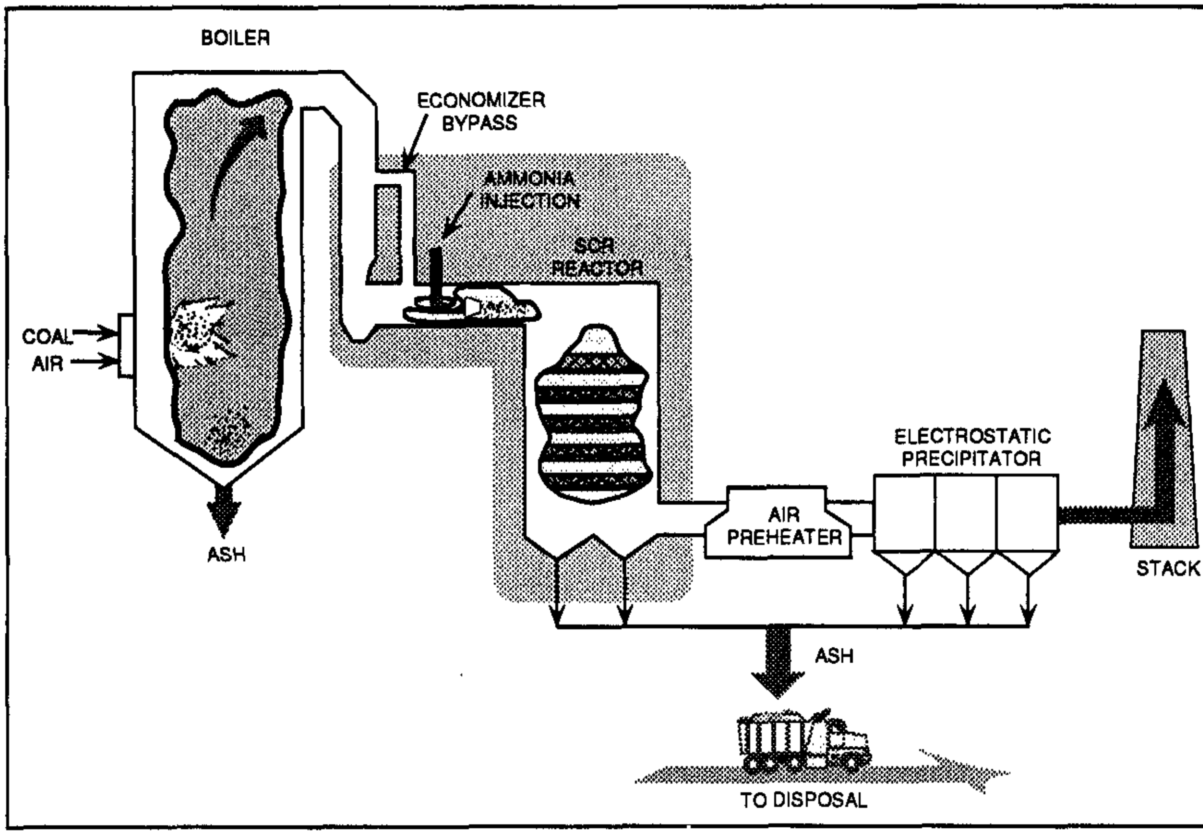
An environmental assessment with a finding of no significant impact was approved by DOE on August 10, 1990. The environmental monitoring plan has been prepared.

Assuming maximum commercialization of the CT-121 process on a national basis by 2010 relative to a no-action alternative, a 48% reduction of SO_2 could be achieved. The significant national reductions of SO_2 are attributable to the 90–95% SO_2 removal capability forecasted for the CT-121 process and the wide potential applicability of the process. Although solid waste would increase by 9%, the waste is readily disposable. The greatest environmental benefits may be achieved in the Northeast because of the large amount of coal-fired capacity in this region that can be retrofitted with the CT-121 process. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

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. By the year 2010, this process would be applicable to 370,000 MWe of new and existing generating capacity. 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.

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



Sponsor:
Southern Company Services, Inc.

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

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

Technology:
Selective catalytic reduction (SCR)

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

Project Funding:

Total project cost	$15,574,355	100%
DOE	7,525,338	48
Participants	8,049,017	52

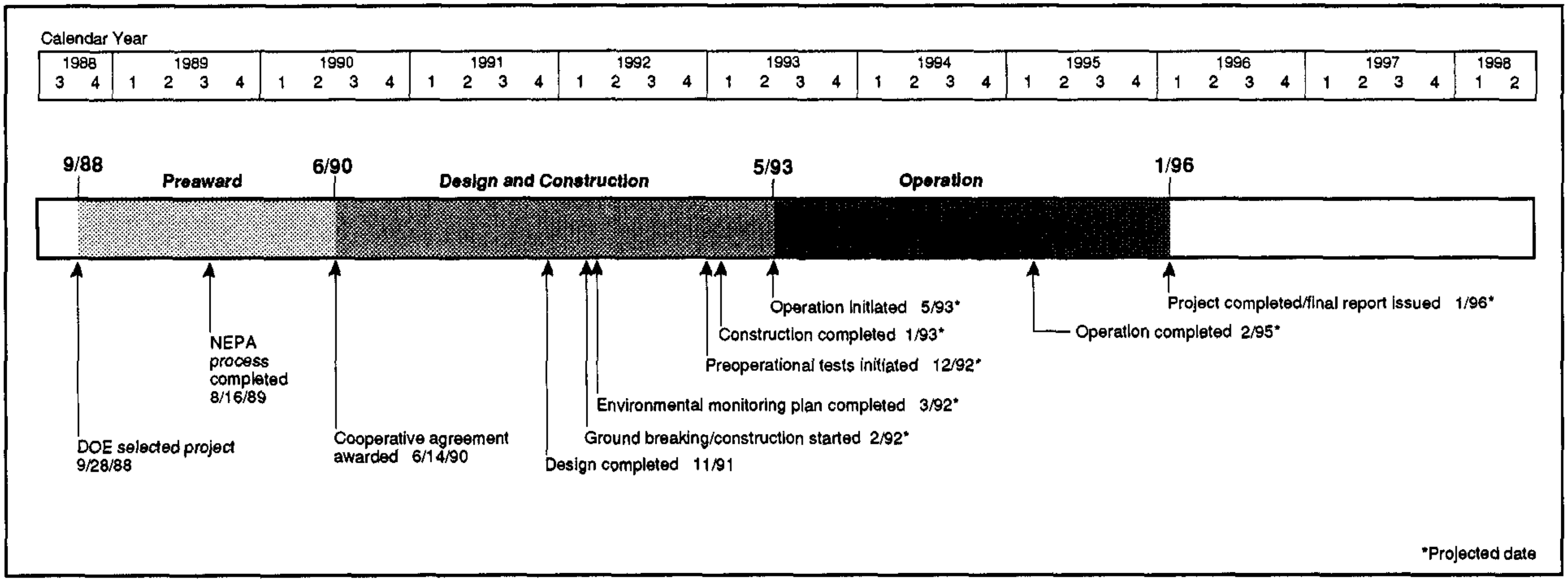
Project Objective:
To evaluate the performance of commercially available SCR catalysts when applied to operating conditions found in U.S. pulverized coal-fired utility boilers using U.S. high-sulfur coal under various operating conditions while achieving as much as 80% NO_x removal.

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

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

The demonstration plant, located at Gulf Power Company's Plant Crist near Pensacola, FL, has access to flue gas from burning approximately 3% sulfur coal under various NO_x and particulate levels.



Project Status/Accomplishments:

Detailed measurements of baseline flue gas conditions at Plant Crist are complete. Final, detailed catalyst specifications have been received from each catalyst supplier. A review of these specifications was made to assist in SCR reactor design. Flow modeling results and the catalyst testing program have been released to the 7 catalyst suppliers for comments and recommendations.

Detailed engineering is about 50% complete. Preliminary reactor design drawings were released for catalyst supplier review. Some catalyst vendors have provided comments on the proposed common laboratory test methods and conditions and reactor design drawings. The flue gas and air fan bid packages have been awarded. A contract for flue gas and air electric heaters was also awarded. Design specification and bid review are ongoing for several project subsystems. Construction is expected to begin in February 1992. Start of operation has slipped from mid-1992 to April 1993 as a result of delays associated with design changes and interface issues.

Environmental Considerations:

NEPA compliance has been satisfied by a memo-to-file approved on August 16, 1989.

Assuming maximum commercialization of the SCR process on a national basis by 2010 relative to a no-action alternative could achieve a 15% NO_x reduction. The significant national reductions of NO_x are attributable to the 80% NO_x removal capability forecasted for the SCR process and the wide potential applicability of the process. There will be no additional solid waste because the spent catalyst will be returned to the respective catalyst suppliers. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

SCR technology can be applied to retrofit and new utility applications for removal of NO_x from flue gas.

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

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

Sponsor:
Southern Company Services, Inc.

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

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

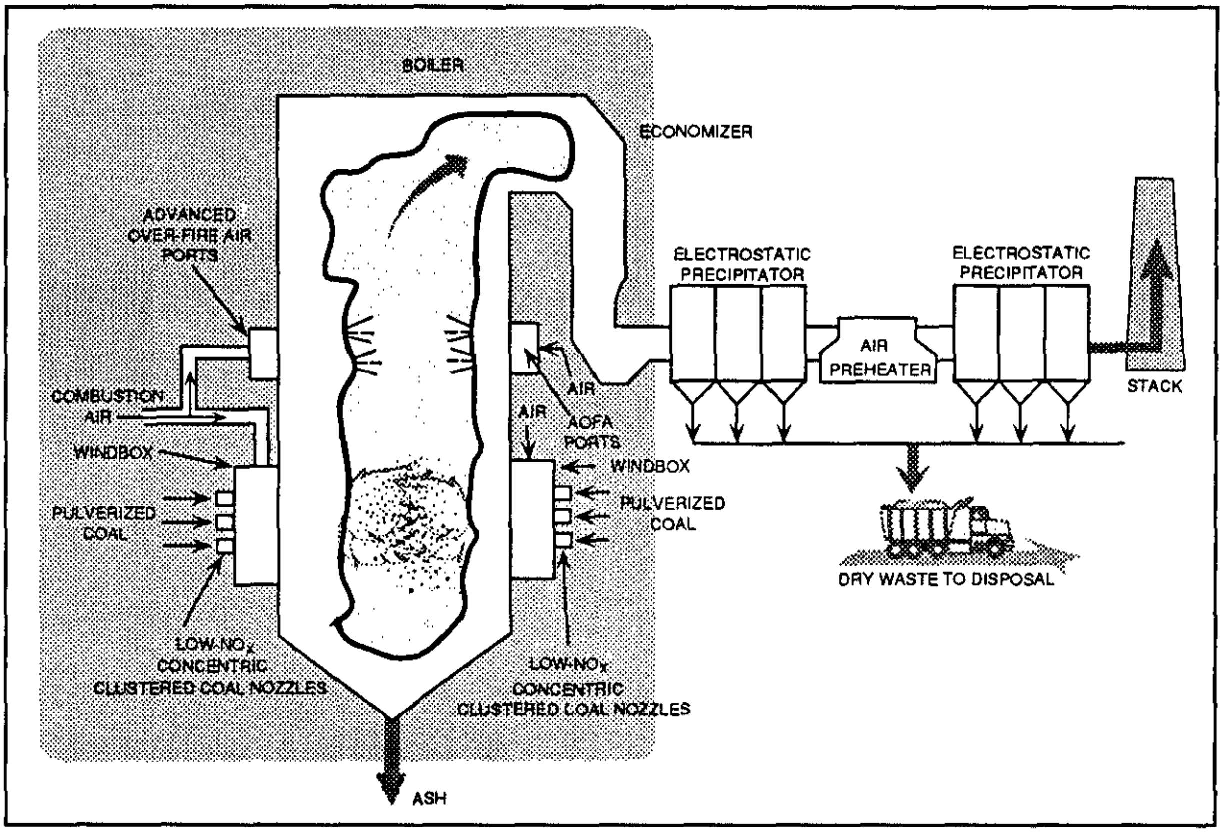
Technology:
ABB Combustion Engineering's low-NO_x bulk furnace staging (LNBFS) system and low-NO_x concentric firing system (LNCFS) with advanced over-fire air (AOFA), clustered coal nozzles, and offset air

Plant Capacity/Production:
180 MWe

Project Funding:

Total project cost	$9,024,765	100%
DOE	4,377,791	49
Participants	4,646,974	51

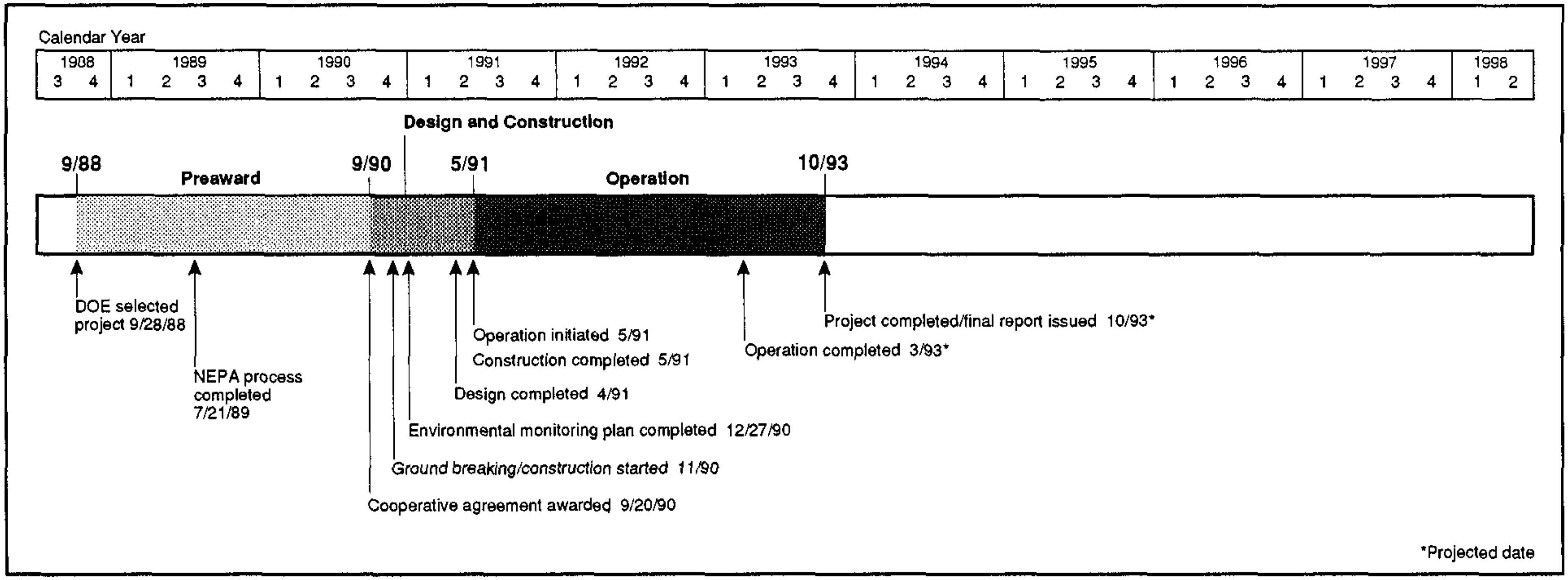
Project Objective:
To demonstrate in a stepwise fashion the short- and long-term NO_x reduction capabilities of low-NO_x concentric firing system (LNCFS) Levels I, II, and III on a single reference boiler under typical dynamic operating conditions, and evaluate the cost effectiveness of each low-NO_x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



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

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

In addition to over-fire air, the LNCFS incorporates other NO_x reducing techniques into the combustion process. Using offset air, two concentric circular combustion regions are formed. The majority of the coal is



contained in the fuel-rich inner region. This region is surrounded by a fuel-lean zone containing combustion air. The size of this outer circle of combustion air can be varied using adjustable offset air nozzles. Separation of air and coal at the burner level further reduces production of NO_x.

The LNBFS consists of a standard tangentially fired windbox with a SOFA system. The offset air nozzles in the main windbox can be repositioned to be in line with the fuel nozzles. No other modifications to the windbox repositioned are required. Due to schedule limits, LNBFS is being demonstrated using short-term diagnostic tests only.

The names of the technologies described above have been changed from those originally considered for this project to reflect the most recent, available 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 Status/Accomplishments:

Installation of LNCFS equipment, including separated over-fire air and offset nozzles, piping, and controls, took place during a scheduled outage in April 1991. Baseline diagnostic and performance testing had been completed the previous month, with 70 days of long-term data collected. The LNCFS Level–II tests (one of three basic air-/coal-feed configurations to be tested) were completed in September 1991. Results indicated NO_x emissions were reduced up to 40% compared to baseline emissions data. The LNCFS Level–III system was installed during an outage in November, as was equipment that will allow further testing with close-coupled over-fire air. Additional work was authorized for the project to allow chemical emissions testing related to the CAAA of 1990. Operation continues.

Environmental Considerations:

NEPA compliance has been satisfied by a memo-to-file approved by DOE on July 21, 1989.

Assuming maximum commercialization of the technology, significant reductions of NO_x (11%) are projected to be achievable nationally by 2010, due to the 60% removal capability forecasted and the wide applicability of the process. Negligible changes in liquid effluents are anticipated, and the technology produces no additional dry solid waste. (Source: CCT Programmatic Environmental Impact Statement)

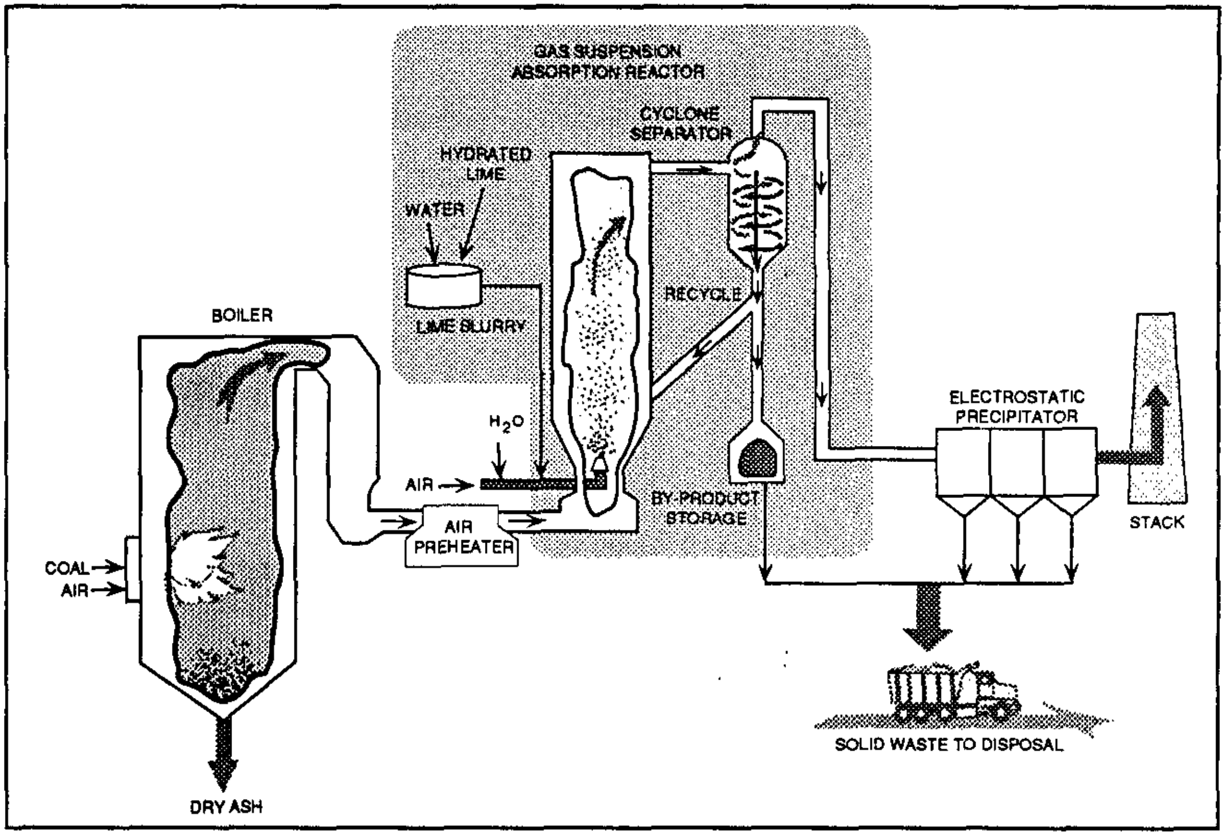
Commercial Application:

Commercial applications include a wide range of tangentially fired utility boilers throughout the United States and abroad. As an example, the Southern Company (which owns Southern Company Services, Inc.) has over 20,000 MWe of coal-fired generating capacity within its system of electric utilities. About two-thirds of this capacity is based on pulverized-coal tangentially fired boilers.

CCT-III

Project Fact Sheets

10-MW Demonstration of Gas Suspension Absorption



Sponsor:
AirPol, Inc.

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

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

Technology:
FLS miljo a/s' gas suspension absorption (GSA) system for flue gas desulfurization (FGD)

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

Project Funding:

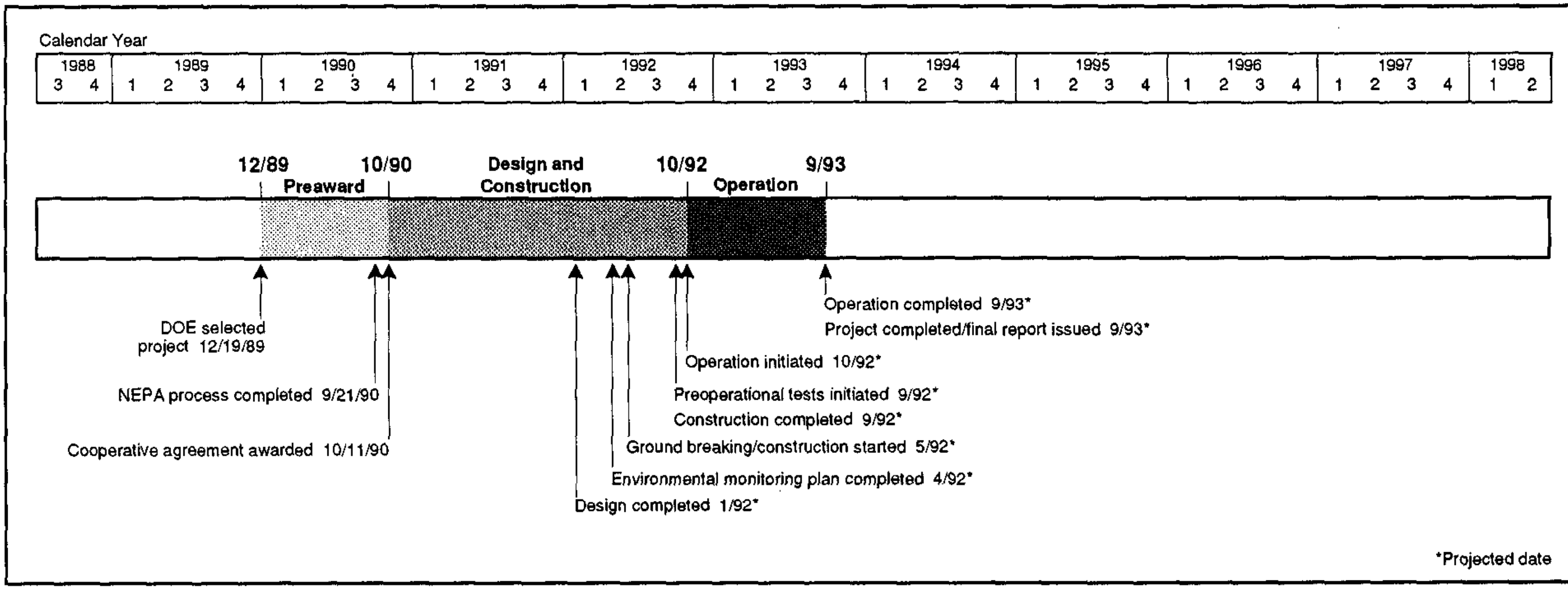
Total project cost	$6,920,679	100%
DOE	2,000,000	29
Participants	4,920,679	71

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

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

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

This project is 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.



Project Status/Accomplishments:

Process flow diagrams have been finalized, and general arrangement drawings and sizing and layout of major equipment are complete.

Piping and instrumentation diagrams for the control system are complete, as are preliminary assembly specifications for the recycled lime feeder box. Combustor material and energy balances are complete, enabling determination/specification of GSA design conditions.

Construction has been delayed 10 months due to unavailability of host site during 1991.

Environmental Considerations:

NEPA compliance has been satisfied by a memo-to-file approved by DOE on September 21, 1990.

The environmental monitoring plan is scheduled for completion in April 1992.

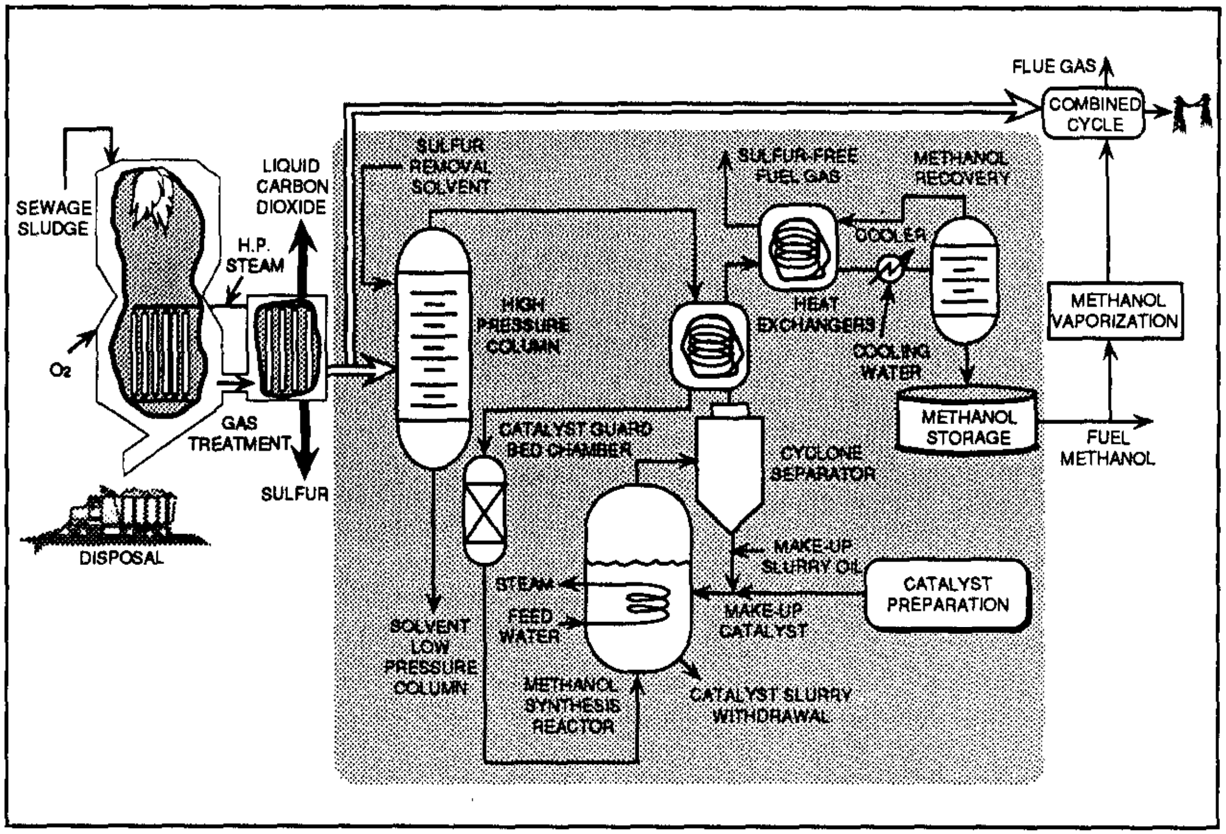
Assuming maximum commercialization of this technology, significant reductions of SO_2 (45%) are achievable nationally by 2010 due to the capability of the GSA process to remove at least 90% of the SO_2 emissions from coal-fired boilers and the wide potential applicability of the process. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

The GSA process offers several advantages over conventional FGD technologies. AirPol estimates that GSA is 40% cheaper than wet FGD and 20% cheaper than spray drying. Moreover, GSA is much simpler to build and operate than wet FGD and regenerable processes and requires much less space. Space requirements, operability, and ease of installation are comparable to spray dryers and duct injection. However, the SO_2 removal capability of the GSA technology (90%) compares to that of wet FGD and the regenerable processes, while dry injection processes and spray dryers generally remove about 50% and 90% respectively. This high removal rate makes the GSA process suitable for use with high-sulfur coal, unlike the spray dryer or dry injection processes, which are suitable only for low- and medium-sulfur coals.

In summary, GSA is expected to find commercial acceptance because it is the only semidry process that offers SO_2 removal rates comparable to the more costly and complex wet FGD systems. In addition, GSA offers relatively low sorbent consumption rates and may perform better than dry systems; it is both less costly and more effective than spray dryers.

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



Sponsor:
Air Products and Chemicals, Inc.

Additional Team Members:
Acurex Corporation — fuel methanol testing cofunder
Texaco Syngas Inc.—host site and cofunder
Dakota Gasification Company—technology consultant

Location:
Daggett, San Bernardino County, CA (Cool Water Gasification Facility; Texaco Syngas negotiating purchase of site)

Technology:
Chem Systems' liquid-phase methanol (LPMEOH®) process

Plant Capacity/Production:
150 tons/day of methanol

Project Funding:

Total project cost:	$213,701,857	100%
DOE	92,701,297	43
Participants	121,000,560	57

(Funding is subject to negotiation.)

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 low-SO_x, low-NO_x alternative fuel in boiler, turbine, and transportation applications.

Technology/Project Description:
This project is demonstrating the LPMEOH® process to produce methanol from coal-derived synthesis gas on a commercial scale. The combined reactor and heat removal system in the LPMEOH® process differentiates it significantly from other commercial methanol processes. The liquid phase not only supports the catalyst but functions as an efficient means to remove the heat of reaction away from the catalyst surface. This feature alone directly permits the use of a low ratio of hydrogen to carbon monoxide in the synthesis gas streams produced from coal gasification facilities as feed to the reactor without the need for shift conversion.

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

- Carbon monoxide conversion to methanol —13% per reactor per pass in a hydrogen-rich feed
- Methanol productivity comparable to gas-phase systems — 6,000 kg of methanol per 1 kg of catalyst
- Raw methanol purity—97.5%
- Feed gas flexibility—permits the use of synthesis gas produced by any commercial coal gasification system to be used without shift conversion
- Diversity— can be combined with integrated coal gasification combined-cycle (IGCC) applications

In addition to the original project objective, DOE will receive data on the use of a combined feedstock of

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LPMEOH is a registered trademark of Chem Systems, Inc.

Calendar Year

1988		1989		
3	4	1	2	3

Healy Clean Coal Project

Sponsor:
Alaska Industrial Development and Export Authority

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

Location:
Healy, AK (Denali Borough)

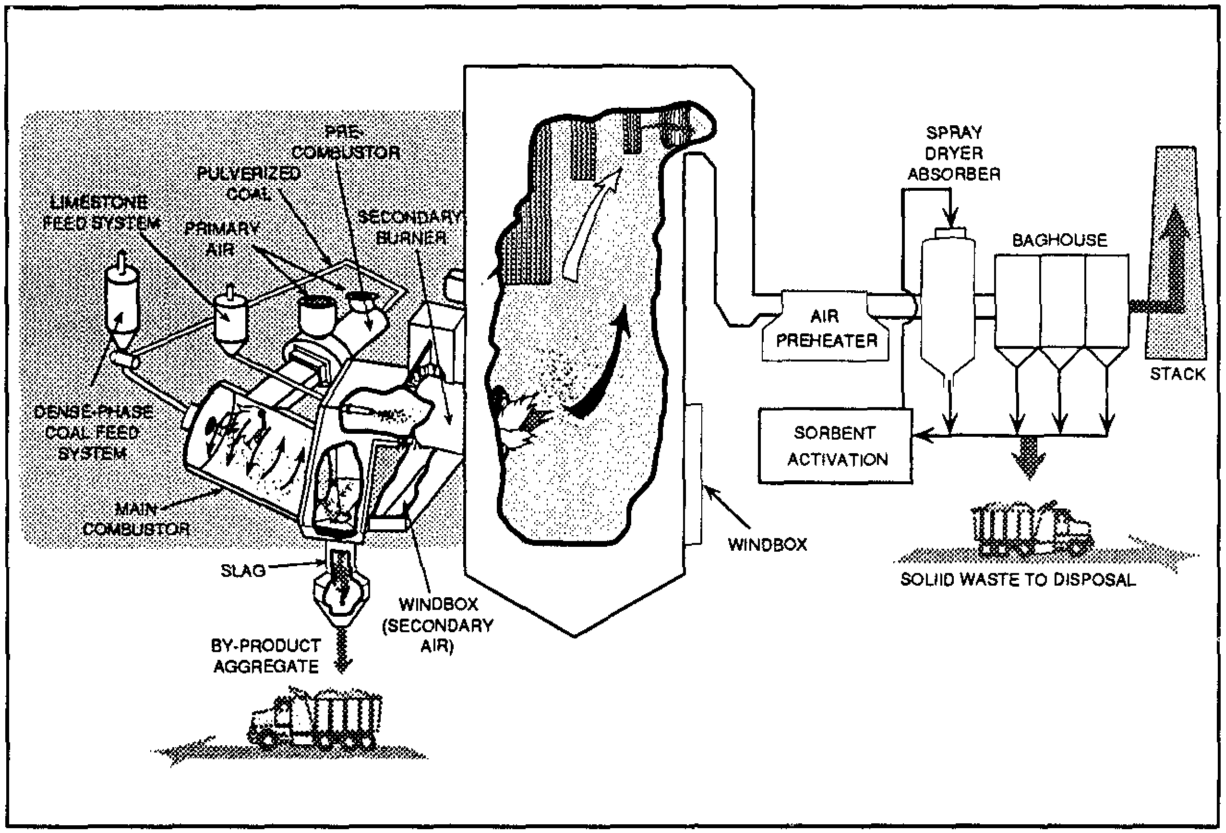
Technology:
TRW's advanced entrained (slagging) combustor
Joy Technologies' spray dryer absorber with sorbent recycle

Plant Capacity/Production:
50 MWe (net)

Project Funding:

Total project cost	$193,407,000	100%
DOE	93,862,000	48
Participants	99,545,000	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.

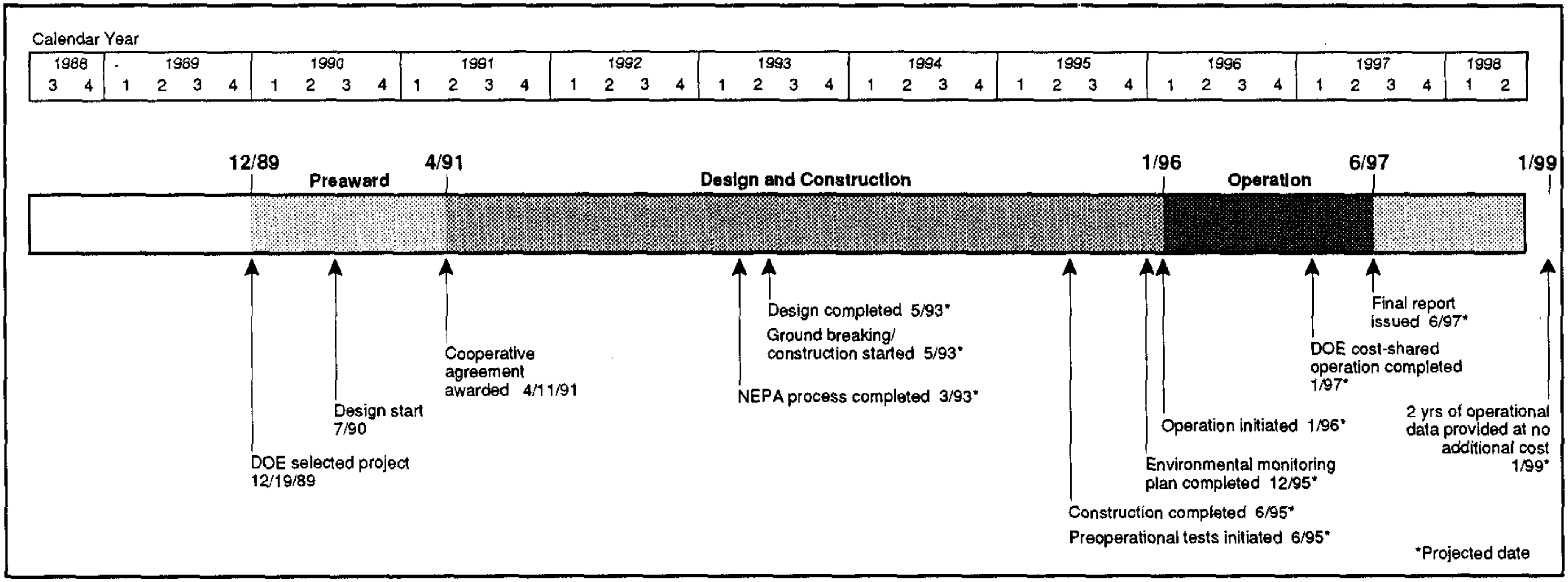


Technology/Project Description:
The heart of the system being demonstrated is an all-metal combustor that consists of two cylindrical sections followed by a short duct that connects the combustor to the boiler. A separate precombustor burns about 25% of the coal, and the combustion air to the main (or slagging-stage) combustor is preheated by mixing it with the hot gases exhausted from the precombustor. The preheated air enters the main combustor section tangentially to impart a swirling motion to the coal and air. The balance of the coal is injected axially at the front end of this cylindrical section.

Molten slag collects on the walls of the combustor and flows toward an opening in the bottom of the main combustor where it falls into a water-filled slag tank. The slagging combustor declines slightly from horizontal to aid in the flow of the molten slag. Some slag solidifies on the water-cooled surface and serves to insulate and protect the metal walls from erosion and excessive temperatures.

The main combustion section operates at a slight air deficiency to reduce the amount of NO_x produced. Combustion products mix with sufficient air to complete the combustion reactions that take place in the boiler. The combustors are coupled with a specially designed boiler that, in addition to its heat recovery function, produces low NO_x levels, functions as a limestone calciner, and accomplishes first-stage SO_2 removal.

The process also uses a single spray dryer absorber vessel for second-stage sulfur removal and a lime activation system that recovers unused reagent from the particulate collected by the baghouse.



The slagging combustor with specially designed boiler and the spray dryer/recycle system should be capable of reducing NO_x by 70% and SO_2 by at least 90%.

The project involves design, construction, and operation of the slagging cumbustor spray dryer/sorbent recycle system at a greenfield site near Healy, AK, to provide power to the Golden Valley Electric Association. The plant will provide 3 years of data, with 2 years of data being provided at no cost to DOE.

Project Status/Accomplishments:

The cooperative agreement was awarded on April 11, 1991. Preparation of Alaska Department of Natural Resources land use and EPA National Pollution Discharge Elimination System permit applications as well as project design and construction schedule activities continue. The advanced slagging combustor was successfully operated using Healy project fuel at TRW's Cleveland facility. Joy/Niro testing of flash calcined sorbent was completed at the Copenhagen facility. The project is on schedule with approximately 20% of the design completed.

Environmental Considerations:

Environmental information is being prepared for use in the NEPA compliance process; an EIS will be prepared.

The following impacts are projected for the Healy demonstration on a national basis by 2010 with maximum commercialization of this technology:

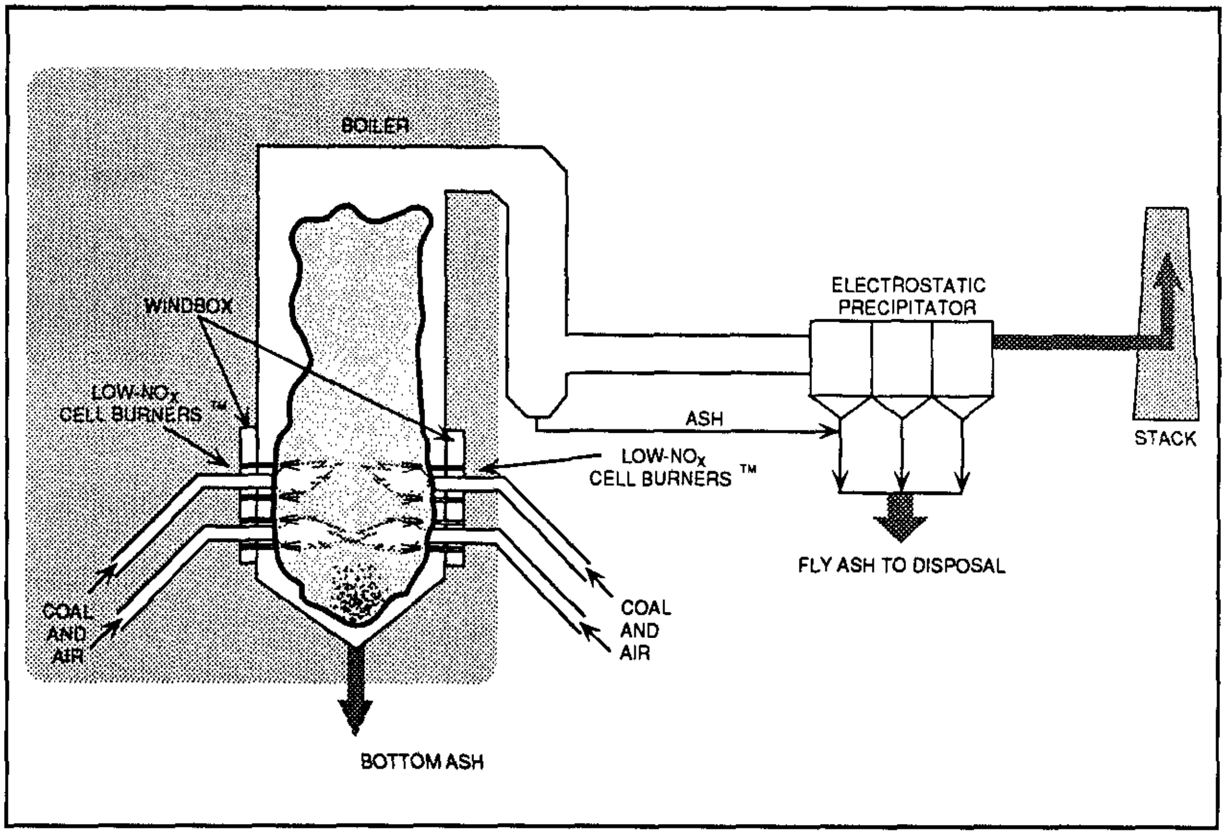
- SO_2 reduction—45%
- NO_x reduction—18%

Ash removal efficiencies in the combustor range from 70% to 90%. Much of the coal's ash content is removed as a molten slag by cyclonic action in the combustor and, when cool, is a dry, coarse solid suitable for a landfill. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

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. Furthermore, coal of any sulfur content can be used as long as the minimum ash content is 5%. 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 to comply with CAAA of 1990 requirements.

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



Sponsor:

The Babcock & Wilcox Company

Additional Team Members:

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

Location:

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

Technology:

The Babcock & Wilcox Company's Low-NO_x Cell Burner™ (LNCB™) system

Plant Capacity/Production:

605 MWe

Project Funding:

Total project cost	$10,046,204	100%
DOE	4,867,204	48
Participants	5,179,000	52

Project Objective:

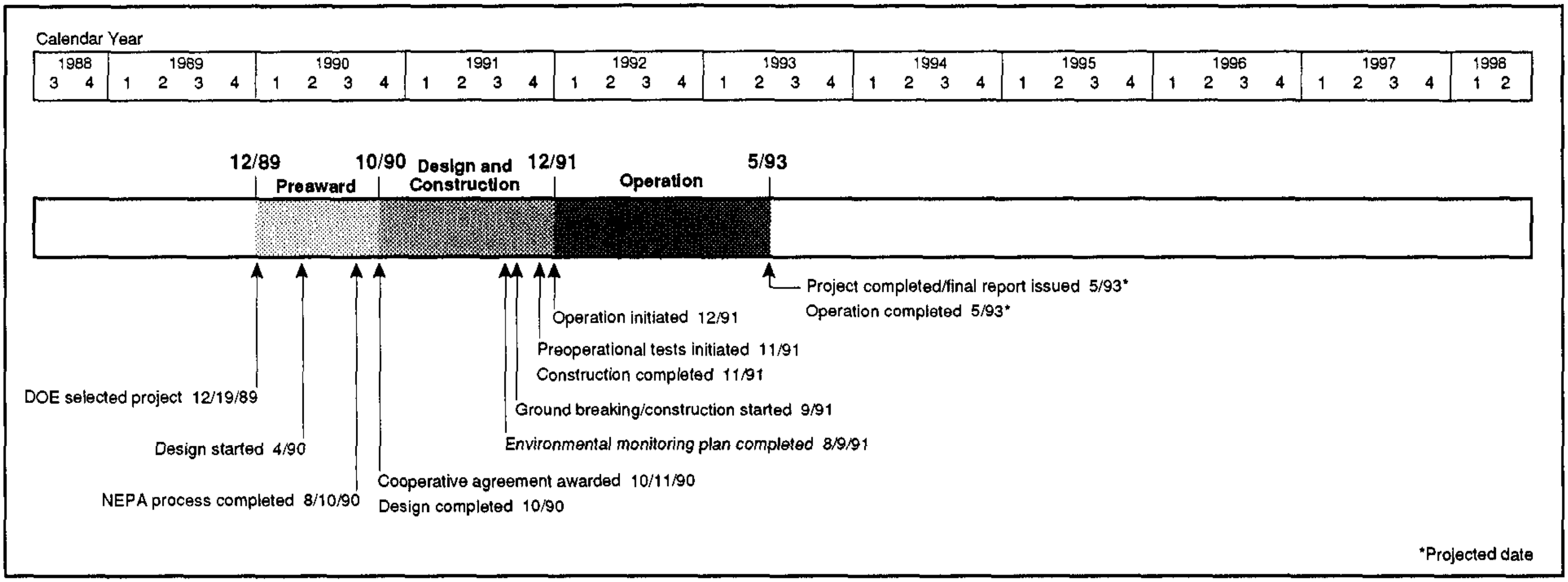
To demonstrate through the first commercial-scale full burner retrofit the cost-effective reduction of NO_x from a large base-load coal-fired utility boiler with Low-NO_x Cell Burner™ technology; and to achieve at least a 50% NO_x reduction without degradation of boiler performance at less cost than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

Technology/Project Description:

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

The net effect of this technology is a 50% reduction in NO_x formation with minimal or 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 is being 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 Southern Ohio Electric Company. The boiler unit is a B&W-designed, supercritical, once-through boiler equipped with an electrostatic precipitator. This unit contains 24 two-nozzle cell burners arranged in an opposed firing



configuration. Twelve burners (arranged in two rows of six burners each) are mounted on each of two opposing walls of the boiler. The proposed demonstration will require the removal of all 24 standard cell burners and the installation of 24 new burners.

Project Status/Accomplishments:

Detailed design for the retrofit was completed in October 1990. Pre-retrofit baseline testing was completed in November 1990, and the data analysis is complete. Commerical boiler flow modeling for both the pre-retrofit baseline and retrofit cases are complete.

The project schedule has been extended 6 months because the host utility, Dayton Power and Light, needed to delay the outage of Unit No. 4 (the project site) due to an extended outage required on another unit for turbine repairs. Fabrication of the 24 new burners is complete, and the burners were installed during the 6-week outage that began September 20, 1991. Additional work was authorized for the project to allow testing of a corrosion test panel and operation of a high-temperature remote video system for recording burner flame characteristics. The outage was completed in early November 1991. Start-up and shakedown of the system was initiated in November 1991.

Environmental Considerations:

NEPA compliance has been satisfied by a memo-to-file approved by DOE on August 1, 1990. The environmental monitoring plan was completed August 9, 1991.

This technology can be retrofitted only with boilers configured with cell-type burners. The retrofit market is limited to approximately 37 boilers that emit an estimated 728,000–1,312,000 tons/yr of NO_x.

Assuming maximum commercialization nationally of the low-NO_x burner technology by the year 2010, NO_x emissions could be reduced by 364,000–656,000 tons/yr relative to a no-action alternative. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

This retrofit technology is applicable to approximately 37 coal-fired boilers that are equipped with cell-type burners, representing a total generating capacity of approximately 26,000 MWe.

Confined Zone Dispersion Flue Gas Desulfurization Demonstration

Sponsor:
Bechtel Corporation

Additional Team Members:
Pennsylvania Electric Company—cofunder and host utility

Pennsylvania Energy Development Authority—cofunder

New York State Electric and Gas Corporation—cofunder

Rockwell Lime Company—cofunder

Location:
Seward, Indiana County, PA (Pennsylvania Electric Company's Seward Station, Unit No. 15)

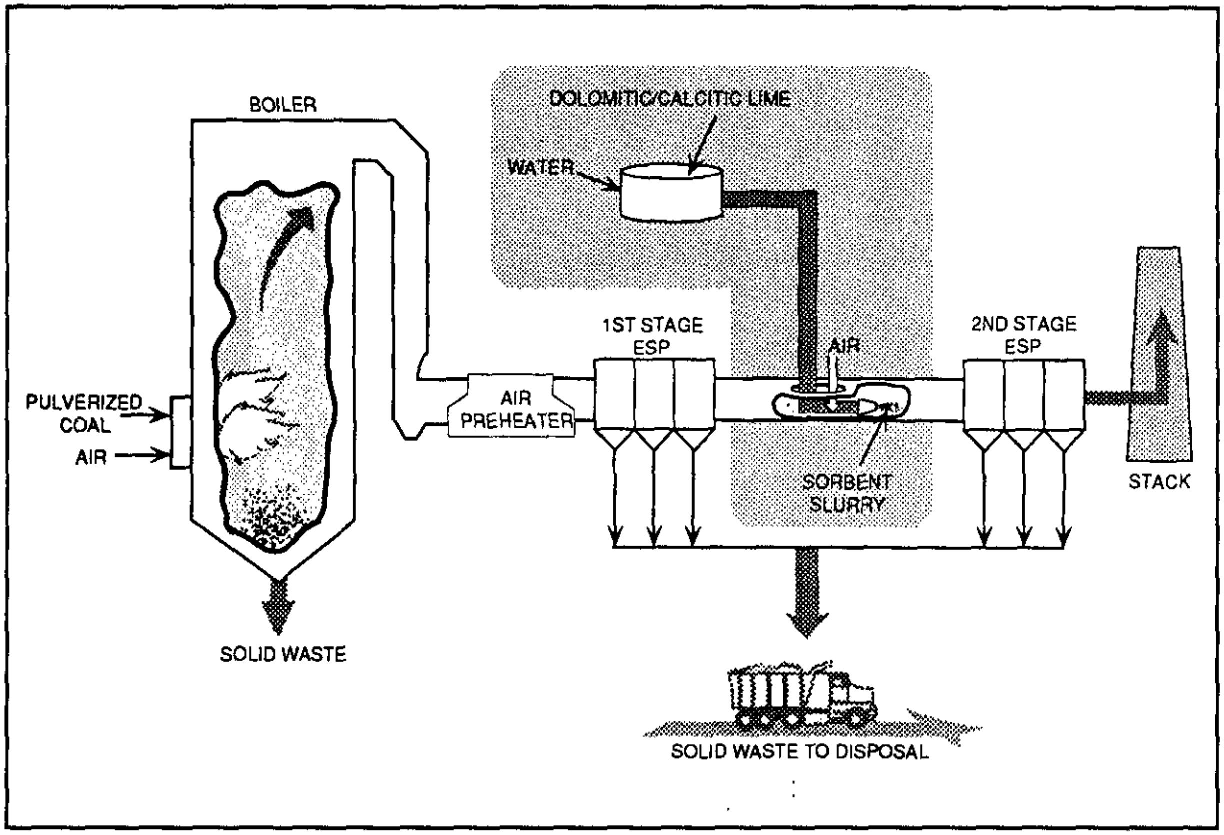
Technology:
Bechtel Corporation's in-duct, confined zone dispersion flue gas desulfurization (CZD/FGD) process

Plant Capacity/Production:
73.5 MWe

Project Funding:

Total project cost	$9,211,600	100%
DOE	4,605,800	50
Participants	4,605,800	50

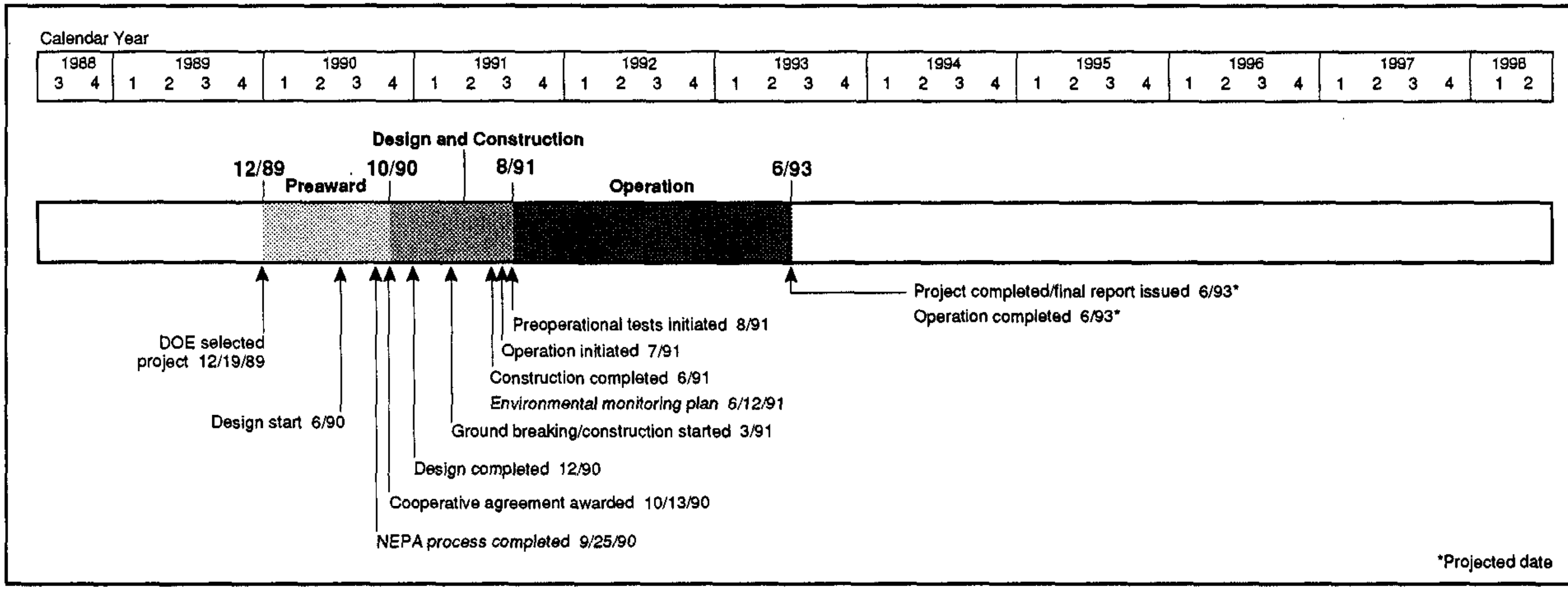
Project Objective:
To demonstrate SO_2 removal capabilities of in-duct CZD/FGD technology; specifically, to define the optimum process operating parameters and to determine CZD/FGD's operability, reliability, and cost-effectiveness during long-term testing and its impact on downstream operations and 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 50% of 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 lime) 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. 15 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. After the variable test program is complete, continuous, fully automated



and integrated (with the regular power plant) operation is planned for 1 yr.

Project Status/Accomplishments:

Ground breaking occurred in March 1991, and construction was completed in June 1991. Bechtel began the 25-month test of its process in July 1991. The new atomizing nozzles were thoroughly tested outside of the duct followed by in-duct testing. Start-up operations were delayed due to late deliveries of some equipment items. The lime slurry injection parametric test program began in October 1991. One project goal is to demonstrate that the CZD process is capable of reducing SO_2 emissions by 50% from coal-fired boilers. Difficulties encountered in achieving stable communications within the new temperature monitoring and recording system installed for this demonstration also caused delays in parametric testing. However, although the CZD technology will not be fully demonstrated until the parametric testing and year-long testing are complete, tests to date indicate that the expected level of emissions reduction can be reached and possibly exceeded. Long-term testing may be delayed by a month or two and is planned for next year with operations expected to continue through the first half of 1993.

Environmental Considerations:

NEPA compliance has been satisfied by a memo-to-file approved by DOE on September 25, 1990. The environmental monitoring plan was completed June 12, 1991.

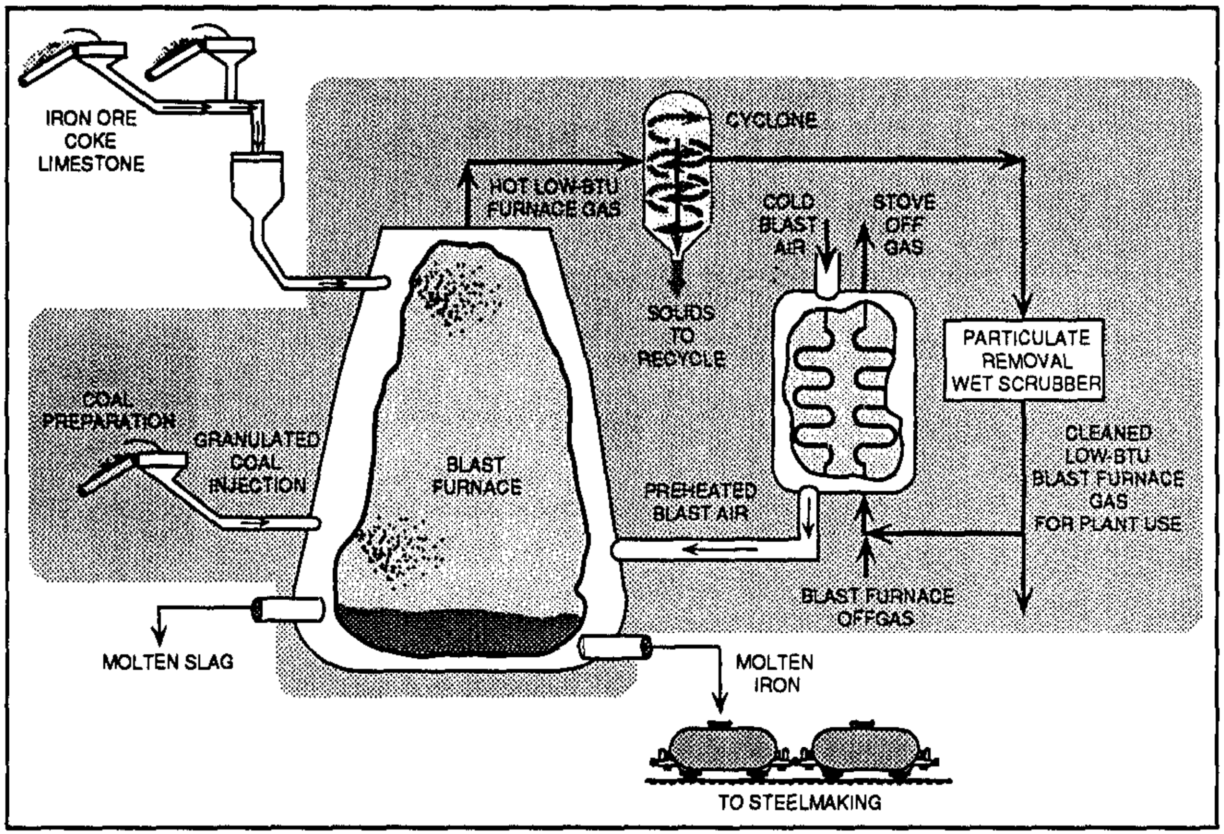
Sorbent injection technologies such as the CZD/FGD process could reduce national emissions of SO_2 by as much as 38% by 2010, assuming maximum commercialization of the technology. NSPS levels of SO_2 reduction could be satisfied with low-sulfur coal. Although the volume of solid waste is increased 8%, it is dry, nontoxic, and easily disposable. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

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

A CZD system can be added to a utility boiler with a capital investment of about $25–55/kW of installed capacity, or approximately one-third the cost of building a conventional wet scrubber. In addition to low capital cost, other advantages include small space requirements, ease of retrofit, and production of only nontoxic, disposable waste. The CZD technology is particularly well suited for retrofitting existing boilers, independent of type, age, or size. Further, CZD use is not dependent on the type of sulfur content of the coal. The CZD installation does not require major power station alterations and can be easily and economically integrated into existing power plants.

Blast Furnace Granulated-Coal Injection System Demonstration Project



Sponsor:
Bethlehem Steel Corporation

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

Simon Macawber, Ltd.—equipment supplier

Fluor Daniel, Inc.—architect and engineer

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

Location:
Burns Harbor, Porter County, IN (Blast Furnace Units C and D)

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

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

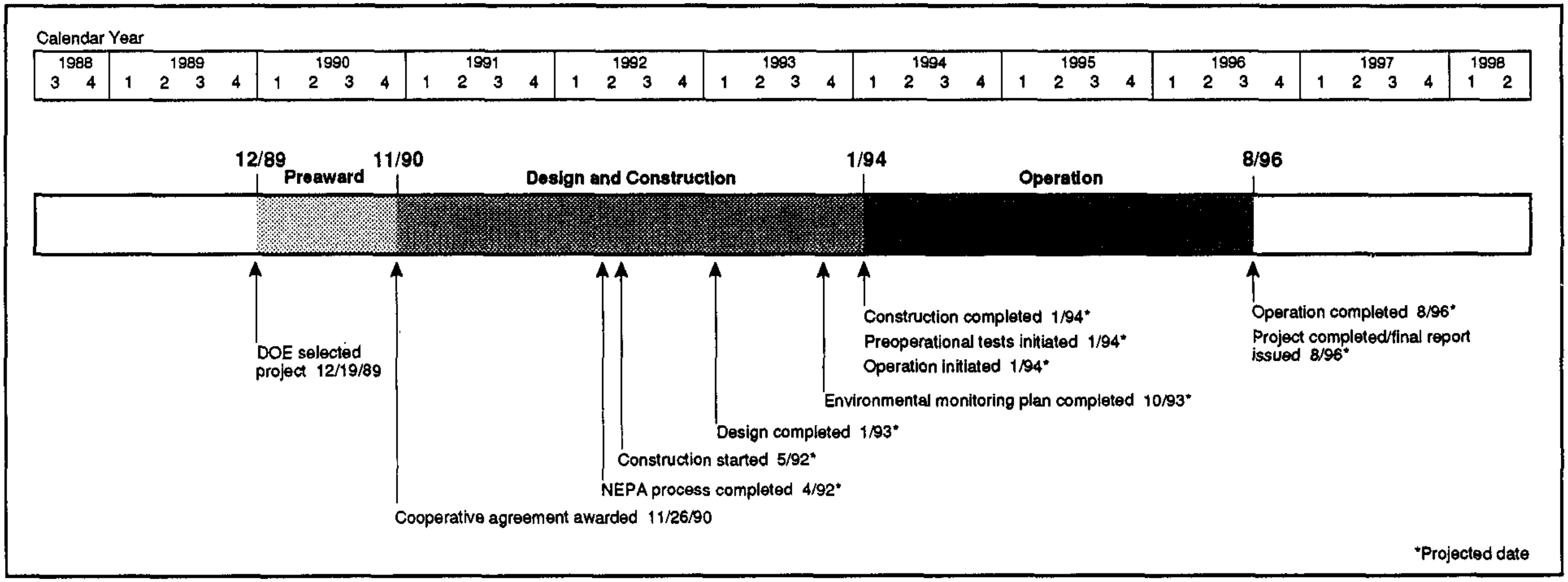
Project Funding:

Total project cost	$143,800,000	100%
DOE	31,259,530	22
Participants	112,540,470	78

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 SO_2 and NO_x emissions 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 SO_2 and NO_x 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.

Project Status/Accomplishments:

Conceptual design of the blast furnace granulated-coal injection system is complete. Process design and detailed engineering are in progress.

Environmental Considerations:

Environmental information for use in the NEPA compliance process has been prepared. Biological assessments of impacts on local lakeshore areas are complete and have been approved by the U.S. Department of Interior Fish and Wildlife Service.

The largest reductions in emissions resulting from commercialization of the BFGCI technology are expected to occur in the coke-making process. As the BFGCI technology reaches full market penetration, the amount of coke required for blast furnaces would decrease, thus reducing the emissions associated with its production. Although a slight increase in slag can be expected from the coal ash, the slag is readily salable as construction aggregate or rock wool.

Commercial Application:

This technology can be applied to essentially all blast furnaces in the United States. It is anticipated that a wide variety of coals can be used.

Air-Blown/Integrated Gasification Combined-Cycle Project

Sponsor:
Clean Power Cogeneration Limited Partnership (wholly owned by TECO Power Services)

Additional Team Member:
Tampa Electric Company—host utility

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

Technology:
Air-blown, integrated gasification combined-cycle (IGCC) system

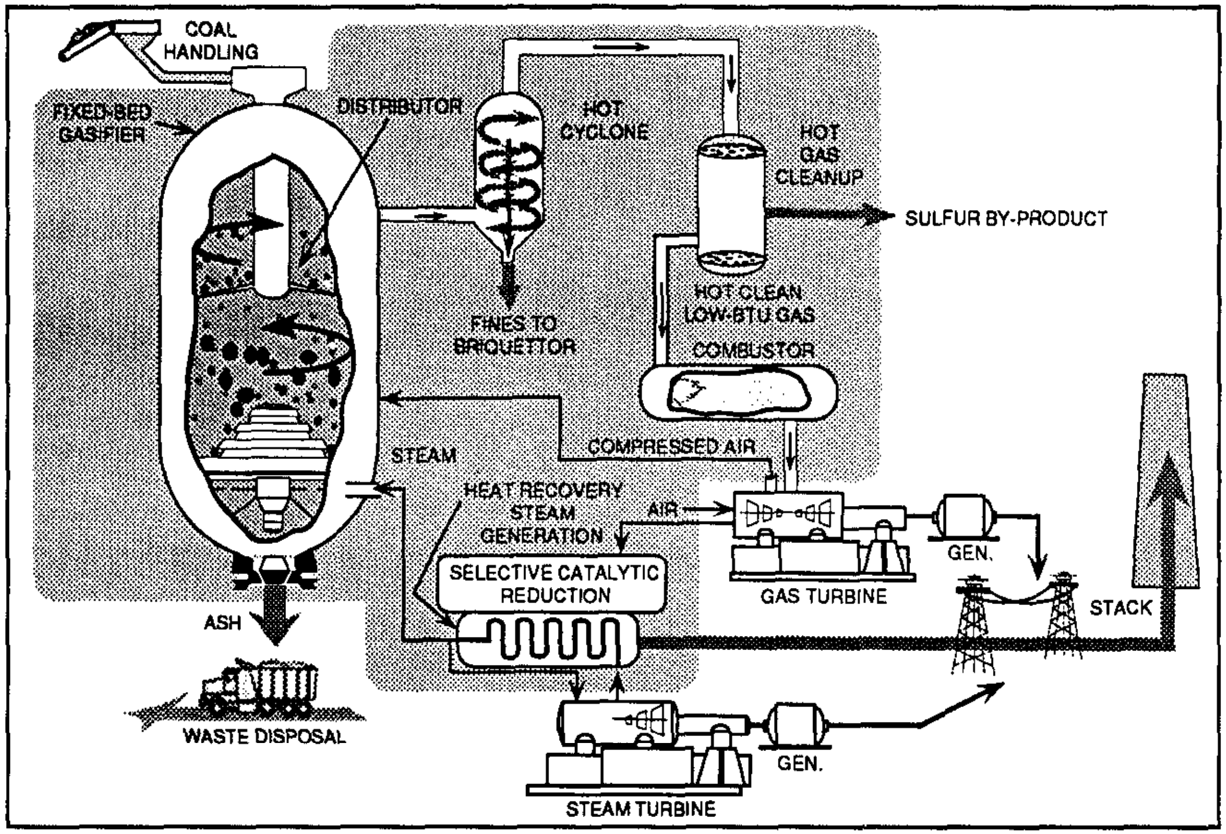
Plant Capacity/Production:
120 MWe

Project Funding:

Total project cost	$241,458,000	100%
DOE	120,729,000	50
Participants	120,729,000	50

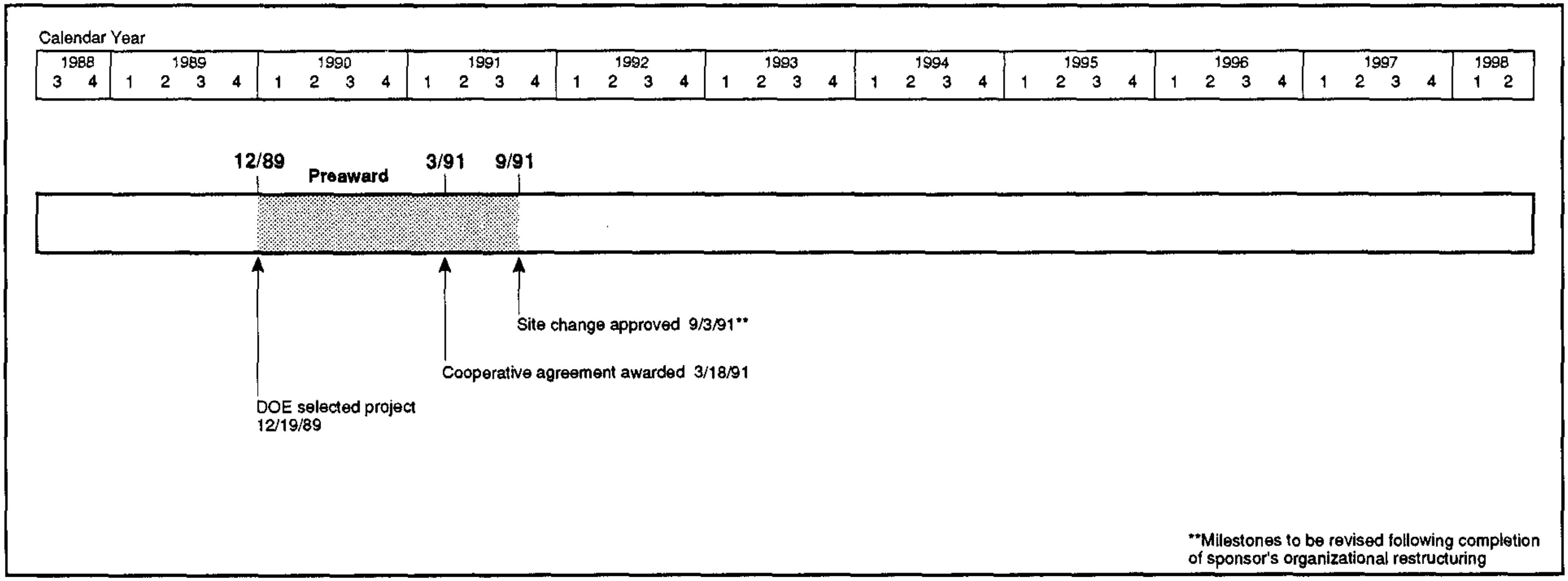
(Funding is subject to project restructuring.)

Project Objective:
To demonstrate air-blown, fixed-bed, integrated gasification combined-cycle technology and to assess long-term reliability, availability, and maintainability at sufficient scale to determine commercial potential.



Technology/Project Description:
Coal is gasified in a pressurized, air-blown, fixed-bed gasifier. The low-Btu coal gas leaves the gasifier at approximately 1,000 °F and goes to a hot gas cleanup system where the removal of sulfur compounds is accomplished in a moving bed of solid sorbent. The cleaned gas is delivered to a combustor, which is on board the gas turbine frame. The gas turbine is integrated with the coal conversion system through pressurized air extraction, which is used as gasifier air supply. The steam generated in the heat recovery generator is used both for driving a conventional steam turbine generator set producing additional electricity and for gasifier blast. The project has the following subsystems: fixed-bed coal gasification, hot gas cleanup, a combustion turbine capable of using low-Btu coal gas, selective catalytic reduction for NO_x control, a briquettor to utilize coal fines, and the balance of plant.

In the demonstration project, a nominal 1,270 tons/day of coal is converted into 120 MWe. The base feed coal for the project is a high-sulfur Illinois Basin bituminous coal. The new site is Tampa Electric Company's Polk Power Station located in Lakeland, FL.



Project Status/Accomplishments:
The cooperative agreement was awarded March 18, 1991. On September 3, 1991, DOE approved a site change from the City of Tallahassee's Arvah B. Hopkins Station to Tampa Electric Company's Polk Power Station located in Polk County, FL. Relocation was necessary due to siting difficulties at the Arvah B. Hopkins Station and failure to obtain a power sales agreement with the City of Tallahassee. Under way are preliminary design and engineering activities and studies for integration of the IGCC project into Tampa Electric's 260-MWe first-phase generation expansion plan.

Environmental Considerations:
Assuming maximum commercialization of IGCC technology on a national basis by 2010 relative to a no-action alternative, the following impacts are projected:

- SO_2 reduction—37%
- NO_x reduction—17%
- Solid waste reduction—5%
- CO_2 reduction—6%

(Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:
In recent years, IGCC is rapidly emerging as an alternative for new electricity generating plants. Such plants require 15% less land area than pulverized coal plants with flue gas desulfurization. IGCC technology also can be used in repowering by replacing the existing coal-fired boiler with a gasifier, gas stream cleanup unit, gas turbine, and waste heat recovery boiler. The remaining equipment is left in place, including the steam turbine and electrical generator. 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 Facility provisions.

The performance potential of IGCC technology in its commercial configuration is characterized as follows:

- SO_2 reduction—99%
- NO_x reduction—95%
- Plant efficiency—up to 48%
- Incremental power increase—230%
- Fuel flexibility—permits use of wide range of coals
- Compactness—high process efficiency reduces space requirements per unit of energy generated
- Modular construction—lends itself to economic addition of capacity increments to match load growth

PCFB Demonstration Project

Sponsor:

DMEC-1 Limited Partnership (a partnership between Dairyland Power Cooperative and 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

Plant Capacity/Production:

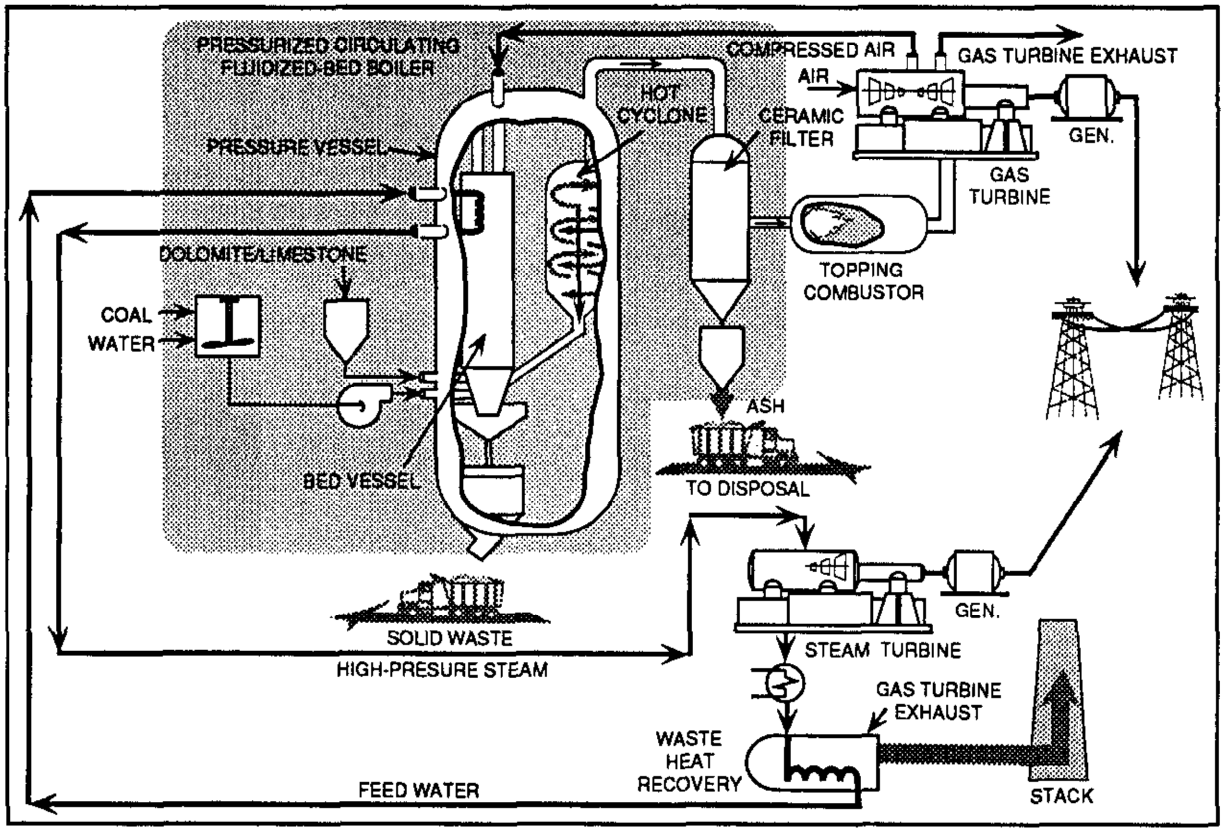
70 MWe

Project Funding:

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

Project Objective:

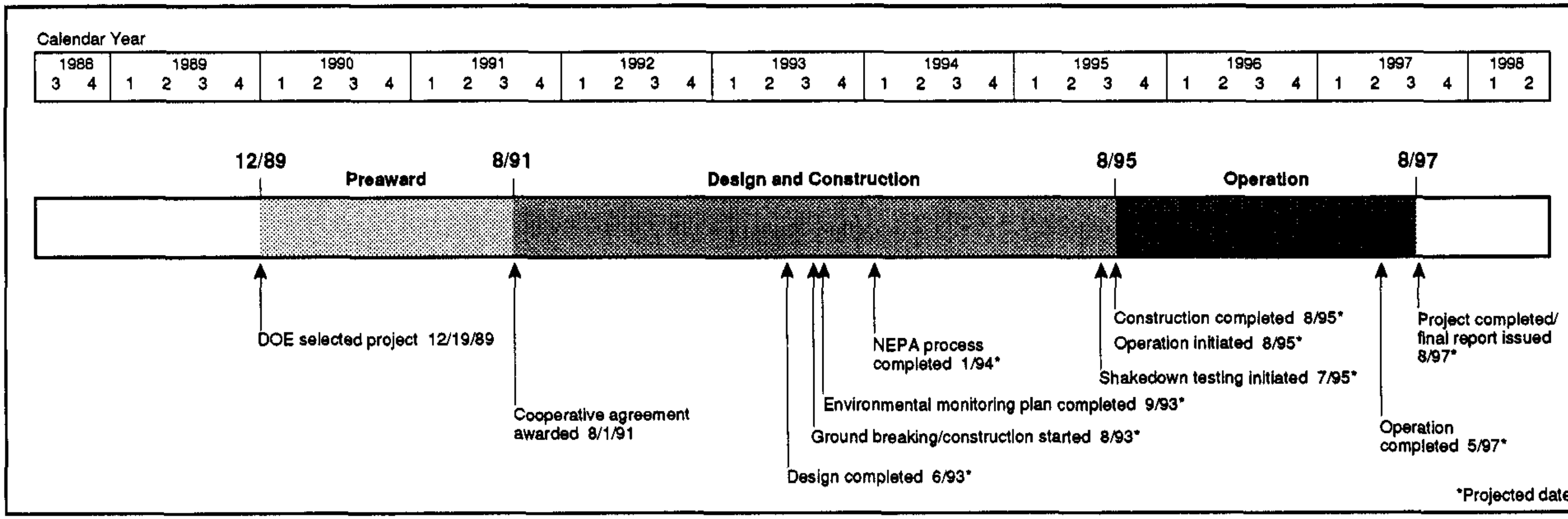
To demonstrate PCFB at sufficient scale to evaluate environmental, cost, and plant performance and to obtain the technical data requisite to commercialization of the technology; to assess efficiency improvements associated with integration of a hot gas cleanup system using a ceramic barrier filter and inclusion of a topping combustor; to achieve SO_2 reduction in excess of 90% and NO_x reduction of 70%; and to improve plant efficiency by up to 15% of its current rating.



Technology/Project Description:

In the PCFB process, coal is combusted at about 1,600 °F in a circulating fluidized bed contained within a pressure vessel. Limestone is used within the bed to absorb sulfur compounds. Particulates from the hot, pressurized combustion gases are removed by a ceramic filter. The clean gas is then expanded through a gas turbine. During peak load demand periods, the topping combustor is fired with fuel oil to raise the inlet temperature of the gases entering the gas turbine. Higher turbine operating temperature increases the turbine efficiency and power output. Steam generated within the PCFB combustor and the heat recovery steam generator downstream from the gas turbine are used to generate power in two existing steam turbines.

The DMEC-1 project would be the world's first large-scale demonstration of PCFB technology. The project provides for repowering an existing pulverized coal-fired boiler with a single PCFB combustor integrated with an oil/gas-fired topping combustor and a gas turbine module operating in a combined-cycle mode. The repowered plant will have a capacity of about 70 MWe. The unit is part of the Des Moines Energy Center located southeast of Des Moines, IA.



Project Status/Accomplishments:

The cooperative agreement was awarded August 1, 1991. Preliminary design and project definition studies are under way.

Environmental Considerations:

Environmental information is being prepared for use in the NEPA compliance process.

Assuming maximum commercialization of the technology on a national basis by 2010 relative to a no-action alternative, the following impacts are projected:

- SO_2 reduction—48%
- NO_x reduction—17%
- Solid waste decrease—4%, with the solid waste in a dry, granular form amenable to alternative uses such as construction aggregate
- CO_2 reduction—8%

(Source: CCT Programmatic Environmental Impact Statement)

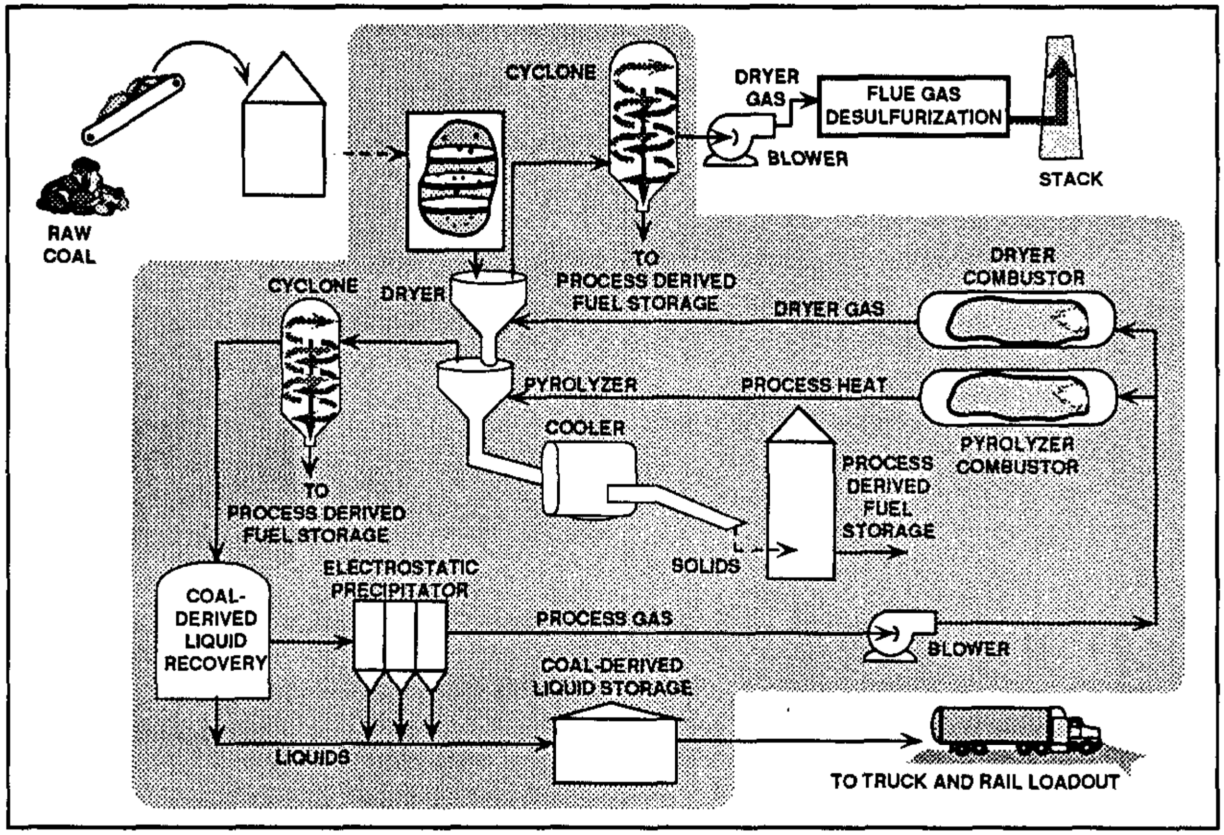
Commercial Application:

The combined-cycle PCFB system permits the combustion of a wide range of coals, including high-sulfur coals, and would compete with the bubbling-bed PFBC system. Like the bubbling-bed system, PCFB can be used to repower oil- and gas-fired boiler units, while switching them to high-sulfur coal; to repower coal-fired power plants; and to build new PCFB units. Combined-cycle PCFB technology appears to be best suited for electric utility plants larger than 100 MWe. Because of modular construction capability, PCFB generating plants permit utilities to add economical increments of capacity to match load growth and to repower with PCFB using the existing plant area, coal- and waste-handling equipment, and steam turbine equipment.

The performance potential of PCFB technology is characterized as follows:

- SO_2 reduction—95%
- NO_x reduction—80%
- Plant efficiency increase—up to 45%
- Incremental plant efficiency—improved 8–15%
- Fuel flexibility—permits use of wide range of coals
- Compactness—high process efficiency reduces space requirements per unit of energy generated
- Modular construction—lends itself to economic additions of capacity increments to match load growth

ENCOAL Mild Coal Gasification Project



Sponsor:

ENCOAL Corporation (subsidiary of Shell Mining Company)

Additional Team Members:

Shell Mining Company—cofunder

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

SGI International—technology developer

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

The M.W. Kellogg Company—engineer and constructor

Location:

Near Gillette, Campbell County, WY (Buckskin Mine)

Technology:

SGI International's liquids from coal process

Plant Capacity/Production:

1,000 tons/day of subbituminous coal feed

Project Funding:

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

Project Objective:

To demonstrate the integrated operation of a number of novel operating 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.

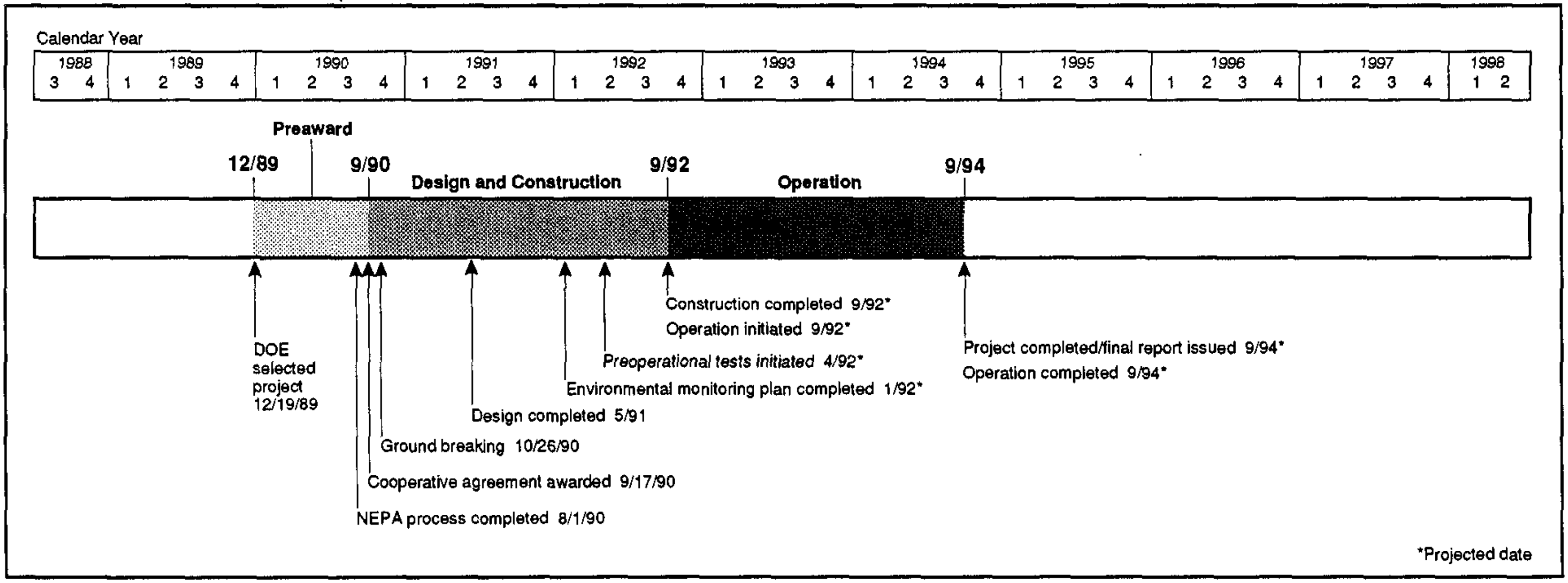
Technology/Project Description:

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 moisture content of the coal. The solid bulk temperature is controlled so that no significant amounts of methane, carbon monoxide, or carbon dioxide 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.



Project Status/Accomplishments:

Design is complete and construction activities are ahead of schedule, with construction of all silos and the coal pyrolyzer complete, mine expansion tasks complete, all major equipment in place, and steel erection 80% complete.

Environmental Considerations:

NEPA compliance has been satisfied by an environmental assessment with a finding of no significant impact approved by DOE on August 1, 1990. The environmental monitoring plan is nearing completion.

Assuming maximum commercialization of the mild coal gasification technology on a national basis by 2010 relative to a no-action alternative, the following impacts are projected:

- SO_2 reduction—5%
- NO_x reduction—2%
- Solid waste increase—14%; however, this is a dry, salable by-product.

(Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

The liquid products from mild coal gasification can be used in any market in place of No. 6 fuel oil. The solid product can be used in any scale industrial or utility boiler. The feedstock for mild gasification facilities is being limited to low-heating-value coals.

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

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

Sponsor:
Energy and Environmental Research Corporation

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

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

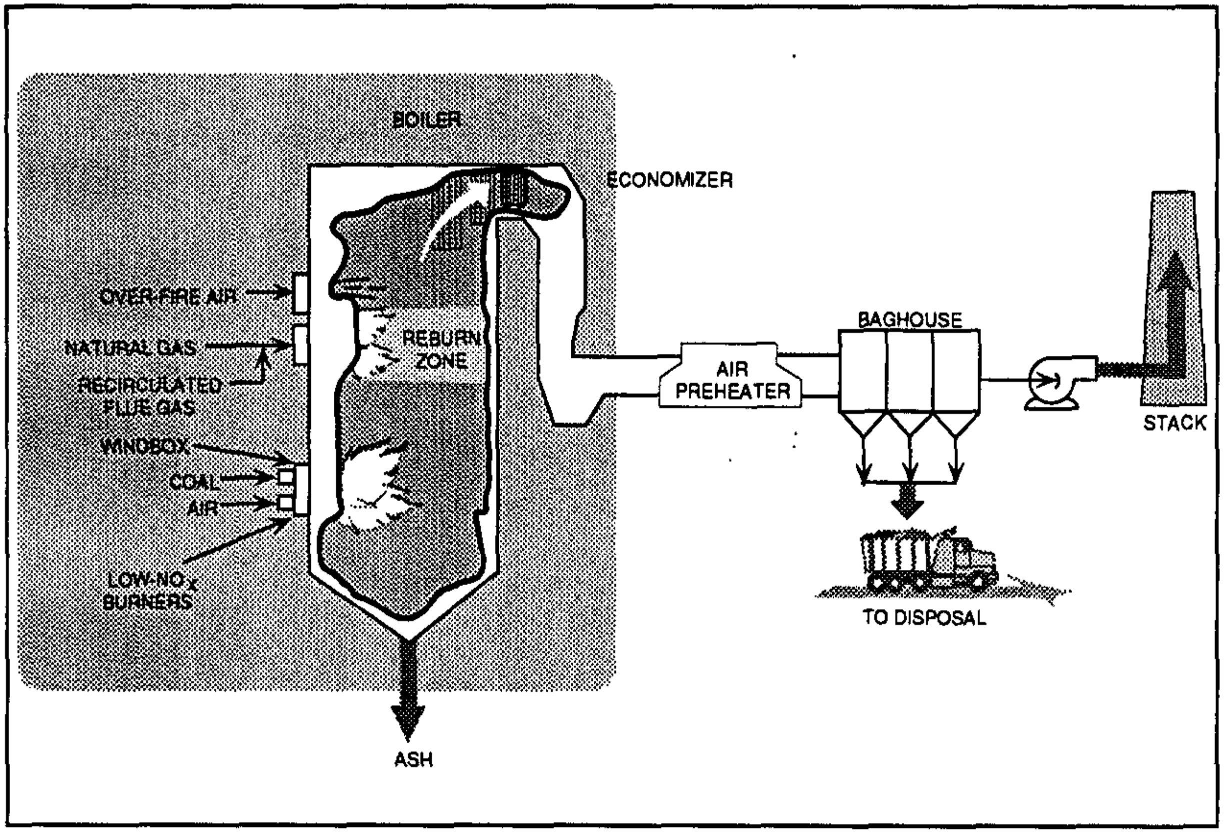
Technology:
Energy and Environmental Research Corporation's gas reburning and low-NO_x burner system

Plant Capacity/Production:
172 MWe

Project Funding:

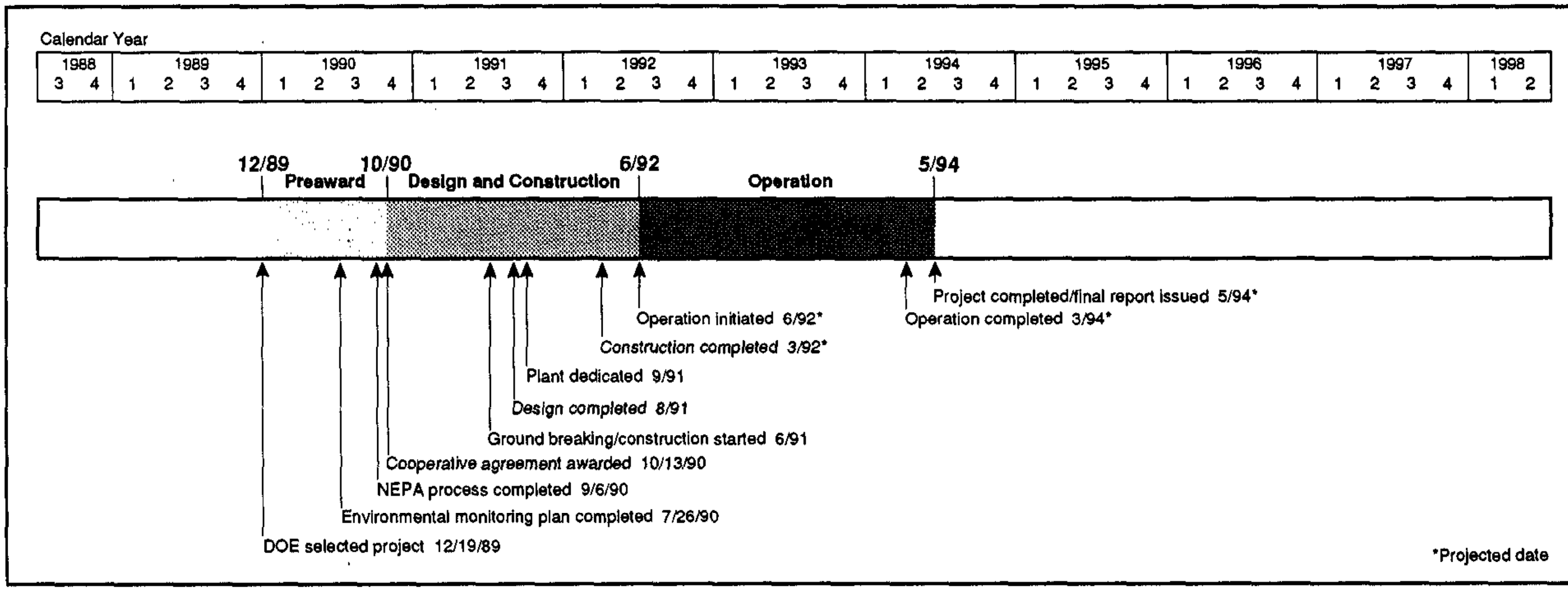
Total project cost	$14,472,117	100%
DOE	7,236,058	50
Participants	7,236,059	50

Project Objective:
To attain up to a 75% 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 harmless molecular nitrogen. Low-NO_x burners positioned in the coal combustion zone retard the production of NO_x by staging the burning process so that the coal-air mixture can be carefully controlled at each stage. The synergistic effect of adding a reburning stage to wall-fired boilers equipped with low-NO_x burners is projected to lower NO_x emissions by as much as 75%.

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 coal is being used.



Project Status/Accomplishments:

Permitting activities are complete; all engineering drawings are complete and have been released for construction. Process specifications for the gas reburning installation are complete and long lead-time items are on order. Construction began in mid-1991, and retrofit work proceeded during the scheduled August–October 1991 boiler outage. Demolition of the old electrostatic precipitator and asbestos removal are complete. All the new boiler penetrations, including refractory and insulation, were installed on October 23, 1991. The new low-NO_x burners also were installed during October 1991. Construction work in November 1991 concentrated on installation of structural steel, ductwork, and fan foundations. The demonstration is expected to enter the operations phase in May–June 1992.

Environmental Considerations:

NEPA compliance has been satisfied by a memo-to-file approved on September 6, 1990. The environmental monitoring plan was completed in July 1990.

Assuming maximum commercialization of gas reburning and low-NO_x burners on a wall-fired boiler on a national basis by 2010 relative to a no-action alternative, NO_x emissions could be reduced by 13%. The substitution of gas for coal results in a 10% reduction of SO_2 on a national basis. No change in liquid effluents or solid wastes is anticipated. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

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

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

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

LIFAC Sorbent Injection Desulfurization Demonstration Project

Sponsor:
LIFAC–North America (a joint venture between Tampella Keeler, a subsidiary of Tampella, Ltd., of Finland, and ICF Kaiser Engineers, Inc.)

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

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

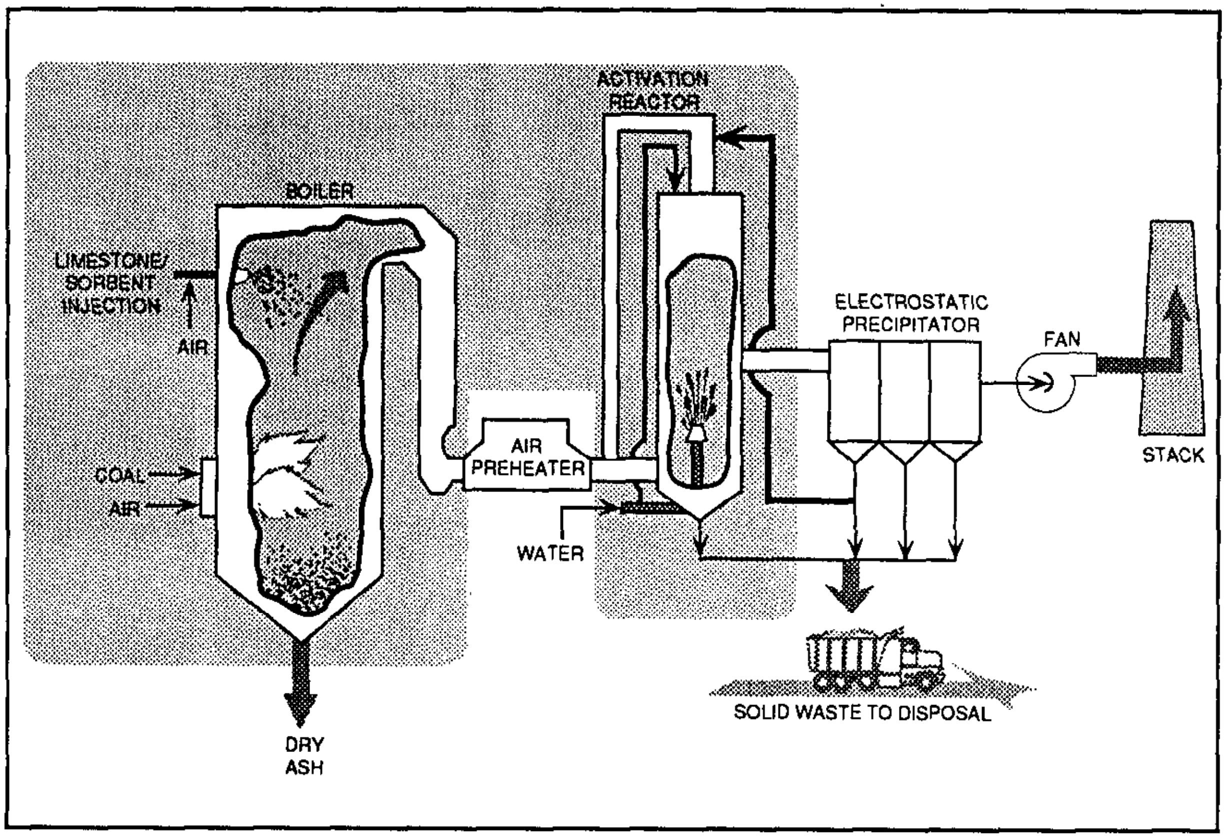
Technology:
LIFAC's sorbent injection process with sulfur capture in a unique, patented vertical activation reactor

Plant Capacity/Production:
60 MWe

Project Funding:

Total project cost	$21,393,772	100%
DOE	10,636,863	50
Participants	10,756,909	50

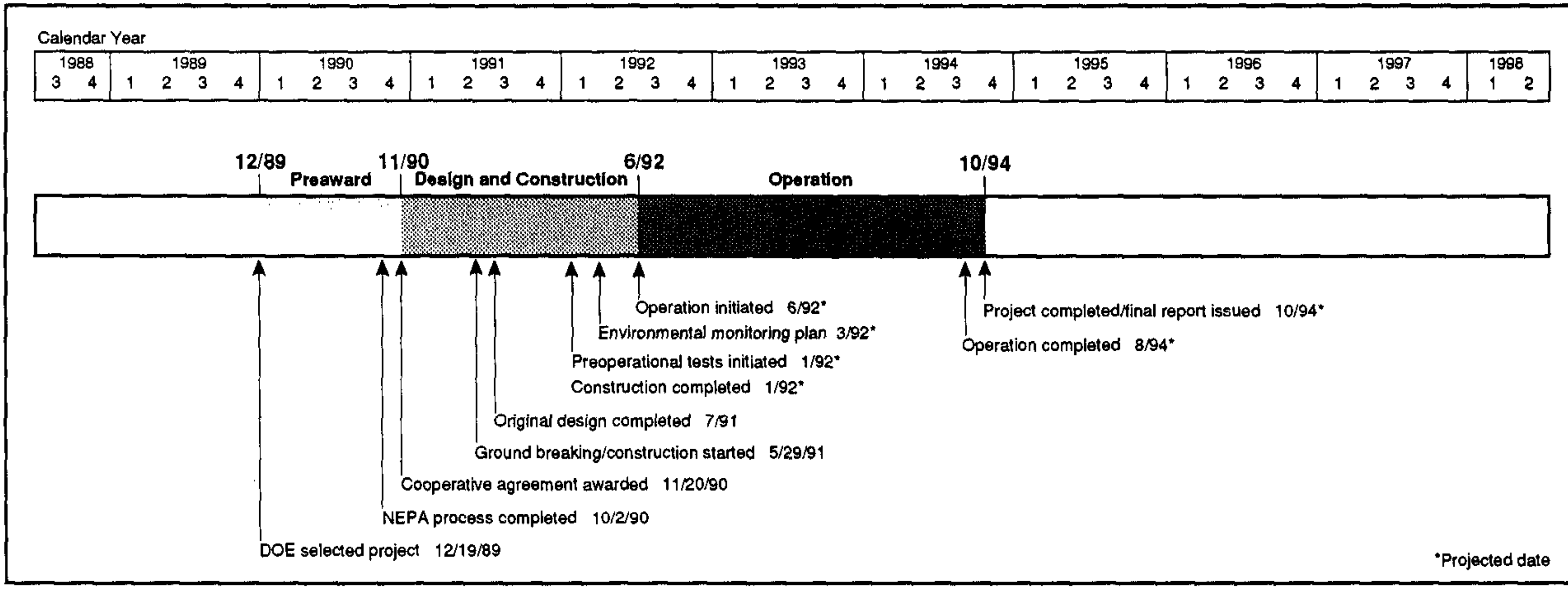
Project Objective:
To demonstrate that electric power plants—especially those with space limitations—burning high-sulfur Indiana coals, can be retrofitted successfully with the LIFAC limestone injection process to remove 75–85% of the SO_2 from flue gas and produce a dry solid waste product for disposal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



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

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

The process is being demonstrated at Whitewater Valley Station, a coal-fired power plant owned and operated by Richmond Power and Light and located in Richmond, IN. The 60-MWe Unit No. 2 is being retrofitted. The activation or humidification chamber is being located next to the boiler building near Unit No. 2.



Project Status/Accomplishments:

All original design activities are complete. Enhanced design features have been proposed and are under consideration. All plant tie-ins were successfully completed during the scheduled March 1991 outage. The balance of the LIFAC equipment can be installed without impacting plant operations. All long-lead procurement activities are complete. Formal ground breaking for the new equipment occurred on May 29, 1991. Construction is now in progress. The start of operations has been delayed to mid-1992 primarily due to additional design and permitting requirements, including redesign of the humidification section of the activation reactor to improve process performance.

Environmental Considerations:

NEPA compliance has been satisfied by a memo-to-file approved on October 2, 1990. DOE has provided comments on the draft environmental monitoring plan.

Assuming maximum commercialization, significant reductions of SO_2 (45%) are projected to be achievable nationally by 2010 with the LIFAC process relative to a no-action alternative. The LIFAC process has wide applicability as it can be retrofitted to many coal-fired boilers. (Source: CCT Programmatic Environmental Impact Statement)

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

Commercial Application:

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

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

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

Sponsor:
MK-Ferguson Company

Additional Team Members:
NOXSO Corporation—cofunder and technology supplier
W. R. Grace and Company—cofunder
Ohio Edison Company—cofunder and host utility
Ohio Coal Development Office—cofunder
Gas Research Institute—cofunder
Electric Power Research Institute—cofunder
East Ohio Gas Company—cofunder

Location:
Niles, Trumbull County, OH (Ohio Edison's Niles Station, Unit 1)

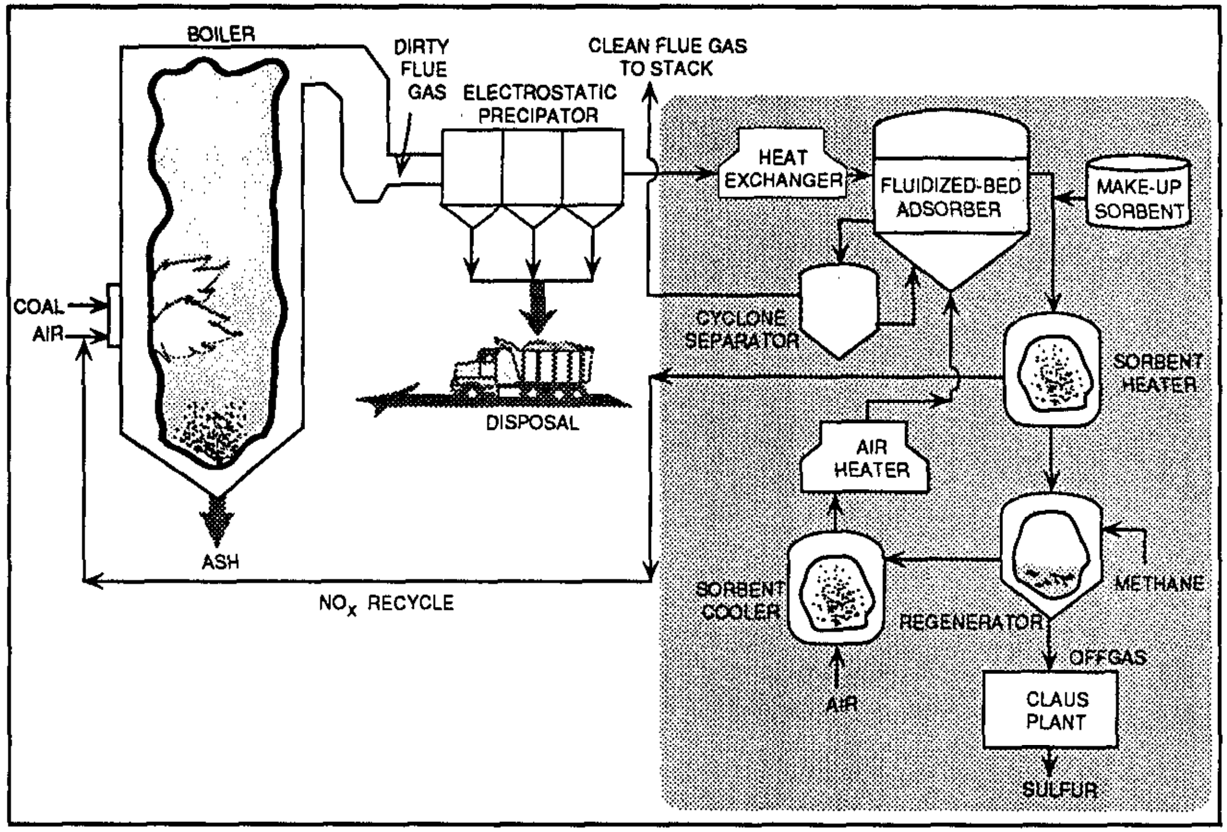
Technology:
NOXSO Corporation's dry, regenerable flue gas cleanup process

Plant Capacity/Production:
108 MWe

Project Funding:

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

Project Objective:
To demonstrate SO_2 and NO_x removal from a coal-fired boiler flue gas using the NOXSO process and to remove 97% of the SO_2 and 70% of the NO_x from the flue gas exhausted to the atmosphere.

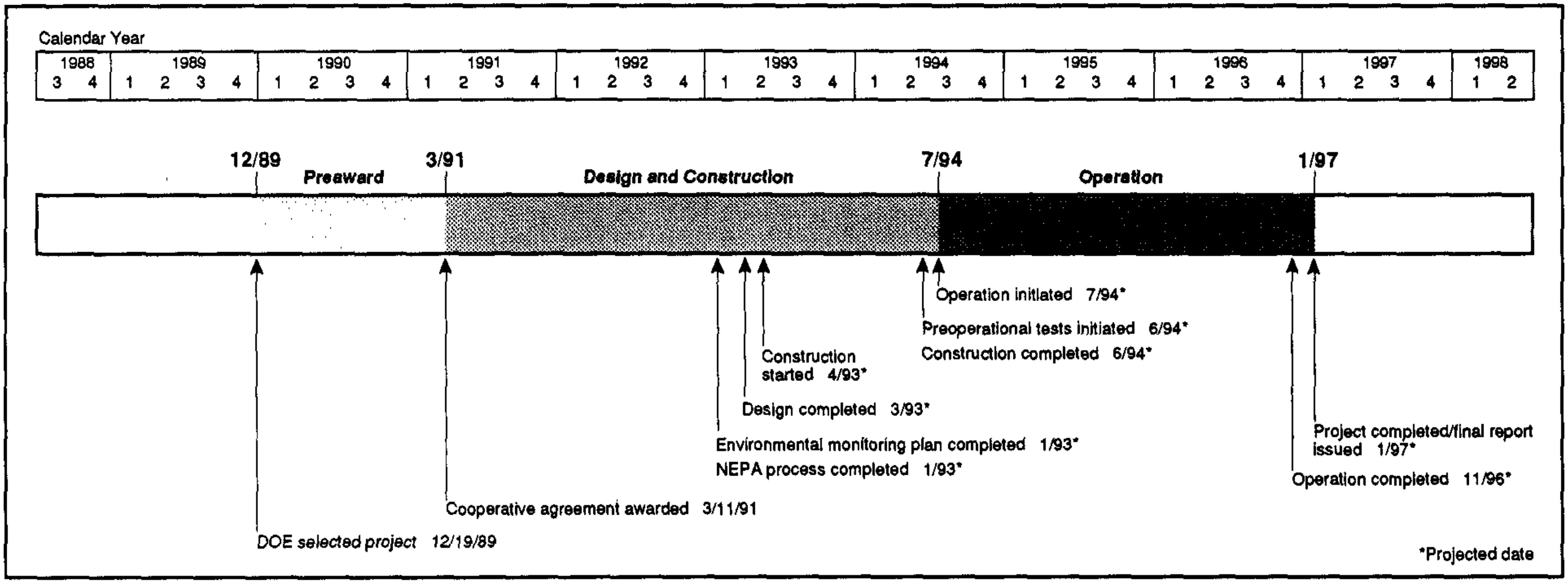


Technology/Project Description:
The NOXSO process is a dry, regenerable system capable of removing both SO_2 and NO_x in flue gas from coal-fired utility boilers. In the basic process, the flue gas passes through a fluidized-bed adsorber located downstream of the precipitator; the SO_2 and NO_x are adsorbed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

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

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

The NOXSO process is being demonstrated at Ohio Edison's Niles Station, Unit 1, a 108-MWe cyclone boiler. MK-Ferguson will design, construct, and operate a full-scale commercial NOXSO unit to demonstrate process feasibility. The project is being structured so that data from the proof-of-concept facility at Ohio Edison's Toronto Station can be available before the end of the project definition activity.



Project Status/Accomplishments:

The cooperative agreement was awarded on March 11, 1991. Evaluation is in progress on recent data and results of the proof-of-concept development work essential to establishing the design baseline. The participant is proceeding with design; completion awaits data from proof-of-concept work.

Environmental Considerations:

Environmental information is being compiled for use in the NEPA process.

By 2010, national emissions of SO_2 could be reduced by as much as 48% and NO_x by 11%, assuming maximum commercialization of this technology relative to a no-action alternative. Also, the process results in essentially no increase in solid waste and produces a salable by-product (sulfur). (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

The NOXSO process is applicable for retrofitting existing coal-fired power plants or for use in new facilities. The demonstration is expected to use southeastern Ohio and western Pennsylvania coal (3.2–3.5% sulfur average). The process is adaptable to coals with higher sulfur content.

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

Integrated Dry NO_x /SO_2 Emission Control System

Sponsor:
Public Service Company of Colorado

Additional Team Members:
Electric Power Research Institute—cofunder
Stone and Webster Engineering Corporation—engineer
The Babcock & Wilcox Company—burner developer
Fossil Energy Research Corporation—operational testing
Western Research Institute—fly ash evaluator
Colorado School of Mines—engineering research and testing
Vendor (to be determined)—urea system provider

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

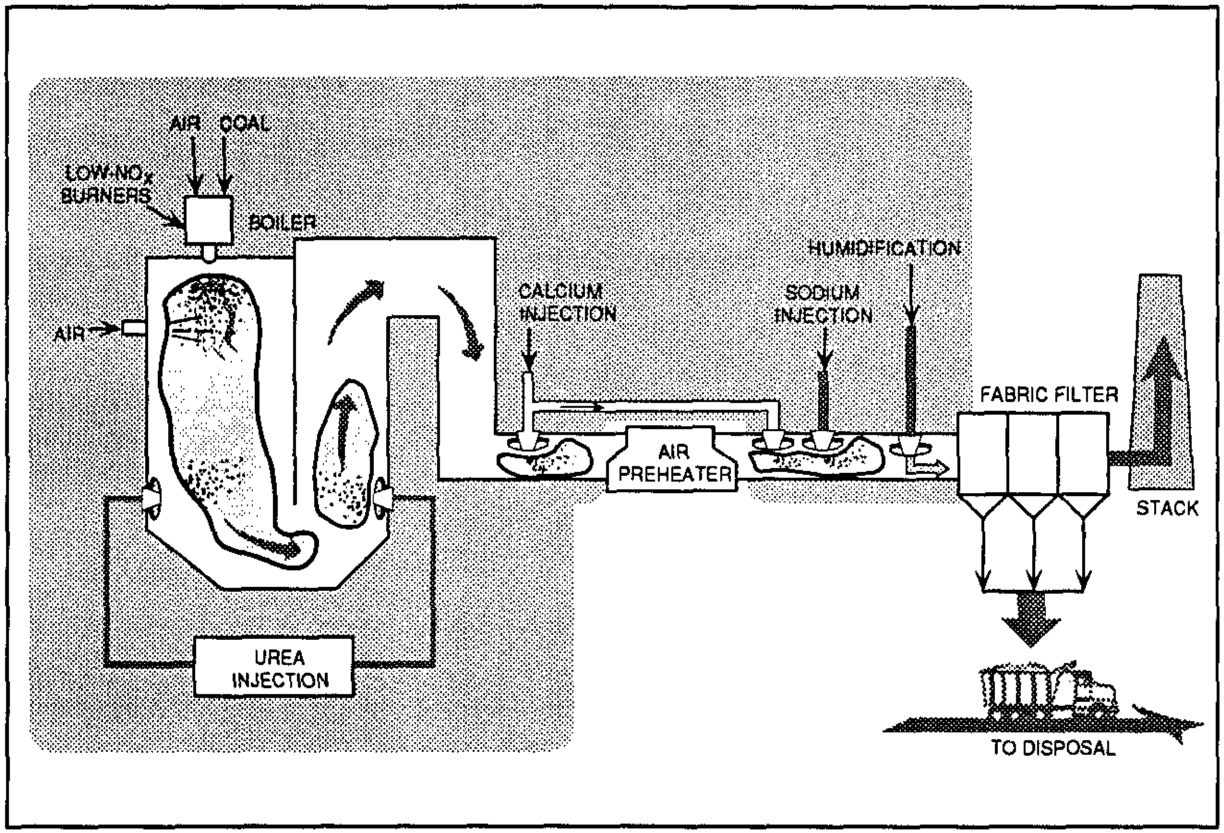
Technology:
The Babcock & Wilcox Company's low-NO_x burners, in-duct sorbent injection, and furnace (urea) injection

Plant Capacity/Production:
100 MWe

Project Funding:

Total project cost	$26,477,878	100%
DOE	13,238,939	50
Participants	13,238,939	50

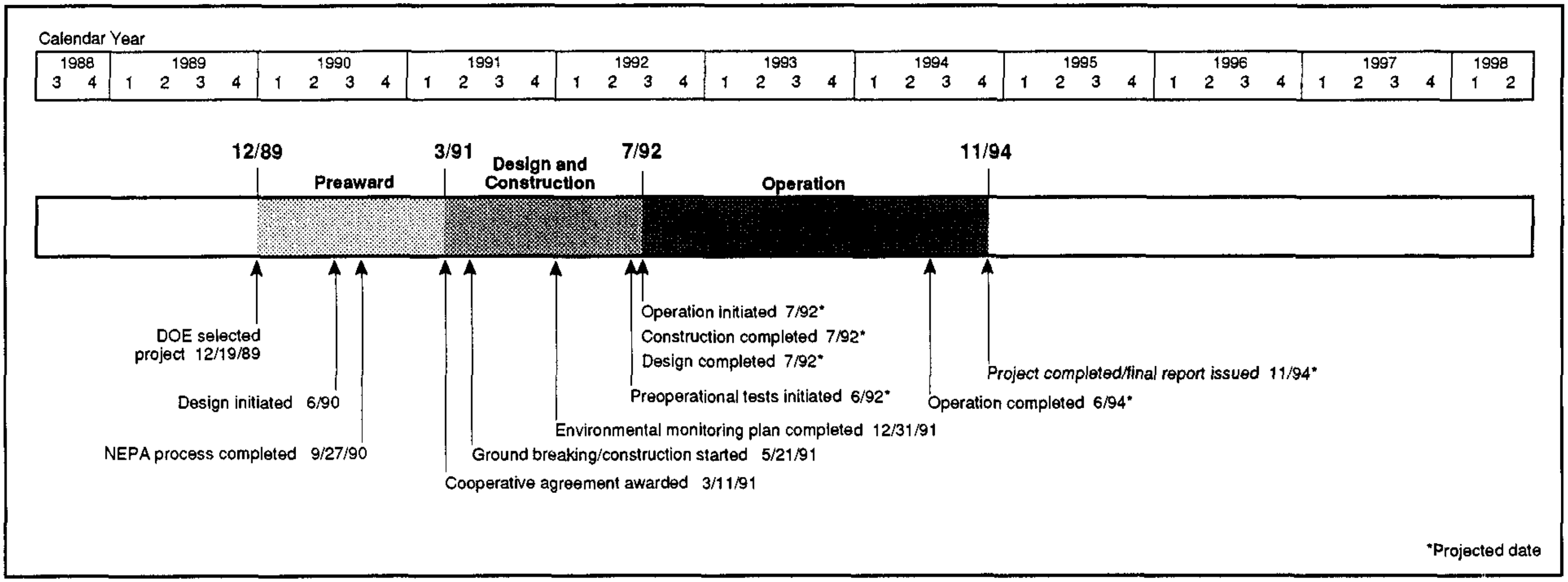
Project Objective:
To demonstrate the integration of three technologies to achieve up to 70% reduction in NO_x and SO_2 emissions; more specifically, to assess the integration of a down-fired low-NO_x burner with in-furnace urea injection for additional NO_x removal and dry sorbent in-duct injection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



Technology/Project Description:
All of the testing will use Babcock & Wilcox's low-NO_x XCL down-fired burners with over-fire air. These burners control NO_x by injecting part of the coal and part of the combustion air in an oxygen-deficient environment. Additional fuel and combustion air are introduced in a second stage to advance the combustion process. Additional air is introduced to complete the combustion process and further enhance NO_x removal. The low-NO_x burners are expected to reduce up to 50% of the NO_x, and with added air, the system is expected to reduce NO_2 emissions 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 enables the electrostatic precipitator to maintain performance. Humidification aids SO_2 capture and lowers flue gas temperature and gas flow, which improves particulate collection efficiency.

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



Project Status/Accomplishments:

The cooperative agreement was awarded March 11, 1991. Ground breaking ceremonies were held May 21, 1991. Design activities continue on the low-NO_x burners, humidification, and site utilities. Fabrication of the low-NO_x burners has begun. Installation and checkout of the urea injection system has been completed. Baseline testing of the boiler without any modifications was completed in mid-December 1991. Baseline testing of the boiler with urea injection is scheduled to start in early February 1992 and continue for approximately one month.

The Colorado School of Mines continues preliminary work on the test reactor. Construction started in mid-1991 and is expected to continue until mid-1992.

Environmental Considerations:

NEPA compliance has been satisfied by the signing of a memo-to-file approved by DOE on September 27, 1990. The environmental monitoring plan has been prepared.

SO_2 reduction is in the range of 55–75%. Although the volume of solid waste is considerably increased, it is dry, easily disposed of, and nontoxic. From a national perspective, a 38% SO_2 reduction is projected by 2010, assuming maximum commercialization of the sorbent injection technology. Urea injection should enhance NO_x reduction, thereby increasing low-NO_x burner impact on national reductions from the presently projected 11%. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

Urea injection and sorbent injection are both applicable to most utility and industrial coal-fired units and can be retrofitted with modest capital investment and downtime.

CCT-IV
Project Fact Sheets

Cordero Coal Upgrading Demonstration Project

Sponsor:
Cordero Mining Company

Additional Team Members:
Carbontec Wyoming Inc.—technology supplier
Dairyland Power Cooperative—host utility
Fluor Daniel, Inc.—engineer

Location:
Gillette, Campbell County, WY

Technology:
New fuel form using the Carbontec Syncoal process

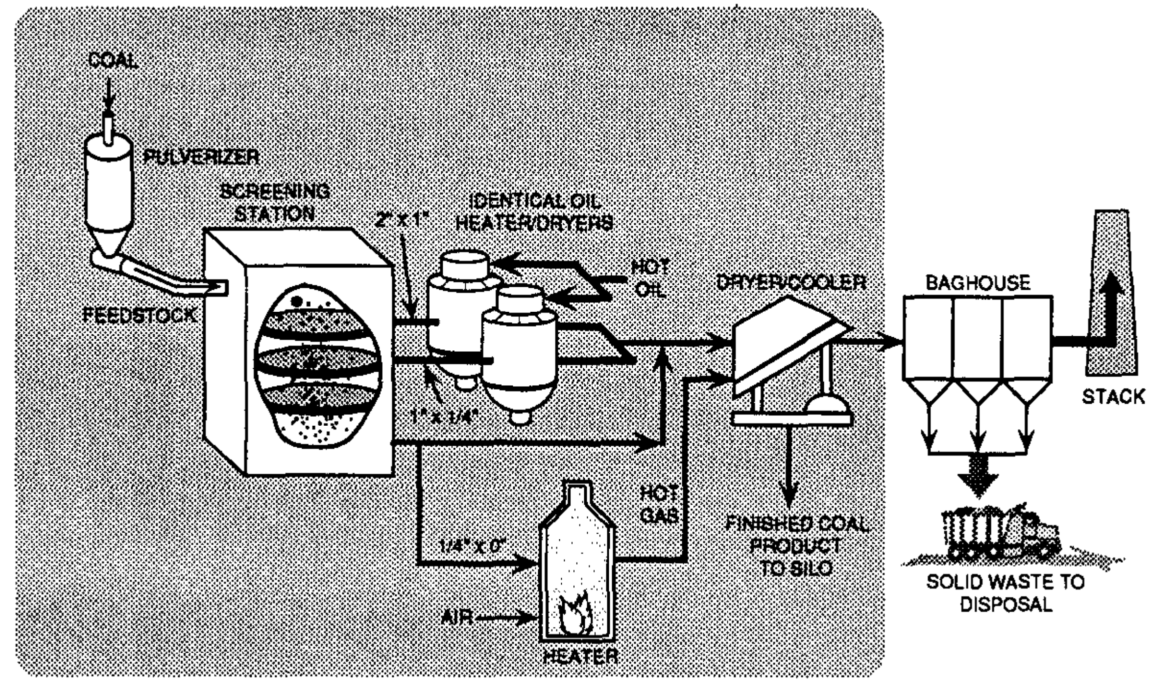
Plant Capacity/Production:
1,200 tons/day of coal

Project Funding:

Total project cost	$34,300,000	100%
DOE	17,150,000	50
Participants	17,150,000	50

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

Project Objective:
To demonstrate the Carbontec Syncoal process to upgrade high-moisture, low-sulfur, low-rank coals for use in power plants designed to burn higher Btu coals, and as a low-sulfur fuel for future power generation and industrial facilities.

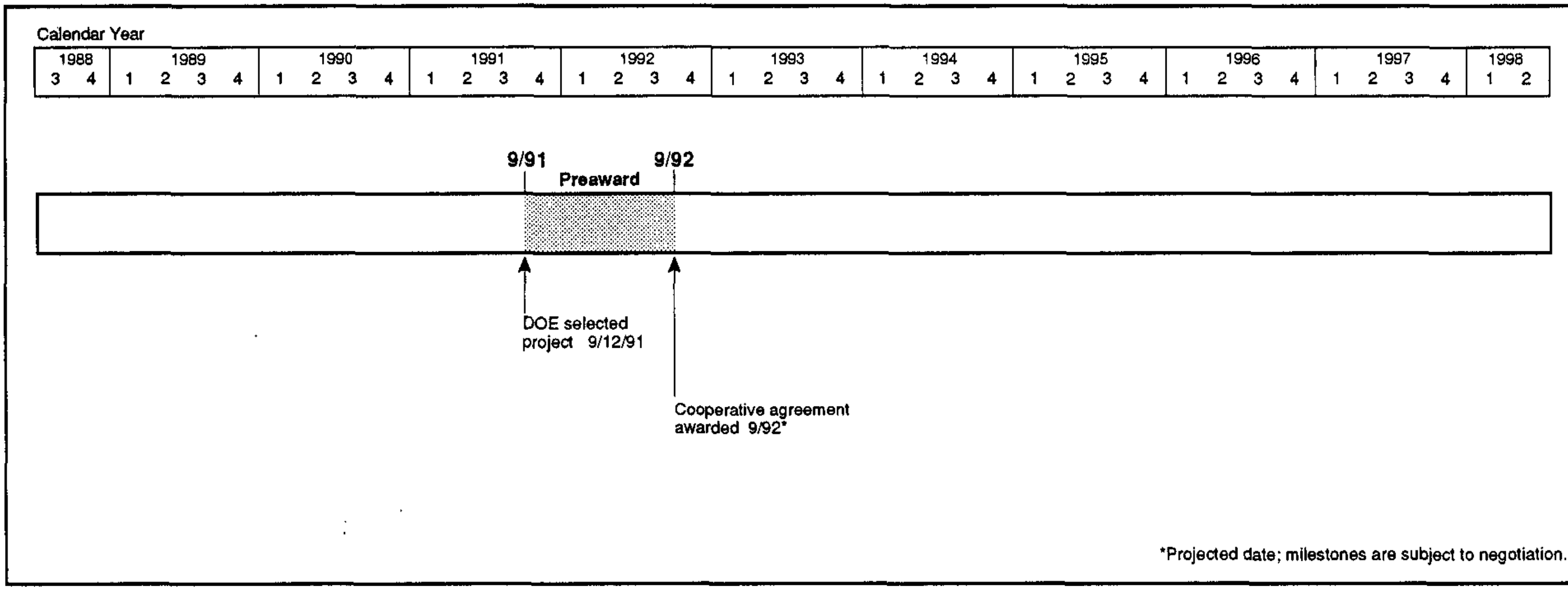


Technology/Project Description:
The Syncoal process converts high-moisture subbituminous coal into a high-Btu, low-moisture, low-sulfur product by using heat to drive off moisture and to stabilize the physical properties of the product. Hot oil and flue gas serve to heat the coal and to keep it in an inert atmosphere during coal processing. The hot oil provides a protective film which seals the surface to moisture as well as preventing surface degradation during handling. The flue gas drives off moisture and provides a relatively inert atmosphere to prevent oxidation of the coal during the treatment process and until the product is cooled to near ambient temperature.

The project facility will be capable of producing 250,000 tons/yr of upgraded coal product. Coal feedstock, which has already undergone two stages of crushing, is diverted from the existing mine-coal-handling system to a feed silo. The coal is fed from the silo to a screening station where it is separated into three fractions: 2x1 in, 1x1/4 in, and 1/4x0 in. Each fraction is conveyed separately to the demonstration plant on a dedicated conveyor.

The 2x1-in coal is fed to one of two identical dryers, and the 1x1/4-in coal is fed to the other dryer. In these first dryers, the feedstock is heated while a mixture of hot fuel oil is sprayed on the coal as it passes slowly through the heater. The coal is carried between two wire mesh conveyors, permitting the excess oil to drain freely to a sump at the bottom of the heater.

A portion of the 1/4x0-in coal is diverted to a feed bin, pulverized, and burned in the direct-fired tube heater. The balance of the 1/4x0-in feedstock is mixed



with the partially processed coal leaving the initial dryers.

The combined mixture is conveyed to a dryer/cooler, a rotary tray device which gently turns the product, exposing it to hot flue gas which drives off more moisture. After passing through the upper, heated section of the dryer/cooler, the coal falls to the lower section where it is exposed to cooled flue gas from a condenser; the coal's temperature is lowered to near ambient conditions. The finished product is then conveyed to a silo for storage.

Cordero Mining Company plans to build the Syncoal plant near its mine in Gillette, WY.

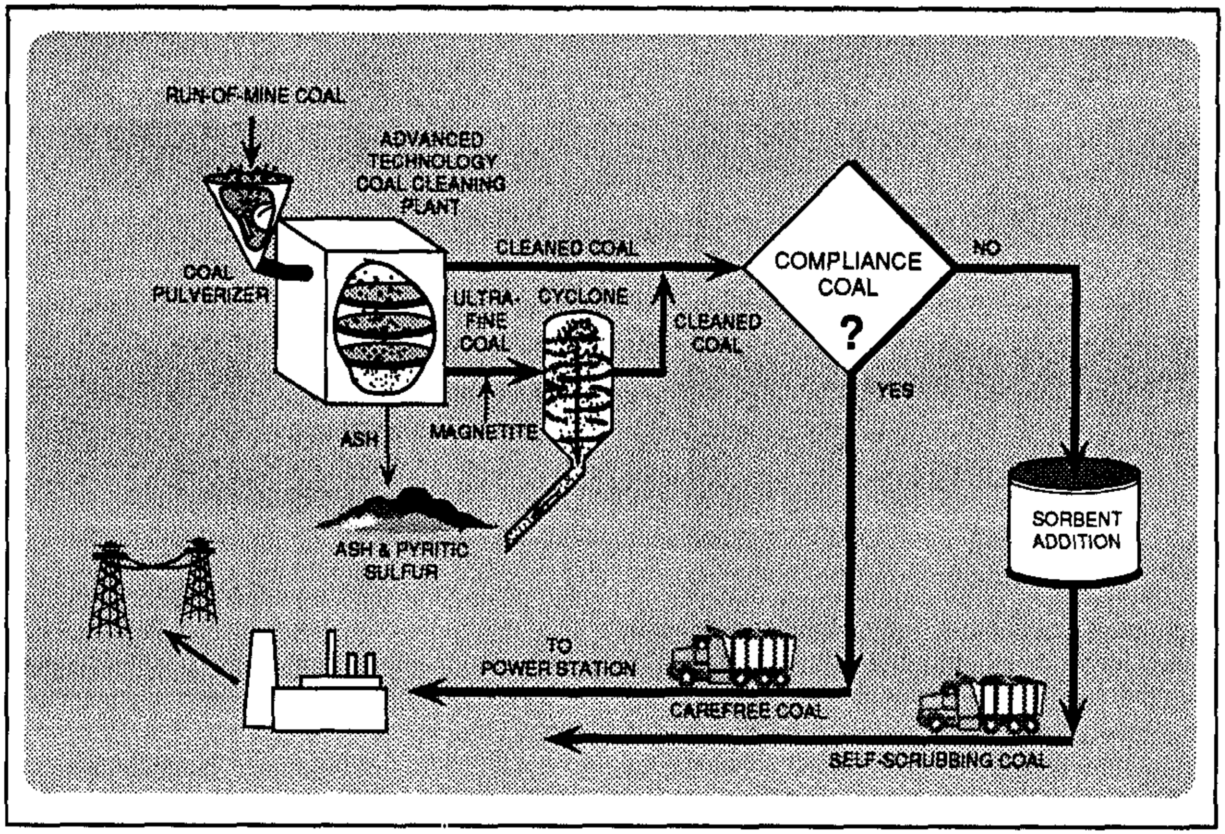
Project Status/Accomplishments:
The project is in negotiation.

Environmental Considerations:
Environmental information is being prepared for use in the NEPA process.

Because the advanced coal conversion process will produce a coal with a very low sulfur content, high heating value, and stable physical/chemical characteristics, it could have significant impact on SO_2 reduction relative to the no-action alternative considered in the PEIS.

Commercial Applications:
This process has the potential to enhance the use of low-rank western subbituminous and lignite coals. It is expected that this upgraded coal product can be utilized by many midwestern and eastern utilities currently burning high-sulfur, high-rank, noncompliance coals to comply with CAAA of 1990 provisions. The processed coal would allow operation under more restrictive emissions guidelines without requiring derating of the units or the addition of costly flue gas desulfurization systems. Utilities are expected to find the upgraded fuel attractive because it will be less costly to use than would be the construction and use of flue gas desulfurization equipment. Moreover, plants that would otherwise be closed could remain in operation.

Self-Scrubbing Coal: An Integrated Approach to Clean Air



Sponsor:

Custom Coals International (a joint venture between Duquesne Ventures, a subsidiary of Duquesne Light Company, and Genesis Research Corporation)

Additional Team Members:

Duquesne Light Company—cofunder and host utility
Richmond Power & Light—host utility
CQ, Inc.—operator
ICF Kaiser Engineers, Inc.—engineer and constructor

Locations:

Greensboro, Greene County, PA (advanced coal-cleaning and magnetite plants)
Springdale, Allegheny County, PA (combustion tests at Duquesne Light Company's Cheswick Power Station)
Richmond, Wayne County, IN (combustion tests at Richmond Power & Light's Whitewater Valley Station, No. 2 boiler)

Technology:

Coal preparation using advanced physical coal cleaning and fine magnetite separation technology plus sorbent addition technology

Plant Capacity/Production:

250 tons/hr

Project Funding:

Total project cost	$76,077,309	100%
DOE	38,038,656	50
Participants	38,038,653	50

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

Project Objective:

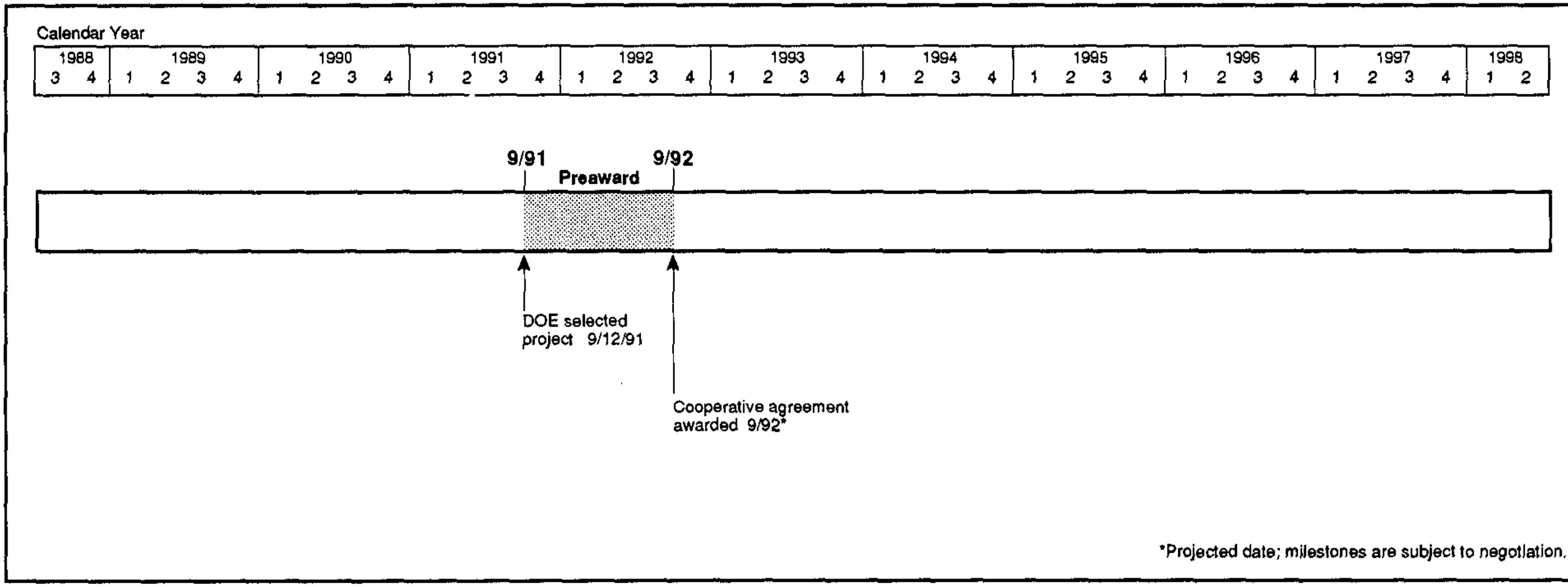
To demonstrate advanced coal-cleaning unit processes to produce low-cost compliance coals that can meet full requirements for commercial-scale utility power plants to satisfy CAAA of 1990 provisions.

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 crushing and screening run-of-mine coal and by using innovative dense-media cyclones and crystallized 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.

The patented 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 250-ton/hr advanced coal-cleaning plant and a 2-ton/hr magnetite production facility are being designed and constructed at a site in Greensboro, PA, owned by the Duquesne Light Company. The advanced coal-cleaning plant will manufacture Self-Scrubbing Coal and Carefree Coal. Two medium- to high-sulfur coals—Illinois No. 5 from Wabash County, IL, and Pittsburgh coal from Greene County, PA—will be used to produce Self-Scrubbing Coal. Carefree Coal will be made using Sewickley coal from Greene County, PA. The Pittsburgh and Sewickley coals will be combustion tested at Duquesne Light Company's Cheswick Power Station located near Pittsburgh, PA; the Illinois No. 5 coal will be tested at Richmond Power & Light's Whitewater Valley Station No. 2 boiler located in Richmond, IN.

Project Status/Accomplishments:

The project is in negotiation.

Environmental Considerations:

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

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

Assuming maximum commercialization of Self-Scrubbing Coal by the year 2010, SO_2 emissions nationally could be reduced 23%. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Applications:

Commercialization of Self-Scrubbing Coal can bring 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 generating stations across the United States.

Milliken Clean Coal Technology Demonstration Project

Sponsor:

New York State Electric & Gas Corporation

Additional Team Members:

Consolidation Coal Company—technical consultant
Saarberg-Hölter-Umwelttechnik GmbH—technology supplier
The Stebbins Engineering and Manufacturing Company—technology supplier
NALCO FuelTech—technology supplier
Electric Power Research Institute—cofunder

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-H-U) GmbH formic-acid-enhanced, wet limestone scrubber technology; NALCO FuelTech's NO_xOUT urea injection system; Stebbins tile-lined split module absorber; and heat-pipe air-heater system

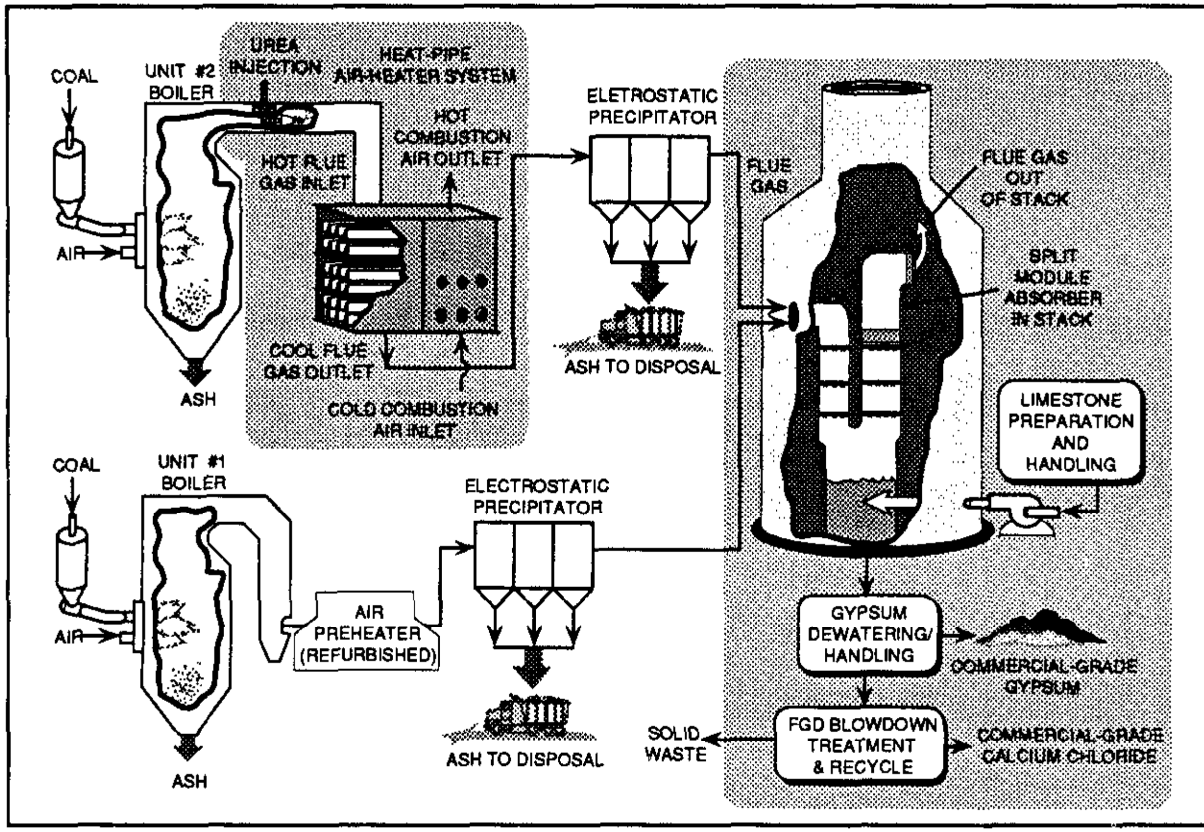
Plant Capacity/Production:

300 MWe

Project Funding:

Total Project Cost	$158,607,807	100%
DOE	64,553,377	41
Participant	94,054,430	59

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



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.

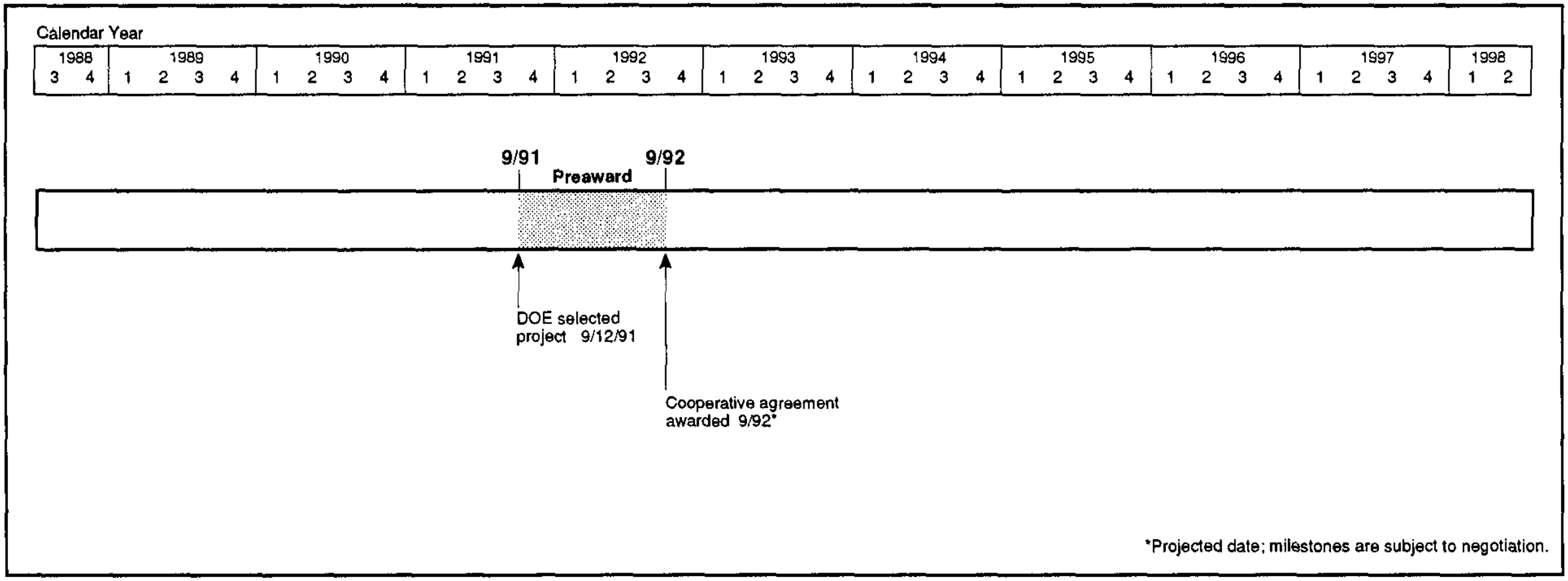
Technology/Project Description:

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

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



The project is designed for "total environmental and energy management," a concept encompassing low emissions, low energy consumption, improved combustion, upgraded boiler controls, and reduced solid waste. The system is being designed to achieve at least a 95% SO_2 removal efficiency using limestone while burning high-sulfur coal. NO_x reductions will be obtained using selective non-catalytic reduction technology and separate combustion modifications. The system has zero wastewater discharge and produces marketable by-products (e.g., commercial-grade gypsum, calcium chloride, and fly ash) to minimize solid waste disposal.

New York State Electric & Gas plans to demonstrate these technologies at Units 1 and 2 of its Milliken Station located in Lansing, NY, using Pittsburgh, Freeport, and Kittoning coals.

Project Status:

The project is in negotiation.

Environmental Considerations:

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

Assuming maximum commercialization of the S-H-U and NALCO processes on a national basis by 2010 relative to a no-action alternative, the following impacts are projected:

- SO_2 reduction—38%
- NO_x reduction—15%

The significant reductions of SO_2 and NO_x are projected to be achievable nationally because of the wide applicability of the technologies. In addition, because the fly ash may be salable, the technology potentially may produce no solid waste by-product. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

The S-H-U SO_2 removal process and the NALCO NO_xOUT non-catalytic reduction technology are applicable to virtually all electric utility power plants. The high removal efficiency, up to 98%, for SO_2 will make the combination of these technologies, together with the tile-lined scrubber at the base of the exhaust stack, attractive for many applications. Elimination of solid waste by sale of the fly ash and zero wastewater discharge enhance the marketability of the technologies.

Piñon Pine IGCC Power Project

Sponsor:
Sierra Pacific Power Company

Additional Team Members:
Foster Wheeler USA Corporation—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, fluidized-bed coal gasification system

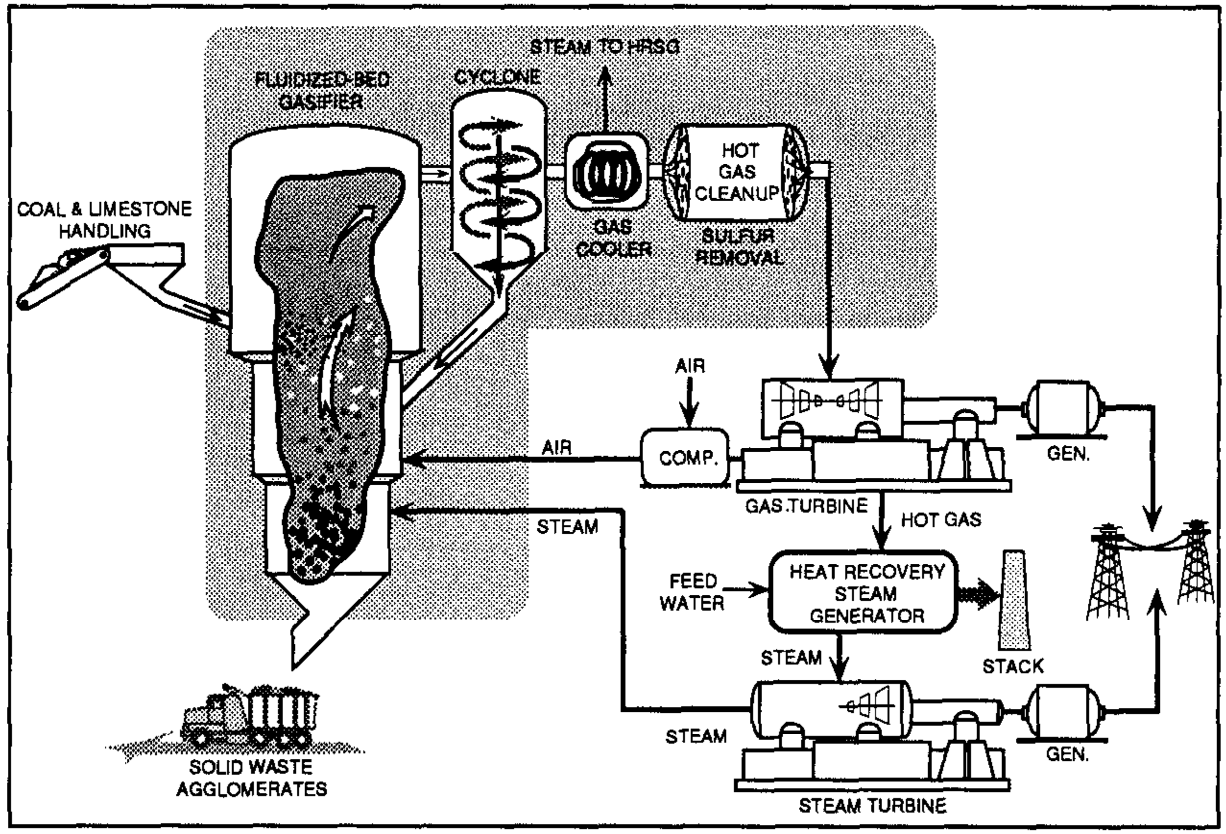
Plant Capacity/Production:
80 MWe (net)

Project Funding:

Total project cost	$340,726,600	100%
DOE	170,363,300	50
Participant	170,363,300	50

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

Project Objective:
To demonstrate air-blown, 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.

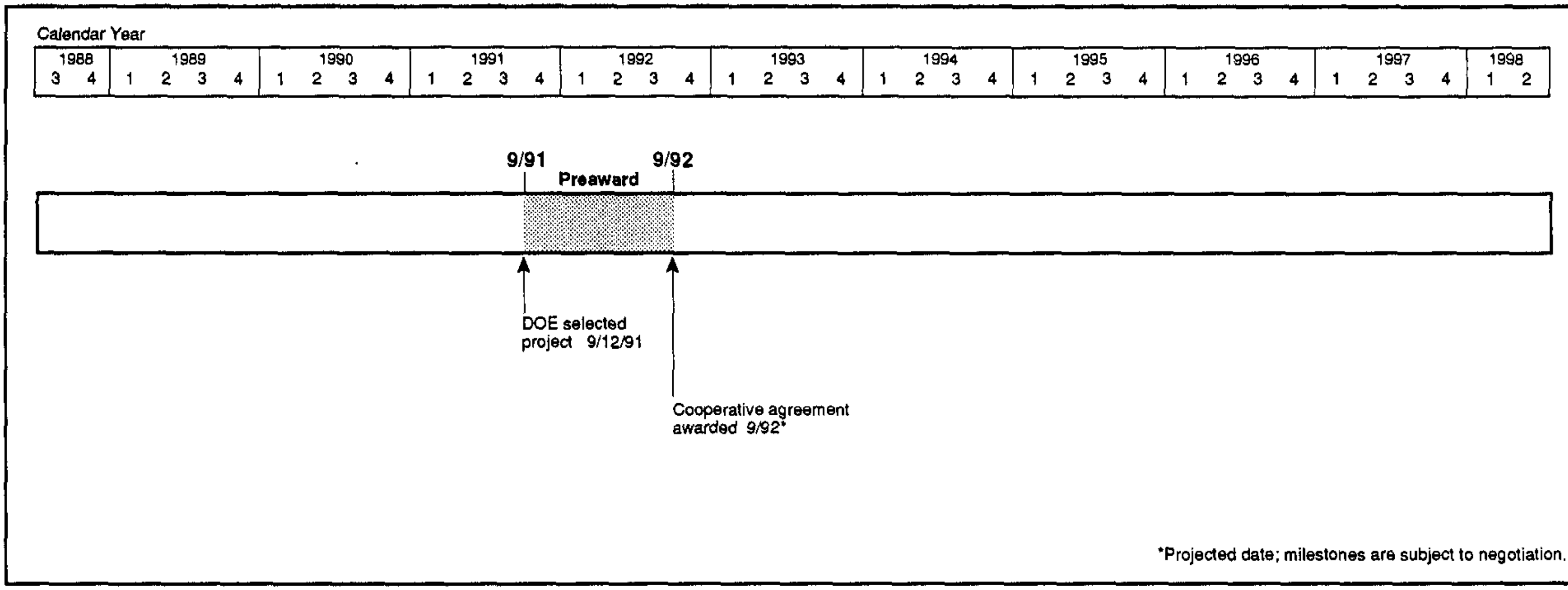


Technology/Project Description:
Dried and crushed coal is introduced into a pressurized, air-blown, fluidized-bed gasifier through a lock hopper system. The bed is fluidized by the injection of air and steam through special nozzles into the combustion zone. Crushed limestone is added to the gasifier to capture a portion of the sulfur introduced with the coal as well as 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 1,050 °F before entering the hot gas cleanup system. During cleanup, virtually all of the remaining particulates are removed by ceramic candle filters, and final traces of sulfur are removed in a fixed bed of zinc ferrite sorbent.

The hot, cleaned gas then enters the combustion turbine. The combustion turbine is coupled to a generator designed to produce 56 MWe (gross). The heat from the combustion turbine's 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 30 MWe (gross).

Due to the relatively low operating temperature of the gasifier and as a result of the injection of steam into the combustion fuel stream, the NO_x content of the exhaust gases is very low.



In the demonstration project, a nominal 800 tons/day of coal is converted into 86 MWe (gross); support facilities for the plant require 6 MWe, leaving 80 MWe for export to the grid. The project will be designed to run on western bituminous coal from Utah; operation with higher sulfur and lower rank coals also is being considered. The gasifier is being built at Sierra Pacific Power Company's Tracy Station, located about 17 miles east of Reno, NV.

Project Status/Accomplishments:

The project is in negotiation.

Environmental Considerations:

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

Assuming maximum commercialization of IGCC technology on a national basis by 2010, relative to a no-action alternative, the following impacts are projected:

- SO_2 reduction—37%
- NO_x reduction—17%
- Solid waste reduction—5%
- CO_2 reduction—6%

(Source: *CCT Programmatic Environmental Impact Statement*)

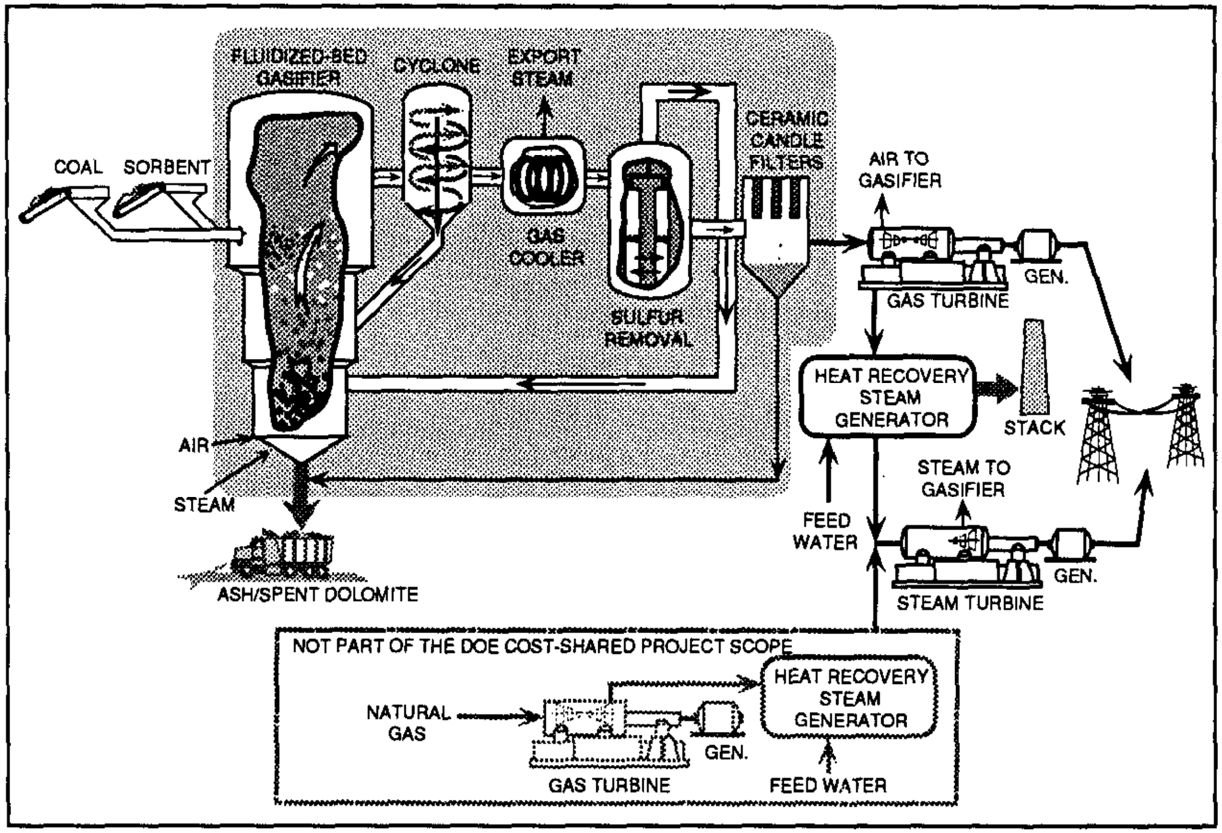
Commercial Application:

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. IGCC technology also can be used in repowering, where a gasifier, gas stream cleanup unit, gas turbine, and waste heat recovery boiler are added to replace the existing coal-fired boiler. The remaining equipment is left in place, including the steam turbine and electrical generator. 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 performance potential of IGCC technology in its commercial configuration is characterized as follows:

- SO_2 reduction—99%
- NO_x reduction—95%
- Plant efficiency—up to 48%
- Incremental power increase (repowering)—230%
- Fuel flexibility—permits use of wide range of coals
- Compactness—high process efficiency reduces space requirements per unit of energy generated
- Modular construction—lends itself to economic increments of capacity additions to match load growth

Toms Creek IGCC Demonstration Project



Sponsor:
TAMCO Power Partners (a partnership between Tampella Power Corporation and Coastal Power Production Company)

Additional Team Member:
Institute of Gas Technology—technology developer and consultant

Location:
Coeburn, Wise County, VA (ANR Coal's Toms Creek Mine)

Technology:
Integrated gasification combined-cycle (IGCC) using the Tampella U-Gas fluidized-bed gasification system

Plant Capacity/Production:
107 MWe (55 MWe net coal-based)

Project Funding:

Total project cost	$219,100,000	100%
DOE	109,003,000	50
Participant	110,097,000	50

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

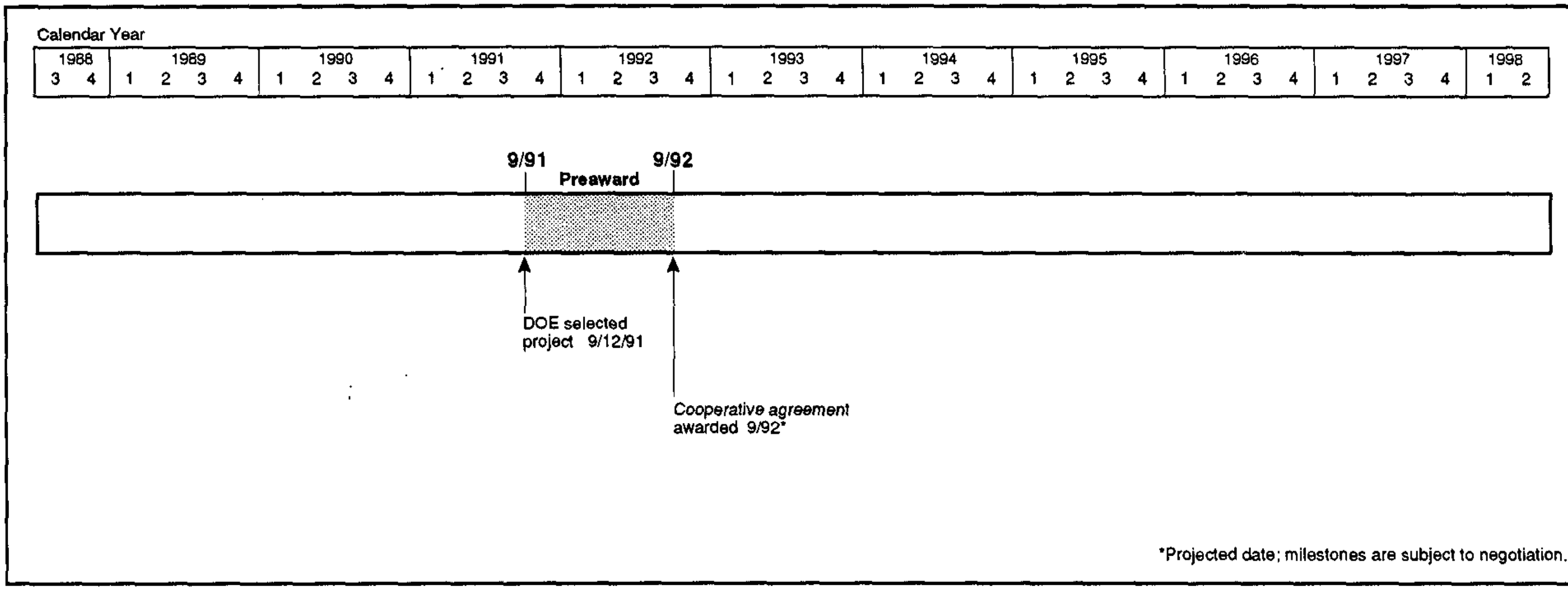
Project Objective:
To demonstrate an air-blown, fluidized-bed gasification, combined-cycle technology incorporating hot gas cleanup for generating electricity and to assess the system's environmental and economic performance for meeting future energy needs.

Technology/Project Description:
Coal is gasified in a pressurized, air-blown, fluidized-bed gasifier in the presence of a calcium-based sorbent. Approximately 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 approximately 1,000 °F before entering the post-gasifier desulfurization unit where zinc titanate is used to remove the bulk of the remaining sulfur in the gas. This is accomplished in two fluid beds. In the first bed the sulfur is absorbed by the zinc titanate and the zinc sorbate 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.

Hot exhaust gases from the combustion turbine are directed to a heat recovery steam generator. The steam generated in the heat recovery generator is used both for driving a conventional steam turbine generator set producing additional electricity and for gasifier blast.

A nominal 430 tons/day of bituminous coal will be converted into 55 MWe by a coal-gas-fired gas turbine. An additional gas turbine fired with natural gas and a heat recovery steam generator will be co-located at the demonstration site. The two gas turbines will be coupled with a single steam turbine to generate a total of 107 MWe and approximately 20,000 lb/hr of steam for export to an adjacent coal preparation facility. The electric power will be sold to a utility.

The planned site for construction of the new IGCC power plant is Coeburn, VA, at the Toms Creek Mine



owned by ANR Coal, a subsidiary of Coastal Power Production Company.

Project Status/Accomplishments:
The project is in negotiation.

Environmental Considerations:
Environmental information is being prepared for use in the NEPA process.

Assuming maximum commercialization of IGCC technology on a national basis by 2010, relative to a no-action alternative, the following impacts are projected:

- SO_2 reduction—37%
- NO_x reduction—17%
- Solid waste reduction—5%
- CO_2 reduction—6%

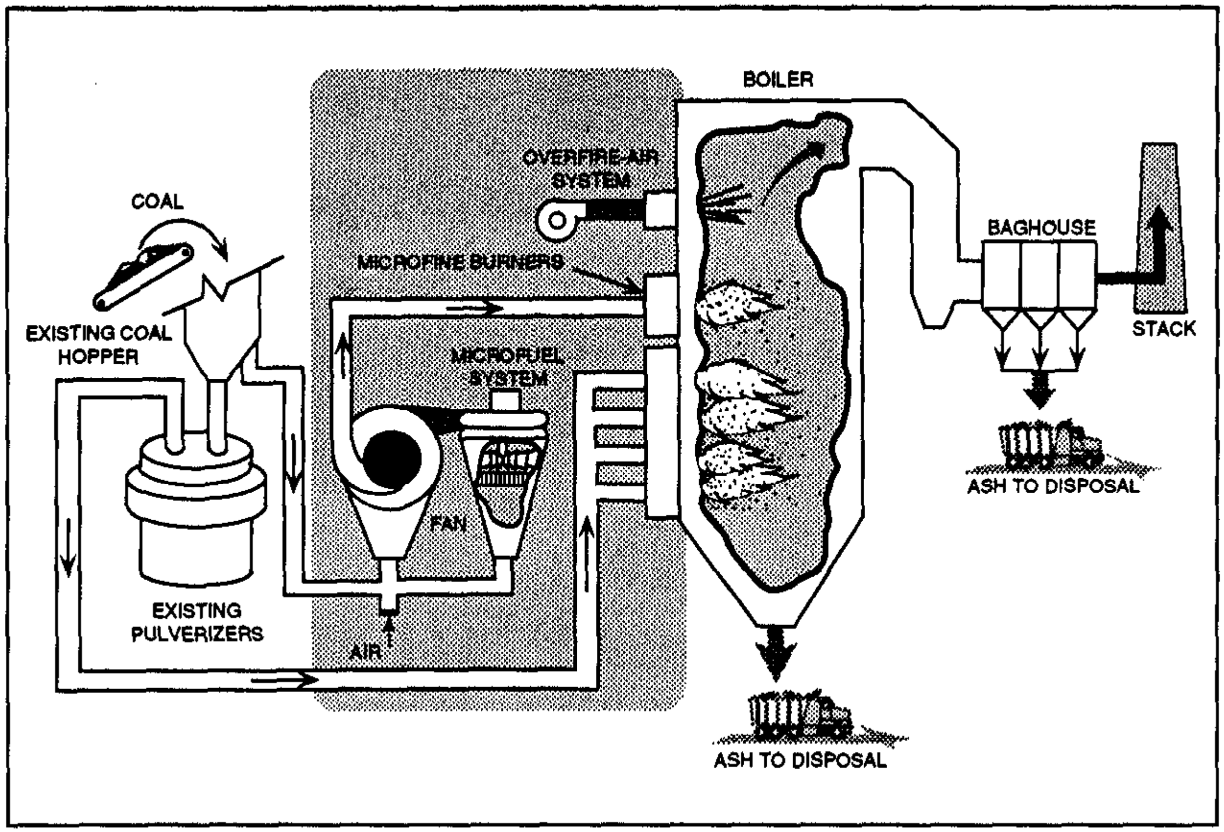
(Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:
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. IGCC technology also can be used in repowering, where a gasifier, gas stream cleanup unit, gas turbine, and waste heat recovery boiler are added to replace the existing coal-fired boiler. The remaining equipment is left in place, including the steam turbine and electrical generator. 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 performance potential of IGCC technology in its commercial configuration is characterized as follows:

- SO_2 reduction—99%
- NO_x reduction—95%
- Plant efficiency—up to 48%
- Incremental power increase (repowering)—230%
- Fuel flexibility—permits use of wide range of coals
- Compactness—high process efficiency reduces space requirements per unit of energy generated
- Modular construction—lends itself to economic increments of capacity additions to match load growth

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



Sponsor:
Tennessee Valley Authority

Additional Team Members:
Duke/Fluor Daniel (partnership between Duke Engineering & Services, Inc., and Fluor Daniel, Inc.) —engineer and constructor
MicroFuel Corporation—technology supplier
R-C Environmental Services and Technologies—technical consultant

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

Technology:
Advanced NO_x control using micronized coal reburning combustion technology

Plant Capacity/Production:
175 MWe

Project Funding:

Total project cost	$7,330,042	100%
DOE	3,515,008	48
Participants	3,815,034	52

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

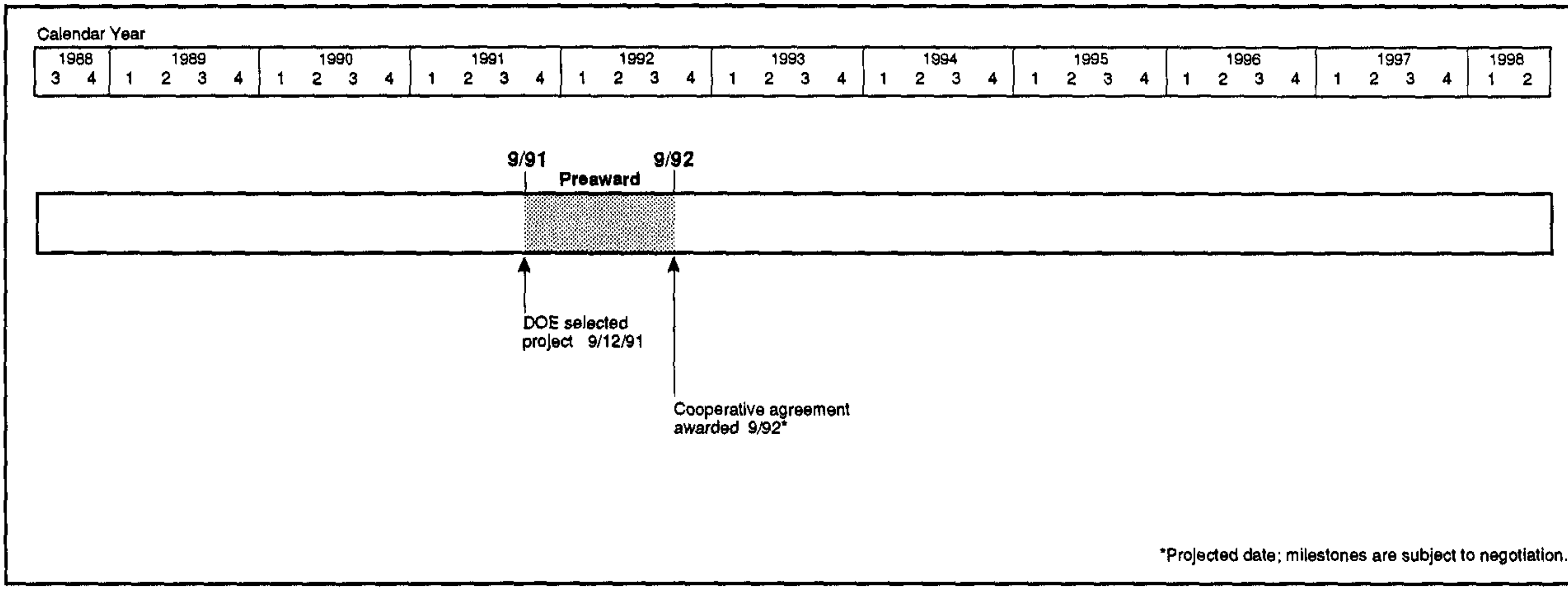
Project Objective:
To reduce NO_x emissions by 50–60% using micronized coal as the reburning fuel combined with advanced coal reburning technology.

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

Central to the project technology is the MicroFuel Corporation's two-element MicroFuel 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 is being installed between the existing pulverizers and the microfine 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 cumbustion 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.

The Tennessee Valley Authority plans to retrofit the micronized-coal-reburning technology to its Shawnee Fossil Plant located 10 miles northwest of Paducah, KY.

Project Status/Accomplishments:

The project is in negotiation.

Environmental Considerations:

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

Assuming maximum commercialization of this reburning technology by the year 2010, NO_x emissions can be reduced by 11%. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Applications:

Micronized-coal-reburning technology can be applied to cyclone-fired, wall-fired, and tangential-fired pulverized coal units. The technology reduces NO_x emissions by 50–60% with minimal furnace modifications and enhances boiler performance with the improved burning characteristics of micronized coal.

The availability of a coal-reburning fuel, as an additional fuel to the furnace, solves several problems concurrently. Units that are "mill limited" from fuel switching would have mill capacity to reach their maximum continuous rating. Restoration of lost capacity, as a benefit to NO_x reduction, can become a very economic source of generation. Reburn burners also can serve as low-load burners, and commercial units can achieve a turn down 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.

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

Sponsor:
ThermoChem, Inc.

Additional Team Members:
Weyerhaeuser Paper Company—host site
Manufacturing and Technology Conversion International, Inc.—technology supplier
Engineering Services, Inc.—constructor

Location:
Springfield, Lane County, OR

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

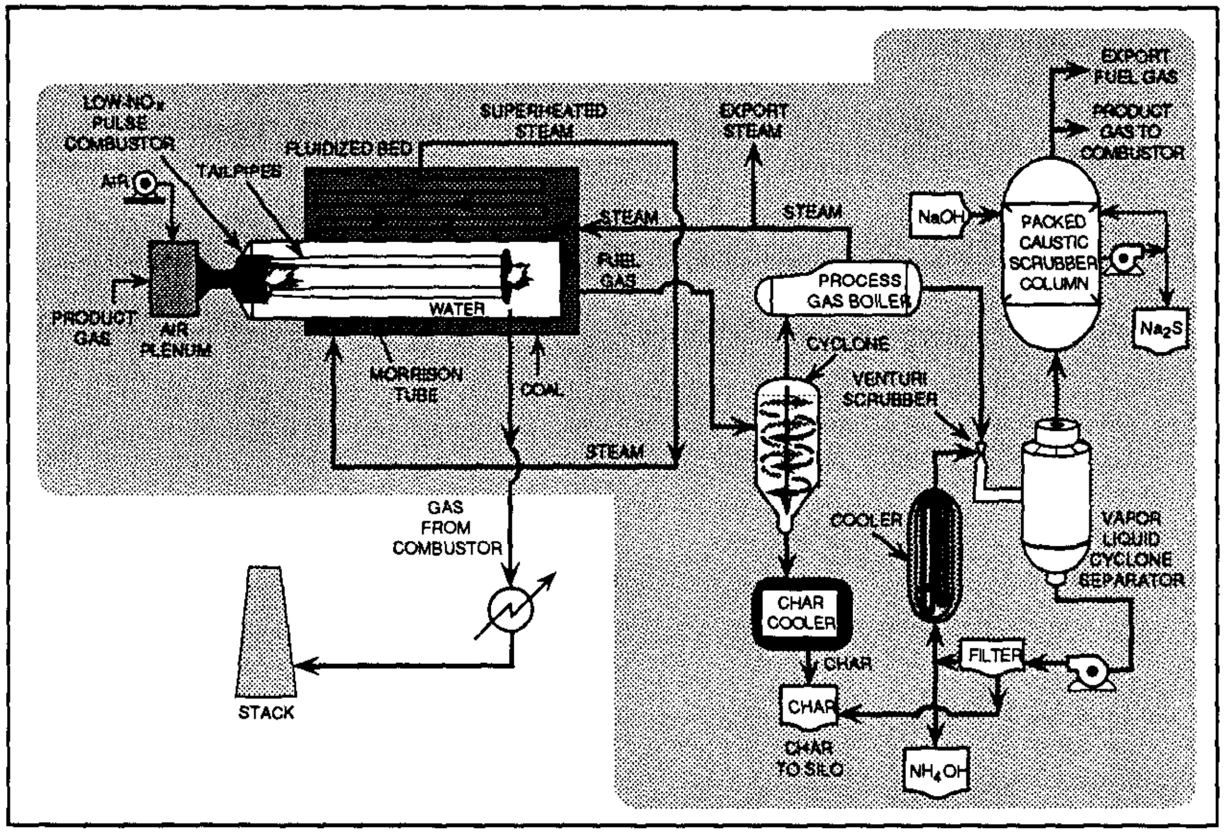
Plant Capacity/Production:
161 million Btu/hr of medium-Btu fuel gas plus 40,000 lb/hr of export steam

Project Funding:

Total project cost	$37,333,473	100%
DOE	18,666,736	50
Participants	18,666,737	50

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

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.

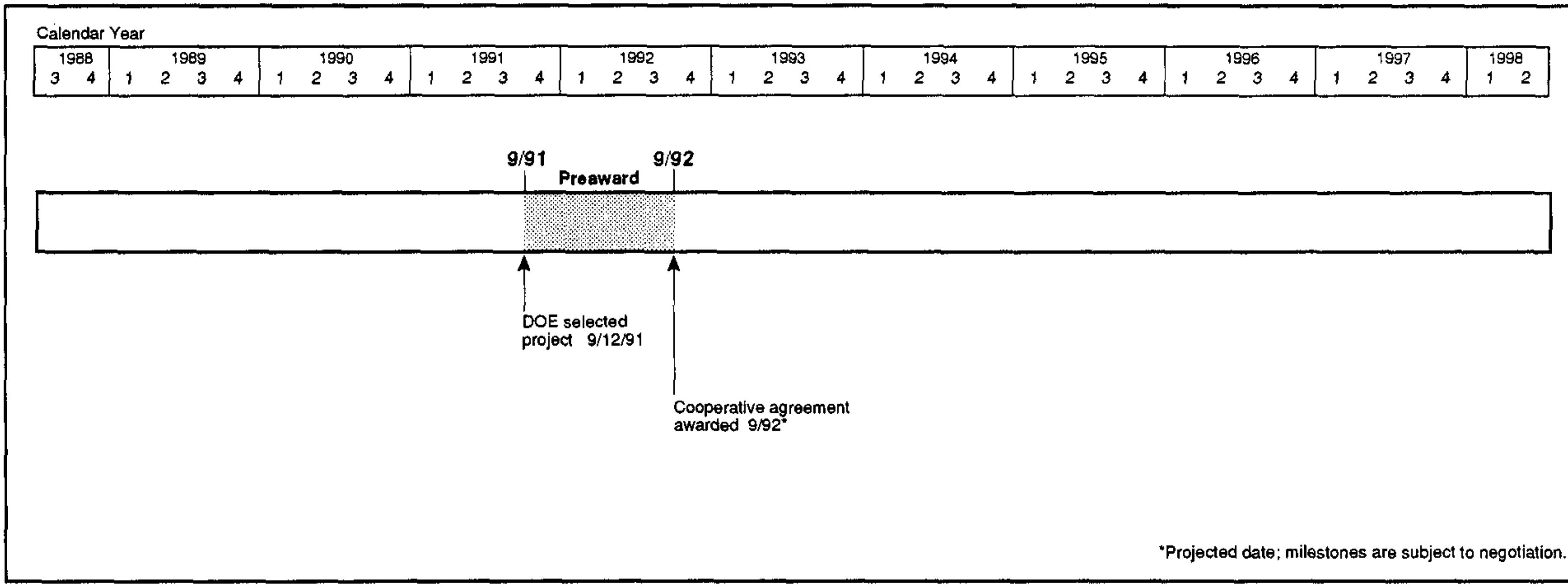


Technology/Project Description:
The MTCI fluidized-bed gasifier incorporates an innovative indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean, medium-Btu fuel gas without the need for an oxygen plant. The indirect heat transfer is provided by MTCI's 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 product gas has a heating value of about 161 million Btu/hr with a cold gas efficiency of 53% or more. 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.

Aqueous sodium hydroxide scrubbing is used to control SO_2 emissions. Scrubber overflow is utilized in the paper mill.

The demonstratioin facility will be built at Weyerhauser Paper Company's Containerboard Division mill in Springfield, OR. The fuel gas and by-product steam produced in the demonstration facility will be consumed by the mill. Subbituminous coal from Gillette, WY, will be used.



Project Status/Accomplishments:
The project is in negotiation.

Environmental Considerations:
Environmental information is being prepared for use in the NEPA process.

The MTCI pulse combustion technology can be expected to significantly reduce SO_2, NO_x, and particulate emissions, compared to conventional technology, in industrial use. The largest reductions in emissions resulting from commercialization of the MTCI pulse combustion technology are expected to occur initially in the pulp and paper industry. In the demonstration application, NO_x emissions reductions of 50–60% are expected. The use of aqueous caustic scrubbing should result in a 99% reduction of SO_2 emissions.

Commercial Applications:
The MTCI pulse combustion technology has a wide range of potential applications, including utility steam and power generation. This project is demonstrating the use of pulse combustion for steam gasification of coal in a major paper company's industrial containerboard mill to produce medium-Btu fuel gas and by-product steam. The new technology will replace hog-fuel boilers currently in use.

Potential applications of this technology in the pulp and paper industry are substantial. There are more than 350 pulp mills, which produce 64 million tons/yr of pulp, and 600 paper mills in the United States alone.

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

Demonstration of the Union Carbide CANSOLV™ at the ALCOA Generating Corporation Warrick Power Plant

Sponsor:
Union Carbide Chemicals and Plastics Company Inc.

Additional Team Members:
Aluminum Company of America (ALCOA) Generating Corporation—host and cofunder
Stone and Webster Engineering Corporation—engineer

Location:
Newburgh, Warrick County, IN (ALCOA Generating Corporation's Warrick Generating Station Unit No. 2)

Technology:
Flue gas cleanup using Union Carbide Chemicals and Plastics Company's CANSOLV™ regenerable flue gas desulfurization (FGD) system

Plant Capacity/Production:
75 MWe

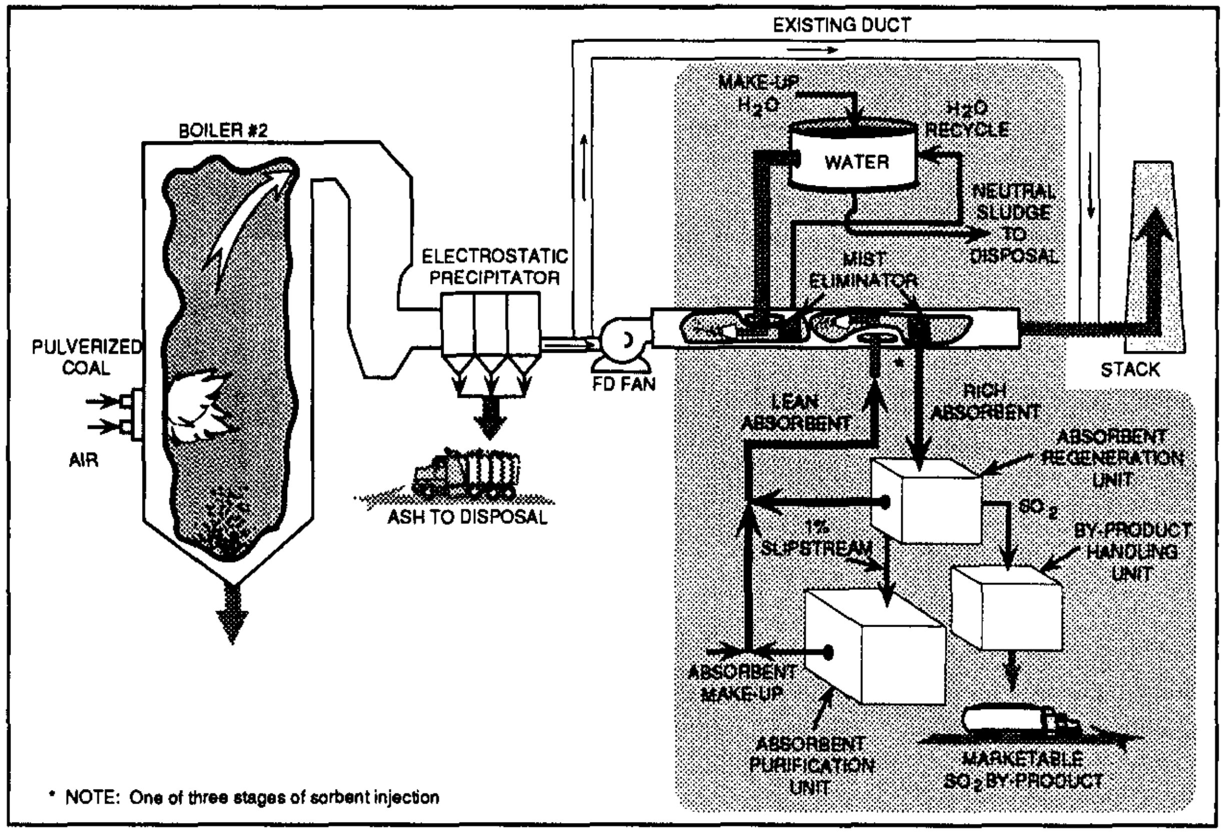
Project Funding:

Total Project Cost	$32,715,000	100%
DOE	16,357,500	50
Participants	16,357,500	50

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

Project Objective:
To demonstrate the CANSOLV™ regenerable flue gas desulfurization system to achieve SO_2 removal efficiencies of at least 99%.

CANSOLV is a trademark of Union Carbide Chemicals and Plastics Company Inc.

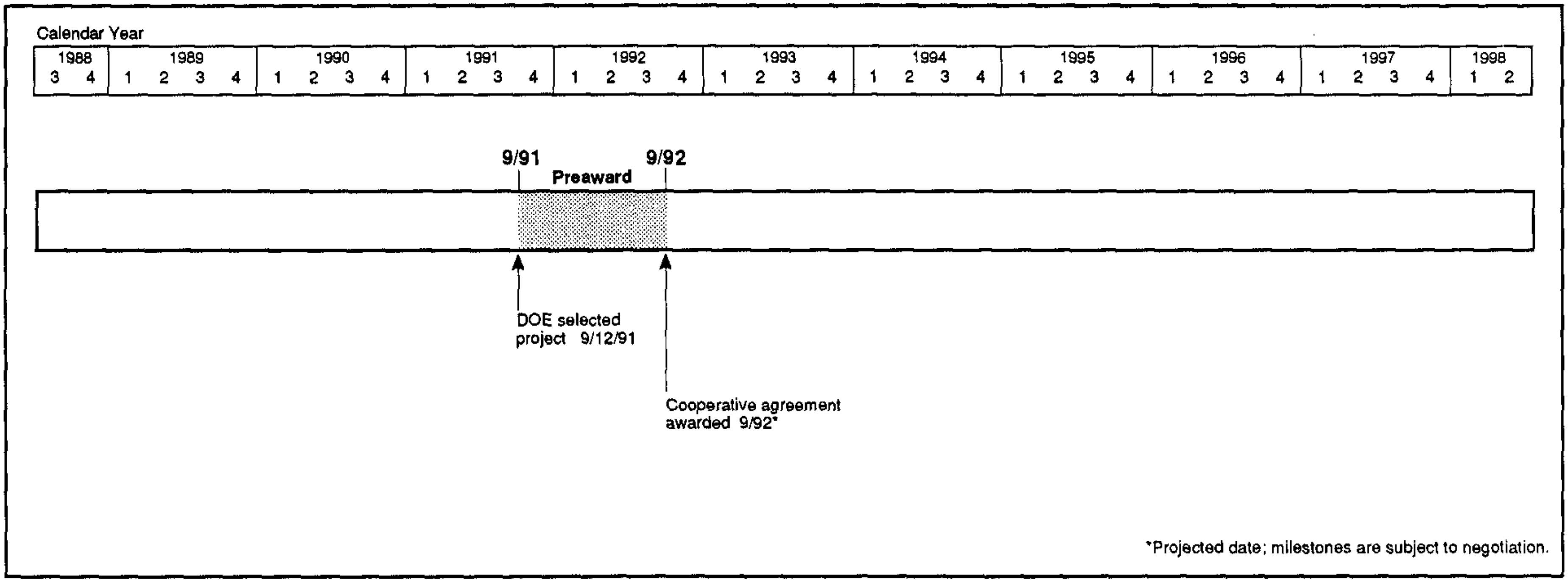


Technology/Project Description:
In the CANSOLV™ process, untreated flue gas enters the process from a particulate control device, such as a electrostatic precipitator, where it is contacted first by water and then by an aqueous solution of the SO_2 absorbent, both introduced to the gas stream as ultra-fine droplets through atomizing nozzles. Following each spraying section, mist elimination equipment removes the droplets from the gas stream, and after the last section, the treated gas is released to the chimney.

The water loop removes any particulate matter remaining in the gas, saturates the gas, and absorbs any chlorides and fluorides. The SO_2 is scrubbed from the flue gas by contact with the absorbent solution. In the absorbent loop, rich absorbent laden with SO_2 is routed to the absorbent regeneration unit where, through the application of heat, the SO_2 is stripped from the absorbent. The SO_2 stream is converted to salable products appropriate to local market conditions and opportunities. A 1% slipstream is taken from the recirculating lean absorbent and treated in the absorbent purification unit to prevent the build-up of impurities.

An advanced FGD technology, the CANSOLV™ process is capable of SO_2 capture rates over 99%. The demonstration project is using Indiana high-sulfur bituminous coal, with a sulfur content of about 3.4%.

ALCOA Generating Corporation's Warrick Generating Station Unit No. 2, located in Newburgh, IN, will be retrofitted with a newly designed and constructed CANSOLV™ scrubber facility capable of treating 50% of the flue gas from the unit.



Project Status/Accomplishments:
The project is in negotiation.

Environmental Considerations:
Environmental information is being prepared for use in the NEPA process.

Assuming maximum commercialization of the CANSOLV™ process, a 48% reduction of SO_2 could be achieved nationally by 2010 relative to the no-action alternative considered in the CCT Programmatic Environmental Impact Statement. This significant reduction of SO_2 is attributable to an average conservative 90–95% SO_2 removal capability for the CANSOLV™ process and its wide potential applicability. It is a regenerable process in which the SO_2 from the gas stream is recovered for conversion to salable products. In the Warrick demonstration, anhydrous (dry) liquid SO_2 is being captured and sold to neighboring SO_2 distributors for resale. Because the absorbent is recirculated and regenerated, the process is particularly advantageous where high-sulfur coals are used.

The CANSOLV™ process generates minimal solid or liquid wastes for disposal. Solids recovered by an in-duct prescrubber are those that pass through the precipitators and are directed to the existing ash handling system.

Commercial Application:
The CANSOLV™ process is attractive for both new and retrofit utility and industrial applications.

The process is designed to operate as an in-duct scrubber system, without the need for costly scrubbing vessels. Regeneration occurs in relatively small vessels requiring a minimal amount of space. Consequently the process potentially is applicable to the many space-constrained facilities. CANSOLV™ may be integrated effectively with other NO_x and particulate control systems to provide for overall emission control.