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Comprehensive Report to Congress Clean Coal Technology Program

Integrated Dry NO_x/SO_2 Emission Control System

A Project Proposed By: Public Service Company of Colorado

U.S. Department of Energy
Assistant Secretary for Fossil Energy
Office of Clean Coal Technology
Washington, D.C. 20585

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1.0 EXECUTIVE SUMMARY

In September 1988, Congress provided $575 million to conduct cost-shared Clean Coal Technology (CCT) projects to demonstrate technologies that are capable of retrofitting or repowering existing facilities. To that end, a Program Opportunity Notice (PON) was issued by the Department of Energy (DOE) in May 1989, soliciting proposals to demonstrate innovative energy efficient technologies that were capable of being commercialized in the 1990s, and were capable of (1) achieving significant reductions in the emissions of sulfur dioxide and/or the oxides of nitrogen from existing facilities to minimize environmental impacts such as transboundary and interstate pollution and/or (2) providing for future energy needs in an environmentally acceptable manner.

In response to the PON, 48 proposals were received in August 1989. After evaluation, 13 projects were selected in December 1989 as best furthering the goals and objectives of the PON. The projects were located in 10 different states and represented a variety of technologies.

One of the projects selected for funding is the Integrated Dry NO_x/SO_2 Emission Control System demonstration project proposed by Public Service Company of Colorado (PSCC). This project will demonstrate the combined removal of NO_x and SO_2 from a down-fired utility coal boiler retrofitted with the Integrated Dry NO_x/SO_2 Emission Control System.

The Integrated Dry NO_x/SO_x Emission Control System is a combination of different processes intended to reduce acid rain precursor emissions in utility flue gases. These processes are: low-NO_x burners and urea injection for NO_x control, sodium- or calcium-based sorbent injection for SO_x control, and flue gas humidification to enhance the reactivity of the SO_2 control compound.

Babcock and Wilcox (B&W) XCL burners will be installed. These burners reduce NO_x formation by a combination coal/air combustion staging and the use of air ports. Urea injected downstream of the XCL burners reacts chemically with NO_x to form nitrogen and water.

Sodium- and calcium-based materials react with the SO_2 in the flue gas to form sulfites and sulfates lowering the emissions of SO_2. Humidification of the flue gas increases the reactivity of the calcium reactants. The sulfites, sulfates, and unreacted sorbent are removed with the fly ash in fabric filters.

Sodium-based injection systems can cause conversion of nitrogen oxide NO to nitrogen dioxide (NO_2) which, in addition to being one form of NO_x, may be visible in the stack plume under certain conditions. Ammonia, from the urea injection, will reduce the NO_2 concentration by reacting with the NO_2. Thus system integration will alleviate a potential undesirable side effect of SO_2 removal.

The Integrated Dry NO_x/SO_2 Emission Control System is expected to remove up to 70% of the NO_x and 70% of the SO_2 emissions from coal-fired utility boilers. If successful, this project will establish an alternative technology to wet or dry flue gas desulfurization (FGD) processes and selective catalytic reduction (SCR) processes, while minimizing capital expenditures and limiting waste production to dry solids that can be handled with conventional ash removal equipment.

The demonstration project will be conducted at PSCC's commercially operating 100 megawatt electric (MWe) Arapahoe Steam Electric Generating Station, Unit No. 4, in Denver, Colorado, as shown in Figure 1. Low-sulfur Western Colorado and high-sulfur Illinois coals will be used in the project. This demonstration project will be performed over a 44 1/2-month period and project activities include design, procurement, baseline characterization testing, fabrication, construction, post-retrofit testing, waste characterization studies, site restoration, and reporting of results.

The total project cost is $26,477,878. The co-funders are PSCC ($11,738,939) and EPRI ($1,500,000) with DOE's share being $13,238,939. Baseline characterization testing is scheduled to begin in mid 1991. Overall project completion is scheduled for late 1994.

2.0 INTRODUCTION AND BACKGROUND

2.1 Requirement for a Report to Congress

On September 27, 1988, Congress made available funds for the third clean coal demonstration program (CCT-III) in Public Law 100-446, "An Act Making Appropriations for the Department of the Interior and Related Agencies for the Fiscal Year Ending September 30, 1989, and for Other Purposes" (the "Act"). Among other things, this Act appropriates funds for the design, construction, and operation of cost-shared, clean coal projects to demonstrate the feasibility of future commercial applications of such "... technologies capable of

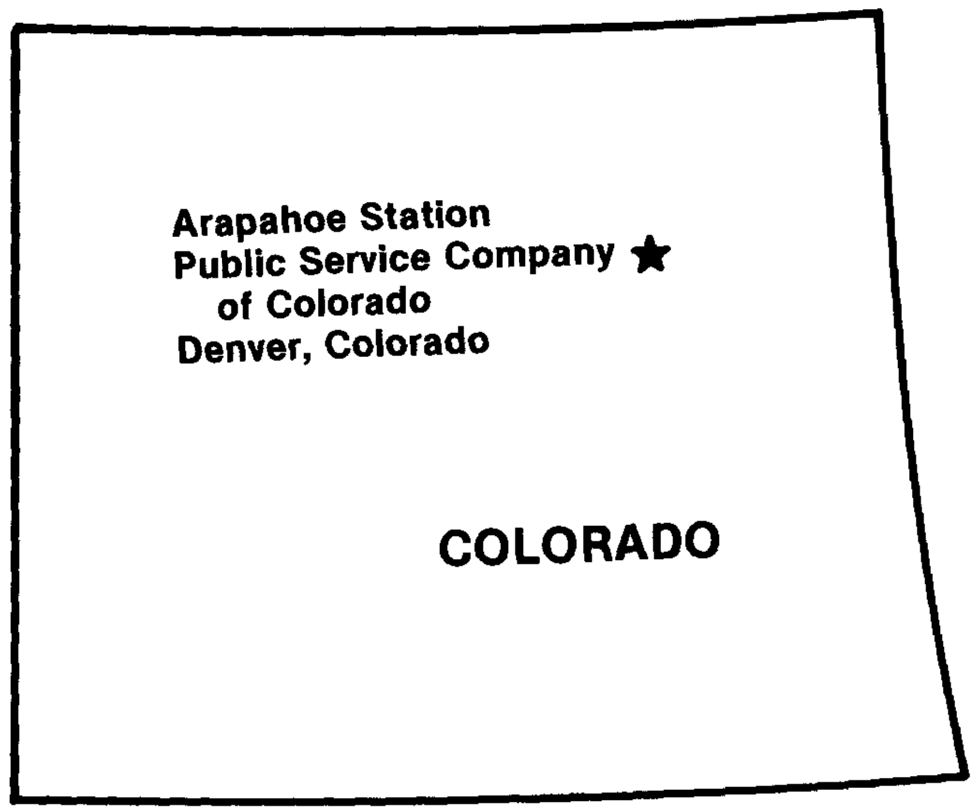

FIGURE 1. PUBLIC SERVICE COMPANY OF COLORADO DEMONSTRATION PROJECT LOCATION.

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retrofitting or repowering existing facilities ...." On June 30, 1989, Public Law 101-45 was signed into law, requiring that CCT-III projects be selected no later than January 1, 1990.

Public Law 100-446 appropriates a total of $575 million for executing CCT-III. Of this total, $6.906 million are required to be reprogrammed for the Small Business and Innovative Research Program (SBIR) and $22.548 million are designated for Program Direction Funds for costs incurred by DOE in implementing the CCT-III program. The remaining, $545.546 million was available for award under the PON.

The purpose of this Comprehensive Report is to comply with Public Law 100-446, which directs the Department to prepare a full and comprehensive report to Congress on each project selected for award under the CCT-III Program.

2.2 Evaluation and Selection Process

DOE issued a draft PON for public comment on March 15, 1989, receiving a total of 26 responses from the public. The final PON was issued on May 1, 1989, and took into consideration the public comments on the draft PON. Notification of its availability was published by DOE in the Federal Register and the Commerce Business Daily on March 8, 1989. DOE received 48 proposals in response to the CCT-III solicitation by the deadline, August 29, 1989.

2.2.1 PON Objective

As stated in PON Section 1.2, the objective of the CCT-III solicitation was to obtain "proposals to conduct cost shared Clean Coal Technology projects to demonstrate innovative, energy efficient technologies that are capable of being commercialized in the 1990s. These technologies must be capable of (1) achieving significant reductions in the emissions of sulfur dioxide and/or the oxides of nitrogen from existing facilities to minimize environmental impacts such as transboundary and interstate pollution and/or (2) providing for future energy needs in an environmentally acceptable manner."

2.2.2 Qualification Review

The PON established seven Qualification Criteria and provided that, "In order to be considered in the Preliminary Evaluation Phase, a proposal must successfully pass Qualification." The Qualification Criteria were as follows:

(a) The proposed demonstration project or facility must be located in the United States.

(b) The proposed demonstration project must be designed for and operated with coal(s) from mines located in the United States.

(c) The proposer must agree to provide a cost share of at least 50 percent of total allowable project cost, with at least 50 percent in each of the three project phases.

(d) The proposer must have access to, and use of, the proposed site and any proposed alternate site(s) for the duration of the project.

(e) The proposed project team must be identified and firmly committed to fulfilling its proposed role in the project.

(f) The proposer agrees that, if selected, it will submit a "Repayment Plan" consistent with PON Section 7.4.

(g) The proposal must be signed by a responsible official of the proposing organization authorized to contractually bind the organization to the performance of the Cooperative Agreement in its entirety.

2.2.3 Preliminary Evaluation

The PON provided that a Preliminary Evaluation would be performed on all proposals that successfully passed the Qualification Review. In order to be considered in the Comprehensive Evaluation phase, a proposal must be consistent with the stated objective of the PON, and must contain sufficient business and management, technical, cost, and other information to permit the Comprehensive Evaluation described in the solicitation to be performed.

2.2.4 Comprehensive Evaluation

The Technical Evaluation Criteria were divided into two major categories: (1) the Demonstration Project Factors were used to assess the technical feasibility and likelihood of success of the project, and (2) the Commercialization Factors were used to assess the potential of the proposed technology to reduce emissions from existing facilities, as well as to meet future energy needs through the environmentally acceptable use of coal, and the cost effectiveness of the proposed technology in comparison to existing technologies.

The Business and Management criteria required a Funding Plan and an indication of Financial Commitment. These were used to determine the business performance potential and commitment of the proposer.

The PON provided that the Cost Estimate would be evaluated to determine the reasonableness of the proposed cost. Proposers were advised that this determination "will be of minimal importance to the selection," and that a detailed cost estimate would be requested after selection. Proposers were cautioned that if the total project cost estimated after selection is greater than the amount specified in the proposal, DOE would be under no obligation to provide more funding than had been requested in the proposer's Cost Sharing Plan.

2.2.5 Program Policy Factors

The PON advised proposers that the following program policy factors could be used by the Source Selection Official to select a range of projects that would best serve program objectives:

(a) The desirability of selecting projects that collectively represent a diversity of methods, technical approaches, and applications.

(b) The desirability of selecting projects in this solicitation that contribute to near term reductions in transboundary transport of pollutants by producing an aggregate net reduction in emissions of sulfur dioxide and/or the oxides of nitrogen.

(c) The desirability of selecting projects that collectively utilize a broad range of U.S. coals and are in locations which represent a diversity of EHSS, regulatory, and climatic conditions.

(d) The desirability of selecting projects in this solicitation that achieve a balance between (1) reducing emissions and transboundary pollution and (2) providing for future energy needs by the environmentally acceptable use of coal or coal-based fuels.

The word "collectively" as used in the foregoing program policy factors, was defined to include projects selected in this solicitation and prior clean coal solicitations, as well as other ongoing demonstrations in the United States.

2.2.6 Other Considerations

The PON provided that in making selections, DOE would consider giving preference to projects located in states for which the rate-making bodies of those states treat the Clean Coal Technologies the same as pollution control projects or technologies. This consideration could be used as a tie breaker if, after application of the evaluation criteria and the program policy factors, two projects receive identical evaluation scores and remain essentially equal in value. This consideration would not be applied if, in doing so, the regional geographic distribution of the projects selected would be altered significantly.

2.2.7 National Environmental Policy Act (NEPA) Compliance

As part of the evaluation and selection process, the Clean Coal Technology Program developed a procedure for compliance with the National Environmental Policy Act of 1969, the Council on Environmental Quality regulations for implementing NEPA (40 CFR Parts 1500-1508) and the DOE guidelines for compliance with NEPA (52 FR 47662, December 15, 1987).

This procedure included the publication and consideration of a publicly available Final Programmatic Environmental Impact Statement (DOE/EIS-0146) issued in November 1989, and the preparation of confidential preselection project-specific environmental reviews for internal DOE use. DOE also prepares publicly available site-specific documents for each selected demonstration project as appropriate under NEPA.

2.2.8 Selection

After considering the evaluation criteria, the program policy factors, and the NEPA strategy as stated in the PON, the Source Selection Official selected 13 projects as best furthering the objectives of the CCT-III PON.

Secretary of Energy, Admiral James D. Watkins, U.S. Navy (Retired), announced the selection of 13 projects on December 21, 1989. In his press briefing, the Secretary stated he had recently signed a DOE directive setting a 12-month deadline for the negotiation and approval of the 13 cooperative agreements to be awarded under the CCT-III solicitation.

3.0 TECHNICAL FEATURES

3.1 Project Description

The Public Service Company of Colorado (PSCC) Integrated Dry NO_x/SO_2 Emission Control System will demonstrate that the combination of low-NO_x burners, urea furnace injection, and sodium- or calcium-based reagent injection is an efficient and economical means of removing the acid rain precursors (NO_x and SO_2) from utility boiler flue gas. The demonstration program is directed at down-fired boilers, but the process can be utilized on other types of boilers. This project will be the first U.S. application of low-NO_x burners to a down-fired boiler.

The demonstration will be conducted at the PSCC Arapahoe Steam Electric Generating Station Unit No. 4. This boiler is a natural gas- and coal-fired unit with burners mounted vertically on the boiler roof.

The specific objectives of the Integrated Dry NO_x/SO_2 Emission Control System demonstration are to (1) achieve up to 70% NO_x and SO_2 removal, (2) demonstrate the cost effectiveness of the technology, and (3) demonstrate that the process has no negative effects on normal boiler operation and does not create any other unwanted releases of gaseous or solid emissions.

3.1.1 Project Summary

Project Title:	Integrated Dry NO_x/SO_2 Emission Control System
Proposer:	Public Service Company of Colorado
Project Location:	Denver, Colorado (Arapahoe Station) Denver County
Technology:	Flue Gas Cleanup by Low-NO_x Burners, Urea Injection, and Sodium- or Calcium-Based Reagent Injection
Application:	Retrofit of Coal-Fired Industrial and Utility Boilers
Types of Coal Used:	Low-Sulfur Western Colorado Coal High-Sulfur Illinois Coal
Product:	Environmental Control Technology
Project Size:	100 MWe
Project Start Date:	January 1991
Project End Date:	October 1994

3.1.2 Project Sponsorship and Cost

Project Sponsor:	Public Service Company of Colorado
Proposed Co-Funder:	Electric Power Research Institute
Proposed Project Cost:	$26,477,878

Proposed Cost Distribution:

Participant Share (%)	DOE Share (%)
50.0	50.0

3.2 Integrated Dry NO_x/SO_2 Emission Control System

3.2.1 Overview of Process Development

This project will demonstrate the combination of several technologies that were independently developed. The XCL burner development is the result of B&W's continuing effort to develop low-NO_x burners. The dual NO_x ports were developed to overcome certain inadequacies of single jet systems. Dry sorbent injection and urea injection were also developed independently starting in the 1960s and 1970s, respectively.

B&W XCL Burner

The dual register burner (DRB), B&W's first low-NO_x pulverized-coal-fired burner, was developed and commercialized in the early 1970s. The DRB differed from conventional wall-fired circular burners in that it incorporated an axial fuel injection arrangement and dual concentric registers for swirl control and air/fuel mixing. The DRB typically achieves 40-50% NO_x reduction from uncontrolled levels. The DRB's installed capacity of over 37,000 MWe includes the burning of lignite, and subbituminous and bituminous coals.

Further enhancements of the DRB led to the development of the Babcock-Hitachi HT-NR burner and more recently to the B&W XCL burner. The XCL burner reduces NO_x an additional 25% over the DRB by the use of fuel staging. A complete XCL burner retrofit was performed in 1986 at Ohio Edison's Edgewater Station, Unit No. 4, as part of the Clean Coal Technology I (CCT I) Program - Limestone Injection Multistage Burner (LIMB) demonstration project.

Dual NO_x Ports

The dual zone NO_x ports were developed by B&W to improve furnace mixing between staging air and the furnace gases and the partially unburned fuel. The conventional single jet is not capable of producing adequate mixing with the furnace gases both across the furnace and near the wall where the port is located. Injecting air at a single velocity cannot accomplish satisfactory mixing in both areas. B&W developed the dual NO_x port which injects air at two different velocities to achieve satisfactory mixing across the furnace.

Urea Injection System

The urea injection process was initially developed in 1976 under sponsorship by EPRI. Urea injection was tested, in 1985, at full scale in an oil- and gas-fired unit by San Diego Gas and Electric. Subsequently, the process was tested in 75 MWe and 150 MWe brown coal-fired boilers in West Germany, in a municipal solid waste incineration plant in Switzerland, and in a 140 MWe oil-fired utility boiler and a 325 MWe coal-fired utility boiler in West Germany. These commercial-scale applications have shown that the process is capable of removing 35-70% of the initial combustion gas NO_x.

Dry Reagent SO_2 Removal System

Sodium material, nahcolite, for SO_2 emissions reduction was initially tested in the 1960s by Southern California Edison. Furthermore, in the 1970s, PSCC, EPRI, and others, examined the technical and economic feasibility of the technology at the laboratory- and pilot-scales. Extensive testing has recently been completed at the 222 MWe R. D. Nixon Generating Station, owned by the City of Colorado Springs. Participants in the demonstration included EPRI, Colorado Springs Department of Utilities, PSCC, FMC Corporation, Church & Dwight, and the Adolph Coors Company.

Calcium-based material injection for SO_2 removal was initially used in the early 1970s at TVA's Shawnee Station. The results of the tests performed were generally unsatisfactory since only a small portion of the sorbent was utilized. However, interest in the technology resurfaced in the late 1970s as a result of technology improvements. Limestone injection at the burners was tested in both the U.S. and in Germany. Later, injection of sorbent into the cooler flue gas upstream of the air heater was tested. Calcium-based reagent injection downstream of the air heater, combined with humidification, has been under development since 1984. Since 1987, calcium-based reagent injection on either side of the air heater has been tested at Ohio Edison's Edgewater Station. The testing was performed under an EPA contract and is continuing under a DOE Cooperative Agreement.

Flue Gas Humidification System

The B&W flue gas humidification system is based on the B&W dry scrubber developed in the 1970s. Two B&W dry scrubber installations, one located in Wheatland, Wyoming, and the other in Craig, Colorado, have been in operation since 1984.

A new atomizer, smaller than those used in these earlier humidification systems, has been developed for in-duct scrubbing and humidification. It is similar to the older atomizers, but has been modified to ensure water is more evenly distributed in the duct and to produce a finer drop size. These modifications ensure complete evaporation in a short residence time in the duct. In-duct humidification testing has been performed at B&W's Alliance Research Center and at Ohio Edison's Edgewater Station as part of the Coolside portion of the CCT I LIMB Demonstration Project Extension.

3.2.2 Process Description

The Integrated Dry NO_x/SO_2 Emission Control System, shown schematically in Figure 2, is a multi-part process in which low-NO_x burners, NO_x ports, and urea injection are used to control NO_x. Sodium-based sorbent injection or calcium-based sorbent injection, combined with in-duct humidification, is used for SO_2 removal.

B&W XCL Burner

NO_x, formed during the combustion of fossil fuels consists of NO_x formed from fuel bound nitrogen, thermal NO_x, and prompt NO_x. NO_x formed from fuel bound nitrogen results from the oxidation of nitrogen which is bonded to the fuel molecules. Thermal NO_x forms when nitrogen in the combustion air dissociates and oxidizes at flame temperatures in excess of 2800 °F. Prompt NO_x forms during the combustion process when hydrocarbon radicals dissociate atmospheric nitrogen, which then oxidizes.

The B&W XCL burner achieves increased NO_x reduction effectiveness by incorporating fuel staging along with air staging. Most of low-NO_x burners reduce NO_x by the use of air staging. Air staging reduces the amount of combustion air during the early stages of combustion. Fuel staging involves the introduction of the fuel downstream of the flame under fuel-rich conditions, causing hydrocarbon radicals to be generated. These radicals reduce NO_x levels. This is accomplished by the coal nozzle/flame stabilizing ring design of the burner. In addition, combustion air is accurately measured and regulated to each burner to provide balanced air and fuel distribution for optimum NO_x reduction and combustion efficiency. Further, the burner assembly is equipped with adjustable burner vanes to provide swirl for flame stabilization and fuel/air mixing.

NO_x Ports

NO_x ports are used in conjunction with low-NO_x burners to increase the effectiveness of air staging. NO_x ports provide the final air necessary to ensure complete combustion. Conventional single jet NO_x ports are not capable of providing adequate mixing across the entire furnace. The B&W dual zone NO_x ports, however, incorporates a central zone which produces an air jet that penetrates across the furnace and a separated outer zone that diverts and disperses the air in the area of the furnace near the NO_x port. The central zone

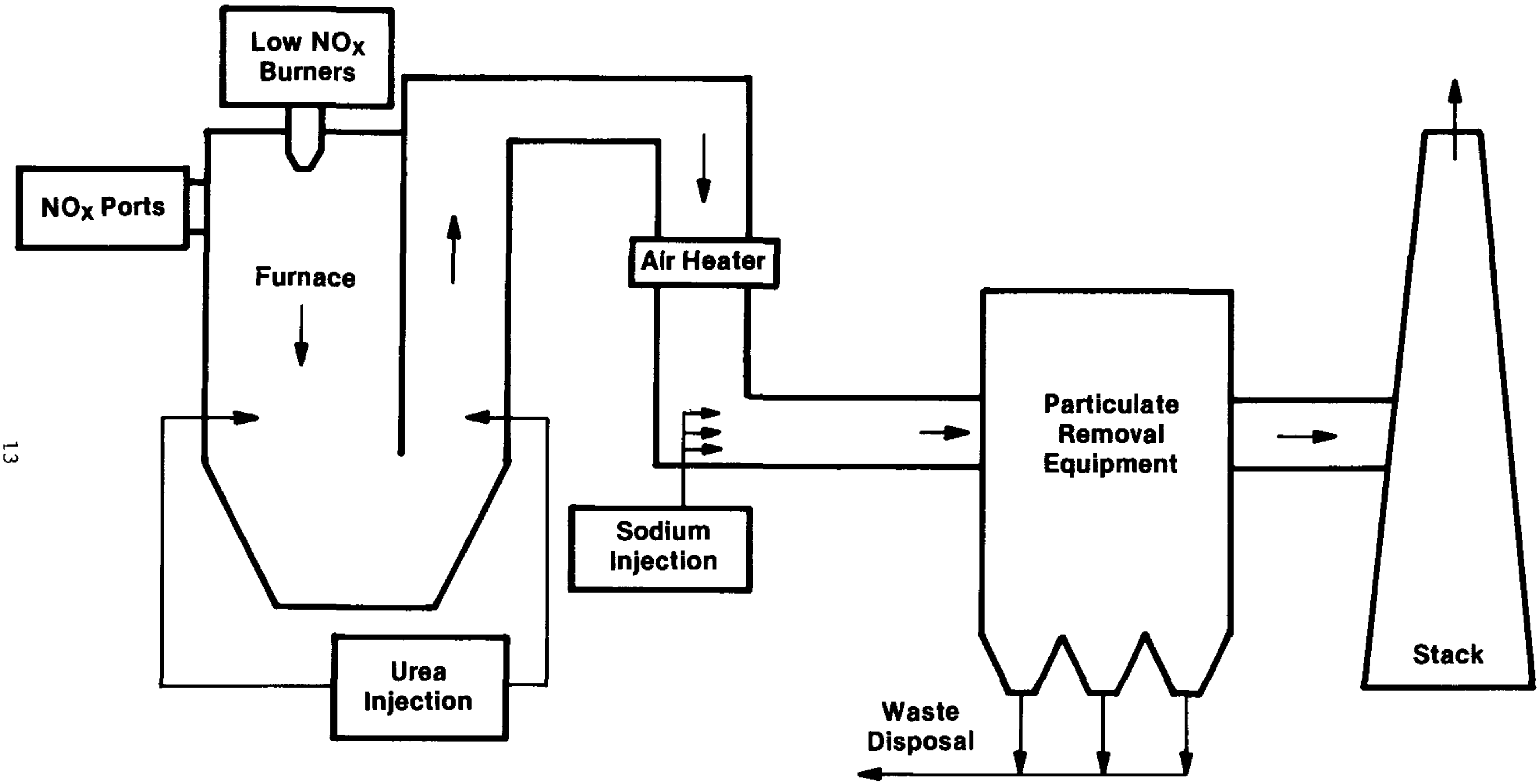

FIGURE 2. INTEGRATED DRY NO_X/SO_2 EMISSION CONTROL SYSTEM PROCESS SCHEMATIC. (Sodium-Based Application)

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is provided with a manual air control disk for flow control and the outer zone incorporates manually adjustable spin vanes for air swirl control.

The combined use of the B&W XCL burners and dual zone NO_x ports is expected to reduce NO_x emissions by up to 70%.

Urea Injection

NO_x reduction in utility boilers can also be accomplished by injecting urea into the furnace. The urea reacts with the NO_x and oxygen in the gases and forms nitrogen, carbon dioxide, and water. A urea injection system is capable of removing 40% to 50% of the remaining NO_x from the combustion process.

The optimum urea injection reaction temperature range is between 1700 ^{o}F and 1900 ^{o}F. At lower temperatures, side reactions can occur, resulting in the undesirable formation of ammonia. At higher temperatures, additional NO is formed. Chemical additives can be injected with the urea to widen the optimum temperature range and minimize the formation of ammonia.

The urea is generally injected into the boiler as an aqueous solution through atomizers. The atomizing medium can be either air or steam. The urea and any additive are stored as a liquid and pumped into the injection atomizers.

Dry Reagent SO_2 Removal System

The dry reagent injection system consists of equipment for storing, conveying, pulverizing, and injecting sodium products into the flue gas between the air heater and the particulate removal equipment or calcium products between the economizer and the air heater. The SO_2 formed during combustion reacts with the sodium- or calcium-based reagents to form sulfates and sulfites. These reaction products are collected in the particulate removal equipment together with the fly ash and the unreacted reagent and removed for disposal. The system is expected to remove up to 70% SO_2 while maintaining high sorbent utilization.

Dry sodium-based reagent injection systems reduce SO_2 emissions. However, NO_2 formation has been observed in some applications. NO_2 is a red/brown gas. A visible plume may form as the NO_2 in flue gas exits the stack. Previous tests have shown that ammonia slip from the urea injection system reduces the formation of NO_2, while removing the ammonia which would otherwise exit the stack.

In certain areas of the country, it may be more economically advantageous to use calcium-based reagents, rather than sodium-based reagents, for SO_2 removal. SO_2 removal using calcium-based reagents involves the dry injection of the reagent into the furnace at a point where the flue gas temperature is approximately 1000 °F. Calcium-based materials can also be injected in the flue gas ductwork downstream of the air heater, but at reduced SO_2 removal effectiveness.

Humidification

In addition to the selection of the proper injection point, the effectiveness of the calcium-based reagent in reducing SO_2 emissions can be increased by flue gas humidification. Flue gas conditioning by humidification involves injecting water into the flue gas stream downstream of the air heater and upstream of any particulate removal equipment. The water is injected into the duct by dual fluid atomizers which produce a fine spray that can be directed downstream and away from the duct walls. The subsequent evaporation causes the flue gas to cool, thereby decreasing its volumetric flow rate and increasing its absolute humidity. It is important that the water be injected in such a way as to prevent it from wetting the duct walls and to ensure complete evaporation before the gas enters the particulate removal equipment or contacts the duct turning vanes. Since calcium-based reagent are not as reactive as sodium-based reagents, the presence of water in the flue gas, which contains unreacted reagent, provides for additional SO_2 removal. Up to 50% SO_2 removal is expected when calcium reagents are used in conjunction with flue gas humidification.

3.2.3 Application of Process in Proposed Project

The Arapahoe Steam Electric Generating Station Unit No. 4 boiler is a nominal 100 MWe pulverized coal-fired boiler with roof-mounted burners designed with a down-fired configuration. The unit is equipped with a fabric filter for particulate removal. Figure 3 is an overall process schematic for the proposed project.

During the demonstration program, the existing roof-mounted multi-tip coal burners will be removed and replaced with B&W model XCL coal and natural gas burners and six overfire air ports. This will require major changes to the waterwall, windbox, structural steel, ductwork, and support structure as well as the addition of upgraded and compatible controls. In addition, a urea injection system consisting of concentrated urea and additive storage tanks, water dilution equipment, pumps, air supply system, distribution piping, and

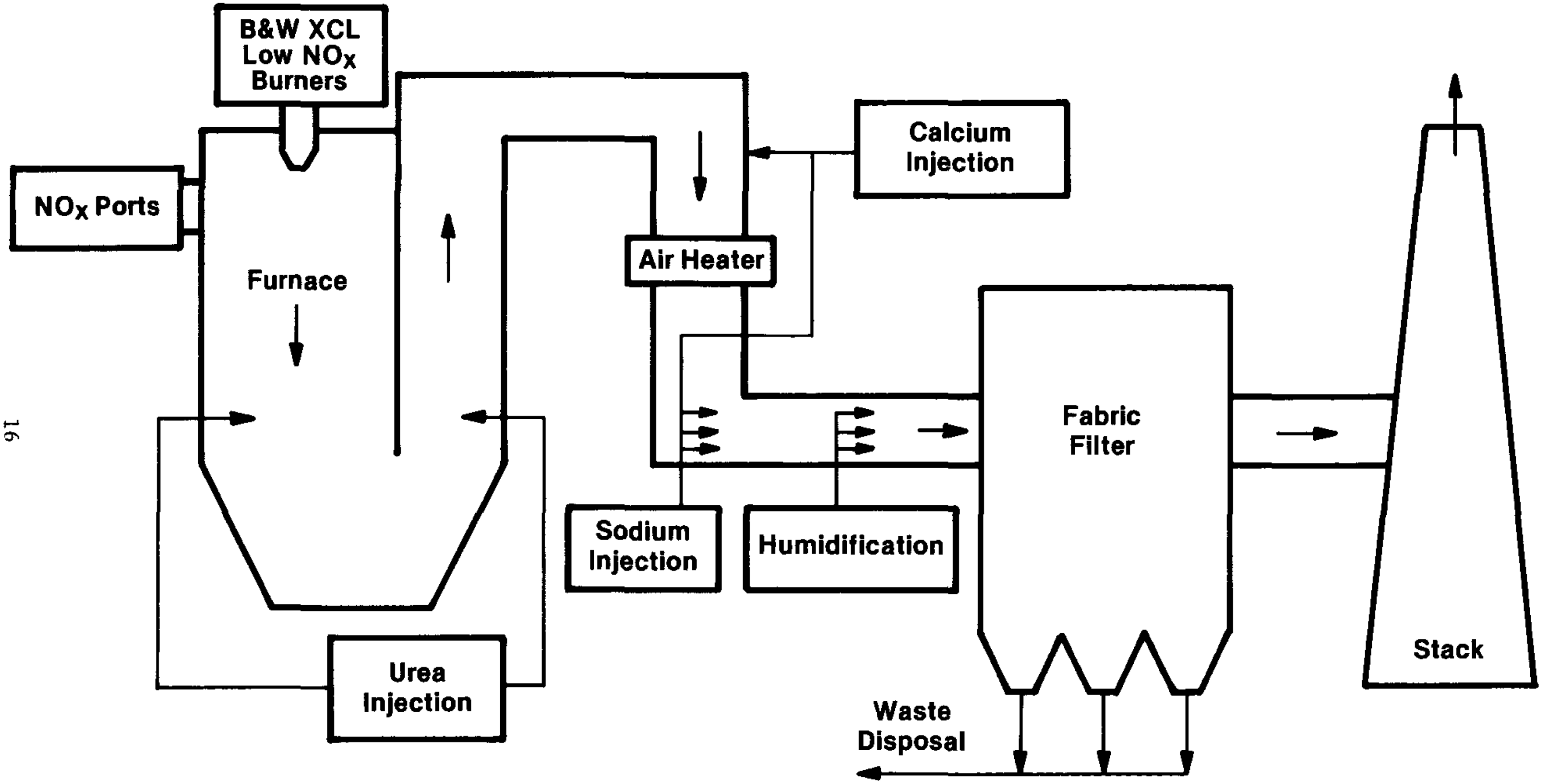

FIGURE 3. ARAPAHOE STATION OVERALL PROCESS SCHEMATIC.

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injection atomizers will be installed. Humidification involves the addition of nozzles, pumps, piping, controls, and an air supply system. The majority of the equipment will be located in a new de-NO_x building located adjacent to the boiler.

Sodium- and/or calcium-based reagent injection involves the addition of storage silos, reagent screw feeders, pulverizers, eductors, blowers, fabric filters, piping, and the installation of injection atomizers in the furnace upstream of the air heater and in the flue gas duct downstream of the air heater, but upstream of the fabric filter. Different reagents will be tested during the demonstration project. The reagents under consideration include: sodium bicarbonate, trona, sodium sesquicarbonate, nahcolite, and calcium hydroxide.

3.3 General Features of the Project

3.3.1 Evaluation of Developmental Risk

Prior work has been performed on the individual portions of the process. The basic principles of the process are similar to other commercially available technologies.

There is some risk, however, associated with this demonstration, as described below:

- Low-NO_x burners and staging air ports tend to increase unburned combustibles.

- The XCL burners have not been previously operated in a down-fired boiler configuration.

- NO_x ports may not be effective in a down-fired boiler arrangement.

- Urea injection has not been used before on a U.S. coal-fired utility boiler.

To minimize the risks noted above, the low-NO_x burner system has been designed to include improved fuel distribution, the XCL burner's ability to measure and control secondary air distribution, and the ability to add turning vanes to correct air flow problems, if encountered. In addition, cold shop testing will be performed to verify mechanical operation of the burner components.

In addition to the measures taken to reduce the risks associated with the burners, other measures are being taken to reduce potential risks with other systems. For example, the mixing effectiveness of the NO_x ports will be assessed prior to the retrofit using B&W computer models and the NO_x ports are provided with manual mixing adjustments, which should further minimize the risk of the ports being ineffective. Careful temperature profile probing of the boiler prior to the retrofit is planned in order to minimize risks.

Based on the considerations stated above, a moderate risk level has been assigned to this project.

3.3.1.1 Similarity of the Project to Other Demonstration/Commercial Efforts

The principal systems that make up the Integrated Dry NO_x/SO_2 Emission Control process are low-NO_x combustion techniques, urea injection, and dry reagent injection. The advantage of the Integrated Dry NO_x/SO_2 Emission Control process is that it removes both NO_x and SO_2 from flue gas.

The low-NO_x combustion techniques are extensions of the same principles used in commercially available low-NO_x burners and overfire air systems. As noted previously, B&W is supplying XCL combination pulverized coal, natural gas, and oil-fired burners for ENEL. In addition, XCL burners, calcium-based sorbent injection, and humidification have been tested at Ohio Edison's Edgewater Plant as part of the Clean Coal I - LIMB demonstration project. Also, sodium-based reagent injection has been tested at Cameo, Nixon and Cherokee Steam Electric Generating Stations. Urea injection has been successfully used commercially in Europe on units ranging in size from 75 MWe to 325 MWe.

Demonstrations of some of the technologies involved in this project are being demonstrated in projects sponsored by B&W, Energy and Environmental Research Corporation, and Southern Company Services. However, none of these projects combines the mix of technologies that the PSCC project will demonstrate.

There are also projects in the Clean Coal Technology Program that will demonstrate combined SO_2/NO_x removal technologies. These are the SOX-NOX-ROX Box, WSA-SNOX, and NOXSO processes. These are sponsored by B&W, Combustion Engineering, and MK-Ferguson, respectively. The SOX-NOX-ROX Box process uses sorbent injection for SO_2 removal and ammonia injection for NO_x destruction. The reaction of NO_x and ammonia is promoted by a catalyst in a high-temperature baghouse. The WSA-SNOX process also uses a catalytically-promoted ammonia-NO_x reaction followed by catalytically oxidizing the SO_2 and SO_3 and absorbing the SO_3 in dilute sulfuric acid to produce a commercial grade of sulfuric acid. The NOXSO process uses a regenerable sorbent to remove both NO_x and SO_2. The NO_x is removed from the sorbent and recycled to the boiler where it is either destroyed or suppresses additional NO_x formation. The sulfur is removed from the sorbent as a mixture of SO_2 and H_2S which are catalytically reacted to form elemental sulfur, a salable byproduct.

3.3.1.2 Technical Feasibility

B&W has been developing low-NO_x burners since the early 1970s. The XCL burner, which will be used in this demonstration project, represents the latest advancement in B&W low-NO_x burner technology. The retrofit of these burners in a down-fired unit will further extend the advancement of the technology. In addition, the technical information gained by B&W in their work with the LIMB and Coolside processes at the Edgewater Station will be beneficial to the development of the calcium-based injection system and the humidification system.

PSCC has been investigating dry sodium-based injection systems since the 1970s. During this period, dry sodium-based reagent injection systems have been operated at the Cameo, Arapahoe, and Cherokee plants. In addition, PSCC, in conjunction with EPRI, has conducted extensive laboratory testing to determine the reactivity and material handling characteristics of various sodium reagents.

The experience of the project team members combined with the successful test work, commercial operation of the various components of the process, and the extensive data base resulting from the prior work indicate that the Integrated Dry NO_x/SO_2 Emission Control System technology is feasible. The success of this demonstration will add credibility to the work previously performed and will prove that 70% reductions in SO_2 and NO_x emissions are possible with little or no risk to the user.

3.3.1.3 Resource Availability

Adequate resources are available for this project. The demonstration will not impact the quantity of coal presently utilized at the Arapahoe Steam Electric Generating Station Unit No. 4; however, during project testing, it is planned that high-sulfur Illinois coal will be burned to verify the effect of the burner/urea/reagent system on NO_x and SO_2 removal when using high-sulfur coal.

This Illinois coal will be available prior to post-retrofit testing. In addition, the demonstration will utilize different types of reagents, such as sodium bicarbonate, a sodium sesquicarbonate material, and a calcium-based sorbent. The supply of these raw materials is anticipated to be adequate not only for the demonstration project, but also for commercialization of the technology.

Construction will be carried out by PSCC personnel and outside contractors, and operation will be carried out by existing PSCC personnel. Therefore, no new hires are anticipated and the project will have minimal economic impact. The project will produce approximately 8,000 tons of additional solid waste over the life of the project. The solid waste will be sent to a PSCC or third party landfill. The landfill will be designed, constructed, and operated in accordance with the requirements of Colorado. The average water withdrawal, 34,000 gallons per day, is within the normal variation of water usage by the plant and well within PSCC's withdrawal limits. This quantity of water will not impact the ecology of the South Platte River and will have no perceptible impact on the flow of the river.

This program involves a pre-NSPS boiler installation. The unit is a fully operational steam-boiler and turbine-generator set with appropriate facilities and scheduling flexibility to accommodate this project. The site selected for the proposed demonstration will provide an excellent opportunity to evaluate the technology in essentially all of the situations that are likely to be encountered in the commercialization of the technology. All appropriate resources can be made available to the site, such as coal, urea, sodium-based reagent, calcium-based reagent, etc. In addition, adequate funds have been committed to cover the Participant's share of the estimated project costs.

3.3.2 Relationship Between Project Size and Projected Scale of Commercial Facility

The Arapahoe Steam Electric Generating Station Unit No. 4 is of sufficient size to avoid scale-up problems, while minimizing the cost associated with the demonstration retrofit. In addition, the individual XCL burners and NO_x ports are of a size that is typical of utility units. Scale-up to larger units would generally require only an increase in the number of burners and NO_x ports. The urea and reagent injection systems and humidification have been tested and used on units of the same size as Arapahoe Unit No. 4 and larger; therefore, no scale-up risks are anticipated for the demonstration or for larger commercial applications since any scale-up will be well within accepted scale-up practice. Based on these considerations, this demonstration should prove the technical and economic feasibility of the Integrated Dry NO_x/SO_2 Emission Control process without further demonstration.

3.3.3 Role of Project in Achieving Commercial Feasibility of the Technology

This project will demonstrate, at utility scale, a new integrated combustion and flue gas clean-up technology for the removal of acid-rain-causing emissions. The project is directed particularly at down-fired units, but the results can also be applied to other types of units. The down-fired units represent a market for which there is currently no demonstrated low-cost NO_x and SO_2 removal system. Consequently, the commercialization of the technology requires a comprehensive data base that demonstrates the emission control, performance enhancements, reliability, and cost effectiveness of the technology. Commercialization also requires the means to transfer data regarding the technology directly to industry. Therefore, project information that is applicable and non-proprietary will be made available to the utility industry and to other potential users of the technology. One team member, EPRI, is particularly suited to disseminating the information gained in this project.

3.3.3.1 Applicability of the Data to be Generated

The demonstration project will be fully instrumented and provided with a new control and data acquisition system. The new controls will include burner drives, damper drives, air and gas flow measuring equipment, gas valves and flow regulators, and flame scanners. The control system will regulate the air and the fuel; control the flame safety system; control the urea, dry reagent injection, and humidification systems; and gather and process data from the emission monitors. The control system will also include on-site training for operators and maintenance personnel.

The control and data acquisition systems will provide all the data necessary to fully characterize the operation of the boiler before and after retrofit and the performance of the Integrated Dry NO_x/SO_2 Emission Control System during the demonstration project. This will allow a comprehensive technical and economic evaluation of the system and will provide the data necessary for other potential users of the technology to determine if this technology is suited to their needs. This type of data is essential to successful commercialization.

3.3.3.2 Identification of Features that Increase Potential for Commercialization

The Integrated Dry NO_x/SO_2 Emission Control System has a number of characteristics that enhance its prospects for commercialization. These include a number of factors dealing with process economics, performance and reliability. Once proven, these characteristics should lead to the acceptance of the technology as a viable means to control NO_x and SO_2 emissions from coal-fired boilers.

Specifically, commercialization of the technology will be aided by:

- The use of proven, commercially available equipment
- *Simultaneous removal of 70% of the NO_x and 70% of the SO_2*
- Low capital cost
- Low to moderate operating and maintenance costs
- Reagent flexibility (sodium or calcium based) depending upon cost and disposal requirements
- Formation of dry, free flowing, non-toxic reaction products, which are removed by the downstream particulate control equipment and easily disposed of with the rest of the fly ash
- Minimal space requirements will aid in retrofit applications

If successful, this demonstration will establish that the Integrated Dry NO_x/SO_2 Emission Control System is an effective, reliable and economic approach to the control of the two major pollutants associated with acid rain. The technology has the potential to penetrate not only the pre-NSPS down-fired and wall-fired wet bottom utility boiler market, but also the pre-NSPS dry bottom wall-fired utility boiler market and the industrial boiler market.

3.3.3.3 Comparative Merits of Project and Projection of Future Commercial Economics and Market Acceptability

Down-fired and wet bottom boilers emit relatively high levels of NO_x. At the present time there is no low-cost, proven technology to reduce NO_x on these units. *The Participant estimates that retrofit of conventional wet scrubbing* systems will be very expensive. Consequently, there is a need for a new technology that is efficient, economical, and reliable and can be retrofitted to these units. The Integrated Dry NO_x/SO_2 Emission Control process combines NOx and SO_2 removal. It requires lower capital and operating costs when compared with conventional systems.

The Participant has made economic comparisons between this process using different absorbents and SCR combined with wet or dry scrubbers for a 500 MWe boiler. The absorbents included nahcolite, trona, lime at 1000 °F and lime at 300 °F. The total capital cost, when burning 1% sulfur coal, of the various retrofits using this process ranges from about $130/kw to $160/kw versus $300/kw to $320/kw for SCR combined with a wet or dry scrubber system. The nahcolite and trona based Integrated Dry NO_x/SO_2 Emission Control systems are the least expensive to retrofit, while both lime systems are about the same in total capital cost. Total annual operating costs range from about 1.70 mills/kwh to 4.20 mills/kwh for this process compared to about 5.80 mills/kwh to 6.20 mills/kwh for SCR combined with wet or dry scrubber systems.

The Participant estimates that the total capital cost for employing this process, using 2.5% sulfur coal, ranges from about $150/kw to $185/kw versus $310/kw to $330/kw for SCR combined with wet or dry scrubbers. Total annual operating costs for all but the trona-based Integrated Dry NO_x/SO_2 Emission Control System range from about 2.90 mills/kwh to 5.40 mills/kwh compared to about 6.80 mills/kwh to 7.30 mills/kwh for SCR combined with wet or dry scrubbers. The trona-based system total annual operating cost is higher than the conventional systems by about 2 mills/kwh, because of the potentially high cost of the reagent. If the reagent can be purchased for $100/ton or less, then the total annual operating costs will be competitive with conventional systems.

The costs associated with using this technology, combined with a successful demonstration, will establish the Integrated Dry NO_x/SO_2 Emission Control System as a viable alternative to other new and established flue gas clean-up systems. Successfully removing 70% of the acid rain precursors from the flue gas in a reliable and economic manner is expected to gain market acceptability for this technology.

4.0 ENVIRONMENTAL CONSIDERATIONS

The NEPA compliance procedure, cited in Section 2.2, contains three major elements: a Programmatic Environmental Impact Statement (PEIS); a preselection, project-specific environmental analysis; and a post-selection, site-specific environmental analysis. DOE issued the final PEIS to the public in November 1989 (DOE/EIS-0146). In the PEIS, results derived from the Regional Emissions Database and Evaluation System (REDES) were used to estimate the environmental impacts that might occur in 2010 if each technology were to reach full commercialization, capturing 100 percent of its applicable market. These impacts were compared to the no-action alternative, which assumed continued use of conventional coal technologies through 2010 with new plants using conventional flue gas desulfurization to meet New Source Performance Standards.

Next, the preselection, project-specific environmental review focusing on environmental issues pertinent to decision-making was completed for internal DOE use. The review summarized the strengths and weaknesses of each proposal against the environmental evaluation criteria. It included, to the extent possible, a discussion of alternative sites and/or processes reasonably available to the offeror, practical mitigating measures, and a list of required permits. This analysis was provided for the Source Selection Official's use before the selection of proposals.

As the final element of the NEPA strategy, the Participant (PSCC) submitted the environmental information specified in the PON. This detailed site- and project-specific information formed the basis for the NEPA document prepared by DOE. This document, prepared in compliance with 40 CFR parts 1500-1508, must be approved before federal funds can be provided for construction and operation activities.

In addition to the NEPA requirements outlined above, the Participant has prepared an Environmental Monitoring Plan (EMP) for the project. The purpose of the EMP is to ensure that sufficient technology, project, and site environmental data are collected to provide health, safety, and environmental information for use in subsequent commercial applications of the technology.

The expected performance characteristics and applicable market for the Integrated Dry NO_x/SO_2 Emission Control System technology were used to estimate the environmental impacts in 2010 which would result from full commercialization of this technology. The REDES model was used to compare Integrated Dry NO_x/SO_2 Emission Control technology impacts to the no-action alternative.

Projected environmental impacts from commercialization of the Integrated Dry NO_x/SO_2 Emission Control System technology into national and regional areas in 2010 are given in Table 1. Negative percentages indicate decreases in emissions or wastes in 2010. Conversely, positive values indicate increases in emissions or wastes. These results should be regarded as approximations of actual impacts.

Table 1. Projected Environmental Impacts in 2010
(Percent Change in Emissions and Solid Wastes)

Region	Sulfur Dioxides	Nitrogen Oxides	Solid Wastes
National	-38	-11	+ 8
Northeast	-56	-17	+10
Southeast	-41	-14	+ 9
Northwest	- 8	- 4	+ 6
Southwest	-12	- 5	+ 2

Source: Programmatic Environmental Impact Statement (DOE/EIS-0146) November, 1989.

As shown in Table 1, the overall trend presented by the analysis for commercialization of the Integrated Dry NO_x/SO_2 Emission Control System technology shows decreases in both sulfur dioxide and nitrogen oxides, and a small increase in solid waste production. The largest reductions of sulfur dioxide and nitrogen oxides emissions occur in the eastern regions because of the large amount of coal used in the area. The least impact occurs in the Northwest because of the minimal use of coal there. The national quadrants used in this study are depicted in Figure 4.

5.0 PROJECT MANAGEMENT

5.1 Overview of Management Organization

The project will be managed by the Participant's (PSCC's) Project Manager. He will be the principal contact with DOE for matters regarding the administration of the Cooperative Agreement between PSCC and DOE. The DOE Contracting Officer is responsible for all contract matters and the DOE Contracting Officer's Technical Representative (COTR) is responsible for technical liaison and monitoring of the project.

In addition to DOE and PSCC, the project will be co-funded by EPRI.

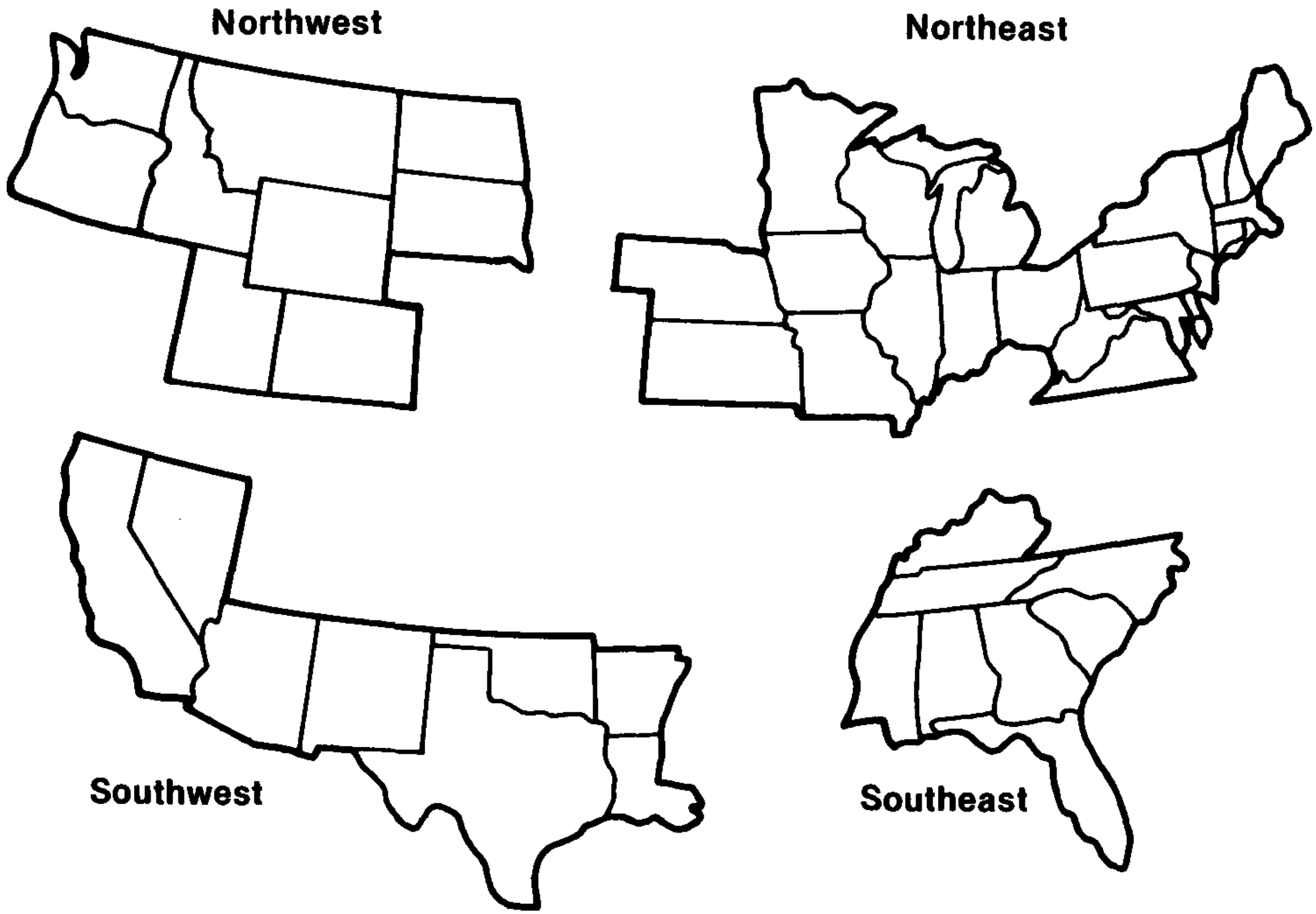

FIGURE 4. QUADRANTS FOR THE CONTIGUOUS UNITED STATES.

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5.2 Identification of Respective Roles and Responsibilities

DOE

The DOE shall be responsible for monitoring all aspects of the project and for granting or denying approvals required by the Cooperative Agreement. The DOE Contracting Officer is the authorized representative of the DOE for all matters related to the Cooperative Agreement.

The DOE Contracting Officer will appoint a COTR who will be the authorized representative for all technical matters and will have the authority to issue "Technical Advice" which may:

- Suggest redirection of the Cooperative Agreement effort, recommend a shifting of work emphasis between work areas or tasks, and suggest pursuit of certain lines of inquiry which assist in accomplishing the Statement of Work.

- Approve those technical reports, plans, and items of technical information required to be delivered by the Participant to the DOE under the Cooperative Agreement.

The DOE COTR does not have the authority to issue technical advice which:

- Constitutes an assignment of additional work outside the Statement of Work.

- In any manner causes an increase or decrease in the total estimated cost, or the time required for performance of the Cooperative Agreement.

- Changes any of the terms, conditions, or specifications of the Cooperative Agreement.

- Interferes with the Participant's right to perform the terms and conditions of the Cooperative Agreement.

All Technical Advice shall be issued in writing by the DOE COTR.

Participant

The Participant's Project Manager is the authorized representative for the technical and administrative performance of all work to be performed under this Cooperative Agreement. He will be the single authorized point of contact for all matters between the Participant and DOE. The Participant (PSCC) will be responsible for all aspects of project performance under this Cooperative Agreement as set forth in the Statement of Work.

PSCC will manage the project, engineer the dry reagent injection system and the modifications to the fly ash system, provide the host site, train the operators, provide start-up services and maintenance, and assist in the testing program.

Stone & Webster Engineering Corporation will assist PSCC with their engineered systems, provide construction management services, and assist in the testing program. B&W will be responsible for engineering, procurement, fabrication, installation, and shop testing of the XCL burners, NO_x port humidification equipment, and associated controls; will assist in the testing program; and will be responsible for commercialization of the technology. The Fossil Energy Research Corporation will conduct the testing program. Western Research Institute will characterize the waste materials and recommend disposal options. The Colorado School of Mines will assist in the engineering and design effort by providing research and testing. Cyprus Coal, Amax Coal, and Coastal Chemical, Inc. will supply the coal and urea to the project. The team members will interface with each other and the DOE as shown in Figure 5, Project Organization.

5.3 Summary of Project Implementation and Control Procedures

All work to be performed under the Cooperative Agreement is divided into three phases. These phases are:

Phase I: Design (12 1/2 months)
Phase IIA: Long-Lead Equipment Acquisition (12 1/2 months)
Phase IIB: Construction (12 months)
Phase III: Operation (28 months)

The total project encompasses a 44 1/2-month period. Phase I and IIA will run concurrently and there will be an eight month overlap between Phase I and Phase IIB. Phase III will start upon completion of Phase IIB.

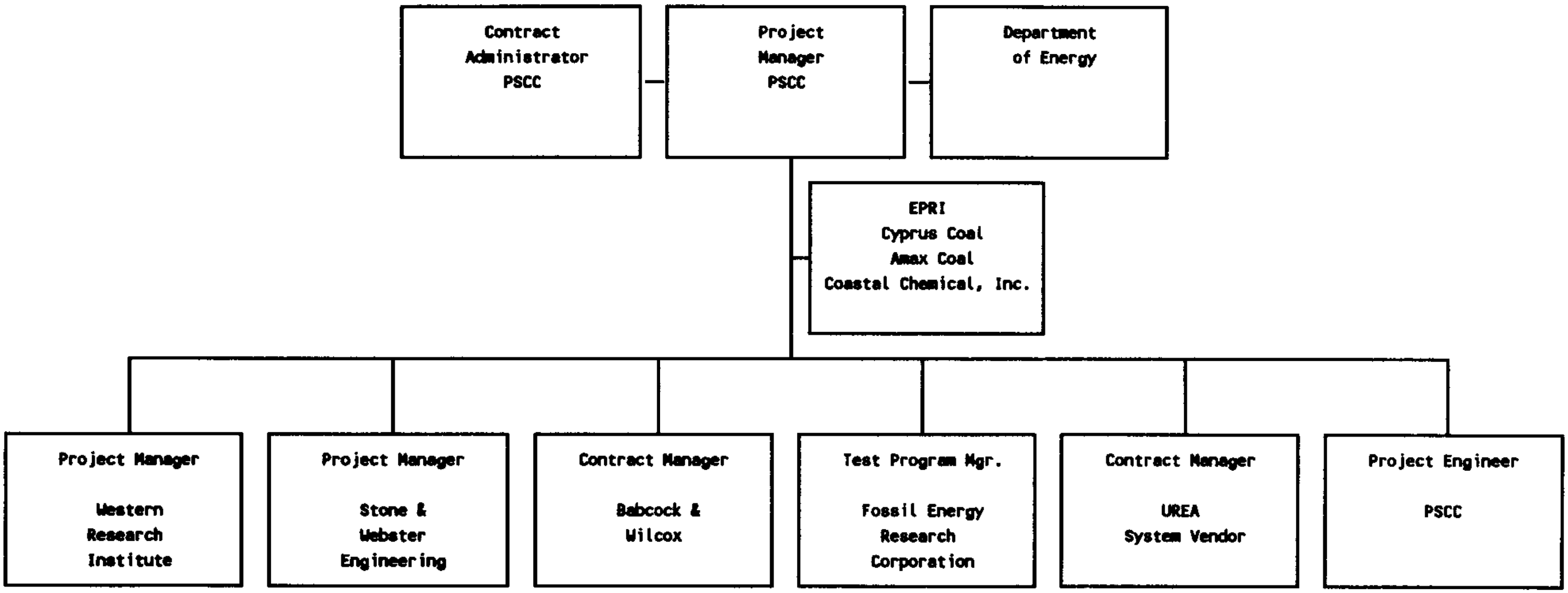

FIGURE 5. DEMONSTRATION PROJECT ORGANIZATION.

Two budget periods will be established. Consistent with P.L. 100-446, DOE will obligate funds sufficient to cover its share of the cost for each budget period. Throughout the course of this project, reports dealing with the technical, management, cost and environmental monitoring aspects of the project will be prepared by PSCC and provided to DOE.

5.4 Key Agreements Impacting Data Rights, Patent Waivers, and Information Reporting

PSCC has filed the necessary documentation required to obtain a patent for the Integrated Dry NO_x/SO_2 Emission Control technology. B&W has developed and owns the rights to the XCL low-NO_x burner technology, the NO_x port system, and the humidifier system. B&W will retain the rights to these systems for subsequent commercialization. The urea injection system is currently available from several manufacturers. The sodium and calcium reagent injection technology was partially developed by B&W and is partially available commercially. Negotiations will be conducted between B&W and PSCC to establish an appropriate commercial licensing arrangement for the use of this system where urea and sodium reagent injection are used. This will enable B&W to achieve full commercialization of the technology.

5.5 Procedures for Commercialization of the Technology

B&W will be responsible for commercialization of the Integrated Dry NO_x/SO_2 Emission Control process and the individual subsystems. In parallel with the demonstration project, detailed marketing and system offering/procurement plans will be developed along with engineering standards for use in proposal preparation and future unit design. Since the equipment comprising this process is similar to existing environmental control and combustion equipment designed and manufactured by B&W, systems are already in place to address the design, manufacturing, and marketing requirements. Utilities usually provide their own financing for retrofit projects. If required, however, financing arrangements can potentially be obtained through B&W or one of its line-of-credit banks or delayed payment arrangements can be made.

The most difficult retrofit situations are down-fired and wet bottom boilers. These boilers emit relatively high levels of NO_x which range from 1.2 to over 2 lbs. per million Btu. Presently, there is no low-cost, proven technology to reduce NO_x emissions from these units. Because these units are designed to be small and compact, retrofit of wet scrubbers will be very expensive. There are approximately 6410 MWe (65 units) of down-fired boiler capacity still in operation. Forty-five of these units are coal fired, fifteen are oil fired and five are gas fired. In addition, there are approximately 4000 MWe (29 units) of wall-fired wet bottom boilers that could use a variation of the Integrated Dry NO_x/SO_2 Emission Control process. The overall primary market is about 10,000 MWe contained in 94 units. In addition, a secondary market of 42,000 to 72,000 MWe for the application of the SO_2 and possibly NO_x control portion of the process will exist for pre-NSPS boilers which burn coals producing greater than 1.2 lb of SO_2 per million Btu and which have electrostatic precipitators or fabric filters which can accommodate the incremental particulate loading.

6.0 PROJECT COST AND EVENT SCHEDULING

6.1 Project Baseline Costs

The total estimated cost for this project is $26,477,878. The Participant's share and the Government's share in the costs of this project are as follows:

	Dollar Share ($)	Percent Share (%)
Pre-Award		
Government	295,000	50.0
Participant	295,000	50.0
Phase I		
Government	668,584	50.0
Participant	668,584	50.0
Phase IIA		
Government	4,459,670	50.0
Participant	4,459,670	50.0
Phase IIB		
Government	3,836,498	50.0
Participant	3,836,498	50.0
Phase III		
Government	3,979,187	50.0
Participant	3,979,187	50.0
Total Project		
Government	13,238,939	50.0
Participant	13,238,939	50.0

Cash contributions will be made by the co-funders as follows:

DOE	$13,238,939
PSCC	$11,738,939
EPRI	$ 1,500,000
TOTAL	$26,477,878

At the beginning of each budget period, DOE will obligate funds sufficient to pay its share of expenses for that budget period.

6.2 Milestone Schedule

The overall project will be completed in 44 1/2 months after award of the Cooperative Agreement. The project schedule, by phase and activity, is shown in Figure 6.

Phase I, which involves engineering and Phase IIA which involves procurement of materials, will start immediately after award and continue for 12 1/2 months. Phase IIB, construction, will overlap Phase I by 8 months and last for 12 months. Phase III, operation, will start upon completion of Phase II and last for 28 months. The final six months of the program will involve site restoration and final report preparation which are included in the Phase III work.

6.3 Repayment Plan

Based on DOE's recoupment policy as stated in Section 7.4 of the PON, DOE is to recover an amount up to the Government's contribution to the project. The Participant has agreed to repay the Government in accordance with a negotiated Repayment Agreement to be executed at the time of award of the Cooperative Agreement.

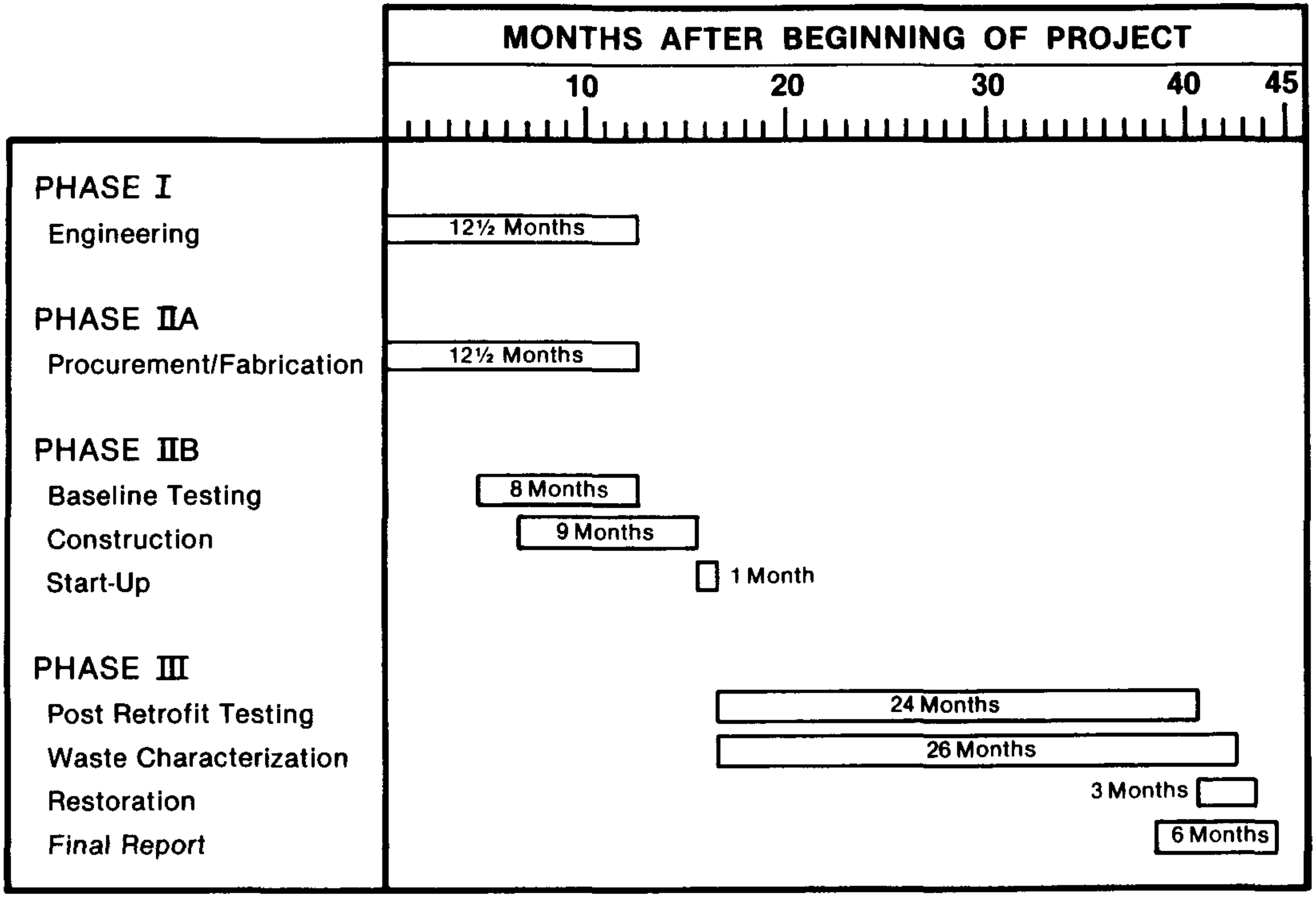

FIGURE 6. PSCC PROJECT SCHEDULE FOR ARAPHOE STATION DEMONSTRATION.

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