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Low NO_x/SO_x Burner Retrofit for Utility Cyclone Boilers

Public Design Report

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Prepared for

US Department of Energy, and Funding Parties

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Prepared by

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ABSTRACT

This Public Design Report provides, in a single document, available nonproprietary design information on the *Low NO_x / SO_x Burner Retrofit of Utility Cyclone Boilers* project. In addition to the design aspects, the history of the project, the organization of the project, and the role of the funding parties are discussed.

An overview of the Low NO_x/SO_x (LNS) Burner, the cyclone boiler and the Southern Illinois Power Cooperative host site is presented. A detailed nonproprietary description of the individual process steps, plant systems, and resulting performance then follows. Narrative process descriptions, simplified process flow diagrams, input/output stream data, operating conditions and requirements are given for each unit. The plant demonstration program and start up provisions, the environmental considerations and control, monitoring and safety factors that are considered are also addressed.

The project design in this report is described to the end of the Budget Period I (September, 1991). Any further alterations or modifications will be covered under non-proprietary Topical Reports.

Proprietary versions of the information contained in this report do exist and were cited and discussed during Project Review Meeting #2 held on April 3, 1991 in Pittsburgh, USA.

ACRONYMS

AEP	American Electric Power
B&W	Babcock and Wilcox
CCT	Clean Coal Technology
CFB	Circulating Fluidized Bed
CIPS	Central Illinois Public Service Company
DCS	distributed control system
EPA	Environmental Protection Agency
EPC	engineering, procurement, construction
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
FGD	flue gas desulfurization
HHV	higher heating value
IDENR	Department of Energy and Natural Resources
IGCC	Integrated Gasification Combined Cycle
MCR	maximum continuous rating
NEDS	National Emissions Data System
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association
NRECA	National Rural Electric Cooperative Association
NSPS	New Source Performance Standards
SCR	selective catalytic reduction
SIPC	Southern Illinois Power Cooperative
UCC	United Conveyor Company

UNIT ABBREVIATIONS

Btu	British thermal unit
°F	degrees Farenheit
in.	inches
ft	foot
ft^3	cubic foot
ft/s	feet per second
ft/m	feet per minute
gpm	gallons per minute
h	hour
hp	horsepower
iwg	inches of water gauge
k	10^3
klb	10^3 lb
kW	kilowatt
kW•h	kilowatt hour
lb	pound
M	10^6
m	meter
µm	10^{-6} meter
MBtu	10^6 Btu
MW	megawatt
MWe	megawatt (electrical)
ppm	parts per million
psia	pounds per square inch absolute
rpm	revolutions per minute
s	second
scfm	standard cubic feet per minute
W	watt
wt. %	weight percent

CONTENTS

FIGURES

TABLES

1. INTRODUCTION

1.1 SIGNIFICANCE OF CYCLONE RETROFIT PROJECT

The United States (US) Department of Energy (DOE) has awarded TransAlta Resources Investment Corporation a Clean Coal Technology II Cooperative Agreement for a retrofit demonstration of TransAlta's Low NO_x /SO_x (LNS) Burner on a cyclone boiler. The project, titled *Low NO_x / SO_x Burner Retrofit for Utility Cyclone Boilers*, is the first commercial scale demonstration of the LNS Burner on a utility boiler. Firing a high-sulfur bituminous coal, the technology will be operated in a conventional commercial power production environment by utility operators.

The significance of this demonstration project is to provide performance and environmental information on a fresh technology that promises to mitigate acid rain emissions from coal utilization. The project will assist in the further commercialization of the LNS Burner technology for all coal-fired utility power plants.

In addition to the technical aspects, the project has brought together government, utility, and private sector interests in the development of a fresh emissions control technology. This partnership is deemed essential for innovative concepts, so they may be proven at a large enough scale to enable the technology to be accepted by the utility industry as a reliable answer to the future US Clean Air Act requirements.

Further, participation by the DOE's Innovative Clean Coal Technology (CCT) Round II was essential to enable this project to proceed. The financial support provided by the CCT Program and the cooperative efforts of DOE working with private industry have opened a new era for similar future energy ventures.

1.2 PURPOSE OF DESIGN REPORT

The purpose of this design report is to consolidate the information developed during the design phase of this project and provide it in a form suitable for public information. The report contains background information and an overview of the project as well as an economic assessment and cost data for the LNS Burner applied to operating utility boilers. The report will supplement and clarify other reports and information concerning the project.

The scope of the report is limited to nonproprietary design information. Therefore, its content is insufficient to provide a complete tool in designing a LNS Burner retrofit for a utility cyclone boiler. Nevertheless, it serves to identify the design considerations involved in the retrofit activity that would be required for the retrofit of a large operating utility cyclone boiler.

1.3 HISTORY OF PROJECT

Operating cyclone-design boilers comprise only about 26,000 MW of generating capacity in the United States. The typical cyclone boiler fires a high-sulfur bituminous coal at high temperature, which results in high SO_2 and NO_x emissions. These boilers are generally older units, predecessors with respect to emission control regulations. The net result is that this relatively small fraction of coal-fired utility generating capacity is responsible for a disproportionate share of total utility boiler emissions.

New environmental regulations are anticipated for all coal-fired boilers. Clearly it would not be economical to fit conventional emission control equipment to the older cyclone units. What is needed then, if these units are to be kept in service, is a low-cost retrofit option. The LNS Burner may be such an option.

To investigate the LNS Burner for cyclone boilers, TransAlta Resources Investment Corporation initiated a retrofit feasibility study. The impetus for the study was the LNS Burner's demonstrated strong control of SO_2 and NO_x emissions and its apparent fit to existing cyclone boiler designs. The LNS Burner's combustion process operates at the very high temperatures of the cyclone and produces a similar slag product. Therefore, the LNS Burner may offer a low-cost retrofit option that would assist the utility industry in their emission control programs and likely extend the economic life of the older cyclone units that must meet new Clean Air Act requirements.

The study was initiated by TransAlta in December 1987 with the organization of an Operating Committee from utility cyclone owners. The listed companies provided representatives to guide the study and sponsored the work:

- Baltimore Gas & Electric Company;
- Union Electric Company;
- Wisconsin Power & Light Company; and,
- Electric Power Research Institute.

The study was managed by TransAlta with engineering support from Bechtel Power Company, Riley Stoker Corporation, and E. M. Griffin Inc. Throughout the program, representatives from the utility and technical organizations provided their expertise and participated in the design reviews The result of the study was a strong endorsement by the Operating Committee to continue the program with a retrofit demonstration project. Therefore, the engineering activity was accelerated to prepare a proposal to the DOE Clean Coal Technology Round II solicitation.

Of the 54 proposals received by DOE, the *Low NO_x/SO_x Burner Retrofit of Utility Cyclone Boilers* was one of 16 selected for a cooperative agreement. The cooperative agreement provides for DOE to cost share up to 50% of the project costs, with private sector funding making up the balance. With the notice of award, TransAlta in association with the funding parties formed an organization to provide guidance and funding for the project.

The project was officially announced in October 1988. Preaward activity commenced immediately to prepare the environmental documentation necessary for the approvals that are required by the National Environmental Policy Act (NEPA). Engineering design was initiated in January 1990. Construction mobilization commenced in May 1990. The Cooperative Agreement with DOE was signed June 14, 1990. The project is now expected to be operational in mid 1992, with completion in 1993.

1.4 PROJECT PLAN AND OBJECTIVES

The project consists of the required planning, design, permitting, equipment retrofit, demonstration, and subsequent return to service of the LNS Burner on a 33-MW utility cyclone boiler. Two LNS Burners, sized at 200 MBtu/h, burning a high-sulfur (nominal 3.2%) bituminous coal, will be retrofitted to the unit 1 boiler (host unit) at Southern Illinois Power Cooperative (SIPC) Marion Station near Marion, Illinois.

The primary objectives of the project are to demonstrate the LNS Burner as retrofitted to the host unit for effective, low-cost control of NO_x and SO_2 emissions while firing a bituminous coal.

The specific performance objectives for the project are to:

- Retrofit a utility cyclone boiler using the technology.
- Evaluate the long-term durability, operability, and reliability of the LNS Burner in a utility environment.
- Demonstrate the LNS Burner's control of SO_2 emissions against a criterion of 70% or greater SO_2 reduction when burning high-sulfur midwestern bituminous coals, with a project goal of meeting the New Source Performance Standards (NSPS) of 90% SO_2 reduction.
- Demonstrate the LNS Burner's control of NO_x emissions with a project goal of NO_x emissions less than 0.2 lb/MBtu (or 150 ppm) when burning high-sulfur midwestern bituminous coals.
- Demonstrate the LNS Burner's effect on cyclone boiler full-load heat rate.

1.5 SCHEDULE AND KEY TASKS

The project schedule in Figure 1 shows the sequence of engineering, procurement, and construction activities and is an integral part of project planning and management controls. Work details are generated from this document to control the project team members. The schedule also displays project scope, major activity durations, activity progress, and major milestones.

The major tasks and activities to conduct the project are described in detail in the State of Work (SOW), Attachment A, of the Cooperative Agreement and are generically as follows:

- **Manage Project**: The project management criteria require completion of the project on schedule and within budget. Performance measurement will be established with management reports.
- **Engineering**: Design and engineering criteria include the timely completion of preliminary and detailed design, equipment specifications, and procurement packages for equipment and construction.
- **Secure Permits**: Permitting criteria include obtaining the required permits, certifications, and licenses for constructing and operating the host unit with the LNS Burner.
- **Procurement and Fabrication**: Includes the procurement of equipment, materials, and services needed to fabricate the LNS Burner and retrofit the host unit.
- **Construction**: Construction criteria include making the necessary modifications for the host unit retrofit, developing/modifying documented procedures and plans for operation, determining the operating characteristics of the host unit retrofit, and preparing the host unit for demonstration tests.
- **Start Up**: Start up criteria include checking out the retrofit installation, performing all required start up testing, reviewing the existing O&M manuals of the host unit, developing plans for plant start up and for conducting demonstration operations, and training plant operating personnel.
- **Testing**: Includes demonstrating the operating characteristics of the retrofitted technology on the host unit, compiling routine and special demonstration operating data, analyzing these data in order to guide plant operation, documenting the demonstration project and its findings, and drawing conclusions on the effectiveness of the technology in limiting emissions.

- **Host Unit Return to Service**: Return to service criteria include identifying and implementing a plan for returning the host unit to commercial power generation status.

- **Baseline Testing**: Baseline testing includes obtaining baseline data and engineering data to establish the operating characteristics of the host unit.

- **Reporting**: Reporting criteria include complying with the reporting requirements as laid down by the DOE.

1.6 PROJECT FUNDING PARTIES

The project is cost-shared by TransAlta together with DOE and the other funding parties, which are listed below:

- State of Illinois; Department of Energy and Natural Resources (IDENR) with funding through the Coal Bond Fund;

- Electric Power Research Institute (EPRI);

- National Rural Electric Cooperative Association (NRECA); represented by Associated Electric Cooperative, Springfield, MO;

- Baltimore Gas & Electric Company, Baltimore, MD; and,

- Central Illinois Public Service Company (CIPS), Springfield, IL.

The role played by each of the funding parties is described below.

1.6.1 US Department of Energy's Role

DOE, as a funding party, monitors all aspects of the project and grant or deny approvals as required by the cooperative agreement between the DOE and TransAlta.

1.6.2 Illinois Department of Energy and Natural Resources' Role

IDENR, as a funding party, provides a support representative to monitor the project and be cognizant of the program status; receive information and status reports on the LNS Burner performance; and report to the State of Illinois utility cyclone owners results of the project.

1.6.3 Electric Power Research Institute's Role

EPRI, as a funding party, provides support and technical advice to document the boiler performance and emissions monitoring of the project based on their experience with fossil energy system demonstrations.

1.6.4 National Rural Electric Cooperative Association's Role

NRECA, as a funding party with responsibility to the US rural power grid, has designated a member utility, Associated Electric Power Cooperative, to monitor the project and provide guidance from their experience as a cyclone boiler operator.

1.6.5 Baltimore Gas & Electric's Role

Baltimore Gas & Electric, as a funding party, provides the project guidance from their experience as a cyclone boiler operator.

1.6.6 Central Illinois Public Service's Role

CIPS, as a funding party, provides the project guidance from their experience as a cyclone boiler operator.

1.7 ORGANIZATION OF PROJECT AND MANAGEMENT

1.7.1 Technology Management

TransAlta Resources Investment Corporation, located in Calgary, Alberta, Canada, is a nonregulated, wholly owned subsidiary of the parent utility, TransAlta Utilities Corporation (~4000 MW on coal). This subsidiary has formed a US corporation, TransAlta Technologies, Inc. (TransAlta) with offices in both Calgary and Woodland Hills (in Los Angeles), California. TransAlta provides program management, implements the project, and is the contract organization to DOE. Figure 2 identifies the project organization. TransAlta program manager oversees the overall program with support of two teams. A technology management team provides for the integrated LNS Burner design. A contract support team provides the necessary balance of plant engineering, contract support, site coordination, and construction. The following companies provide support with specialists in each field:

- Dykema Engineering; Owen Dykema, LNS Burner technology;
- Riley Stoker, LNS Burner fabrication and installation, including boiler modifications and host site support;
- E. M. Griffin, Inc., cyclone boiler consultants; and,
- Bechtel Power Corporation, balance of plant engineering and construction.

1.7.1.1 TransAlta Technologies Role

Reporting to the program manager, the TransAlta project manager oversees and coordinates the engineering, construction, and demonstration phases of the project. The technology management team coordinates the LNS Burner design and calls on specialists from Dykema Engineering; E. M. Griffin, Inc.; and Riley Stoker Corporation for specific details. TransAlta is responsible for the following:

- Develop the LNS Burner criteria;
- Coordinate the LNS Burner design and engineering;
- Provide LNS Burner start up and test criteria;
- Analyze and interpret all demonstration data;
- Provide technical data for permitting and licensing; and,
- Provide reporting and accounting for the program.

1.7.1.2 Bechtel Power Corporation's Role

Bechtel provides the contract support management for the balance of plant engineering, construction, and conduct the testing program. The contract support manager is responsible for all assigned tasks on the host site including plans, organization, and staff necessary to complete the work.

The major responsibilities of the contract support team manager are to:

- Ensure that the project team operates in conformance with project directives and policies, instructions, and guidelines;
- Assure that the project will meet all cost and schedule objectives;
- Evaluate regularly the deliveries relative to schedule, the cost of commitments against budget, the quality of the products furnished by the suppliers;
- Monitor the construction effort to ensure that job procedures are followed;
- Manage construction manpower, materials, and equipment to meet engineering and design requirements, costs, schedule, and quality objectives; and,
- Coordinate all host site functions with SIPC.

Engineering and procurement functions report directly to the contract support manager located in Gaithersburg, Maryland. The construction and demonstration test organizations are located in Marion, Illinois.

The Bechtel construction organization is headed by a construction manager, who is responsible for all construction activity using direct hire personnel, contract personnel, or a combination of both. The construction manager has key individuals reporting to him in the following typical areas: craft supervision, field engineering, cost and scheduling, field procurement, and contracts administration. The quality control function is also under the direction of the project field engineer. Modifications to the cyclone boiler and installation of the LNS Burner will be under the supervision of the Riley Stoker site manager reporting to the Bechtel construction manager.

A demonstration manager is responsible for managing and conducting the demonstration phase of the project in accordance with the Demonstration Plan. This includes equipment baseline inspections, operational readiness plans and inspections, premodification performance and air quality testing, and the postmodification demonstration tests. He is responsible for all demonstration interface activities, the unit operational plans, and coordination of all reporting and data requirements. Performance of all contracts for testing and inspection is also under his direction. He is assisted by direct hire personnel, contract personnel, or a combination of both.

1.7.1.3 Riley Stoker Corporation's Role

Riley Stoker Corporation report to both the technology management and the contract support teams with specific roles in each area. As a member of the technology management team, reporting to TransAlta, Riley Stoker provide:

- Process flow, logic, and control system design;
- LNS Burner detail engineering and fabrication drawings;
- Pulverizer, fuel feed, and support systems design;
- Computer flow modeling studies as required; and,
- Boiler expertise for all burner boiler interface criteria.

As a member of the contract support team reporting to Bechtel, Riley Stoker will fabricate and install the LNS Burner and perform the boiler modifications to complete the retrofit. In this role, Riley Stoker will perform the following:

- Provide detailed engineering for the boiler modifications;
- Provide and install the LNS Burner;
- Provide support to Bechtel engineering;
- Provide support to Bechtel construction;
- Provide support to Bechtel start up and test group;
- Provide pulverizer and fuel feed equipment;
- Provide boiler modifications/components;
- Analyze boiler performance data; and,

- Interface and train SIPC Operation and Maintenance personnel concerning LNS Burner/boiler operation.

1.7.1.4 Southern Illinois Power Co-operative's Role

Under contract to TransAlta, SIPC have provided the host unit for the project. In this major role, SIPC will:

- Operate the host unit as required;
- Participate in all project review and planning meetings; and
- Provide services necessary for supplying fuel, disposing of ash, and generating power in the operation of the host unit.

1.7.1.5 E. M. Griffin Inc.'s Role

E.M. Griffin Inc. report to the technology management team with personnel and technical expertise for design, operation, and testing of the Babcock & Wilcox cyclone boiler.

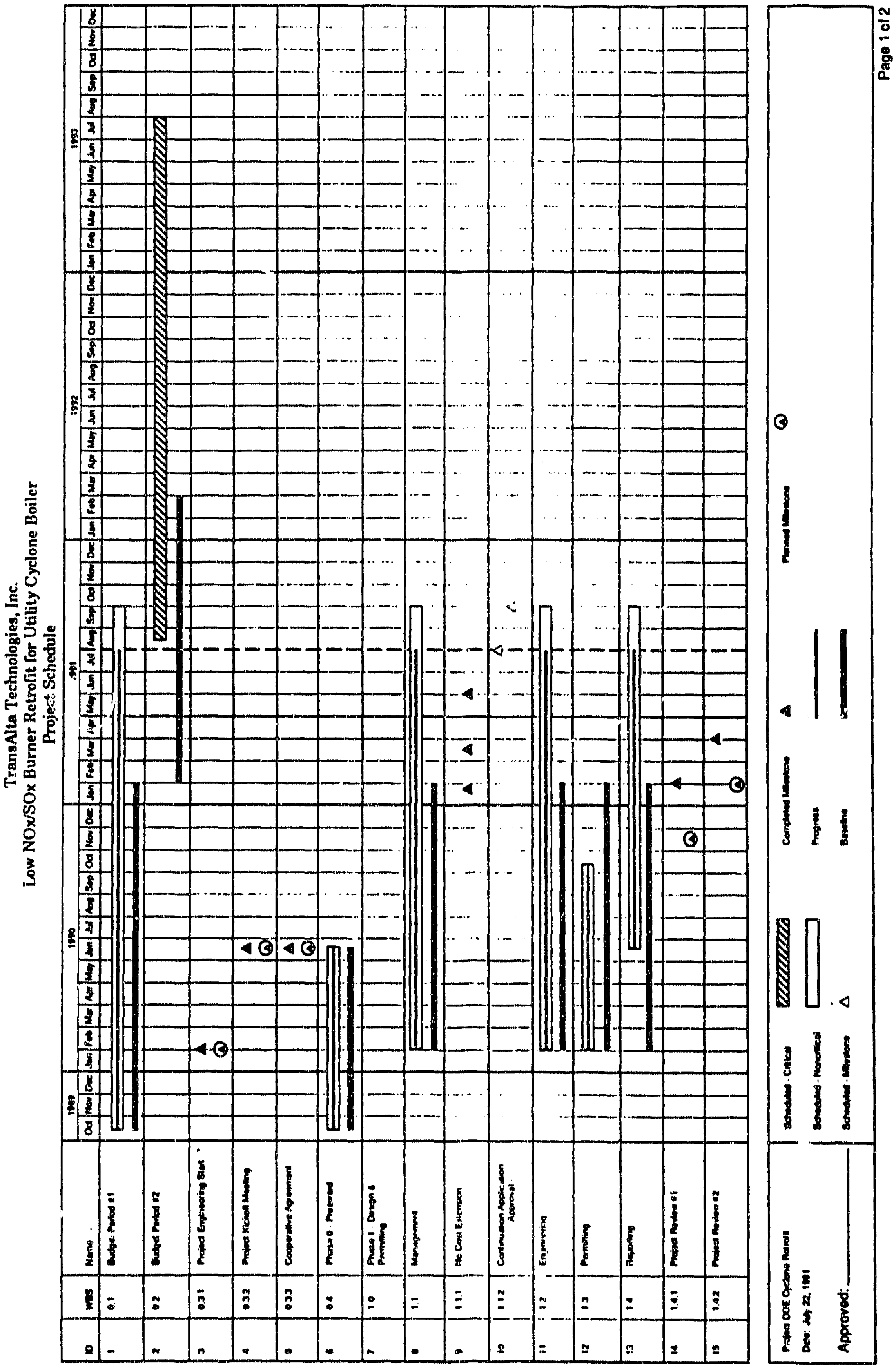

Figure 1. Project Schedule/Milestones

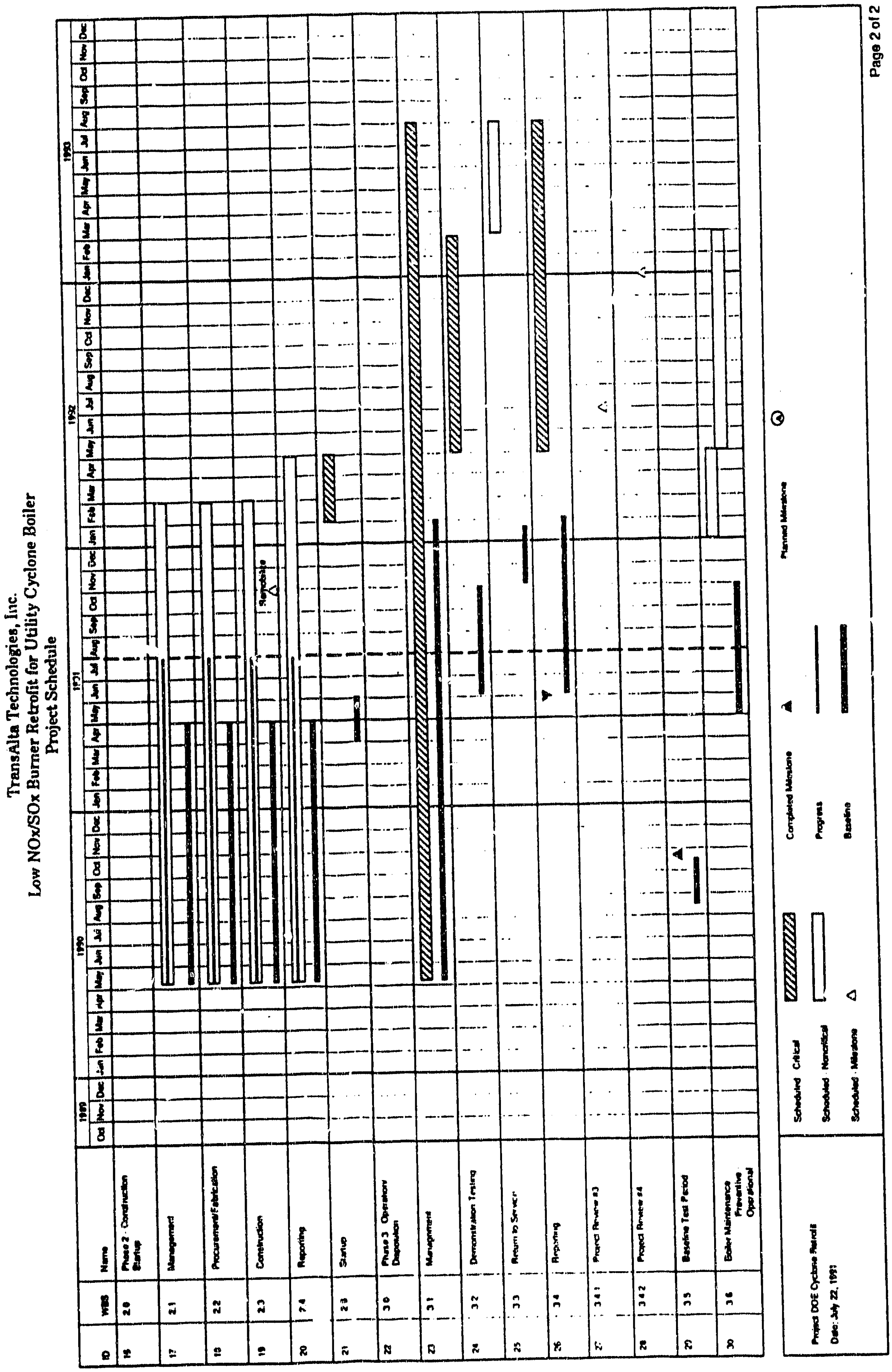

Figure 1. Project Schedule/Milestones

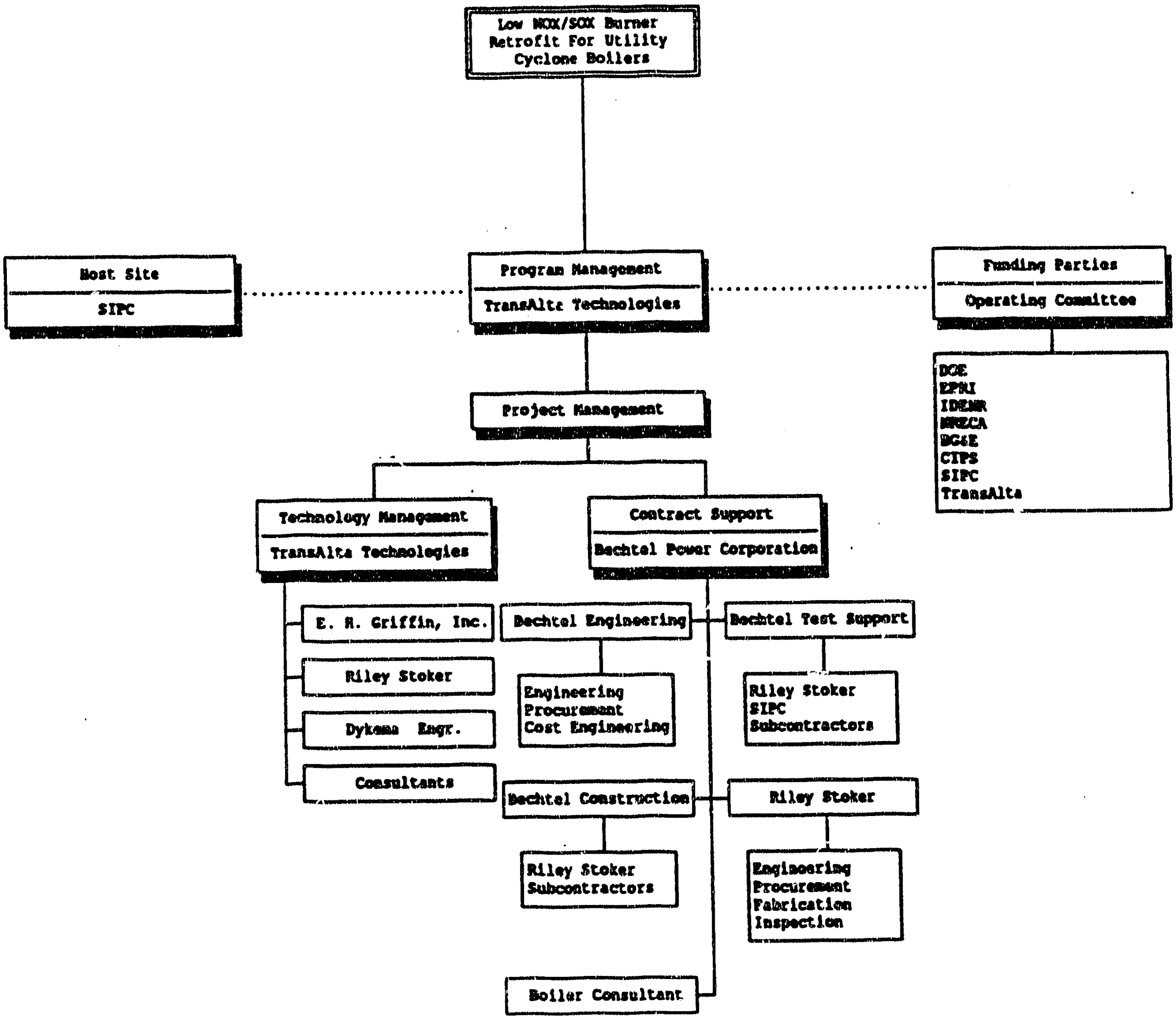

Figure 2. Project Organization

2. OVERVIEW OF PROJECT

The project consists of integrating a fresh combustion technology, the LNS Burner, with a well established boiler design, the cyclone boiler, on an operating utility power plant, the unit 1 of Southern Illinois Power Co-operative. This discussion outlines the engineering steps to retrofit the LNS Burner and then provides background on three key subjects. Appendices are provided for specific details on the cyclone boiler population and the Marion Plant host unit. Subsequent sections discuss the integration of the cyclone boiler with the LNS Burner technology.

The LNS Burner technology employs a simple innovative combustion process that achieves substantial sulfur dioxide (SO_2) and nitrous oxides (NO_x) control during the combustion process when burning pulverized coal. This technology thereby achieves control of the two major precursors to acid rain identified by the Clean Air Act. The LNS Burner also operates at high temperatures, thus maintaining the potential for high-efficiency electrical generation, for equivalent reduced carbon dioxide emissions.

2.1 LNS BURNER RETROFIT SEQUENCE

In addition to SO_2 and NO_x control, the LNS Burner's operation as a slagging burner is a feature that makes the retrofit of cyclone boilers an attractive application. As most of the infrastructure is in place, the LNS Burner may be adapted to the existing cyclone boiler design with a minimum of work. Figure 3 shows the necessary modifications schematically. The preliminary engineering studies anticipate that the installation of this equipment can be fitted to the existing plant without major modifications to the building structures. The study assumes the coal preparation equipment is located adjacent to the plant building.

The design details for each LNS Burner retrofit will differ to fit the particular boiler and plan area/layout of the plant. Generally, the changes to retrofit the cyclone plant are summarized as:

- Modifying the cyclone boiler with the LNS Burner and overfire air.
- Reworking the coal preparation and conveying system with a coal pulverizer to replace the crushed coal system.
- Providing a silo and metering system to add limestone and other additives to the coal.

The primary purpose of the LNS Burner retrofit project is to provide control of the SO_2 and NO_x emissions from the cyclone furnace. Table 2-1 summarizes the performance goals with the LNS Burner to make a successful conversion demonstration.

Table 2-1 LNS Burner Retrofit Goals

Item	Existing Cyclone	LNS Burner Goals
Size (MBtu/h)	200	200
Turn down	2:1	2:1
Slag/fly ash split (%)	60/40	80/20
Emissions at the stack (lb/MBtu)		
SO_2	5.85	1.76
NO_x	1.35	0.2
Particulates	0.1	0.1
Opacity (%)	<20	<20

There are several steps to follow in designing a retrofit application of the LNS Burner. The design approach first estimates the coal quantity, its quality, and the overall boiler heat requirements. With this information, the air and coal flow rates and the quantity of additives, such as limestone, are determined. In some cases, particularly for western subbituminous coals, the coal's calcium content is nearly adequate for the LNS Burner's sulfur control and little or no additional limestone is required. However, high-sulfur bituminous coals have very little calcium, and nearly all the required amounts must be added. Therefore, the need for coal additives affects the overall LNS Burner design/control configuration. Once the fuel and additives are specified, the LNS Burner can be sized to provide both the unit performance and the emission control requirements. Finally, the burner's control requirements are integrated with the boiler plant, thus completing the retrofit configuration.

2.2 LNS BURNER TECHNOLOGY

The LNS Burner was conceived in 1979 as the result of theoretical combustion work done at Rockwell International. This theory predicts that both the sulfur and the nitrogen compounds formed from burning coal can be reduced to zero in the combustion step. A series of concept verification tests followed by more prototypical burner tests have verified the underlying theory of the LNS Burner. TransAlta Resources Investment Corporation acquired the LNS Burner from Rockwell in 1986. TransAlta has now undertaken the task of commercializing the technology for the utility industry with an appropriate series of demonstration programs.

2.2.1 Sulfur Control

Although the LNS Burner is classed as a slagging combustor, its primary purpose is the simultaneous control of SO_2 and NO_x emissions to very low levels. The process schematic of the LNS Burner provided in Figure 4 illustrates the following steps.

The LNS Burner involves high-temperature, fuel-rich combustion. Generally, the LNS Burner operates as a gasifier in that a large fraction of the coal is gasified, thus releasing the coal's sulfur into the gas stream. Under these conditions, the sulfur is captured by calcium (using a 2:1 Ca/S ratio) that is inherent in the fuel or that is added to the coal in the form of limestone. The captured sulfur is retained as a solid in the coal ash. In addition, as the operation is at very high temperatures, the ash is molten and a simple fly ash separator at the end of the LNS Burner can be employed to remove a major fraction of the ash as a slag product. All of these operations are carried out in the burner. No solids or other fuels need be injected downstream into the boiler, and no flue gas scrubbing is necessary.

2.2.2 NO_x Control

The nitrogen in NO_x generated during coal combustion is derived from two sources: high-temperature oxidation of the nitrogen in the air (so-called *thermal* NO_x) and conversion of the nitrogen chemically bound in the fuel. The two conversion processes are quite different. In the *thermal* mechanism, the formation of the NO_x from nitrogen in the air is very sensitive to combustion temperature. At normal flame temperatures, the rate of formation of *thermal* NO_x is quite slow. Therefore, attempts to control NO_x formation via the *thermal* mechanism are based on two well understood approaches:

- Reduce the temperature (the *thermal* NO_x formation rate is very sensitive to temperature); and.
- Pass through regions of high temperature in the combustion process quickly (the rate of formation of thermal NO_x is slow) to avoid NO_x formation even in those regions.

However, the mechanism by which *fuel-bound* nitrogen is converted to NO_x is not well understood. Rockwell was one of the first to study the conversion of *fuel-bound* nitrogen to NO_x in flames and to observe that NO_x formation by this mechanism is very fast. NO_x formation occurs at the same time and at the same rate as the formation of CO and CO_2. Since it is the intent of combustion to burn a hydrocarbon fuel to CO_2, it becomes almost axiomatic that NO_x or its precursors will be formed by the conversion of *fuel-bound* nitrogen. Therefore, the approach to NO_x control followed in the LNS Burner involves driving as much of the nitrogen as possible out of the fuel, into gaseous nitrogenous species, and then providing combustion conditions under which molecular nitrogen is the thermodynamically preferred form of nitrogen.

The importance of the conversion of *fuel-bound* nitrogen in the formation of NO_x depends on the fuel. With natural gas, there is no nitrogen chemically bound in the fuel, and NO_x results entirely from the oxidation of nitrogen in the combustion air (the *thermal* mechanism). With coal, however, where the nitrogen content may be as high as 1.6 wt. % of the fuel, NO_x results almost entirely from the conversion of *fuel-bound* nitrogen. It has been estimated that NO_x from the combustion of pulverized coal in a utility boiler is about 85 to 100% from *fuel-bound* nitrogen and only 0 to 15% from *thermal* NO_x. The very high NO_x observed in the cyclone furnace, however, is very likely the result of both the conversion of *fuel-bound* nitrogen and additional large *thermal* NO_x generation.

Equilibrium combustion calculations for almost all hydrocarbon fuels show that there is a rather broad range of stoichiometry around 0.6 in. which the thermodynamically preferred form of nitrogen is molecular nitrogen. Above this "window," NO_x levels become significant. Below this window, the precursors of NO_x (HCN and NH_3) become significant. Thus, any gaseous nitrogen that may exist when the combustion stoichiometry is brought into this window must, by definition, be in "super equilibrium" (i.e., levels above that required by equilibrium). Under these conditions, all chemical kinetics that determine the equilibria of these nitrogenous species are "running" in directions leading to the conversion of these nitrogenous species to molecular nitrogen. Since (harmless) molecular nitrogen is the desired nitrogenous form, it is highly desirable that gas temperatures, under these conditions, be as **high** as possible to hasten this conversion (destruction) to molecular nitrogen. High gas temperatures, limited only by practical materials capable of containing the high-temperature gases, are a major design requirement for the LNS Burner. These temperatures are also above the melting temperatures of most coal ashes.

2.2.3 Fly Ash Separation

In applying the burner to the conversion to coal of a boiler designed for ga, or oil (and in the tight cyclone design), however, it is desirable to remove most of this fly ash before it enters the furnace. TransAlta's design for this is based on a simple, low-pressure-drop, impact-type slag separator, in which a series of tubes extend vertically through the gas stream. The hot gases are required to travel a tortuous path through this staggered array of tubes. Along this path, the larger particles are spun out of the gases and strike the tubes. Since the particles are liquid when they strike the separator tubes, they adhere to the tubes, run down, and can be removed by a slag tap at the bottom of the burner. With this design, it is expected that the remaining fly ash particles conveyed through the boiler will solidify rapidly in the radiant section and be too small to impinge and erode the boiler superheater tubes. Figure 5 shows a cross section of the slag screen concept.

2.2.4 Final Combustion

By the time that solids and gases have reached the end of the LNS Burner, all sulfur control processes, conversion of solid and gaseous nitrogenous species to N_2, and the melting of the solids have been accomplished. In addition, particularly under these high-temperature conditions, about 90% of the carbon has been burned out to CO and CO_2. The combustion gases are at high temperature (above the fluid temperature of the ash), and high in CO and H_2. SO_2 and NO_x concentrations are very low. These fuel gases exiting the LNS Burner still contain some free carbon and ash as finely divided fly ash. Final combustion takes place in the boiler furnace with added over-fire air. In the furnace:

- The remaining solid carbon is burned out;
- CO and H_2 is burned to CO_2 and H_2O; and,
- The molten fly ash cools and solidifies.

In the final stage of combustion, in the furnace, after all (excess) combustion air has been added, the remaining major combustion process requiring special attention and control involves final burnout of CO to CO_2, while simultaneously limiting the formation of any new NO_x via the thermal mechanism. This process is present in all combustion systems and furnaces even if the fuel is natural gas or low-nitrogen oil. The techniques for burning out CO to CO_2 without forming a great deal of NO_x are well known and have been described in the literature for more than a decade. The same techniques are used in gas turbine combustion and many other kinds of gas flame combustors. At temperatures between 2800 and 3100°F, CO (and H_2) burnout is a moderately fast process, while the NO_x formation rate is fairly low. Thus, the technique for burning out the CO and H_2 in the gases in the furnace without forming appreciable new NO_x is to complete the combustion very quickly while the gas temperature is in this range.

In the LNS Burner, this is accomplished by controlling the point in the furnace where the final excess air is added. Since the combustion gases entering the furnace from the LNS Burner are very hot, adding the final excess air at the burner exit can yield combustion temperatures above 3100°F. Therefore, the addition of the final air is delayed until heat rejection from the burner gases to the working medium (boiler walls) cools the gases to about 2800°F.

As a result of this CO burnout technique, the maximum gas temperature in the early part of the boiler may be a few hundred degrees Fahrenheit lower than normal. This is unavoidable and is not a function of the LNS Burner characteristics. Regardless of burner or fuel as previously stated, any combustion system for *thermal* NO_x control must avoid very high temperature gases and slow gas cooling.

2.2.5 LNS Burner Pilot Scale Test Performance

A pilot scale program was initiated in 1982 to develop empirical information necessary to design, with reasonable understanding and confidence, a Burner for a full scale operating utility boiler.

A pilot scale Test Facility, without a boiler but with a 25 MBtu/hr Burner operating at atmospheric pressure, was built near Los Angeles, California. Figure 6 shows a photograph of this facility. The program testing was conducted between 1982 and 1986. A number of tests were conducted firing both sub-bituminous and bituminous coals. While the testing was for relatively short operating periods, the LNS Burner's performance capabilities were fully characterized. Basically, all requirements for a practical and effective LNS Burner for sub-bituminous coals was demonstrated at the pilot scale. Simultaneous 70% SO_2 and 80% to 90% NO_x reduction were demonstrated while achieving over 95% carbon burnout.

Testing and development with bituminous coal was less complete than with sub-bituminous coals. NO_x emissions were reduced by 85 to 90% while

SO_2 was reduced only about 50% for the same carbon burnout of 95%. On an individual test basis, 50% SO_2 capture was achieved, identifying the need for further development to achieve consistent high sulfur capture.

Based on the pilot scale testing (no boiler) and on extensive studies of thermal NO_x formation in utility boilers, it was estimated that no more than 50 to 100 ppm of NO_x would be generated in the boiler. With the planned use of over-fire air, it was estimated that not only will no new thermal NO_x be formed in the boiler but NO_x levels at the burner exit may actually be reduced. It was therefore estimated the NO_x emission goal of 150 ppm (0.21 lb/MBtu) out the stack would be met.

2.2.6 LNS Burner Slag Separator Performance

Tests were conducted during the Pilot-Scale Program to evaluate the slag separator design. The design objective was to obtain approximately 80% removal efficiency with only a few inches of water-pressure drop with resulting fly ash particle sizes less than 10 mm. The concept tested in the Pilot Scale Test Facility (see Figure 6) consisted of water-cooled tubes extending vertically through the gas stream. These specially designed tubes were studded and coated with refractory to provide a surface for the slag to freeze on. The frozen slag protects the tube from the entrained ash. A slag tap downstream from the separator drained the collected slag. The slag formed a protective glassy coating on the surface of the water-cooled tubes. The photograph in Figure 7 shows the upstream face of the slag screen. The slag separator efficiency demonstrated during tests with both sub-bituminous and bituminous coals on the Pilot-Scale Test Facility averaged 81.3%. Pressure drop across the slag screen was generally steady at 3.5 in. of H_2O. In some cases where the pressure drop increased, the burner combustion temperatures were simply increased. With the higher temperatures providing a more fluid slag, the pressure drop returned to normal.

2.2.7 LNS Burner Demonstration on an Industrial Boiler

The first industrial demonstration of the Burner was initiated in late 1988. The LNS-CAP Project (Low NO_x SO_x Coal Application Pilot Project), located at Esso Resources Canada Mahikan heavy oil recovery site near Cold Lake, Alberta, Canada is a new facility with a 50 MBtu (3T/hr coal) LNS Burner and a heavy oil recovery steam generator. This facility was built to demonstrate the feasibility of using the LNS Burner to convert the existing natural gas fired steam generator to coal. This requirement dictated a vertical configuration of the Burner, in order that conversion would be carried out within the restricted footprint of an existing steam generator. It also dictated that the steam generator be designed similar to a typical gas fired unit, i.e., generally not designed to handle coal ash.

Performance goals for this demonstration included, in addition to SO_2 and NO_x control, goals for carbon burnout, ash removal from the gas stream before entering the boiler, slag tap operation, refractory durability, and both burner and boiler operability.

The project completed demonstration testing of a Western low sulfur sub-bituminous coal in September 1991.

2.2.7.1 LNS Burner Performance and Lessons Learned

The project encountered engineering challenges relating to tapping of the slag, loss of refractory in the burner, fouling in the steam generator and coal and air flow control.

The original design of the slag tap was small, and for mechanical reasons was offset from the centre of the burners. As a result, relatively large amounts of heat was lost from the tap. In the early stages of operation, slag tap "freezing" was experienced.

During the early operation of the Burner the refractory was being washed away and mixed with the molten slag. This significantly raised the freezing temperature of what was now a slag/refractory mixture and made continuous slag tapping a challenge. A new larger improved slag tap was designed and installed. The detailed design of the retrofit burner was reviewed and the knowledge gained on the slag flow characteristics was incorporated in the cyclone retrofit.

The original choice of refractory was based on experience gained in pilot scale program (refer Section 2.2.5). This choice proved to be incompatible with the coal burnt in the LNS-CAP Project. An intensive program was initiated to understand the chemistry of the slag/refractory interaction and to identify suitable refractory materials. A set of potential candidate refractories were selected and sample panels of each were installed in the burner to verify durability over a test run. Based on this experience a majority of the original refractory was replaced.

With the new refractory in place and with the new design of the slag tap, no more problems were experienced in tapping the slag. Final selection of the refractory for the retrofit is based on the lessons learned on the LNS-CAP Project.

Emission goals for the LNS-CAP Project are compared below in Table 2-2:

Table 2-2 Emission Goals for LNS-CAP

Emission	Project Goal	Delivered Coal	Canadian Guidelines*
SO_x lb/MBtu (ng/J)	0.3 (129)	0.5 (215)	0.6 (258)
NO_x lb/MBtu (ng/J)	0.2 (86)	0.6 (258)	0.6 (258)

* For Canadian Utility Power Plants

The measured emissions from the project have been better than the project goals. NO_x control has been clearly demonstrated. Operating the burner to achieve NO_x level below project goals was easily accomplished.

Coal sulfur levels proved to be quite variable. Since measurements were taken only on a spot basis, the continuous percent sulfur capture has been difficult to quantify. To date, it has not been possible to identify the sulfur in the slag. It is possible that the sulfur located within the slag is a very complex molecular structure, but this has proved difficult to verify. Until the sulfur is identified in the slag, the sulfur balance cannot be accurately completed. Therefore, at the time of writing this report, the analysis of the sulfur capture is inconclusive. Future developments in this area may necessitate changes to the retrofit design.

Carbon burnout achieved in the LNS-CAP project was greater than 99.9%, with only about 0.1% carbon measured in the fly ash.

Accurate coal and air flow control also proved to be an important criteria for proper Burner performance. These flows will be readily managed by a Distributed Control System (DCS), configured in the retrofit design.

At the time of writing this report, testing at the LNS-CAP project has been concluded. However, data analysis has not been completed. The results of the analysis may affect the final design of the retrofit burner.

2.3. CYCLONE BOILER DEMOGRAPHICS

Cyclone-fired boiler units are used widely in the Midwest for generating steam, primarily in large electric power plants but also by industry and large institutions for power generation and/or steam supply. Cyclone-fired primary steam generating capacity totals approximately 9% of total steam generating capacity in the United States. Cyclone boilers have traditionally been labeled high NO_x emitters, and coal-fired cyclone boilers contribute nearly 20% of total NO_x emissions from all coal-fired utility boilers in the United States.[1]

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[1] *Applicability of NO_X Combustion Modifications to Cyclone Boilers (Furnaces)*, EPA Report No. EPA-600/7-77-006, January 1977.

2.3.1 Cyclone Boiler Definition

There are several types of coal-fired boiler designs in use by the utility industry. A cyclone boiler is characterized by its use of crushed coal (roughly 0.25 inch or 50 mesh in size) fired in a round "furnace" attached to the boiler. All of the combustion air along with the coal is introduced tangentially, providing a high-velocity cyclonic flow that causes the burning coal and resulting ash to deposit on the walls of the furnace. The very hot gases from the combustion melt the ash, which then drains from the furnace. The hot gases exit into the boiler to produce steam. Figures 8 and 9 show the typical cyclone design produced by Babcock and Wilcox (B&W) for US utility cyclone boilers.

2.3.2 US Cyclone Population and Distribution

The first full-scale cyclone-furnace-fired boiler unit was placed on line in 1944 at the Calumet Station (Calumet, Illinois) of the Commonwealth Edison Company, based in Chicago, Illinois. Since then, 84 cyclone-fired installations have been built in the United States. These installations, located in 26 states and containing 149 boiler units fired by 736 cyclone furnaces, generate approximately 200 million lb/h of primary steam.

Figure 10, showing the geographical distribution of cyclone boiler units, indicates that most of these boilers and the states having the significant proportion of the steaming capacity are in Illinois, Missouri, and Indiana. These three states account for nearly half of the total cyclone steaming capacity and one-third of the boilers.[1]

A further detail of the cyclone fired-boiler population now in operation is given in Appendix A. Note that over 94% of the total primary steaming capacity is held by the electric utility sector. The primary steam generating capacities of the individual boiler units range from 127,000 to 555,000 lb/h for industrial and commercial units and from 182,000 to 8,000,000 lb/h for electric utility units. From their inception in 1944, cyclone-fired boilers were readily accepted by the utility industry, and sales were excellent. The technology was able to meet the demands of boiler owners who wished to burn low-quality, high-sulfur coals with low ash fusion temperatures. In fact, in the 1950s, 1960s, and early 1970s, cyclone boilers accounted for a large portion of Babcock & Wilcox's (B&W's) total sales. However, in 1973, B&W discontinued sales of cyclone units in favor of pulverized-coal-fired units.

2.3.3 Cyclone Unit Operating/Availability Characteristics

In general, there are fewer combustion problems with cyclone boilers than with pulverized-coal-fired (PC-fired) boilers because of their simpler coal-preparation and burner systems. The cyclone tends to maintain stable flames over wide operating ranges. Once the furnace is lit off and hot, a flame-out is unlikely, and flame detection is maintained even at low excess air, since the furnace does not go "black." Units typically operate at a carbon loss less than 0.1% and can reject up to 80% of the coal ash as a slag product. Consequently, combustion efficiencies are very high, and the amount of ash that must be handled by the baghouse or electrostatic precipitator (ESP) is only about 25% of that of PC-fired units.

Other advantages with the cyclone design include reduced boiler foot-print and fewer tons of steel per MW, as coal combustion is nearly completed in the cyclone with the boiler providing just the necessary heat absorption surfaces. Coal preparation only requires crushing, thus saving on pulverizing costs, and the cyclone can handle a wide variety of coals, particularly the poor-quality, low-fusion temperature, lower-cost coals.

The cyclone boiler operating load turndown is typically no more than 50% for extended periods of operation. Further boiler turndown is generally achieved by taking individual cyclone furnaces out of service. This lowering of the load can be tolerated only briefly because the slag temperatures in the lower boiler may soon drop below acceptable tapping temperatures.

Cyclone boilers have two high-maintenance items: the coal crusher and the cyclone refractory. As the crusher wears, the coal size distribution varies; as the cyclone liner wears, the water-cooled walls are subject to erosion/corrosion. A major disadvantage in the cyclone design is the need for high fan horse power to maintain the necessary pressure drop across the cyclone furnace. This fan power accounts for over 90% of a cyclone boiler's auxiliary power requirements.[2]

2.3.4 Generic Cyclone Emissions

Baseline emissions from cyclone boilers are defined to be those NO_x, SO_x, CO, and particulate emissions reflecting normal or near-normal boiler operation at various loads. The data base, summarized in Ref. 1, contains data from B&W, Commonwealth Edison, the open literature, and various government-funded studies as well as those contained in the National Emissions Data System (NEDS).

Emissions of SO_2 fluctuated greatly reflecting the sulfur in the coal. The highest levels occurred in high-sulfur bituminous-coal-fired units.

The data indicate that at full load none of the cyclone units was able to meet the NSPS for NO_x with respect to each fuel (bituminous coal, 0.6 lb/MBtu; oil, 0.3 lb/MBtu; or gas-fired, 0.2 lb/MBtu). In general, the full-load NO_x emission data indicate that the NO_x concentrations decrease with fuel type in the following order (from most to least): bituminous coal (1.44 lb/MBtu average), subbituminous coal and lignite (0.726 lb/MBtu average), natural gas firing (0.717 lb/MBtu average), and residual oil (0.604 lb/MBtu average).

ESPs are typically used to control particulate emissions.

2.4 SOUTHERN ILLINOIS POWER COOPERATIVE

Southern Illinois Power Co-operative (SIPC) operates a single generating plant near Marion, Illinois. The plant's net generation capacity is 272-MW. The plant contains four cyclone boilers: three 33-MW units and

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[2] *Steam--Its Generation and Use*, Babcock & Wilcox Company

one 173-MW unit. The three 33-MW units were commissioned in 1963, the 173-MW unit in 1972. The 173-MW unit generation is about 100% for summer and winter loads with one 33-MW unit providing peaking loads (generally in January and July). The other two 33-MW units are maintained on cold standby and operated when required.

All four units have precipitators; the large unit also has a wet limestone scrubber. Table 2-3 shows the emission control limits required by current regulations for each unit.

Table 2-3 Required Emission Control Limits

Unit No.	Size (MW)	Particulates (lb/MBtu)	NO_x (lb/MBtu)	SO_x (lb/MBtu)
1-3	33	0.1	None	6.0
4	173	0.1	None	1.2

A photograph of the Marion Station is shown in Figure 11. The plan view of the Marion station is shown in Figure 12.

2.4.1 Host Site Facilities, Marion Station, Unit 1

SIPC's unit 1 is a front-wall-fired two cyclone furnace Babcock & Wilcox boiler rated at 33 MW. A sectional view of the boiler showing the general furnace and convective pass arrangement is provided in Figure 13. The photograph in Figure 14 shows an operator's view of the front right-hand cyclone on Marion unit 1. The overall unit design is typical of later cyclone furnaces. Total slag-fly ash rejection control relies on the cyclone reentrant throat design (see Figure 8). Table 2-4 shows the calculated design parameters of Marion unit 1 before modification. Appendix B provides further information. Note that unit 1 also shares a common stack with the Marion Station unit 2. This will require that unit 2 be off line when stack emissions data are required from unit 1.

2.4.2 Horizontal Cyclone Furnace

The horizontal cyclone furnaces on Marion unit 1 are about 7 ft in diameter by 9.5 ft long. The cyclone furnace walls and reentrant throat are fabricated from water-cooled tubes. The tubes are studded and coated with refractory for protection from the high heat fluxes in this region.

Each cyclone furnace has a heat input of about 200 MBtu/h. Crushed coal is introduced through a center rotary distributor along with tertiary air and immediately swirled by the incoming tangential primary air input at the head end of the cyclone. Secondary air is introduced downstream tangentially into the cyclone barrel, as shown in Figures 8 and 9.

The pressure drop across the cyclone furnace is approximately 26 in. H_2O. The volumetric heat release for each cyclone is about 550,000 Btu/h•ft^3. The cyclone furnace operates at 13% excess air. Combustion occurs primarily along the chamber wall zone in the mixture of slag and coal. The slag formed flows down the chamber wall and passes into the boiler through a key slot that is located in the lower portion of the cyclone furnace back wall. To minimize slag carryover in the gas stream to the lower furnace, the reentrant throat is designed to provide adequate aerodynamic flow. Typical slag (bottom ash) rejection rates are about 50%. Control of the cyclone combustion temperature is critical to achieving proper slag flow.

2.4.3 Boiler Unit

The boiler radiant section is divided into two parts as shown in **Figure 13**. The lower section, 19 ft wide by 6 ft deep, is refractory lined to keep the temperature of the slag high, to ensure adequate tapping from the boiler bottom. Typical gas temperature in the lower section is over 3000°F. Some heat extraction occurs in the lower section, but most occurs in the upper bare tube zone. The upper boiler section is 19 ft wide by 12 ft deep. The overall height of the furnace is 55 ft. The average temperature entering the high-temperature superheater is 1900°F. The overall pressure drop across the cyclone furnace and boiler system is approximately 42 in. H_2O. Platens connected to the cyclone furnace water wall are located in the upper boiler section to provide additional heat transfer surface and the necessary cyclone cooling flow. The Marion Station unit 1 calculated boiler performance is summarized in Table 2-4.

Table 2-4 Calculated Unit 1 Boiler Performance

Marion Unit 1	Original Design
Steam flow (lb/h)	335,000
Coal Flow (lb/h)	37,000
Additive (lb/h)	0
Excess air leaving air heater (%)	16
Flue gas leaving air heater (°F)	330
Air entering air heater (°F)	110
Ash tapped as slag (%)	60 [1]
Waste Disposal (lb/h)	
Slag	3780
Fly Ash	2440
Emissions (lb/MBtu)	
SO_x	5.85
NO_x	1.35
Particulates	0.1
Efficiency Losses (%)	
Dry gas	4.89
$H_2 + H_20$ in fuel	4.56
Moisture in air	0.10
Unburned comb.	0.10
Radiation	0.40
Slag heat loss	0.85
Unaccounted & mfg. margin[2]	0.65
Total losses	11.55
Boiler efficiency (net)	88.45

1 Assumed
2 1.5% unaccounted for and manufacturer's margin less calculated slag heat loss.

2.4.4 Marion Station Emissions

The current emission requirements for the Marion Station unit 1 are noted in Table 2.4. The only control criteria are for SO_2 and particulates; no control requirements are imposed for NO_x. The present SO_2 emissions are not measured and are controlled by blending Illinois #5 or 6 coal with mine washings to achieve permitted coal sulfur content. Actual SO_2 and NO_x emissions from unit 1 have now been measured and are presented in Section 5, under baseline testing.

2.4.4.1 Particulate Emissions

Unit 1 utilizes both a multiclone cyclone separator for removal of coarse material and an electrostatic precipitator for control of particulate emissions. The permitted particulate emission rates are 0.1 lb/MBtu.

2.5 COAL AND LIMESTONE RESOURCE

2.5.1 Coal

The coal currently being fired at SIPC is a blend of raw Illinois #5 or 6 seam coal and GOB. GOB is the term for the inexpensive high-Btu-content coal fines from the mine washing operation. The ultimate and proximate ash analyses for the design basis coal are presented in Table 2-5.

Table 2-5 Coal Properties (As Received) for Marion Unit 1

Ultimate Analysis (% wt)	
C	59.00
H	3.75
O	6.27
N	1.35
H_2O	10.73.
S	3.20
Ash	15.73
HHV (Btu/lb)	10,553

2.5.2 Limestone

The limestone selected for the project will be the same as presently used in SIPC's wet scrubber for unit 4. The limestone properties are shown in Table 2-6.

Table 2-6 Typical Limestone Composition

Component	% wt
$CaCO_3$	95
$MgCO_3$	1.5
Inerts	3.5

2.5.3 Other Additives

A small quantity of other additives may also be used in the preparation of the fuel for the LNS Burner. This additive is the subject of a patent in process and is therefore considered proprietary. The purpose of the additive is to condition the resulting slag product. The additive is an inexpensive, inert (nonreactive), nonsoluble, nonmetallic inorganic compound that becomes fused in the slag.

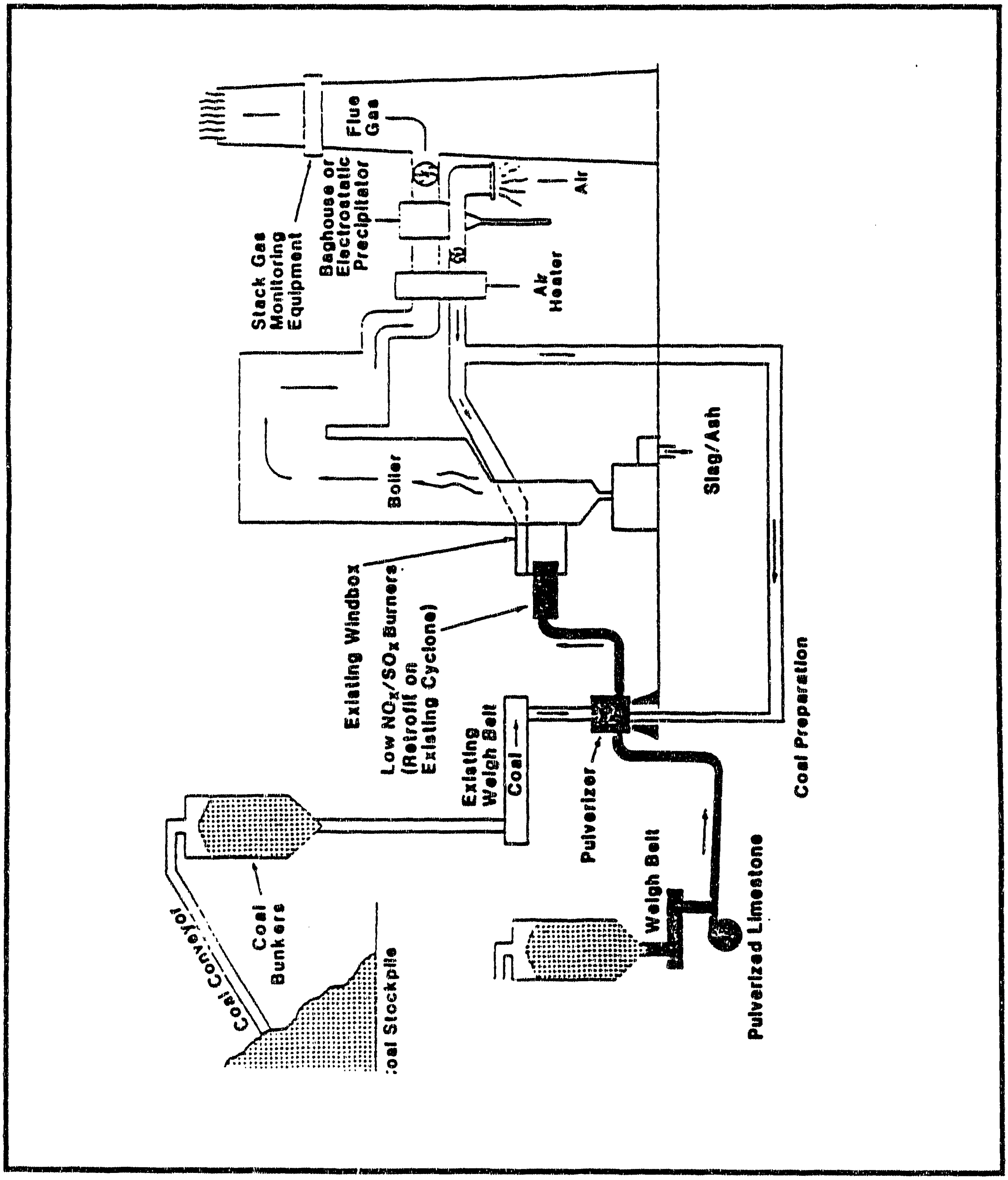

Figure 3. LNS Burner/Cyclone Retrofit Schematic

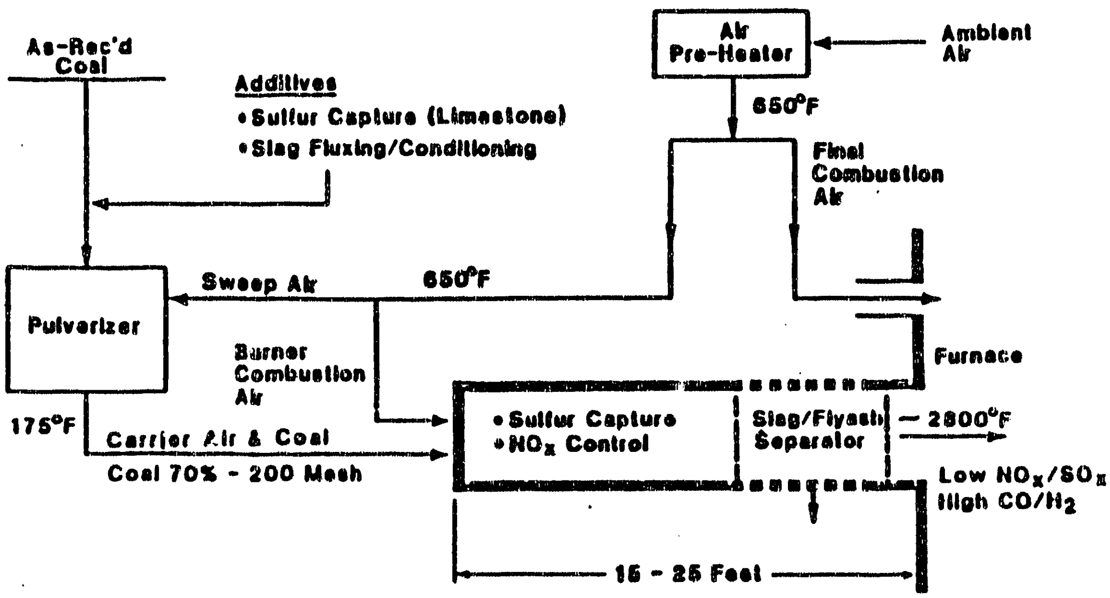

Figure 4. LNS Burner Process Schematic (Conceptual)

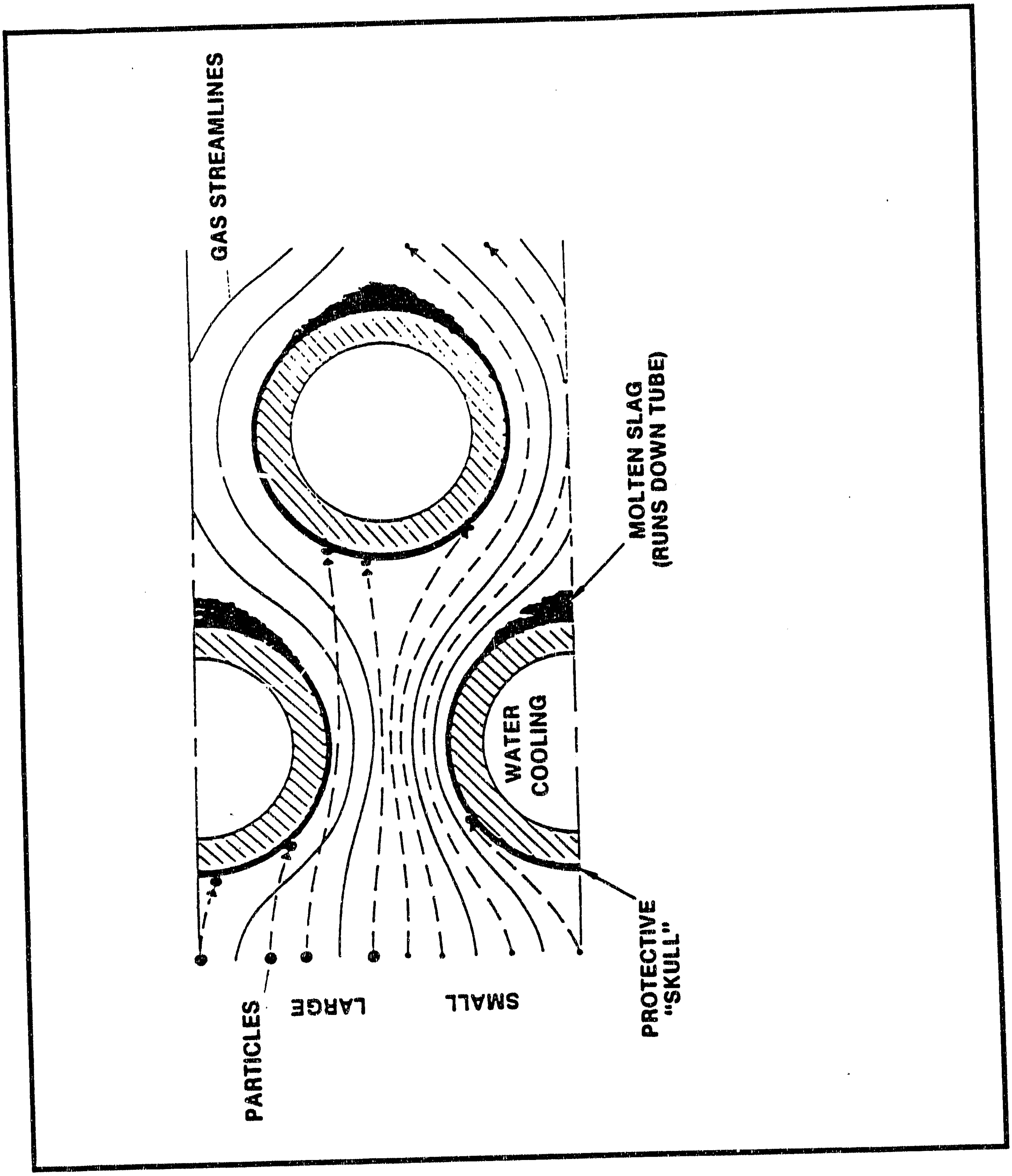

Figure 5. Slag Screen Cross Section (Typical)

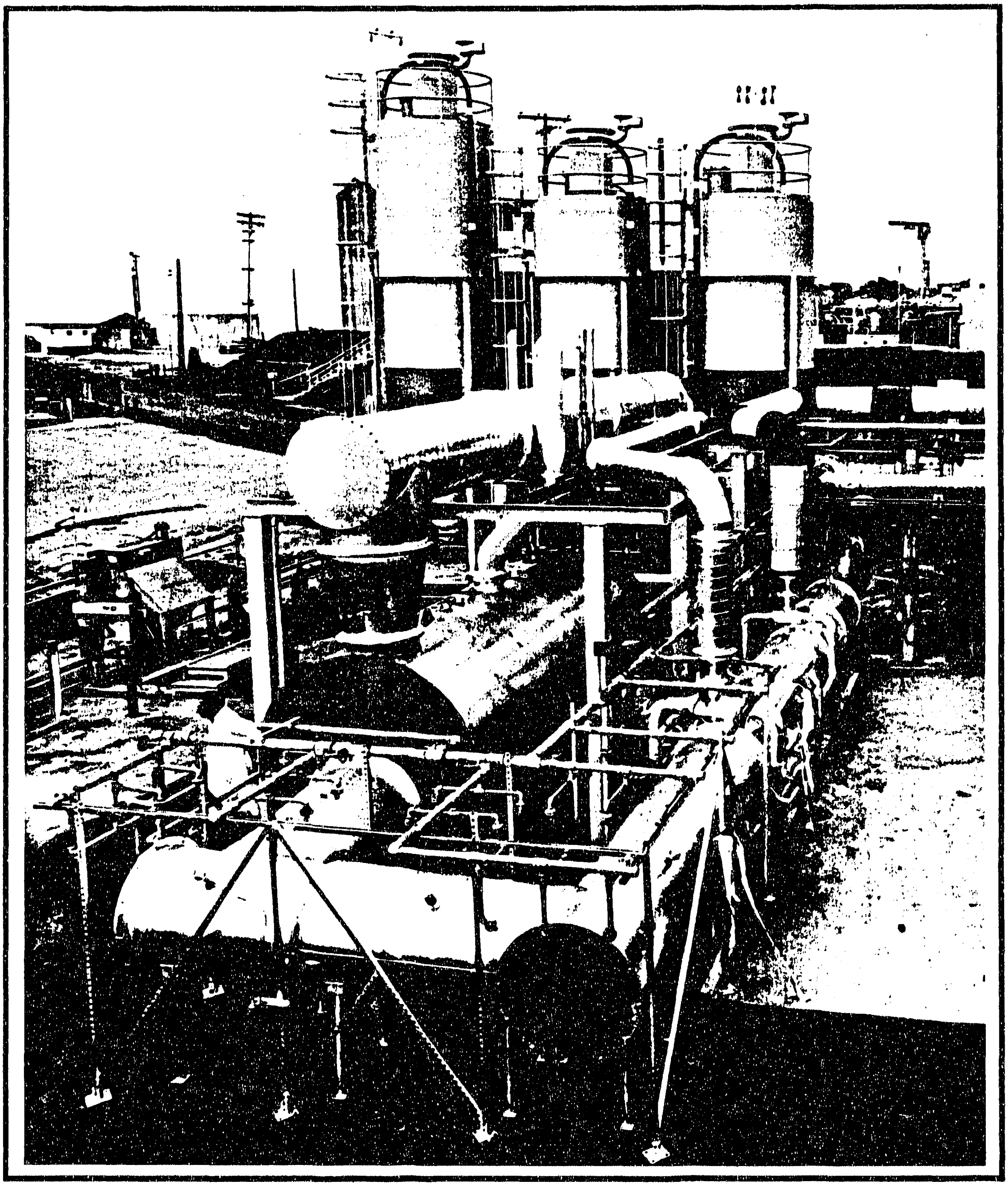

Figure 6. Photograph of the LNS Pilot-Scale Test Facility

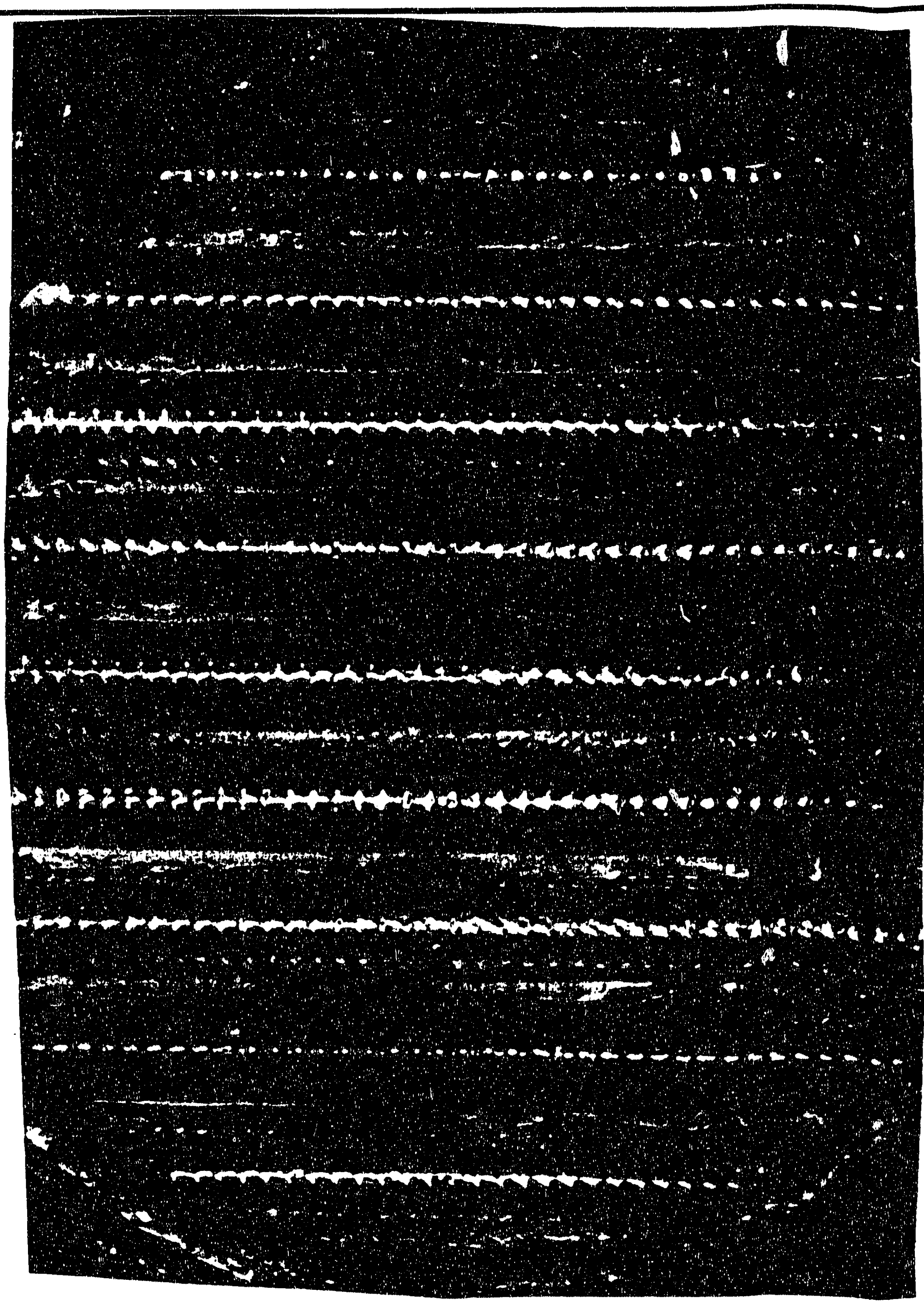

Figure 7. Photograph of the Pilot-Scale Slag Screen

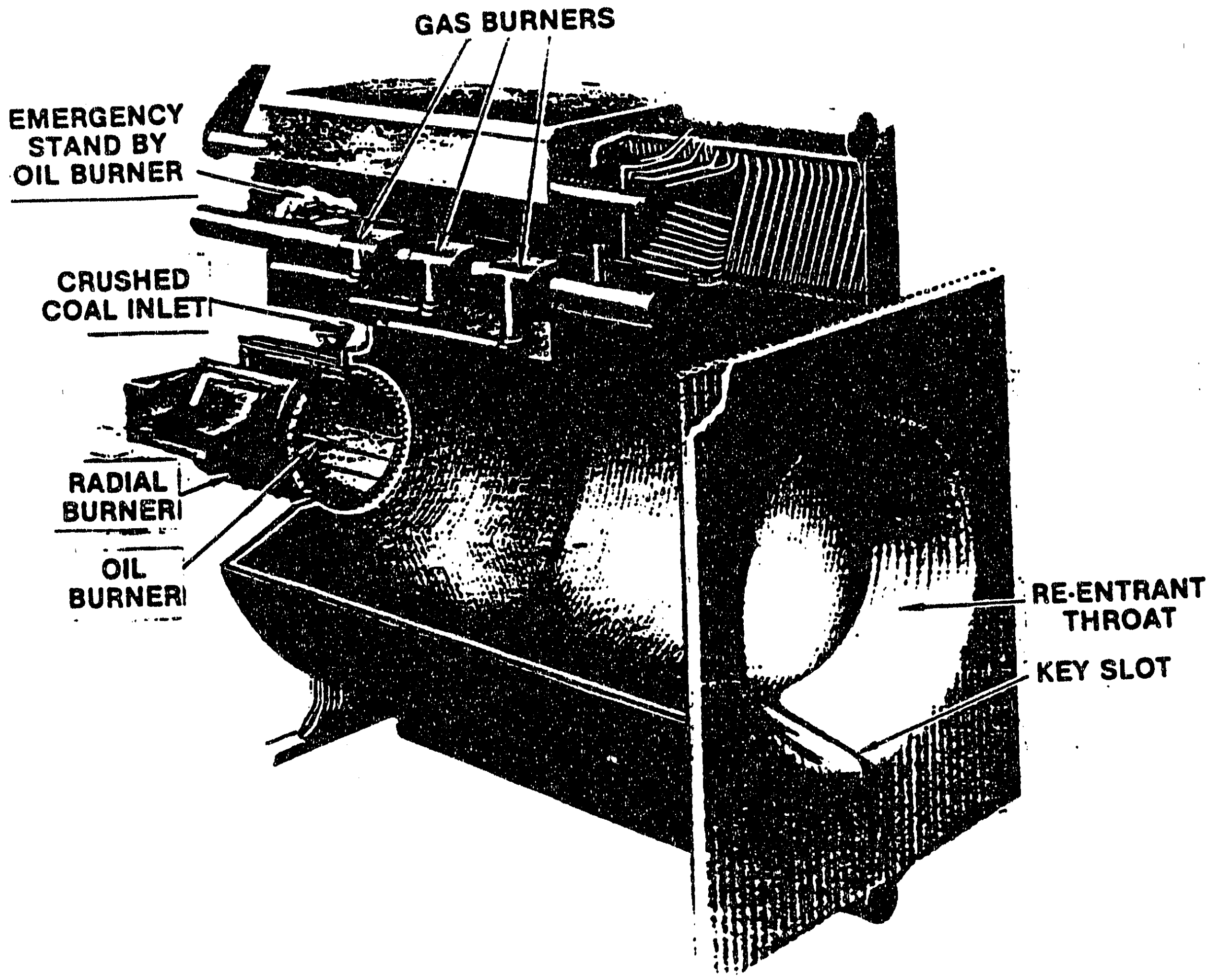

Figure 8. Cyclone Burner

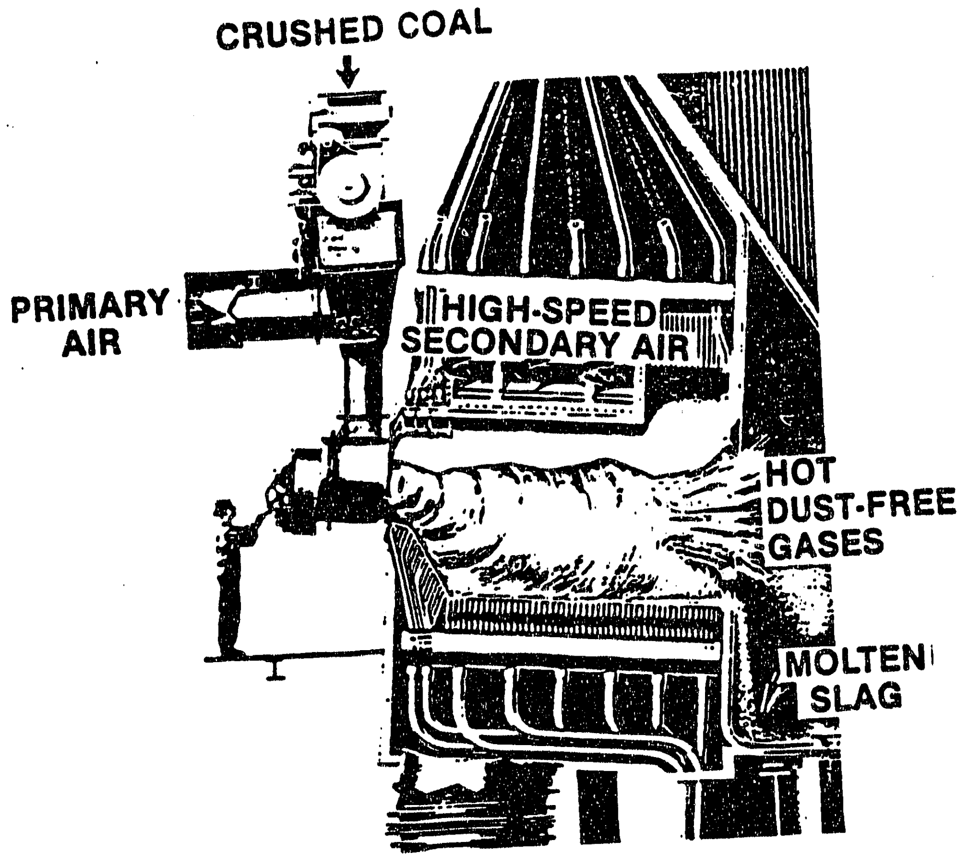

Figure 9. Cyclone Burner - Side View

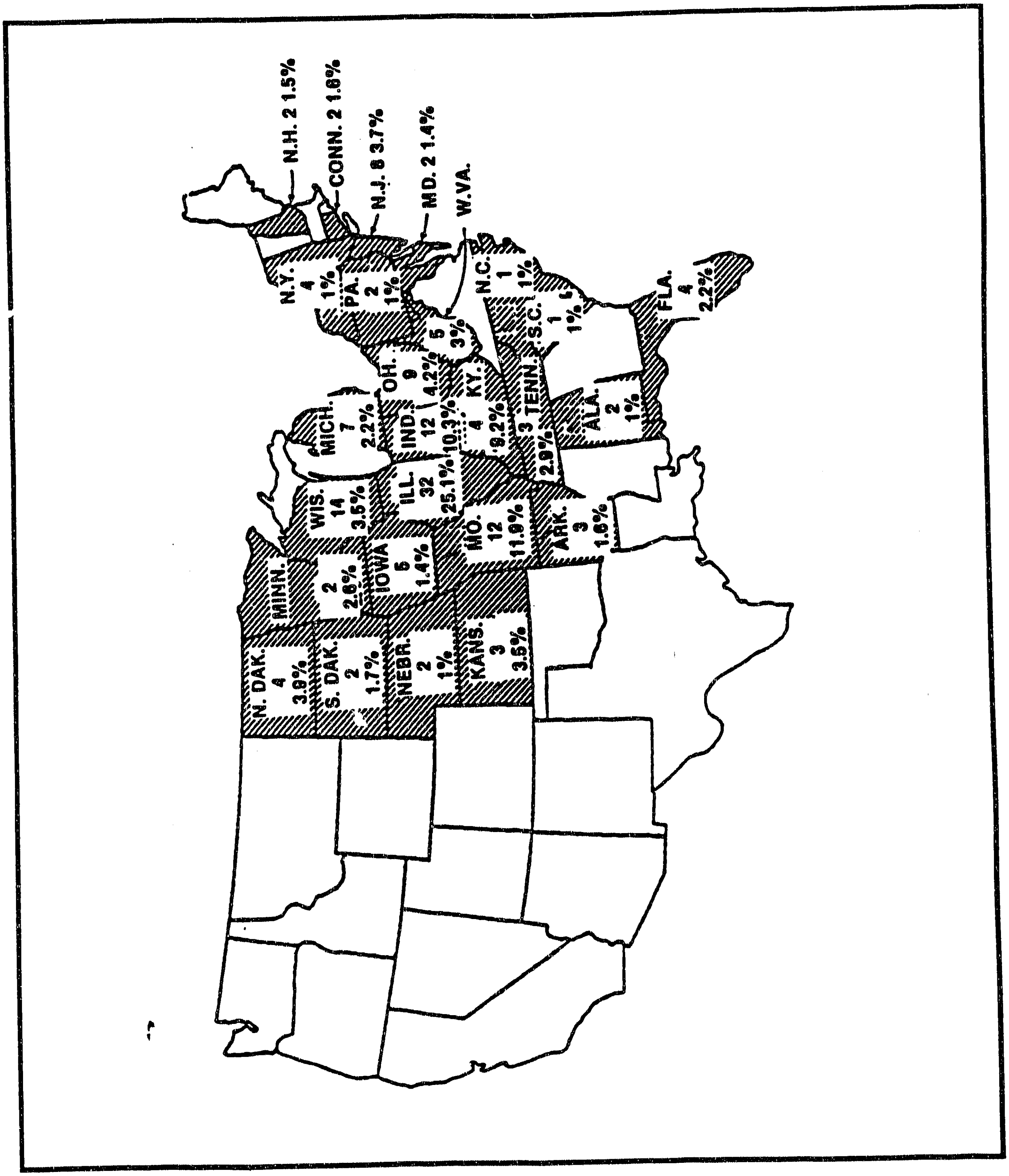

Figure 10. Cyclone Population by State

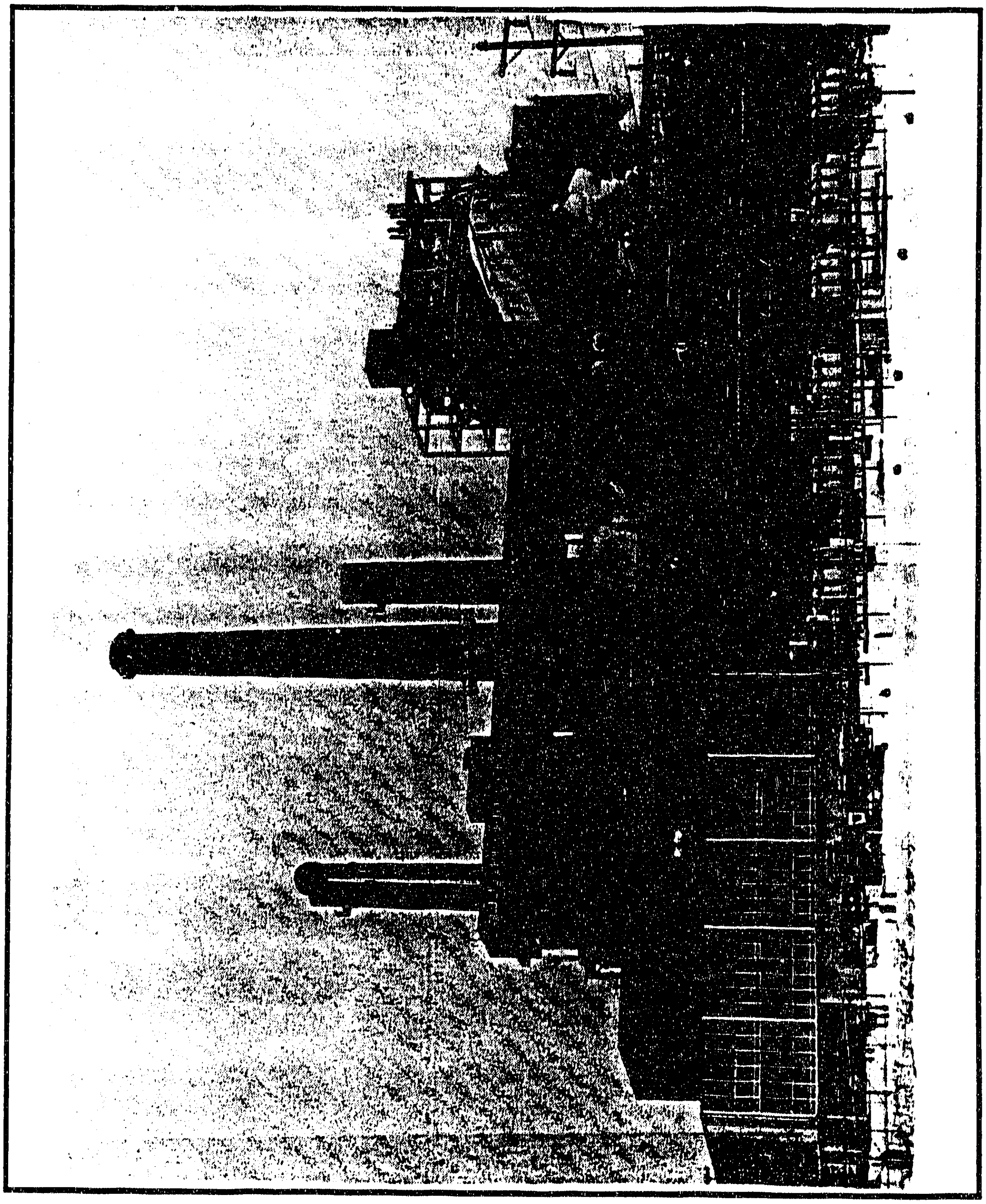

Figure 11. SIPC's Marion Station

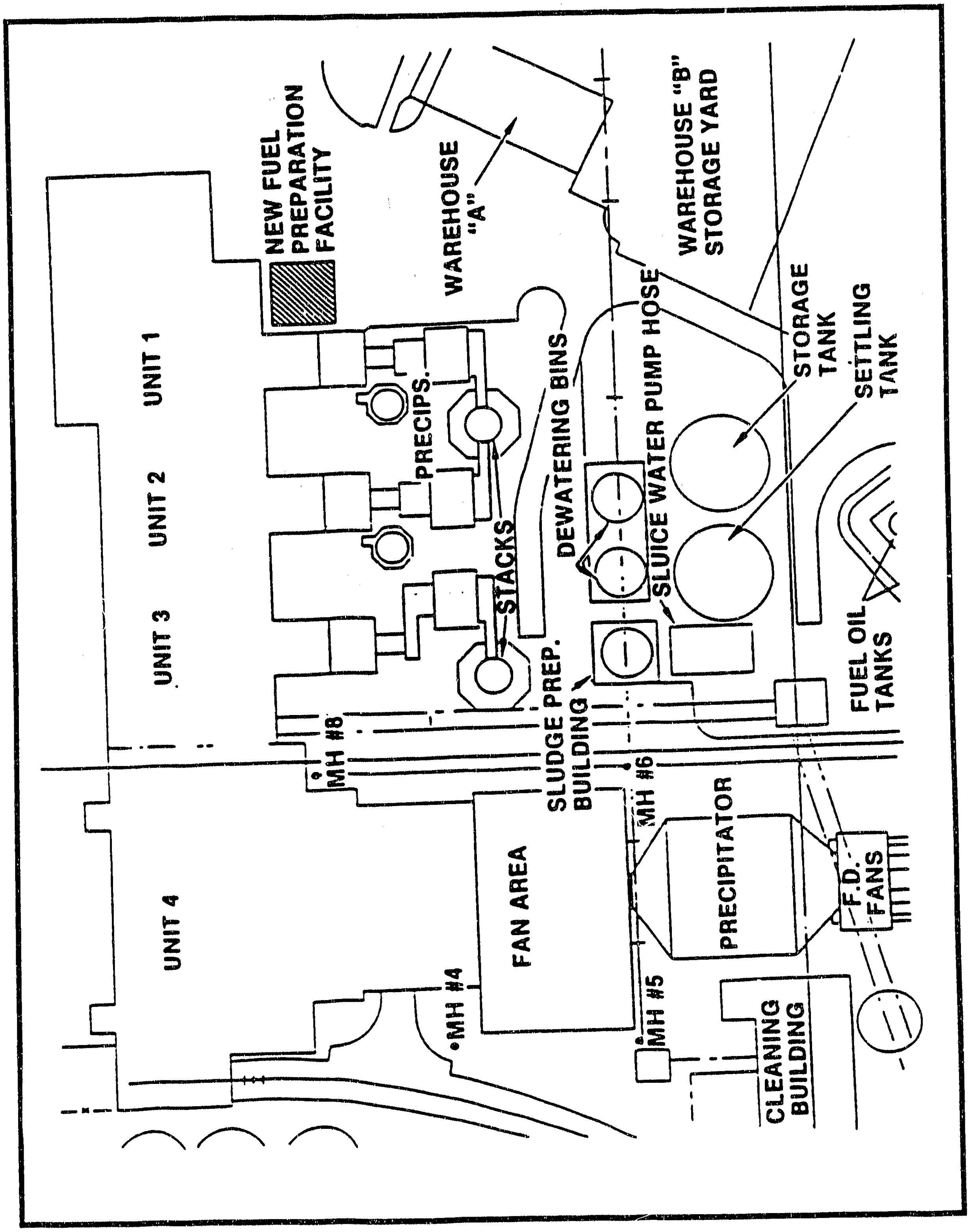

Figure 12. Site Plan View of Marion Station

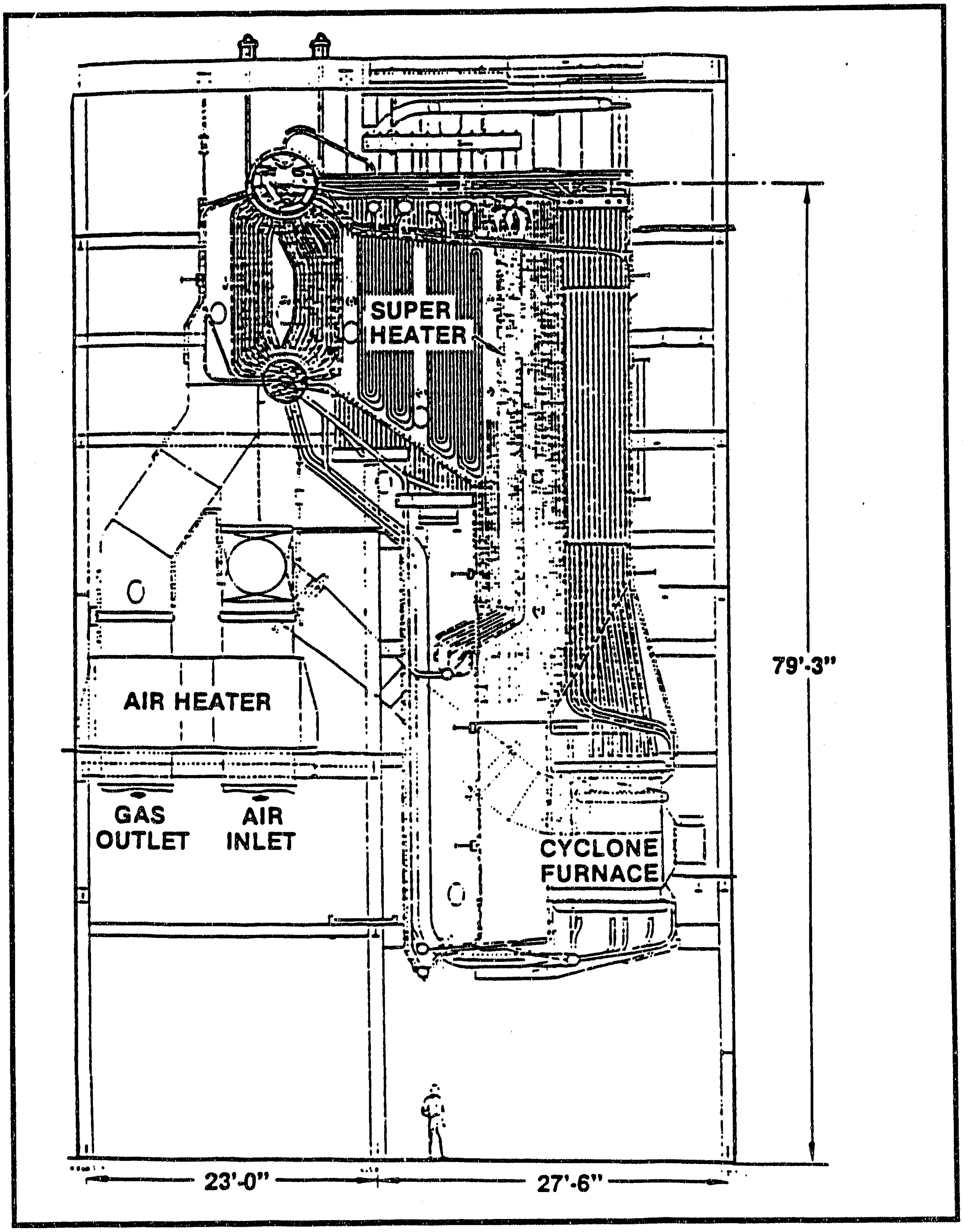

Figure 13. General View of the Boiler and Convective Pass Arrangement

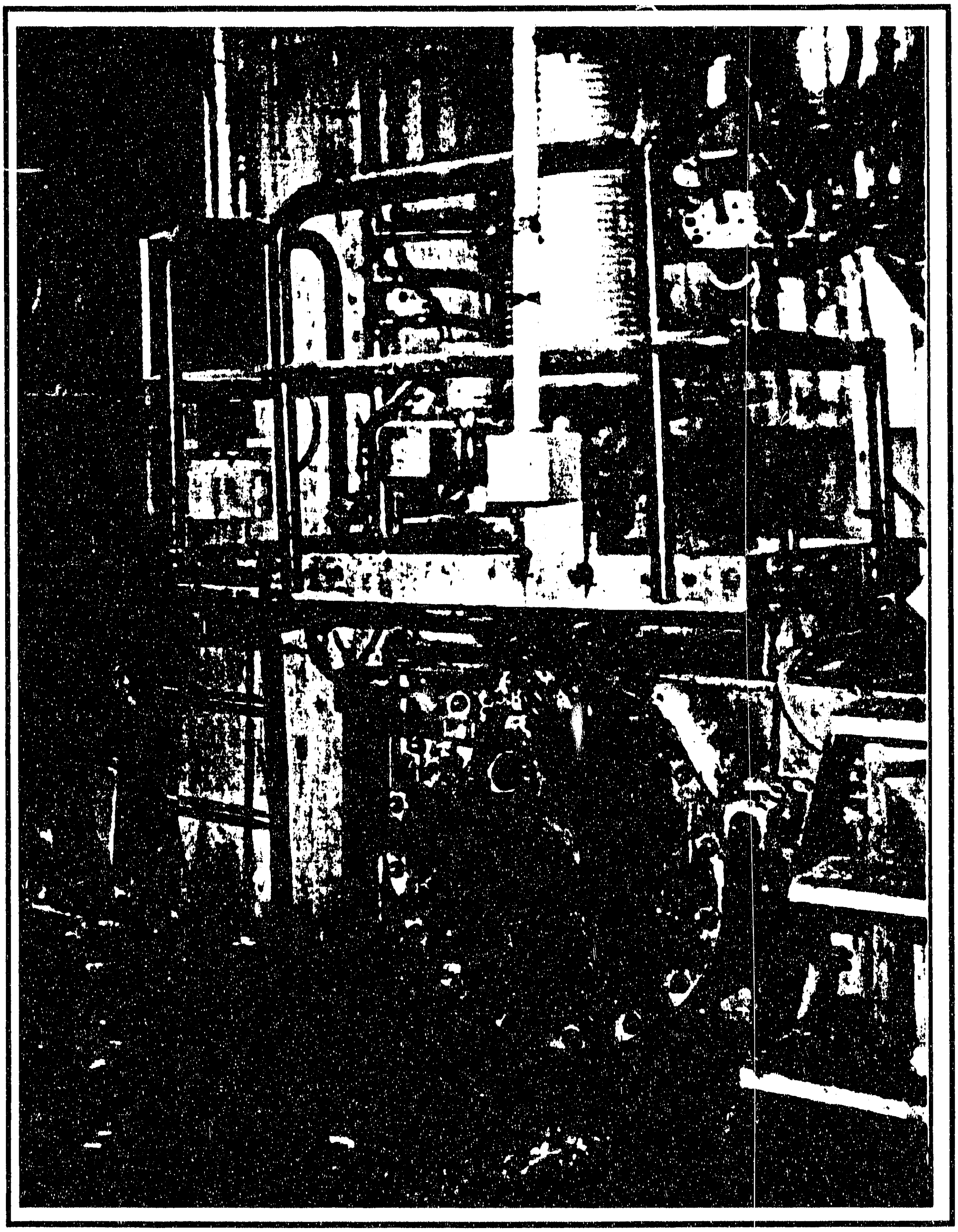

Figure 14. Cyclone Furnace, Marion Unit 1

3. PROJECT DISCUSSION

3.1 GENERAL DESCRIPTION

Selecting a suitable host site for a cyclone boiler retrofit demonstration was an important first step in forming the project. A key requirement for the host site is that it adequately demonstrate the LNS Burner technology to enable extrapolation of the results to future commercial units. It was assumed that the cost of retrofitting the LNS Burner technology to the reference site need not be representative. However, a major criterion in selecting a host site is minimum retrofit costs. Consequently, the selection criteria fit two categories:

- Identify requirements needed to demonstrate LNS Burner technology.
- Identify considerations that affect retrofit costs.

The following factors evolved to form the site-selection process:

- **Technology Demonstration Requirements**
- Unit burning high-sulfur bituminous coal.
- Cyclone furnace size (200 to 400 MBtu/h).
- LNS Burner/cyclone arrangement consistent with typical large units.
- Furnace heat absorption rate, volume, and residence time typical of large units.
- Operated by a utility.
- **Project Economic Considerations**
- Unit not critical to meeting utility demand (i.e., no makeup power costs for unit outage).
- Small boiler (<100 MW).
- Plant area available for inclusion of additional equipment.
- Required modifications made with minimum of interference with existing structures, etc.

- Limestone storage/handling facilities available.
- Minimum additional power, restoration, and insurance costs.
- Identified funding support.

Several utilities owning cyclone boilers were contacted to determine their interest in participating with their units for this program. An evaluation was conducted following the above technical and economic criteria. The small boiler units at Southern Illinois Power Co-operative were identified, and after careful consideration for their concerns and interests, the Marion Station unit 1 was selected as the host site.

3.2 SITE DESCRIPTION

Marion Power Station occupies a 300-acre site at the northwest end of the Lake of Egypt in Williamson County, Illinois, about 8 miles south of Marion, Illinois. The station is owned and operated by SIPC, whose main offices are across the spillway from the plant. SIPC created the lake to provide cooling water for the generating station.

Marion Units 1, 2, and 3, which are 33 Mwe each, were commissioned in 1963; Unit 4, 173 MWe, was commissioned in 1978. The three small units have mechanical dust collectors and electrostatic precipitators, while the large unit has both an electrostatic precipitator and a wet scrubber. A photograph of the front of the Marion Station is shown in Figure 11. A more detailed view of the unit is shown in Figure 12.

Marion Power Station is accessible by rail and truck. An interchange with Interstate Highway 57 is located about 3 miles from the plant entrance. A rail spur runs to the plant, but is currently unused.

All four units at the Marion Power Station are cyclone fired. The plant's total net generation capacity is 272 Mwe. Gross electric generation was 1,281,510 MWh in 1988. Typically, two of the small units are cold and only used when required due to the unavailability of the other units. The LNS Burner project will be conducted at unit 1.

Units 1, 2, and 3 fire a combination of predominantly No. 5 and No. 6 Illinois bituminous coal and mine washings (also called coal refuse, gob, or washer plant silts) in a ratio of 60:40. The coal and washings are stored in separate piles in the fuel storage area. Coal is delivered to the site daily, but the mine washings are only delivered during the summer when a large pile is built up to last the rest of the year.

The coal and mine washings are loaded into separate hoppers in the fuel storage area. The hoppers feed a crusher, also located in the fuel storage area. The feed rate from the two hoppers maintains the 60:40 ratio. The mixture is conveyed to the coal bunkers at each unit. Unit 1 consumes about 18.5 tons/hr at peak capacity. A 90-day supply of fuel is maintained on site by SIPC.

The fly ash from Units 1, 2, and 3 is sluiced to a series of ash ponds where the ash settles out. Because of cyclone boiler inefficiencies, the fly ash from these units still contains a significant amount of unburned carbon which can present a fire hazard when handled by a dry ash handling system while the ash is still hot. The primary fly ash pond was emptied recently and the dredged ash was used during some regrading work in the coal storage area. The remaining volume in the fly ash ponds is estimated at 2.5 million cubic feet. Because of the low capacity factors for the three units, the ash ponds have an expected remaining life of approximately 10 years. The ash pond area is shown on Figure 15.

Unit 4 uses the same coal/washings mixture as Units 1, 2, and 3. However, the fly ash from Unit 4 is mixed with the sludge from the limestone scrubber and landfilled on the site.

The bottom ash from all four units is sluiced to one of two bottom ash ponds. The slag is sold to a company which uses the ash for grit in different commercial applications such as sandblasting, winter road conditioning, septic system filters, cement additive, etc. While one bottom ash pond is being filled, the buyer empties the other. The fly ash hoppers have a storage capacity of 4 tons, which is equal to about 5 hours of Unit I operation. The fly ash sluice water system can empty the hoppers in one hour using 450 gpm of water. The bottom ash hoppers have a 10-ton storage capacity, which also equals about 5 hours of operation. The bottom ash sluice water system can empty the hoppers in one hour using 1,000 gpm of water. The bottom ash and fly ash sluice water systems are once-through systems.

Table 3.1 Stream List

Stream	Air/Gas/ Steam Flow Rate (lb/h)	Solids Flow Rate (lb/h)	Total Stream Flow Rate (lb/h)	Conditions, Temp./ Pressure
1. Raw coal		38,074	38,074	Ambient
2. Limestone		6,889	6,889	Ambient
3. Additive		1,341	1,341	Ambient
4. Air from FD fan	382,459		382,459	110°F/46 iwg
5. Tempering air to transport blower	25,196		25,196	110°F
6. Tempering air to pulverizer	NNF			110°F
7 Air to air heater	357,263		357,263	110°F
8. Hot air to transport blower	8,996		8,996	480°F/35 iwg
9. Hot air to pulverizer	71,115		71,115	480 F/35 iwg
10. Overfire air to boiler	74,480	207	74,687	180°F
11. Hot air to LNS Burners	232,494		232,494	480°F/>24 iwg
12. Fuel to LNS Burners	34,186	42,732	76,918	120°F/63 iwg
13. Flue gas from boiler	372,675	2,285	374,950	621°F
14. Slag from boiler after sluice		9,138	9,138	Ambient
15. Gas to multiclones	417,333	2,285	419,618	300°F
16. Gas to stack	417,333	40	417,373	272°F
17. Fly ash collected after sluice		2,245	2,245	Ambient
18. Steam produced	335,000		335,000	905°F/875 psia

Notes:
1. Air leakage at 12.5%
2. Pressure units, iwg = inches of water gauge
3. Stack particulate emissions are 0.1 lb/MBtu
4. NNF = Not normally flowing stream

Waste streams from the plant include fly ash collected by the mechanical and electrostatic dust collection system, bottom ash (slag) from the furnaces, scrubber sludge from Unit 4, the water used to sluice both the fly ash and bottom ash to the ash ponds, and miscellaneous streams such as boiler blowdown, demineralizer regeneration wastes, etc.

All water used by the plant except for potable water is withdrawn from the Lake of Egypt. Condenser cooling water is discharged back to the Lake of Egypt. Water treatment wastes, demineralizer regeneration wastes, floor drainage, service water system blowdown, coal pile runoff, boiler blowdown, and yard drainage are all routed to one of the ash ponds. The overflow water from the ash ponds is discharged to Little Saline Creek.

3.3 MASS AND ENERGY BALANCE

Mass and energy balances have been made with the design coal. A stream list which represents the design conditions at 100% boiler maximum continuous rating (MCR) is presented in Table 3-1. For reference, the process flow diagram, Figure 16, shows the location of the stream number. This table presents the mass flow rates for major stream constituents including temperature and pressure estimates for these streams.

3.4 PROCESS DESCRIPTION

The process flow diagram shown in Figure 16 identifies the major streams for the retrofit of the LNS Burner system into Marion unit 1. A summary description of the major components in the plant is also shown.

The as-received coal is conveyed from the existing bunkers at a rate of 38,074 lb/h and mixed with limestone before pulverization to provide a Ca/S ratio of 2:1. Additional proprietary additives may used to flux the slag. These coal, limestone, and additive solids are then fed to the coal pulverizer at a rate of 46,304 lb/h along with sufficient heated sweep air. This air is then utilized to convey the pulverized fuel to a cyclone separator. A cyclone separator provides for removing the fuel from the pulverizer sweep air. After the cyclone separator, the pulverizer sweep air is ducted to the boiler as overfire air. From the bottom of the cyclone, the fuel flow continues through rotary valves to the LNS Burners' fuel pipes. Using a separate source of 34,186 lb/h warm air driven by a blower, the fuel is conveyed to the LNS Burners at a rate of 42,732 lb/h. The fuel feed stream is then split to properly distribute the fuel to the LNS Burners. The coal is first split by a conventional "riffle" box into two streams, one for each LNS Burner. Each stream is then further split into six equal streams that convey the fuel from the fuel preparation building to the face of the LNS Burners. These 12 streams utilize heavy-wall pipe with abrasion-resistant elbows.

At each LNS Burner, an additional 116,247 lb/h of heated combustion air from the air preheater provides for combustion. The LNS Burner creates a hot fuel-rich gas and provides for reaction of the sulfur and nitrogen species to remove them from the gas stream. The coal ash also melts. The resulting hot combustion gas and molten ash then passes through the modified cyclone barrel to a new slag screen located at the entrance to the boiler. This slag screen removes up to 80 wt. % of the ash, which drains to a slag tap in the bottom of the boiler. The hot gases and remaining ash that enter the boiler at this point are at peak gas temperatures to assure good slag tap drain performance for all boiler loads. An estimated slag quantity of 9,138 lb/h will drain from the unit. The remaining quantity of very fine fly ash (<10 μm) in the amount of 2,285 lb/h will continue through the boiler back pass sections.

The gas products then flow up through the furnace losing heat to the boilers radiant section, where the final overfire air is added at a rate of 74,687 lb/h. This overfire air includes the pulverizer sweep air and is distributed through the boiler wall through multiple ports to assure good mixing and further reduce NO_x. This final combustion step at an overall stoichiometry of 1.16 assures complete combustion of the CO well before the gases enter the superheater section of the boiler convective passes.

From the boiler convective pass, the gases continue to cool before entering the Ljunstrom air preheater. The air preheater recovers the heat and cools the gas to about 280°F as it heats the ambient incoming air to about 480°F. As the gas leaves the air preheater, it flows through a bank of

9-inch multiclones, where the coarse particulate from the cyclone burner is normally removed. This equipment will be left in place, but the LNS Burner is not expected to create any coarse particulate.

The gas then flows at a rate of 372,675 lb/h into a three field electrostatic precipitator where the fine fly ash is removed at a rate of 2,245 lb/h. The clean flue gas containing only 40 lb/h (0.1 lb/MBtu) particulate, approximately 0.2 lb/MBtu NO_x and less than 1.76 lb/MBtu SO_2 is discharged from a 200-ft-high concrete stack.

All combustion air is provided by the existing centrifugal fan driven by with a combination of low- and high-speed motors. The low-speed motor is rated at 300 HP and the high speed motor at 1250 HP. Air at 342,459 lb/h is delivered to a manifold which supplies air for preheat and coal transport. The majority of the air stream flows through a small steam-air heat exchanger and then into the Ljunstrom air heater. The air from the air heater is then split into three streams: one stream to the pulverizer, one stream for coal transport with the majority being used for the LNS Burners. The pulverizer exit gas temperature is controlled by blending cold tempering air to the pulverizer inlet based on temperature of the outlet gases. The small stream of the heated air sent to the new transport blower is diluted by 25,196 lb/h of cold air to hold the temperature about 120°F and to eliminate the possibility of condensation in the fuel conveying lines.

3.5 ENVIRONMENTAL CONTROL PERFORMANCE

The two 200-MBtu/h LNS Burners firing into the unit 1 boiler have been designed to match the original design requirement of generating 335,000 lb/h of steam at 905°F at 875 psig. The retrofitted boiler efficiency may be slightly lower than the cyclone boiler due to the minor heat loss from the increased quantity of slag. However, the overall LNS Burner efficiency is expected to be much higher than the efficiency noted during the Baseline test due to the excellent carbon conversion of the LNS Burner. As a result, the gross heat rate will show a significant improvement.

Auxiliary power requirements will increase to supply the new pulverizer and added equipment. For a post demonstration retrofit project, these new loads may be offset by a reduction in the fan power requirements due to the lower (than cyclone) LNS Burner pressure drop. However, for this demonstration project, the cost considerations do not warrant modifying the fan and ducting.

One important concern is related to the expected increased quantity of ash resulting from the additives necessary for sulfur capture. The total ash quantity into the LNS Burner is expected to nearly double. The Marion Station unit 1 ESP is now operating near its limit for ash collection efficiency, and any fly ash load increase may cause particulate emission problems. Further, it is always desirable to minimize any ash load through a boiler. As noted above, the estimate of the ash load exiting the LNS Burner slag screen shows that even with the increased quantity of ash, the fly ash load is expected to be less than that of the original cyclone design. The slag quantity for sale or disposal however, will increase by a factor of three.

The performance of the LNS Burner retrofit design in the Marion cyclone boiler was evaluated to see if any significant boiler efficiency degradation would occur due to differences between the conventional and LNS Burner process technology. Based on stoichiometry, combustion completeness, and heat extraction conditions entering the boiler for both burner designs, an analysis is presented in Table 3-2 comparing overall boiler efficiency that shows very similar overall design efficiencies. The current as found efficiency of about 82.7%

Table 3.2 Expected Unit 1 Boiler Performance with LNS Burner

Marion Unit 1	Original Design (Calculated)	LNS Burner Design
Steam flow (lb/h)	335,000	335,000
Coal Flow (lb/h)	37,000	38,074
Additive (lb/h)		
Limestone	0	6,889
Other	0	1,341
Excess air leaving air heater (%)	16	16
Flue gas leaving air heater (°F)	330	300 [1]
Air entering air heater (°F)	110	110
Ash tapped as slag [2] (%)	60	80
Waste Disposal (lb/h)		
Slag	3780	9,138
Fly ash	2440	2,245
Stack Emissions	80	40
Emissions (lb/MBtu)		
SO_2	5.85	1.76
NO_x	1.35	0.2
Particulates	0.1	0.1
Efficiency Losses (%)		
Dry gas	4.89	5.00
$H_2 + H_2O$ in fuel	4.56	4.57
Moisture in air	0.10	0.10
Unburned comb.	0.10	0.10
Radiation	0.40	0.40
Slag heat loss	0.85	1.13
Unaccounted & mfg. margins	0.65	0.65
Total losses	11.55	11.95
Boiler efficiency (net)	88.45	88.05

1 Assumed 5°F higher than original design due to use of pulverizer tempering air.

2 Assumed.

3 1.5% unaccounted for and manufacturer's margin less calculated slag heat loss.

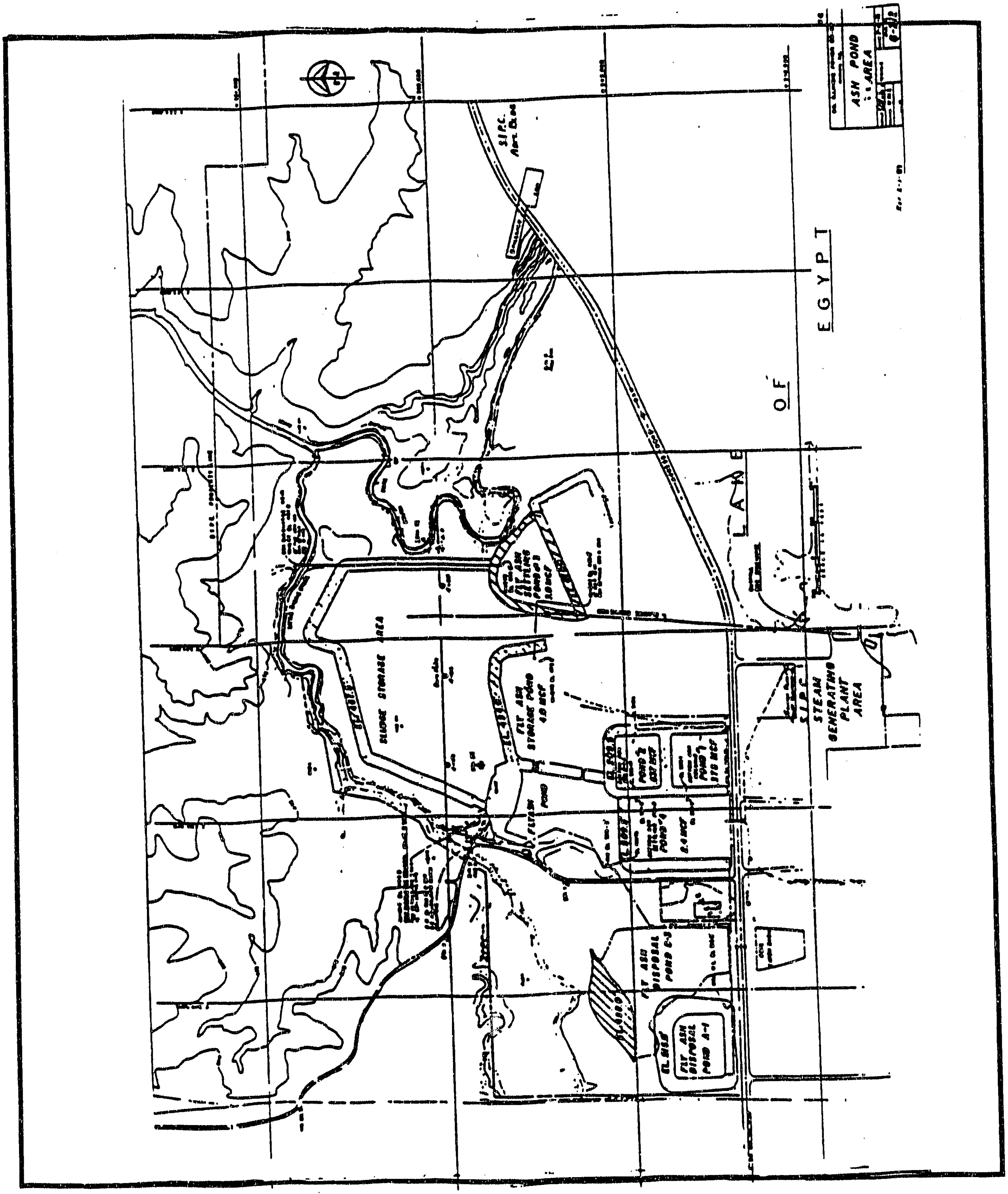

Figure 15. Ash Pond Area

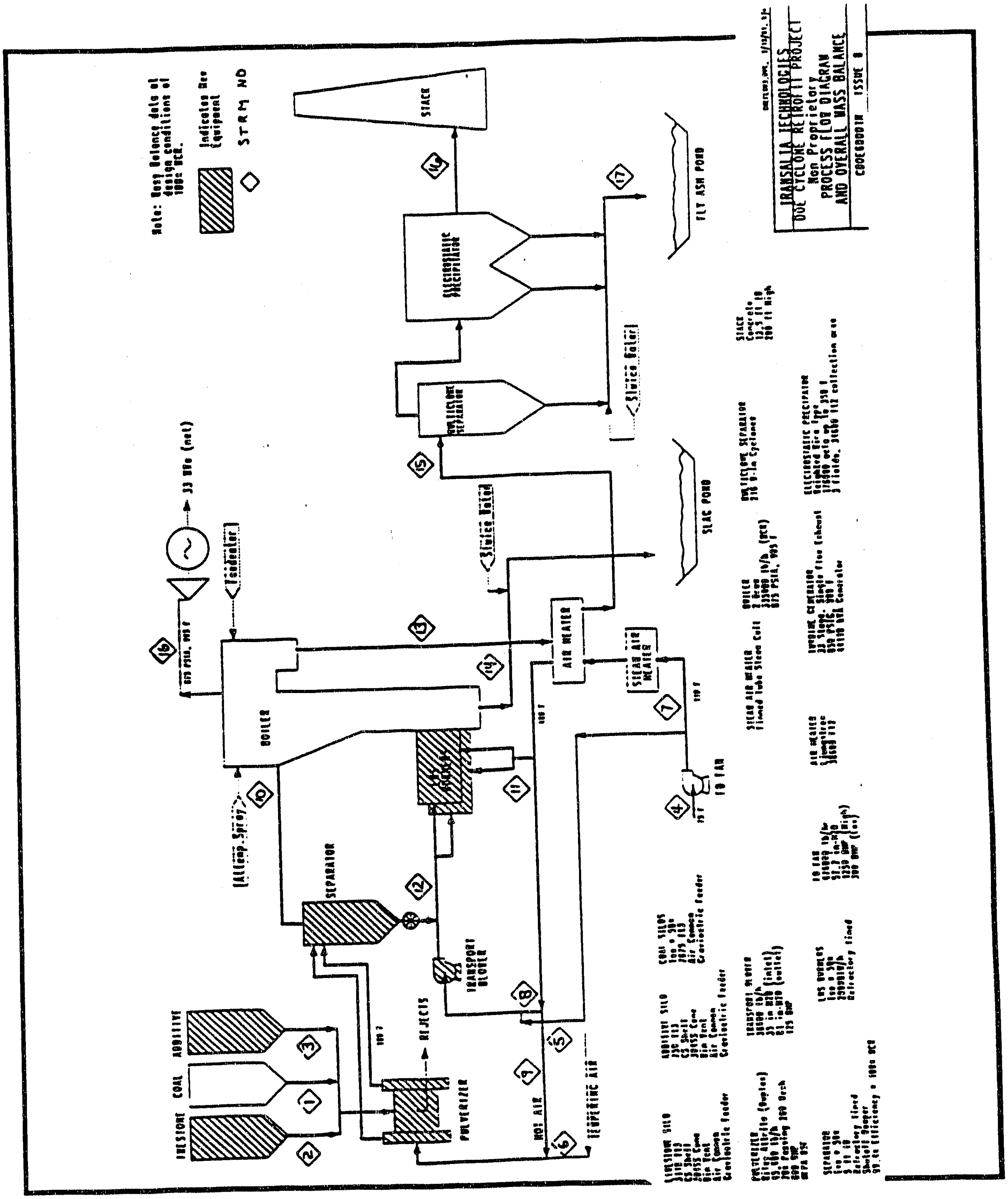

Figure 16. Process Flow Diagram

4. PLANT SYSTEMS AND PROCESSES

Significant technical work was accomplished before the signing of the Cooperative Agreement. The proprietary report submitted to the Cyclone Retrofit Feasibility Operation Committee entitled "Cyclone Boiler Retrofit Feasibility Study with the Low NO_x/SO_x Burner, CYC20501P, Issue A", dated April, 1989, served as the basis for TransAlta's work.

The design criteria and requirements presented in the feasibility study were reviewed. The site specific requirements were updated, the design fuel analysis was updated based on current coal used on site and standards, such as NFPA 85F were reviewed and applied to the ongoing design tasks. The Marion unit 1 operating requirements were reviewed with the SIPC to incorporate all necessary design and operating criteria and requirements into the Project.

The material balance used in the DOE Program Opportunity Notice (PON) submission was updated to use the Project design coal and to better reflect boiler and plant operating conditions, boiler efficiencies were updated, the coal cyclone separator efficiencies were updated and boiler excess air levels were reviewed. The proprietary Process Flow Diagram was updated and stream flows were revised as necessary.

The design coal was reviewed to determine a basis which reflects normal variations. The design coal was determined from data obtained from about 40 analyses taken from January 1989 through July 1989.

Control philosophy and requirements were reviewed with all Project Team Members, including cyclone boiler consultants and operators. Initial information as shown in the feasibility study on incorporating the LNS Burner into Marion unit 1 was reassessed. An initial review of existing plant operating procedures and policies was started. The development of process logic will be an ongoing task until the completion of engineering.

Outline dimensions of major equipment was identified since space was at a premium for this retrofit. Design requirements for not-to-exceed dimensions were established for key equipment items, including the LNS Burner.

4.1 LNS BURNER RETROFIT DESIGN

The LNS Burner process design criteria were applied to the Marion unit 1 cyclone boiler. Each LNS Burner was sized for 200 MBtu/h, firing approximately 10 tons/h of coal, the same as the existing cyclone furnaces.

Commercial utility cyclone boilers range between 150 to 470 MBtu/h heat input per combustor. A first step in LNS Burner scale-up has been the information gathered and the lessons learned from operation of the 50-MBtu/h LNS Burner on the LNS-CAP Project at Cold Lake, Alberta, Canada. This activity has directed the scale-up criteria for this application and verify its use for the 200-MBtu/h cyclone boiler application.

Fortunately, the scaleup criteria for the LNS Burner are not as restrictive as for typical coal-fired pulverized coal (PC) burners.

The scale-up of an LNS Burner heat release rate is accomplished by:

1. Increasing the number of coal and air feeds per LNS Burner.
2. Simply increasing the LNS Burner's diameter to maintain process specifications. The burner length is essentially fixed.

These approaches give the LNS Burner the ability to be sized to nearly any practical scale, similar in heat release rates to any typical cyclone furnace (or PC burner). LNS Burners have been conceptually scaled to 500 MBtu/h.

For the retrofit, the cyclone furnace preburner end will be replaced with a new section that functions as the LNS Burner. The existing cyclone furnace section will also be used to establish the overall combustion length. The existing cyclone throat, consisting of water wall tubes, will be removed and replaced with a new assembly of water wall tubes forming the slag screen. Figure 17 shows the elevation view of the boiler before modification and Figure 18 shows the retrofitted configuration.

The LNS Burner for this retrofit is formed by two sections; the existing cyclone furnace barrel with an extension of the end of the cyclone furnace barrel. Due to the configuration of the cyclone furnaces for Marion unit 1, the end of the cyclone furnace is very close to the level of the main turbine operating floor. The estimated diameter of the extended portion of the LNS Burner interfered with the deck. Work was done in assessing the impact of either decreasing the burner diameter, removing a portion of the concrete floor, or inclining the extended portion to miss the floor. Studies indicated that if the extended portion could be offset from the cyclone furnace and tilted about 15 degrees, the interference could be eliminated.

4.1.1 LNS Burner Configuration

The LNS Burner is a simple air-cooled refractory lined combustion chamber about 20 ft in overall length. The internal diameter is about 5-ft. Coal is distributed at the LNS Burner face from six coal feed pipes. The hot air from the air preheater provides sufficient cooling of the LNS Burner refractory wall before mixing with coal for combustion.

The LNS Burner for this retrofit is formed of two sections; the existing cyclone furnace barrel and extension piece protruding from the end of the cyclone furnace barrel. The existing cyclone furnace barrel will remain virtually unchanged. The air ducts and other cyclone-furnace-related changes will be removed. The cyclone furnace barrel will remain water-cooled. The new LNS Burner extension piece will be added to the cyclone barrel consisting of a refractory-lined section, about 16-feet long. This section is externally air-cooled by incoming combustion air flowing through a one-inch thick cooling air annulus from the cyclone end and flowing up to the head end where it enters into the LNS Burner. A schematic of the LNS Burner and its interface with the boiler is shown in Figure 19. Coal with carrier air also enters at the head end.

4.1.2 LNS Burner Thermal Analysis

A thermal model of the LNS Burner was developed and used to evaluate thermal profiles and start up conditions. Three modules were developed: LNS Burner, modified cyclone barrel and a combined system. Each module covers specific tasks: the LNS Burner model is used to validate refractory thickness, cooling air gap design and the overall fabrication design; the cyclone barrel model is used to validate refractory thickness and overall heat balance to the cooling water circuit; and the system module is used to evaluate start up and cool-down transients.

Each model uses a commercially available thermal analyzer program to solve the finite difference equations and to determine the temperature distribution. The model incorporates thermal convection and radiation from the hot gas to the refractory hotface, conduction across refractory material, convection and radiation across the cooling gap (LNS Burner model) conduction across the outer thermal insulation, convection and radiation from the insulation to the environment and energy transport into the cooling media. Input variables are provided for different material properties, transport properties, process conditions, and physical geometries, such as annulus thickness, refractory thickness, etc.

Typical results of the thermal analysis are presented in the attached table. Also included are the design goals including maximum metal wall temperature, air temperature and refractory limits. Two operating conditions were examined: flow at 100% and 50% boiler load. The most severe operating conditions for the LNS Burner design is at part load when the amount of air available to cool the inside surface of the metal wall is reduced which in turn reduces the convective heat transfer coefficient. The design requirements and model predictions are presented in Tables 4-1 and 4-2.

Table 4-1 100% Load Condition

Location	Desired	Predicted
Metal Wall	<1100°F	835°F
Air Preheat	Maximize	675°F
Dense Refractory CF	<2200°F	2025°F

Table 4-2 50% Design Conditions

Location	Desired	Predicted
Metal Wall	<1100°F	1085°F
Air Preheat	Maximize	863°F
Dense Refractory CF	<2200°F	2110°F

The thermal model has also been used to evaluate thermal profiles and start up requirements. The thermal model has been applied to the current mechanical design to estimate temperature profiles across the refractory and metal shell. The model has been used to assess typical start up conditions and evaluate their subsequent thermal impacts on the design.

An evaluation of a typical start up condition has been made in which refractory hotface, metal wall and slag screen temperatures were determined. Figure 20 shows these profiles for the selected conditions. Key events in this start up are the initial warm-up on oil using the 30 MBtu/h oil ignitors, a switchover to coal and the ramp up to full load on coal. The illustrated cold start up takes about eight hours to complete. In the case presented in Figure 20, the boiler and turbine requirements were included in the start up ramp rate as follows:

1. The boiler was brought up about 75% operating pressure and turbine roll was established using oil.

2. Coal firing was established to complete start up after the turbine stabilized and was held at about 15% load for one hour.

4.1.3 Mechanical Design

The mechanical design activities for the LNS Burner were initially started during the preparation of the feasibility study. These early efforts determined overall length, diameter, refractory thickness and required design features. This effort was continued incorporating design refinements. The diameter and overall length have been finalized, the refractory thickness has been selected and checked with the thermal model. The design features have been selected; details, such as thermocouple selection and placement, provisions for flame scanning, observation ports, air manifold design and placement and structural support are complete. The design of the coal injector pipes is complete and incorporated into the mechanical layout. The fabrication drawings are complete and are ready for issue. Material for the metal shells of the front end has been selected; 310 stainless steel is the material of choice for the demonstration test unit because of its higher tolerance to thermal upsets and transients. The type of refractory material has been selected; the specific brand will be finalized when the refractory supplier and installer have been selected.

4.2 BOILER AND PLANT SYSTEM MODIFICATIONS AND REPAIRS

4.2.1 Initial Boiler Inspections

The operational readiness inspection for the project was completed in the January to June, 1990 time frame. The following major plant deficiencies and remedial measures required to bring the unit operational capability up to standard were identified.

Boiler and Auxiliaries - Boiler Casing Leaks

This has been a continuous historical problem which has resulted in severe bulging and deformation of the casing in a number of areas. The flue gas leaks and subsequent casing damage due to overheating were caused by failures in the refractory used to seal the convection pass tangent waterwall tubes. The failure of the refractory can result from improper installation, unit cycling and/or a combination of both. Refractory failure allows localized overheating of the boiler casing and its ultimate failure.

Known casing leaks had previously been repaired by SIPC during the November - December 1988 unit outage. Additional boiler casing, ducting and refractory repairs will be done before plant is restarted with the LNS Burners.

Chelate Cleaning

The boiler was acid (chelate) cleaned in December of 1988. This was the first time the boiler had been acid cleaned since 1973. A few tube leaks occurred as a result of the acid cleaning which would indicate that some degree of waterside corrosion exists. All leaks were repaired. No further remedial action is required at this time.

Boiler Tubes

During the November-December 1988 overhaul outage, the boiler furnace floor tubes were ultrasoni[illegible] tested (UT) to determine wall thickness. A total of 31 furnace floor and 28 boiler roof tubes were repaired as a result of this activity and a visual inspection throughout the boiler. The furnace floor tube repairs were required as their wall thickness was less than the ASME minimum allowed thickness. Evidence was not found to indicate if the tube wastage was due to fireside abrasion, erosion, corrosion or water side corrosion or both. The boiler was discovered to have been operated for at least the last 15 years without installation of the lower furnace section refractory as called for on the boiler erection drawings. This would support the assumption that the majority of tube metal wastage was the result of fireside abrasion, erosion or corrosion.

All boiler tubes in the lower furnace area will be included in the material monitoring program to be conducted before and after operation of the retrofit in addition to selected tubes in the superheater and convection pass generating tubes section.

Air Preheater

In November 1988 a vendor representative made an inspection of the regenerative air heater. The following performance related problems and recommended corrective measures to be taken were identified.

- The cold end basket elements are in bad condition and should be replaced.
- Four hot end axial seals are missing and should be replaced.
- All cold end radial seals are bad and should be replaced.

Prior to major replacement of air heater components, a pre-baseline test was performed to determine the performance of the as found air preheater and to ensure successful completion of the Baseline Test. The air preheater will be inspected in detail as part of the Material Monitoring Inspection prior to the Demonstration Testing of the project.

Electrostatic Precipitator

The electrostatic precipitator (ESP) was not inspected during the operational readiness inspection, but the ESP was inspected prior to the Baseline Test to photograph and document the as-found condition as outlined in the Materials Performance Plan.

Turbine-Generator and Unit Auxiliary Systems and Equipment

The turbine-generator unit, which underwent a major overhaul during March-April of 1986, has been highly reliable throughout the life of the plant.

Historically, the unit auxiliary systems and equipment have been reliable. The redundancy of equipment will provide maximum assurance of reliability during the demonstration program.

4.2.2 Re-assessment of Boiler Condition

Further assessment of the boiler condition was made in October, 1990 during the Baseline Test and is described below.

An inspection of Marion Unit #1 boiler was completed as part of the Materials Monitoring Program. The purpose of this inspection was to provide detailed information regarding the present condition of the boiler and determine any repairs necessary to assure operability and availability for baseload operation during the Demonstration Phase of the retrofitted plant. The scope of work of this inspection included visual inspection and ultrasonic non-destructive examination of the following areas:

- Cyclone burners
- Floor and water wall tubing
- Furnace roof and penthouse area
- Dead air spaces in furnace casing
- Hangers, supports, braces, attachments
- Convection pass wall tube refractory
- Superheater and generating bank tube gross alignment

The results of the detailed inspection and assessment indicate that some areas of the boiler are in fair condition considering its length of service. Specific areas will require repair and further inspection to ensure that the boiler can be reliably operated over the burner test program.

Figure 21 shows a elevation view of the boiler and the large diameter primary air ducting.

Severe tube thinning was determined from ultrasonic (UT) inspection on the exterior thickness of the waterwall tubing in the front of the boiler. The condition was the result of tube and attachment corrosion caused by rain water entering the boiler casing and settling in the buckstay areas over the life of the unit. Major panels of the front wall tubing will require replacement. The floor tubing of the unit was found to have extensive thinning and will be replaced up to the entrance of the cyclone in the furnace area by SIPC.

Both cyclones show signs of significant tube thinning. The most severe thinning is located on the bottom half (3 o'clock to 9 o'clock) of both cyclones. The amount of tube thinning in both cyclones averages approximately 15 to 20% of the original thickness. However, in the design of the cyclones, extra heavy wall tube (1-15/32 in. outside diameter (OD), 0,25 in. wall thickness) was selected due to the expected tube wastage. For the 1-15/32 in. OD tubing, the code calculated minimum wall is only 0.06 in. thickness. Fabricating the cyclones with 0.25 in. wall tubing incorporates a large corrosion allowance into the design. Therefore, the average amount of tube thinning is not detrimental to providing a year of reliable service. Figure 23 shows the inside of one of the cyclones after it was cleaned and inspected.

It is noteworthy that previous tube failures in the cyclone indicate that isolated problem areas do exist. While the lowest thickness reading was 0.17 in., lower wall thicknesses probably exist and may cause a few tube leaks during the next year or so of operation. These tubes will be repaired or replaced.

The UT survey taken of the front waterwall indicates that severe corrosion has occurred on the exterior (non-fireside) surface of the tubes. Some of the readings are below the calculated code minimum wall thickness of 0.102 in. for 2-1/2 in. O.D. tubes. Replacement of the affected area is required to remove those tubes which will probably fail during the next year of operation. As a minimum, the first 16 tubes in from the side wall (not including the areas of new tubing at the furnace corners installed by SIPC) will be replaced. The replacement tubes will extend from the tubes currently being installed, to just past the front wall to furnace roof tube bend. A view of the front wall tubes prepared for UT testing is shown in Figure 24.

The buckstays on the rear gas outlet duct are badly corroded and will be repaired or replaced. Two broken buckstays located on the front wall confirm concerns regarding the integrity of the supports. No significant limitations or effects on boiler operation is expected over the next year unless furnace pressure excursions occur. Most likely causes of downtime over the next year are possible fatigue failures at the buckstay/ tube attachments. The cyclic duty, external corrosion and attachment design create an environment conducive to fatigue crack growth. Past fatigue failures at these locations indicate that some of the existing attachment welds are in various stages of fatigue damage. Non-cyclic operation will limit the number of failures which will occur over the next year of operation.

All of the pressure parts internal to the boiler furnace (superheater and generating bank, etc.) appear to be in good condition. No signs of damage which would cause reliability problems were noted. Damage to external parts of the boiler has been caused by flue gas leaking to the external surfaces of the boiler, then cooling and mixing with water and oxygen to produce a corrosive environment. Streaks of yellow in the deposits found on the corroded areas indicate that sulfur may have a major part in the problem. Repairing the leaks and prohibiting the corrosive environment from developing will have significant positive effects on the next year of boiler operation.

Broken refractory around the superheater tube roof penetrations and holes in refractory over the furnace roof tubes will be repaired. These repairs are necessary to prevent gas leaks to and excessive buildup of flyash in the penthouse. The additional weight of any flyash buildup in the penthouse may cause damage to the roof refractory and tubing.

Lagging and insulation over the furnace will be replaced including hanger rod seals and covers. Lagging joints will be weatherproofed using sealant. Repairing the lagging and insulation is not vital to a one year operation cycle since the lagging is primarily for personnel protection and weatherproofing.

All casing endorsing dead air spaces will be repaired. Each air space will be made air tight to prevent the intrusion of flue gases from the boiler replacement. The floor tubing of the unit was found to have extensive thinning and will be replaced up to the entrance of the cyclone in the furnace area by SIPC.

Both cyclones show signs of significant tube thinning. The most severe thinning is located on the bottom half (3 o'clock to 9 o'clock) of both cyclones. The amount of tube thinning in both cyclones averages approximately 15 to 20% of the original thickness. However, in the design of the cyclones, extra heavy wall tube (1-15/32 in. outside diameter (OD), 0,25 in. wall thickness) was selected due to the expected tube wastage. For the 1-15/32 in. OD tubing, the code calculated minimum wall is only 0.06 in. thickness. Fabricating the cyclones with 0.25 in. wall tubing incorporates a large corrosion allowance into the design. Therefore, the average amount of tube thinning is not detrimental to providing a year of reliable service. Figure 23 shows the inside of one of the cyclones after it was cleaned and inspected.

It is noteworthy that previous tube failures in the cyclone indicate that isolated problem areas do exist. While the lowest thickness reading was 0.17 in., lower wall thicknesses probably exist and may cause a few tube leaks during the next year or so of operation. These tubes will be repaired or replaced.

The UT survey taken of the front waterwall indicates that severe corrosion has occurred on the exterior (non-fireside) surface of the tubes. Some of the readings are below the calculated code minimum wall thickness of 0.102 in. for 2-1/2 in. O.D. tubes. Replacement of the affected area is required to remove those tubes which will probably fail during the next year of operation. As a minimum, the first 16 tubes in from the side wall (not including the areas of new tubing at the furnace corners installed by SIPC) will be replaced. The replacement tubes will extend from the tubes currently being installed, to just past the front wall to furnace roof tube bend. A view of the front wall tubes prepared for UT testing is shown in Figure 24.

The buckstays on the rear gas outlet duct are badly corroded and will be repaired or replaced. Two broken buckstays located on the front wall confirm concerns regarding the integrity of the supports. No significant limitations or effects on boiler operation is expected over the next year unless furnace pressure excursions occur. Most likely causes of downtime over the next year are possible fatigue failures at the buckstay/ tube attachments. The cyclic duty, external corrosion and attachment design create an environment conducive to fatigue crack growth. Past fatigue failures at these locations indicate that some of the existing attachment welds are in various stages of fatigue damage. Non-cyclic operation will limit the number of failures which will occur over the next year of operation.

All of the pressure parts internal to the boiler furnace (superheater and generating bank, etc.) appear to be in good condition. No signs of damage which would cause reliability problems were noted. Damage to external parts of the boiler has been caused by flue gas leaking to the external surfaces of the boiler, then cooling and mixing with water and oxygen to produce a corrosive environment. Streaks of yellow in the deposits found on the corroded areas indicate that sulfur may have a major part in the problem. Repairing the leaks and prohibiting the corrosive environment from developing will have significant positive effects on the next year of boiler operation.

Broken refractory around the superheater tube roof penetrations and holes in refractory over the furnace roof tubes will be repaired. These repairs are necessary to prevent gas leaks to and excessive buildup of flyash in the penthouse. The additional weight of any flyash buildup in the penthouse may cause damage to the roof refractory and tubing.

Lagging and insulation over the furnace will be replaced including hanger rod seals and covers. Lagging joints will be weatherproofed using sealant. Repairing the lagging and insulation is not vital to a one year operation cycle since the lagging is primarily for personnel protection and weatherproofing.

All casing endorsing dead air spaces will be repaired. Each air space will be made air tight to prevent the intrusion of flue gases from the boiler and moisture from the outside. None of the observed corrosion in the dead air spaces is serious enough to affect the boiler's reliability over the next year.

Gas outlet duct support systems need to be replaced. Severe corrosion of the supports may lead to failure at any time. Holes in the ductwork should be patched to minimize the amount of escaping flue gas. Holes in the flue gas pressure boundary adversely affect the performance of the boiler. Buckstay attachments along the rear and side walls (exposed to weather) will be inspected.

4.2.3 Modifications to Existing Cyclones

The existing cyclone furnace will be modified to install the LNS Burner. The internal diameter of the existing cyclone furnaces is about 7-ft. Therefore, a portion of the cyclones existing conical front-piece will be removed. A truncated mating support ring will be welded to the cyclone furnace. The LNS Burner will be attached to this opening. The cyclones existing tangential air ports will be blocked off with refractory.

4.2.4 Slag Screen

To increase the slag removal efficiency of the existing cyclone design and thereby accommodate the increased ash loading inherent with the LNS Burner, each cyclone's reentry throat will be removed and replaced with a staggered, refractory-covered water-cooled slag screen. Figure 5 shows this concept. At the slag screen stage in the LNS Burner, the resulting combustion gases are sufficiently hot such that the coal ash is in molten droplets (called slag). The droplets contact the tubes by inertial forces and flow down the tubes into the boiler. The slag drains down through the boilers slag tap and into a water-filled slag tank. The material solidifies and is sluiced with water into the slag pond.

To form the slag screen, the 2-1/2 in. OD on 3 in. centers front waterwall tubes will bend inward at alternate intervals vertically traversing the cyclone discharge opening forming a staggered array. Both the front and rear rows of tubes will be studded and coated with refractory to protect the metal from the slag/fly ash loads. The heat flux on these tubes is expected to be the same as that on the existing cyclone throat tubes. The end view towards the boiler is shown in Figure 25.

The total pressure drop (air inlet to gas outlet basis) across the LNS Burner and slag screen is estimated to be about 30 in. of water gauge (W.G.). As the slag collects on the screen, it drains to the slag tap located in the boiler's floor. This slag screen technique will provide a positive control of the larger size coal ash, resulting in a controlled uniform fly ash particle size. Further, even with the higher expected ash loading from the LNS Burner, the quantity of the fly ash load downstream in the boiler and ESP system will be maintained to less than that of the original cyclone system.

4.2.5 NO_x Control, Final Combustion (Overfire Air)

The location of the overfire air is determined by two criteria:

- Combustion air mixing requirements to complete CO burn out.
- Operation within the gas temperature limits to avoid formation of *thermal* NO_x.

Since the furnace gas velocities are relatively low (about 20 ft/s) and the furnace cross section large, the ability to achieve acceptable mixing quality is dependent on the number and location of air ports, injected gas momentum, and angle of injection. Obviously, the lower in the furnace the air is introduced, the greater the available residence time for mixing. The location of the overfire air injection was determined from a furnace heat transfer analysis that defined gas temperature as a function of furnace height. Overfire air is distributed into the upper region of the furnace through twelve 4-in.-diameter pipes. The air used for overfire comes from the spent pulverizer sweep air exiting the coal separators. To increase turndown capability and to better match the pulverizer operating requirements to overfire air demand, a bypass line from the outlet of the coal separators permits a small fraction of the spent sweep air to be dumped downstream into the ash multiclone separator.

Cyclone furnaces operate with high excess air and at high temperature. The heat release during combustion is very high and as a result the boiler volume is much smaller than would be found in a conventional pc-fired system. The Marion unit 1 boiler entrance has a small cross-section; about 5-feet depth and about 20-feet in width.

The LNS Burner's combustion process is fundamentally different from that of the cyclone, and the combustion products are also different. The LNS Burner products enter the boiler as hot, fuel-rich gases. Additional overfire air must be added to complete this combustion step with care taken to avoid the formation of thermal NO_x. If done correctly, SO_2 is controlled and significant NO_x reductions are achieved. Because of the small boiler volume, flow modelling was found to be necessary to insure that adequate mixing of LNS Burner combustion products with air can be accomplished to achieve NO_x emissions goals.

Design requirements for the air injection system for the Marion boiler were developed using a commercially available computational fluid dynamics (CFD) computer program, FLUENT developed by Creare, New Hampshire. A series of runs were made to obtain a design for final air injection that met the process design goals as closely as possible.

A primary design goal for the overfire air (OFA) system is to control gas temperatures at the boiler superheat region to the same temperatures that existed in prior cyclone boiler operation (1900 - 2200°F). Constraints on this goal took two forms: the physical geometry of the boiler and process considerations. The physical constraint was the small depth of the lower boiler at Marion, which offers a limited volume for mixing air into the gases exiting from the LNS Burner. Air addition within the boiler must be carefully controlled in order to limit the formation of thermal NO_x until the flue gas reaches the superheat region. Additionally, as the design matured a concern developed over gas temperatures in the lower boiler relative to slag fusion points. A new design goal was added to insure gas temperature below the slag screens was above slag fusion points to guarantee that slag from the combustors will flow properly to and through the slag tap located in the boiler floor.

FLUENT is a finite difference computer program used for solving the Navier-Stokes equations within a computational domain. It can treat 3-dimensional, steady, turbulent flows with chemically reacting components and convective/radiation heat transfer at boundaries. This combination of physical modelling abilities corresponds to the requirements for designing the Marion air injection system.

Because of the scale difference between small air ports and overall boiler dimensions, simulation of boiler flow fields inevitably leads to large models which translates directly to long computer execution times needed to achieve a reasonably converged solution. A goal when using CFD programs is to maximize the node size (coarse grid) which minimizes the number of nodes and yet keeps the computational errors within bounds. Small jets entering and mixing in large volumes make this a difficult task. For the Marion boiler, right-left symmetry allowed a half-width model (sidewall to boiler centerline) to be used. This helped reduce the number of nodes. However, the need to mix air within the entire boiler volume meant that the model had to cover the full height and depth.

Two models were used in the development of design requirements: first a model with 79,092 nodes (Runs 1 through 3); and a second model (Run 4 and following) with 116,480 nodes. The first, simpler model used 78 nodes from floor to roof (56.1 ft); 26 nodes from front wall to rear wall (12 ft); and 39 nodes from sidewall to boiler centerline (9.25 ft). The second, more detailed model used 80 nodes from floor to roof; 26 nodes from front wall to rear wall; and 56 nodes from sidewall to boiler centerline. The proportionately larger numbers of nodes in the sideways direction was needed to accommodate non-symmetrical air injection locations. The change in node number reflected a change in the slag screen design and elevation of the OFA relative to the evaporative rear platens in the boiler.

The modelling has been completed and a final report has been prepared. The calculations predicted at the process design goal of enough tertiary and especially OFA mixing with the slag screen gas flow for good final temperature distribution will be met. The modelling indicates that there are some small channels of hot gas near the walls at 2500°F which is higher than desired. However, these channels are part of the rear wall separation flow from the superheater inlet bottom edge. As the flow moves into the superheater, the heat is dissipated into the walls and gas temperatures range from 1600°F to 1900°F over the majority of flow, with peak temperatures of 2200°F. The predicted temperature field entering the super heater is reasonably uniform.

4.2.6 System Air Ducting Design and Modifications

The following modifications were made to the arrangement of new and existing ducts to accommodate the LNS Burner's air entry requirements and removing the existing cyclone burner primary and secondary air duct connections:

- Removal of the cyclone's primary air duct, blockage and sealing of the cyclone's secondary air entrance ducting and removal of the entire section of existing 54 in. diameter secondary air ducting downstream of the existing air flow measuring venturis.
- Interconnection of the LNS Burner air ducting to the new terminus of the 54 in. diameter secondary air ducting. Each duct section was equipped with a control damper and mass air flow measuring device.

For the over-fire air requirements, new furnace wall ports will be incorporated into the design and installed in both front and rear walls. The design of these ports were confirmed with boiler flow mixing modelling as discussed previously.

From the air heater air side discharge, and FD fan discharge, new hot air and tempering air ducting with control dampers were designed for both the Atrita pulverizer and transport blower inlet ducting. This inlet ducting was equipped with a flow control damper and air flow measuring device (a mass flow meter for the transport blower; a segmental orifice plate for the less critical Atrita circuit). In this way, control of air flow and temperature could be achieved in both flow circuits.

All ducting will be fabricated from 1/4 in. carbon steel plate and sized to provide a nominal full load duct velocity of 60 ft/s, thereby achieving a reasonable balance between duct size and system pressure drop.

The existing FD fan flow capability is sufficient for all air flow circuits, however, the FD fan's developed head required a boost from the pulverizer primary air fan for the boiler combustion air circuit and a boost from a separately provided transport blower for the combustor air/fuel feed circuit.

Modifications to the boiler furnace walls and flue gas ducting were completed to accommodate furnace temperature and flue gas sampling ports respectively required during performance testing. The modifications were required to permit test probes to be inserted directly into the flue gas streams and furnace streams to determine temperature and gas analysis profiles for the Baseline Test to be compared with the retrofitted plant.

4.2.7 Turbine Generator And Supporting Systems

Modifications to the turbine generator and supporting systems are not required. Their performance will be unaffected since the heat input to the boiler from the LNS Burners will be the same as from the original cyclone burners. Some maintenance is required to insure unit reliability is acceptable for demonstration testing.

4.2.8 Instrument Air

A new centrifugal air compressor supplied by SIPC furnishes supply air to a new 4 in. header. The existing instrument air dryer is fed from the new header and supplies air to the unit, the new Fuel Preparation Building and the new fuel system.

4.2.9 Existing Coal Bunkers and Feeders

The existing coal storage bunkers allow for 16 h of full-load operation. The coal feeds by gravity to existing weigh belt feeders. The existing coal feeders are being upgraded from a mechanical to microcomputer-based feeder controllers which have better accuracy and control. Also, the feeders are raised from the floor to enable the installation of coal transfer conveying equipment which interconnect the existing coal feed system to the retrofit fuel preparation building. Other than the modifications to the existing coal feeders and chutes required to accommodate the new cross-feeder, no additional work will be required to the existing plant's coal handling facilities.

4.2.10 Ash Waste Collection

The existing ash waste collection system will be used. This facility was thoroughly reviewed to assure environmental standards would continue to be met. No issues were identified that might change the existing operation.

The existing cyclone slag is sluiced by pipes and water pumps into a slag collection pond. Slag is removed from the pond and sold by a vendor as grit blasting material.

Currently, fly ash is also water sluiced to a fly ash pond. The existing cyclone ash has a significant carbon content in the ash which can ignite if pneumatically conveyed. However, it is expected that the fly ash produced with the LNS Burner will be very low in carbon (nearly zero) such that pneumatic conveying will be safe to use. The LNS Burner fly ash would then be mixed with SIPC's unit 4 limestone wet scrubber waste as a stabilizing material and used for landfill.

4.2.11 Boiler Maintenance

The maintenance program for the Demonstration Phase of Marion Unit #1 was established from data provided by SIPC. The program was based on maintenance history for a single 33 MW unit averaged from actual data for all three Marion 33 MW units. All have been operated recently either for peaking service for replacement power or when unit 4 was shut down. Recent performance of unit 1 observed by site personnel and development of a list of known equipment and other defects which directly effect both peaking and baseload operating capability indicate that preventative maintenance will be required prior to commencement of Demonstration Testing.

The following is a summary of tasks associated with preventative maintenance program to be accomplished prior to Demonstration Testing:

- Repack the 1st valve (root valve) and critical valves in key piping systems. Repack 1st and 2nd valves to level, flow and pressure transmitters and replace instrument piping as necessary.
- Inspect unit 1 balance of plant heat exchangers and chemically/mechanically clean as necessary.
- Replace high pressure drain valves (2 in. and under) as necessary.
- Load test and replace two main steam line hangers.
- Check out, calibrate and tune existing unit field instrument.
- Inspect and rebuild key control valves.
- Load test/replace two main steam pipe hangers and check sway suppressor.
- Set the drum and superheater safety valves.
- Repair the broken personnel protection safety locking devices on the electrostatic precipitator.
- Repair the known boiler and multi-clone casing and breaching leaks.
- Replace defective insulation and lagging and reinsulate uninsulated areas of the boiler breaching, casing and ductwork.
- Repair the superheater drain piping failures - may involve the replacement of approximately 160 ft of 1-1/2 in. Schedule 80 piping.
- Replace the boiler blowdown tank.
- Replace the defective bushing on the No. 3 electrostatic precipitator field.
- Miscellaneous maintenance to local power supplies, plant lighting, and electrical controls. The above maintenance items will be completed in parallel with retrofit construction in Phase II of the project.

4.3 NEW FUEL PREPARATION BUILDING DESIGN

A new structure will be constructed adjacent to the unit 1 to house the new fuel preparation equipment and silos. This structure, sized approximately 24 ft wide, 27.5 ft long, and 95.5 ft tall will include the following: (see Figure 26 through 29 showing various elevation and plan views of the fuel preparation building).

- Pulverizer.
- Cyclone separator.
- Fuel transport blower.
- Fuel pipes, coal splitters, hot and cold air ducting.
- New limestone silo and gravimetric feeder.
- New additive silo and gravimetric feeder.
- New cross-feed coal conveyor.
- New switchgear to supply power and overload protection to the new equipment.

4.3.1 Design Description

Architectural sketches and layouts of the fuel preparation building were prepared to define the structural steel framework for the building.

Floor and roof drawings and elevations were produced showing the locations of all doors and other openings and these were developed into detailed drawings for use in material procurement and construction.

4.3.2 Civil and Structural Design

The Marion site Soils Report was reviewed to determine conceptual foundation requirements of the fuel preparation building design.

Existing borings obtained from SIPC in the area of the new fuel preparation building indicated that the natural soil would probably provide suitable foundation bearing material. The actual conditions as they actually existed were not known, particularly regarding backfill for adjacent buildings and previous structures. Based on verbal information received from SIPC, it was assumed that the area was assumed returned to the original condition after construction and demolition of an old facility. This was confirmed prior to completion of the foundation.

Two new test (2) borings, each to a 30-foot depth, were drilled to confirm the validity of the previous soils report data. The results confirmed the previous Soils Report data.

A structural steelwork arrangement was developed from the architectural layouts and design parameters established. These were revised and updated as vendor equipment information on dimensions and loadings became available.

Design and preparation of detailed drawings was carried out for the structural steelwork and reinforced concrete foundations for the fuel preparation building, structural steelwork and foundations for the bucket elevator and the foundation for the continuous emissions monitoring shelter.

At SIPC's request, the bucket elevator location was changed from the east to the south side of the new building to avoid impacting existing maintenance and road accesses. This move also resulted in changes to the conveyor system being used to transport the materials from the bucket elevator to the limestone and additive silos. These changes impacted the structural framing designs and details for the roof and floor plans and the foundation concepts. Significant calculation and drawing revisions were required. Subsequently, material and/or detailing changes were necessary.

During this period, the most significant rework occurred as a result of a request from SIPC to upgrade the designs to conform with Seismic Zone 3 Criteria due to the site's close proximity to the New Madrid Fault. All designs had originally been performed for Seismic Zone 2 criteria in accordance with code requirements. This request resulted in major calculation and drawing revisions and entailed significant material and detailing changes.

Approximately 15 structural members required replacement with a larger section, 9 addition structural members were added as a result of the increased seismic forces, and significant number of minor detailing changes were required to columns, bracing, gusset plates and connection details.

Elevation drawings were revised to show access requirements for maintenance of the coal conveyor which transports coal from the silos to the Fuel Preparation Building.

Similar revisions were made to the roof drawings to show all roof penetrations such as hatches and ventilation details.

Design and drafting work associated with the installation of equipment and raceways in the existing plant structures was completed. Evaluations of structural adequacy were performed and modifications designed for existing structural components which needed strengthening to accommodate the additional loads.

Design documents, calculations and drawings were finalized in preparation for microfilming and project design completion close-out procedures.

4.3.3 Mechanical Design

Fuel Preparation Building equipment heat loads and ventilation requirements were determined. The large amount of heat released by electric motors (725 HP) in the fuel preparation building required the use of power ventilators. Roof ventilators were selected since they were self-contained and reliable, and would more effectively remove the heat that accumulates in the upper levels of the building than wall mounted fans. Each ventilator is equipped with a local adjustable thermostat, and a backdraft damper. Inlet air is admitted near grade level, below the feeder floor, through weather louvers. Each will be provided with manual shutoff dampers which will be manually closed in winter as required to maintain room temperature.

Fire protection for the fuel preparation building will be provided by a dry pipe riser system with hose racks on the ground and feeder floors. All areas of the building will be accessible with a 75 foot fire hose and automatic filling of the system will be initiated by opening any hose valve. Water will also be available from two yard hydrants outside the building.

The fire protection system was designed in accordance with requirements for Group F-1 Moderate Hazard Factory and Industrial Use and the applicable NFPA codes.

Mechanical and piping penetrations in the siding and roof of the Fuel Preparation Building were located from the preliminary routing of service systems piping to the equipment in the building. Field inspection showed that additional removable panels were also required in the north wall siding to give access to the coal feeder conveyor.

4.3.4 Painting

A study was made to determine final painting requirements for the Fuel Preparation Building and mechanical equipment. The structural and miscellaneous steelwork was coated with an epoxy polyamide after fabrication and before delivery to the site. It was determined that this coating is suitable for all steelwork surfaces within the building envelope because service conditions are not corrosive and will not be detrimental to this particular epoxy.

All outside surfaces which are exposed to ultra-violet light will require a finish coat of enamel because ultra-violet light can cause deterioration of the epoxy within five to ten years. All such exposed surfaces, including the steelwork supports for the bucket elevator and the screw conveyor to the limestone and additive silos, will have a finish coat of Kolorane U Series enamel.

All uninsulated piping and mechanical equipment which was treated with a light red oxide primer will be given a finish coat of standard enamel.

All finish coat paint will be applied after construction has been completed to avoid damage to the paint during construction activities and the need for subsequent touch up.

4.4 NEW EQUIPMENT AND PIPING IN FUEL PREPARATION BUILDING

All new mechanical equipment required to support the LNS Burners is located in the fuel preparation building, except for a new coal conveyor which will receive coal from the existing plant coal feeders and transport it through the unit 1 boiler siding to the fuel preparation building. The arrangement of equipment is shown in Figure 20 and 21, Partial Plan and Section.

4.4 Materials Storage

New silos will be provided for the storage of limestone (3118 ft^3) and fuel additive (750 ft^3) inside the fuel preparation building. These new silos are sized for 45 hours and 73 hours of full load operation respectively. The upper sections of the silos are cylindrical in shape and fabricated from mild steel. The lower sections are conical with sides sloping at 70° to the horizontal to ensure the flow of wet material and are fabricated from stainless steel to reduce friction and prevent corrosion.

Bulk storage for four days supply of limestone and fuel additive will be located approximately 100 feet south of the common stack for Units 1 and 2, and will be sited to avoid obstruction to plant maintenance and laydown areas. This location was chosen to ensure that the silos could be filled with materials from the bulk storage stockpile within a maximum period of one hour.

The limestone bulk storage stockpile will not be covered because the graded limestone currently used by SIPC at the plant is known to flow freely in all weather condition. The fuel additive stockpile will be covered with tarpaulins.

Loading of materials from the stockpiles will be carried out by the existing rubber tired loaders used at the plant.

Coal will be stored in the existing coal bunkers at the plant because preliminary studies showed that a coal conveyor from the existing plant storage would be less expensive than new bunkers and feeders. It was also considered that maximum utilization of the existing plant fuel feed would assist extrapolation of the retrofit design to fit other existing plants.

4.4.2 Materials Handling

The original design concept was based on the use of pulverized limestone delivered directly to the new storage silos. A subsequent design study confirmed a change to crushed limestone to take advantage of its availability at the site, at a considerable saving in cost ($6/ton versus $30/ton), where it is used for the unit 4 scrubber. Additional loading equipment, including a bucket elevator rated at 144 tons/hour and loading hopper of 240 ft^3 capacity located at grade level were required to handle this material.

The existing SIPC coal handling system will be used, with the addition of a covered, explosion-proof conveyor to intercept coal downstream of the existing coal feeders and transport it to the fuel preparation building. It was originally planned to use the existing coal feeders without modification and a drag chain conveyor to transfer coal from the existing feeders to the pulverizer. The drag chain conveyor was later replaced by a covered belt type conveyor of 25 tons/hour capacity meeting NFPA-85F requirements for explosion-proof design, which is expected to operate more reliably with abrasive coals. Additional space requirements for the new explosion-proof belt conveyor and the geometry of the discharge chute at the pulverizer necessitated the raising and rotation of the existing feeders in unit 1 to fit the new arrangement. The coal handling arrangement is shown in Figure 31.

Coal, limestone and additive will be fed to the "Attrita" pulverizer where the materials will be thoroughly mixed and pulverized to a grading of 70% passing a 200 size mesh. The pulverizer is sized to handle the full design coal flow plus limestone and additive at a maximum rate of 23 tons/hour. At full load, the pulverizer has a reserve capacity of 3 percent.

The existing coal bunkers and the new silos for limestone and fuel additive will be fitted with air cannons to clear blockages in material flow.

4.4.3 Coal Piping Layout and Materials

Coal and fuel piping to the LNS Burners are either fabricated from of wear-resistant material, or will incorporate provision for rotation of the pipe sections to equalize wear. Minimum flow velocities of 4,250 ft/m were used to prevent settling of the coal in the pipe.

Pipe materials for the LNS Burner and fuel systems will be carbon steel. Materials for burner support auxiliary systems match those of the existing plant systems.

The original coal delivery piping design for the LNS Burner required coal feed splits from one 12 in. diameter to six 5 in. diameter pipes. The design of the coal splitter assemblies had not been finalized at that time and it was assumed that the splitter location would be at the burner.

The coal splitter design eventually selected for the retrofit is orientated vertically with flow entering at the bottom and leaving from the top. Several straight pipe runs are required on the upstream side of the splitter to achieve a uniform distribution of flow. Because this pipe configuration could not be accommodated in the space available at the burner front, the coal splitter assemblies were relocated in the Fuel Preparation Building. An optimum route for the two sets of six 5 in. diameter fuel lines was selected.

The relocation of the coal splitter assemblies to the Fuel Preparation Building increased by six times the length of fuel pipe between the splitters and the burners. With butt welded pipe joints as in the original design and allowing for the reduction in diameter from 12 in. to 5 in., the cost would have increased by more than 3-1/2 times. After further study, a combination of flanged and mechanically coupled joints was adopted.

Piping runs follow the shortest and most direct routes to minimize pressure drops in the system. All feeders, chutes and piping from the pulverizer to the LNS Burner, including the cyclone separator, will be designed for an internal pressure of 50 psig in accordance with NFPA-85F requirements. The general layout of coal piping from cyclones to burners is shown in Figures 27 and 28.

4.4.4 Solids Flow Splitting

The pulverized coal, limestone and additive are pneumatically conveyed from the bottom of the coal separator cyclone to the two LNS Burners through two sets of flow splitters. The required split is one to twelve, with six coal pipes to feed each of the two LNS Burners. Riley Stoker uses a standard design "riffle box" which works well for them in other installations. The riffle box splitter uses mechanical fingers to split the incoming flow stream into two outlets. The standard riffle box design cannot be easily modified to use more than two outlets, so a design was developed which would take the flow from each riffle box and divide that flow into six outlets. This splitter is based on designs used in the coal and steel industries. The splitter chosen is orientated vertically with flow entering the bottom and leaving from the top. This one-to-six splitter design is similar to that successfully used for TransAlta's application of the LNS Burner to the LNS-CAP Project at Cold Lake, Alberta, Canada. This design incorporate one to three split.

The Marion splitter is placed in a long vertical section of pipe designed to eliminate any non-uniform flow of solids. The flow enters through an expanding inlet where the velocity of the gas and solids is reduced to ensure that the solids are uniformly distributed over the internal cross-section. The outlet pipes are located in a contracting cone to increase their velocity before they enter the coal conveying pipes to reduce the contraction losses at the outlet. The split of the solids is expected to be within the desired limits. A drawing of the splitter is shown in Figure 32.

4.4.5 Fuel Oil System

Details of the fuel oil system have been completed and incorporated into a Process and Instrumentation Drawing (P&ID). The existing ignitor oil pumps and piping will be used up to and including the ring header at the boiler front.

The LNS Burner ignitor oil guns will be supplied from the existing fuel oil system, but the system storage and pumping capacities will be upgraded as necessary to accommodate the increased ignitor fuel requirements.

4.4.6 Dust Collection

Dust collection for the limestone and fuel additive handling system will be by means of a power operated bag filter installed on the limestone silo which will draw dust-laden air from the entire system. The filter will be self-cleaning and fines will be returned to the limestone silo.

Dust in the coal system will be controlled by the flow of low pressure seal air through the coal conveyor to the pulverizer.

4.4.7 Pulverizer

A Riley Attrita duplex pulverizer will be used to pulverizer the coal, limestone and additive mixture to 70% passing a 200 mesh screen. This unit is fabricated with abrasion-resistant materials and is powered by a 600 HP electric motor. The Attrita pulverizer is shown in Figure 22.

The amount of pulverizer carrier air flow was dictated by the air temperature level achievable from the air heater and amount of remaining moisture required in the pulverized product. Because the required pulverizer carrier air flow exceeds that required to convey coal to the combustor, an indirect system is used in which a high-efficiency cyclone separator removes all pulverizer carrier air (which in turn becomes boiler overfire air) and collects pulverized product for rotary valve injection into a separately metered air flow combustor coal delivery stream. This latter circuit contains a booster transport blower, two, two-way riffle distributors, two sets of tight shut-off valves (NFPA requirement) and two, six-way fuel splitters.

4.4.8 Cyclone Separators

Two 50% cyclones are used to separate pulverized coal from the sweep air. The units are 5 ft in diameter and are refractory-lined for abrasion protection. A shutoff damper permits one cyclone to be isolated for better turndown. The cyclones at full load have a design efficiency of 99.4% with the expected pulverizer size distribution. Figure 33 shows a drawing of the two cyclones.

4.4.9 Transport Blower

The coal transport blower is rated at 38,600 lb/h of air at an increase in head from 35 iwg to 81 iwg. The blower is powered by a 125 HP motor.

4.4.10 Bucket Elevator

A bucket elevator (rated at 144 tons/h) is used to load the limestone and additive silos from a 240 ft^3 hopper located at grade level.

4.4.11 Coal Conveyor

A coal feed conveyor (rated at 25 tons/h) runs under the existing weighbelt feeders to collect the coal and transport it to the fuel preparation building. The coal falls by gravity into the pulverizer inlet.

4.5 INSTRUMENTATION AND CONTROL SYSTEM

4.5.1 Criteria

Criteria for the design of the plant control system were established early in the preliminary design effort. These criteria were subject to continual review as the design progressed. The significant criteria are summarized below:

1. The control system and equipment will be designed in accordance with industry I&C design codes and standards as listed in Appendix C.

2. Control systems will be provided for steady state operation of the retrofitted unit in the main control room. The operator will also be operating other units at the same time when not in the start up or test mode.

3. Design criteria for start up and testing will consider one dedicated operator in the control room and one dedicated operator outside the control room.

4. System design will permit operation of the unit at reduced loads with either one or two burners. Actuator design will be pneumatic, signal design will be electric and power supply will be AC.

5. The LNS Burner will require multiple control loops for burner operation such as coal and air flow, burner temperature combustion control, in addition to those required for the existing balance of plant equipment.

6. A status board will also be required, together with several switches for operation of auxiliary equipment such as blowers and feeders as there is not sufficient space for these items on the existing main control panel.

The combustion control design criteria for the existing plant was used as the basis for establishing interface requirements between the LNS Burner controls and balance of plant equipment.

4.5.2 Design

A detailed review of unit 1 control and instrumentation drawings, plant equipment, and maintenance records was completed to determine

LNS Burner interface requirements for balance of plant design. Information from the review was integrated into design of the new LNS Burner combustion control system.

Detail design of the balance of plant control functions for the feedwater controls, feedwater recirculation controls, steam desuperheater controls, generator cooling controls, and other minor control loops and design of instrumentation for the materials handling system was completed.

Detailed design for control room layout and integration of the digital control system equipment into a functional system was completed. Instrumentation and control devices not required for LNS Burner operation or which require modification were identified and demolition requirements were determined.

Demolition requirements for the existing boiler front panel were defined. All equipment that will be required for LNS Burner operation was identified and design requirements for integration of this equipment into the retrofit design were completed.

Maintenance and upgrade requirements for balance of plant local instruments, actuators, auxiliary control devices and installation detail requirements were established.

Field walkdowns were completed to determine maintenance requirements for all balance of plant instruments.

4.5.3 Distributed Control System

The existing plant control system combines vintage-1960 pneumatics with 25-V controls. This equipment is difficult to repair and spare parts nearly impossible to find. The new control requirements for the LNS Burner and auxiliary systems greatly exceeded the limited capability of this old system. Therefore, the boiler control system is being upgraded to a modern distributed control system (DCS). The new system will utilize workstations connected by two redundant data highways housed in three freestanding cabinets. The control room operator will have two workstations and an alarm message printer. An engineering workstation will be located in a room just to the side of the boiler and will be used for data acquisition and system configuration management. The new DCS will completely replace the existing boiler control system.

The DCS will incorporate the following three control systems required for the retrofit :

- combustion controls and auxiliaries;
- burner flame safety controls; and,
- data acquisition.

A microprocessor based distributed control system was selected for the following reasons:

- There were many common inputs which could be "shared" in a DCS, but would require separate hard wiring to the three separate systems listed above.
- There was very limited space available in the control room, and especially on the control board, for operator interface devices and start/stop stations for new major equipment such as the pulverizer, fuel/air blower, feeders for limestone and additive. The distributed control system provided two CRT based operator interface stations for all of the start/stop and moldulating controls. These would fit the space available.

By utilizing the distributed nature of the control system, one cabinet will be located at the boiler front resulting in significant savings in wiring costs. The cabling requirements were significantly reduced by the use of four data highway cables 250 ft long instead of numerous cables of that length.

One DCS cabinet was located where the previous control cabinet was located utilizing existing wire trays and conduit. The third cabinet will be located in available space approximately 50 cable feet away. This has avoided the need to enlarge or build a new electrical equipment room. The location of the cabinets and the interconnections of the data highways is shown in Figure 34.

The nature of a DCS is such that the cost of the system is governed by the input/output count and the operator interface. Once these are purchased, the computational hardware costs are insignificant in comparison. This permits the flexibility to make significant changes in the control strategy and implement control improvements as testing provides feedback on the operating characteristics of the process, i.e., the control system can be modified without purchasing additional hardware.

Another key feature of the DCS is the redundant controller approach used in the combustion/boiler control and the burner control systems. In the event of a controller failure, the unit will continue to operating safely on automatic control allowing the failed controller to be replaced at a convenient time.

Design drawings were prepared for the modifications required to the main control room console to add the control system operator interface.

The existing plant annunciator alarm points were reviewed for all functions required for operation of the LNS Burner retrofit. It was concluded that most of the existing balance of plant alarms would be used with the new system. The existing annunciator will be retained for ease of operation and the alarm points will be wired to the DCS for alarm printing and logging.

A review of the existing boiler protective interlocks was completed to determine the functions to be utilized with the new controls for the LNS Burner retrofit. All necessary interlocks will be incorporated into the new system, which is designed to meet applicable sections of the NFPA standard covering boiler and burner operation.

Detailed design drawings for physical modifications to the control room were developed. The lack of space in the control room and the continued use of existing control functions on the unit 1 console section prohibited the transfer of all functions to the new DCS console. The control equipment in the existing console will be replaced, new operator interface will be added on the top of the console. Figure 35 shows the existing control panel area dedicated for units 1-3.

The bunker and silo air cannon design was modified to suit the operation of the controller units supplied with the air cannons. Operation from the DCS was changed to pushbutton control on the unit 1 console because DCS actuation would require additional components. The air cannon pushbutton operation from the console will be similar to other plant units for consistency of operation.

A review of the DCS design documentation was performed to verify that all instruments have been incorporated into the control system and that the BMS logic and combustion control/Balance of Plant (BOP) loops have been configured as shown. Instrument grouping within the system was reviewed to ensure that components with the same end destination were located in the same area to minimize system cabling and raceway.

A study to determine design and installation requirements for steam level instrumentation for unit 1 has been completed. Boiler requirements are for two independent direct level indications to be available to the operator. The existing retrofit equipment comprised direct visual indication by mirror visible from the control room and a level gauge at the boiler front panel which received an electrical signal from a transmitter attached to the boiler drum and was also visible from the control room. Both signals are no longer available because the sources of indication have been obstructed by the LNS Burner. Also, the level receiver that had been located at the boiler front was found to be defective. The study showed that a replacement transmitter and receiver must be purchased and installed. The direct reading visual system will be operable after installation of a new mirror. Adjustments will be made and operability verified during start up.

4.5.4 Acoustic Pyrometry

Gas temperature measurement is important in many production processes which involved furnace or boiler units such as electric utility steam units, refuse fired boilers or chemical process recovery boilers. Gas temperatures have been difficult to measure in these systems because of the hostile environment created by the combustion processes. Intrusive measurements using water-cooled thermocouple probes are difficult, costly, yield questionable results and have generally been limited to short term test applications.

The velocity with which acoustic waves propagate through a gas mixture is a primary function of absolute temperature and, to a lesser extent, a function of the gas composition. For most applications, the gas constituents and their relative quantities are well known or fall within a small range of values. The average gas temperatures along a path between a sound source and a receiver can therefore be determined by measuring the flight time of the acoustic wave along the known distance between the source and receiver, as shown in Figure 36.

A short audio tone burst with a specific frequency range and duration is launched from an electrodynamic source transducer at one side of the boiler and its arrival detected at the opposite side by a receiver transducer. The time interval, (flight time), is divided by the distance to give the acoustic velocity.

An acoustic temperature measurement system will be installed prior to the demonstration phase of the project in order to monitor the furnace internal temperature. The equipment will include electronic readout purchased on a rental basis and permanent boiler-mounted temperature sensors. The system is required to provide temperature profile map at elevation 550, one temperature measurement down the furnace centerline at elevation 566 and one temperature measurement down the furnace centerline at elevation 540.

The acoustic temperature measurement system will provide the following information:

1. Perform gas-temperature measurement by measuring speed of sound on eight channels.
2. Allow rapid sampling during quiet intervals (such as sootblower pauses) while buffering the sampled data, for computation later.

3. Allow periodic activation of solenoid controlled air purge valves to remove debris from speaker horns. The duration and interval are programmable.

4) Allow for averaging temperature data using a variable length moving average.

5) Present averaged temperature data in analog form.

6) Accumulate data log array containing the most recent readings over a period of several hours.

4.4.5 Access to Valves, Instruments and Test Connections

A design review of access to valve stations, instrumentation, and test connections on pipe and duct in the fuel preparation building was completed. All of these items were added to the general arrangement drawings and an assessment was made to determine access requirements. From this study it was determined that there were several valve stations and instruments where routine access would require the added expense to design and construct new platforms. None of these were identified as in a critical category, although additional access would be desirable. Temporary platforms that are required for erection and maintenance will be put in place as necessary during the construction program.

Sketches were made to determine optimum arrangements for the LNS Burner Platforms and layout of equipment related to the burner oil ignitor system and instrumentation. The general area around the burner is extremely congested with operational and test instrumentation and required a detail study to assure proper installation. The valve rack for the control valves for each burner will be field fabricated. Auxiliary equipment and instrumentation for the oil ignition system and burner instruments (two racks each burner) will require field assembly.

4.5.6 Instruments

Existing plant equipment to be retained includes the force draft fan control drive (modified for constant pressure operation), feedwater controls, cyclone air flow transmitters and local air devices. Secondary air shut-off damper drives will be retained in place, but are not required for operation. New transmitters will be provide for main steam pressure and flow and forced draft fan pressure.

A signal will be provided from the burner control system to the existing coal feeder control, but feedback will not be required. Coal feed indication will be retained in the control room and all other existing plant combustion control equipment will be disconnected from service and left in place or removed for storage.

Additional engineering time was required to research data on most of the older original plant instruments which have often been replaced by equivalent instruments from various instrument suppliers.

The instrument installation detail drawings have been drafted. These drawings provide standard tubing, valve and instrument installation details in an isometric format for all of the field mounted instruments. Also shown with these details are material lists itemizing all required materials needed to complete the installation and installation notes detailing any special installation requirements.

A completed configuration was developed of the DCS inputs and outputs. This allowed for the identification of circuits to each field device. To minimize the amount and size of raceway required to house these circuits a study was undertaken to establish ways to group non-line mounted devices located in similar areas. This approach was used in reviewing each area with a large concentration of instruments that have a common destination.

As an example, since there is large number of field devices located at each burner, a scheme was developed to minimize the number of conduits and supports. A stand-off bracket was designed that would allow for the mounting of instrument piping and conduits on each side of the burner.

Two main conduits were then run on each side of the burner barrel length. Conduits from the field devices on the barrel tie into one of the two conduits acting as a main artery depending on whether the device is wired directly to the DCS or if it is connected to a transmitter mounted on the instrument rack for each burner. By taking this approach the number of conduits were minimized in this congested area.

To accommodate temperature measurement of the burner gas at the slag screen, a terminal point and junction box was designed for the connection of these three thermocouples per burner. They are housed inside the existing abandoned burner air duct. Because this is a enclosed (seal welded) and high temperature environment, a special high temperature armored cable was routed out through a sealed fitting to a junction box for connection to the transmitters.

4.5.7 Emissions Monitoring Instrumentation

New stack monitoring instrumentation consisting of sulfur dioxide, nitrous oxides, oxygen, carbon dioxide, temperature and opacity instruments were installed early in the first phase of the project. Relative accuracy testing of the stack monitoring instruments was completed during the Baseline Test.

4.6 ELECTRICAL SYSTEM DESIGN

4.6.1 Design

Design criteria were developed for the new 2.4 kV switchgear, 480 volt load center and motor control center, raceway and conduit, motors, lighting, cable and the removal, dismantling or disconnection of existing equipment. Applicable sections of Electrical Standards (as listed in Appendix C) were used as design requirements for the electrical equipment.

Load studies confirmed that the capacity of the existing unit 1 auxiliary transformer is 3,750 kVA. The running load for unit was determined to be 3,450 kVA with a spare capacity of 300 kVA. Additional load requirements for the retrofit equipment were calculated to be approximately 600 KW which are taken from the station's 2.4 kV system. The addition of new switchgear and a new 480 volt load center are required.

The existing load center require extensive modifications because of retrofit requirements for these new equipment loads.

The new switchgear services the unit 1 circulating pump, which was removed from the existing unit 1 bus. The new coal pulverizer required for the LNS Burner retrofit then will receive power from the existing 2.4 kV power supply. Transient load studies will be carried out at the detailed engineering stage to ensure that the system is fully coordinated.

The existing motor control center at the front of the boiler was surveyed to determine which panel sections and equipment can be retained or relocated. Those which cannot be relocated on the existing panel sections will be removed and mounted on the new motor control center. This will be placed adjacent to the existing motor control center to avoid interference with the new LNS Burners.

Load studies were completed of electrical equipment in the Fuel Preparation Building for sizing of the new motor control center and incorporated in design and purchase specifications. This included line drop calculations required for cable sizing. All results were within initial project estimates.

Load studies and voltage drop calculations were completed for the stack monitoring equipment to finalize power center and cable sizing requirements. Grounding, conduit and power and control routing and connection drawings were issued for the equipment.

Voltage drop calculations were completed for the feeder lines to the circulating water pump and the new pulverizer. Field walkdowns were completed for the routing of all tray and conduit in the existing buildings to prevent interferences during construction and thereby optimize design and minimize construction costs. Electrical cable tray was completed for all portions of the fuel preparation and boiler buildings. Portions of cable tray and conduit were routed in longer runs through some portions of the lower levels of the boiler building to avoid interferences noted during the field walkdowns.

Electrical single line schematics were developed for all retrofitted electrical equipment. Layout of lighting in the fuel preparation building was completed. Detailed conduit and cable routing were started in the fuel preparation building.

Studies were made to determine the optimum location of the receiving equipment of the digital control system. Field devices feeding to the equipment originate in the new fuel preparation building and the existing boiler building. Space was available to locate equipment only in the lower levels of the plant which would have required long cable runs. From this study it was determined that plant space which now functions as a storage and lunch room could be relocated at considerably less expense to the lower levels and the new control equipment placed in the space thus made available. Cable runs were thus significantly reduced and access to the equipment for test and operating personnel greatly improved.

The locations of electrical components and peripherals in the Fuel Preparation Building, such as control panels, terminal boxes and marshalling junction boxes, were reviewed to eliminate or minimize structural and piping interferences.

Cable tray drawings for the new and existing buildings were finalized from the site reconnaissance data and design sketches developed during the previous reporting period. These drawings were issued for procurement and installation.

4.6.2 Fire Alarm System

The fire alarm system design for the Fuel Preparation Building was developed. Consideration was given to thermal and ionization detectors in the building, but it was concluded that, because of the high ceilings and the open nature of the structure, neither type of detector would prove to be effective. The selected design includes manual pull stations and external alarm horns.

4.6.3 Public Address System

The design of the public address system in the Fuel Preparation Building was completed. This system will utilize page/party line stations which are compatible with the existing system used in the Marion Power Plant.

4.6.4 Modification Drawings

A study was completed to determine the optimum configuration of the existing plant motor control center to be relocated. The equipment interferes with installation of the new burner and support equipment. Results were that only a portion of the equipment must be dismantled and relocated. The portions that would require relocation would have minimum impact on the cost of construction. Design drawings were issued reflecting the configuration change.

As part of the reassessment of the control scheme, modification drawings were prepared to identify all electrical power and control devices and associated circuits that would need to be modified, relocated or deleted. This activity required the revalidation of each existing plant circuit in relation to the overall retrofit design.

The modified wiring diagram for the main control panel has been developed. This drawing will identify existing panel wiring which must be disconnected and removed with the control and instrumentation devices that require removal. The electrical terminals which become available will be reused to wire up and connect the new devices, such as the air cannon remote switches, which will be installed in the panel.

The modification drawing for the unit 1 main control panel layout was completed. This drawing reflects the deletion of control and instrumentation devices which have been consolidated into the DCS and the addition of the bunker and silo air cannon remote control switches, DCS system CRT's and keyboard.

4.6.5 Grounding

A review of the existing plant ground grid was completed and determination made of details to expand the grid to the new fuel preparation building.

Ground system requirements for the Digital Control System were reviewed. Two ground systems will be required. The AC safety ground can be connected to the existing plant ground, but the system common ground requires a dedicated and isolated ground conductor from each common bus directly to the plant grid. These systems will meet the requirements of NEC Article 250 and will minimize the possibility of circulating currents.

4.6.6 Cables and Conduits

Conduit routing drawings of the 480V circuits originating from the new MCC were completed.

Prior to the relocation of the right half of MCC 1B at the burner front, a detailed study of the actual loads was performed. This was required to identify common plant loads that are fed from this MCC and need to be maintained while unit 1 is shut down for the retrofit. After identification of these loads, an alternative source of power was located and connected to ensure continuity of supply.

Detailed design documentation for the powering and control of major electrical components has been completed. The schematic and wiring connection diagrams are used for physical termination of cabling and identification of the control scheme and interfaces.

Piping drawings for the new fuel preparation building were reviewed to establish physical locations of instruments. The locations of non line-mounted devices, such as transmitters, were examined relative to the routing of conduit and raceway. Grouping of devices was maximized to reduce raceway and cabling requirements.

Identification and tabulation of new electrical circuits was completed. Scheduling of these circuits will include origin and destination points, cable types and sizes and the routing of the circuits. The grouping of circuits by service type and function has been established, together with standard nomenclature for identification of the circuits.

Electrical design details for instrumentation and minor control devices have been completed, including cabling and wiring termination data required for field installation and checkout.

Schematic and connection drawings for the Fuel Handling System, (including the pulverizer, fuel transport blower, rotary valve, screw conveyor, diverter gate, bucket elevator, silo level indicator, limestone and additive feeders, coal feeder and coal conveyor), were finalized and drafted. These drawings illustrate diagrammatically the control scheme of each of the above components and also reflect external cable pulls between components and wiring connections at each component. All reference drawings used to develop the control schemes and connections are listed and any pertinent notes related to the operation and installation of the components have been included.

4.6.7 Miscellaneous Wiring

Control design of the air cannons for the coal bunker and the limestone and additive silos was finalized and the corresponding wiring/connection diagram was developed. Each bunker and silo will have up to three microprocessor-controlled air cannons which, when fired in their predetermined sequence, will clear any blockages. Each bunker and silo will have its own microprocessor control panel to control its air cannons. Operation of each set of cannons will be possible either locally from the control panel or remotely via a push-button switch located on the unit 1 control console.

Schematic connection and wiring diagrams for the flame scanner/igniter system and DCS control modification for the oil pumps and unit 1 circulating water pump were completed.

4.7 MISCELLANEOUS DESIGN AREAS

4.7.1 Layout and Piping Design

Equipment layout studies, including associated pipe layout configuration, were completed. Flow diagrams were prepared for material handling systems, and field walkdowns of existing pipe, equipment, and structures were performed to plan out new piping layouts.

A general arrangement drawing was prepared to form a framework for detailing pipe layout and fabrication drawings for both LNS Burner and balance of plant systems.

LNS Burner system coal pipe drawings were reviewed for compliance with the general arrangements and locations of LNS Burner system pipe hangers established.

P&ID's were prepared for the balance of plant service system and sketches prepared for resolving field pipe and equipment constructability problems. Preparation of suggested field routings of balance of plant pipe systems commenced in accordance with the general arrangement drawings.

P&ID's for the Limestone and Additive Handling system and the Instrument and Service Air system have been issued for use. The Limestone and Additive Handling system incorporates all data from the vendor's drawings.

Mechanical design requirements were completed for the major components of the Materials Handling System. Piping and Instrument drawings and technical requirements were completed for the bucket elevator, coal limestone and additive storage, screw conveyor system and other related support equipment.

A mechanical equipment list was prepared, equipment weights and electrical loads for all mechanical equipment outlined on the equipment list were determined, and operating requirements for fuel handling equipment prepared. The equipment list is shown in Appendix B.

Engineering requirements for plant start up using light oil were determined. Start up will use an oil gun/ignitor mounted in the end of the LNS Burner. Each oil burner has been sized for this capacity with 8/1 turndown capability. 150,000 gallons of oil is available on site for all four units. No additional storage capacity is required. An air atomization system is used for the oil burners in lieu of the existing plant mechanical atomization system.

Control equipment for the oil ignition system was purchased as loose components and an engineering evaluation is required to determine the most cost effective method for field installation. Additional requirements such as isolation valves, strainers, small pipe and fittings must be purchased and bills of material and field installation drawings will be prepared for these.

A physical check was made of all areas of the existing plant and structures where new raceways, piping or equipment were to be added. This was done to identify potential interferences and to obtain sufficient information to check the capability of the existing structures to support the piping and raceway hanger loads, since no existing structural drawings were available. The structural evaluations were made and design and detailing of the hanger supports completed.

4.7.2 Piping, Equipment and Valve Lists

Equipment, line and valve lists and piping class sheets were prepared. Numbering of all lines and valves used the same system as the original design documents. Piping class sheets are as originally issued wherever possible, with updates where necessary to incorporate more modern materials and procedures. New plant equipment has been numbered in accordance with the Bechtel standard system, since no system exists at present.

Plant Data Book and the Start Up Plan have been updated to include equipment system descriptions. Recommended spares list has been obtained from suppliers and are incorporated in the Spare Parts List.

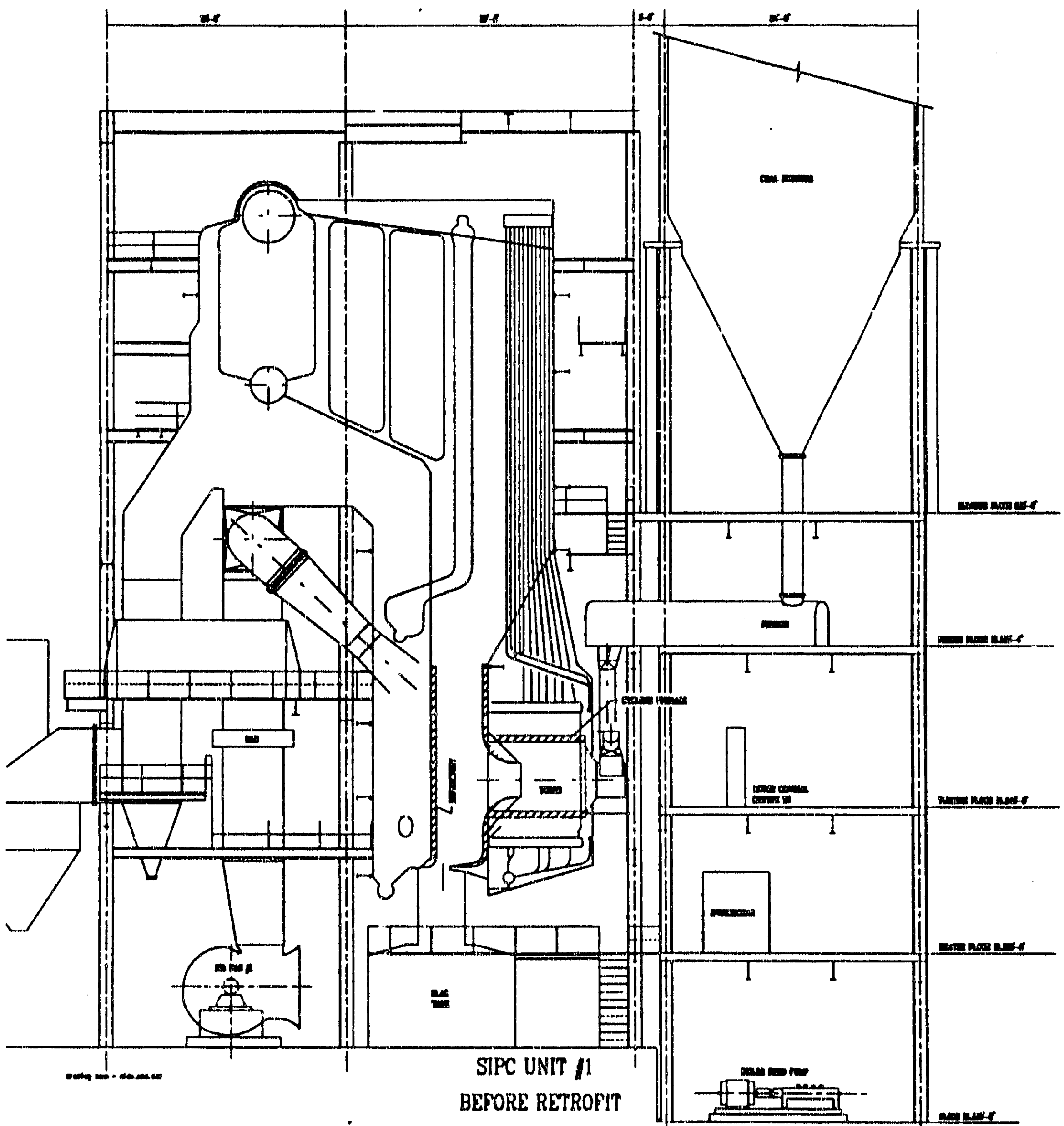

Figure 17. SIPC Unit 1 Before Retrofit

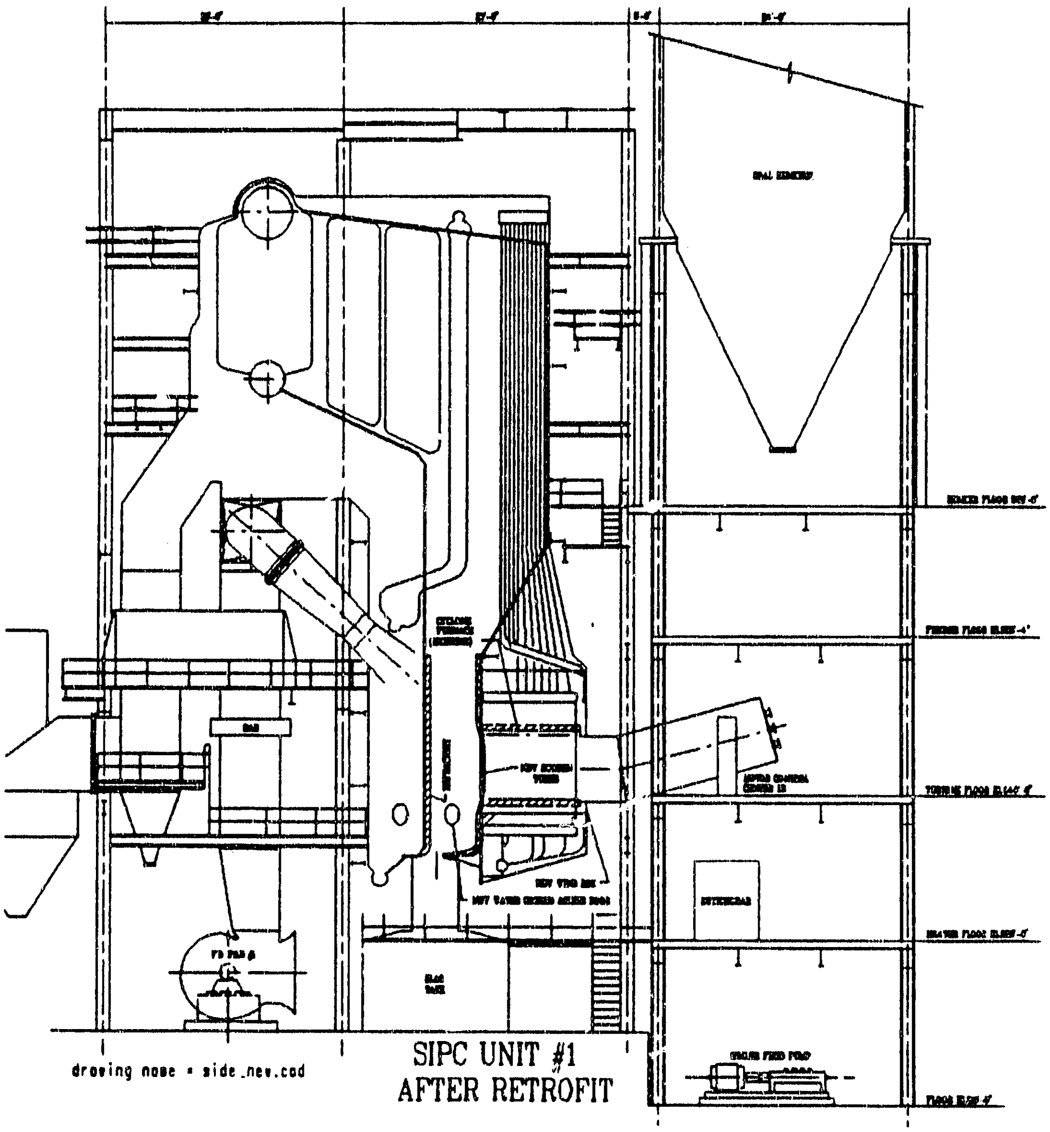

Figure 18. SIPC Unit 1 After Retrofit

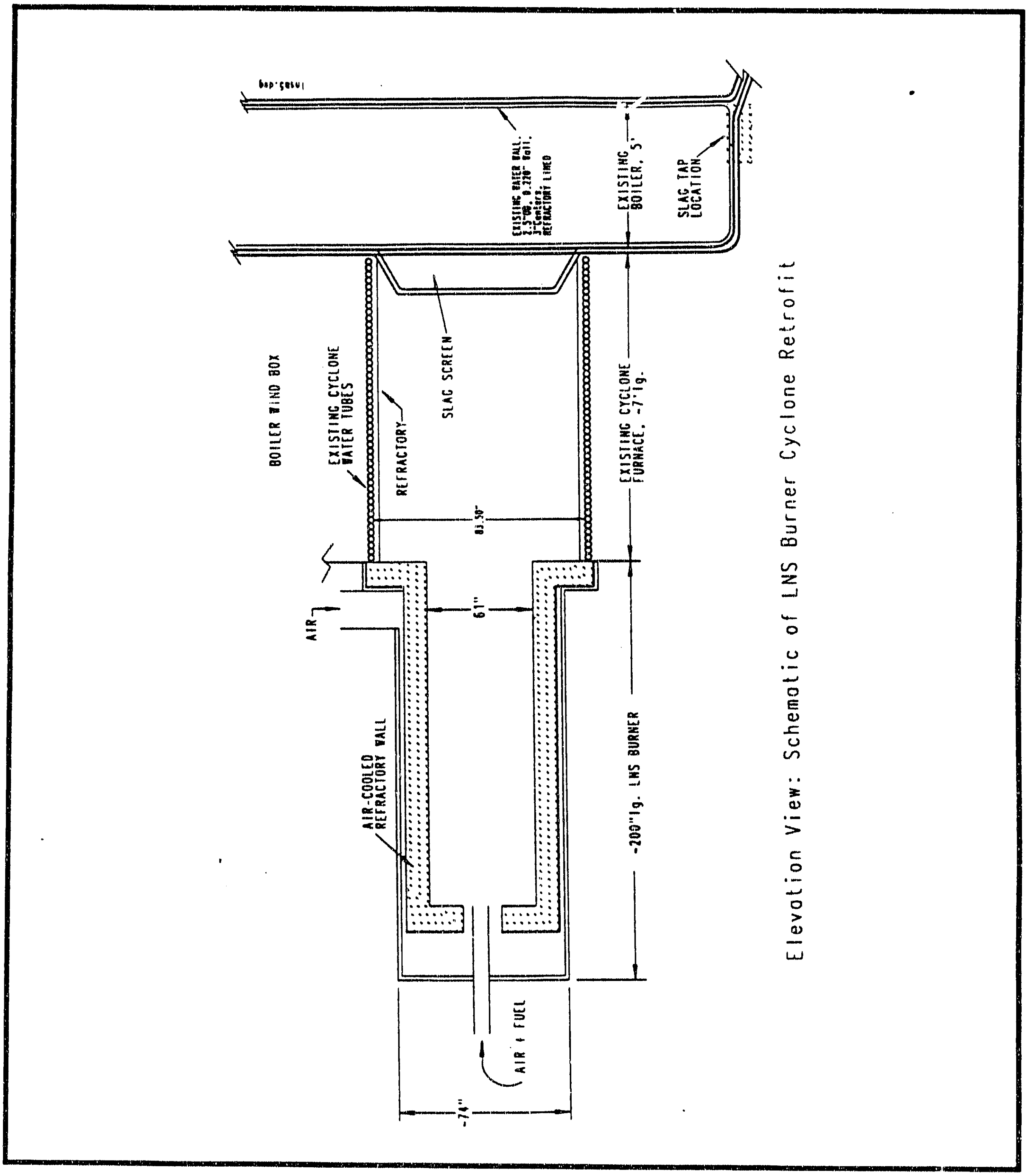

Figure 19. Elevation View: Schematic of LNS Burner Cyclone Retrofit

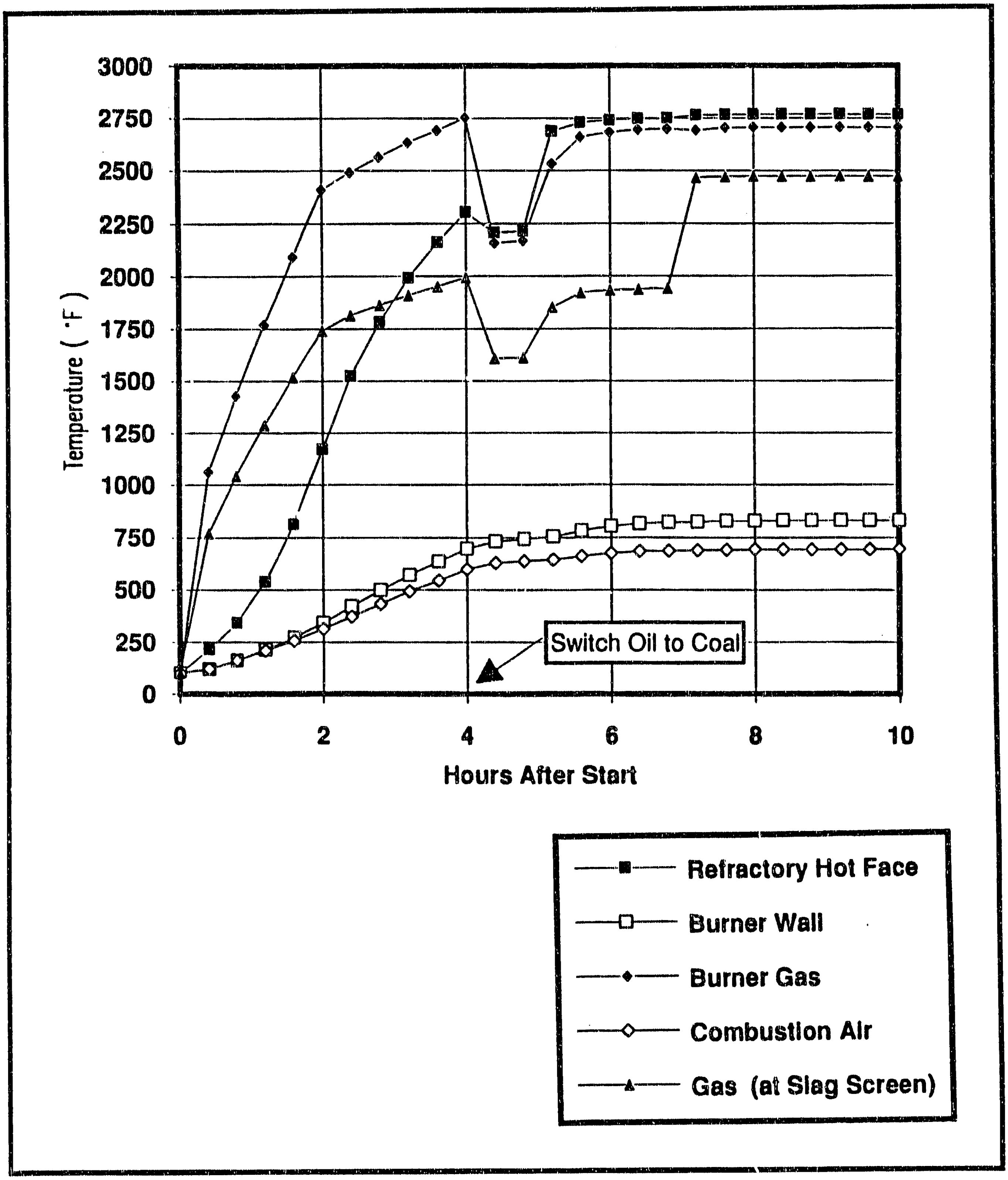

Figure 20. LNS Burner Temperatures after Start Up

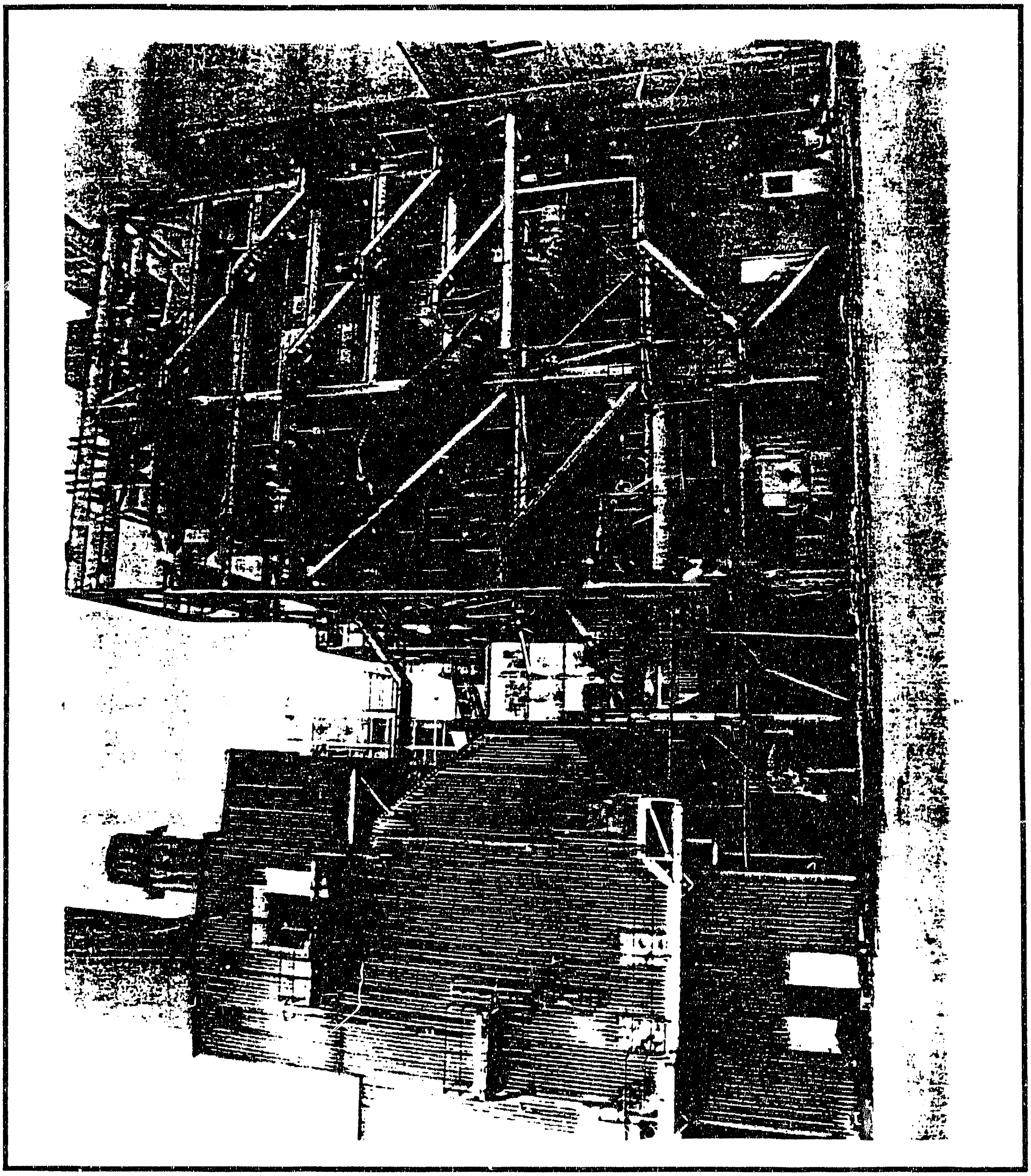

Figure 21. Elevation View of Boiler and Primary Air Ducting

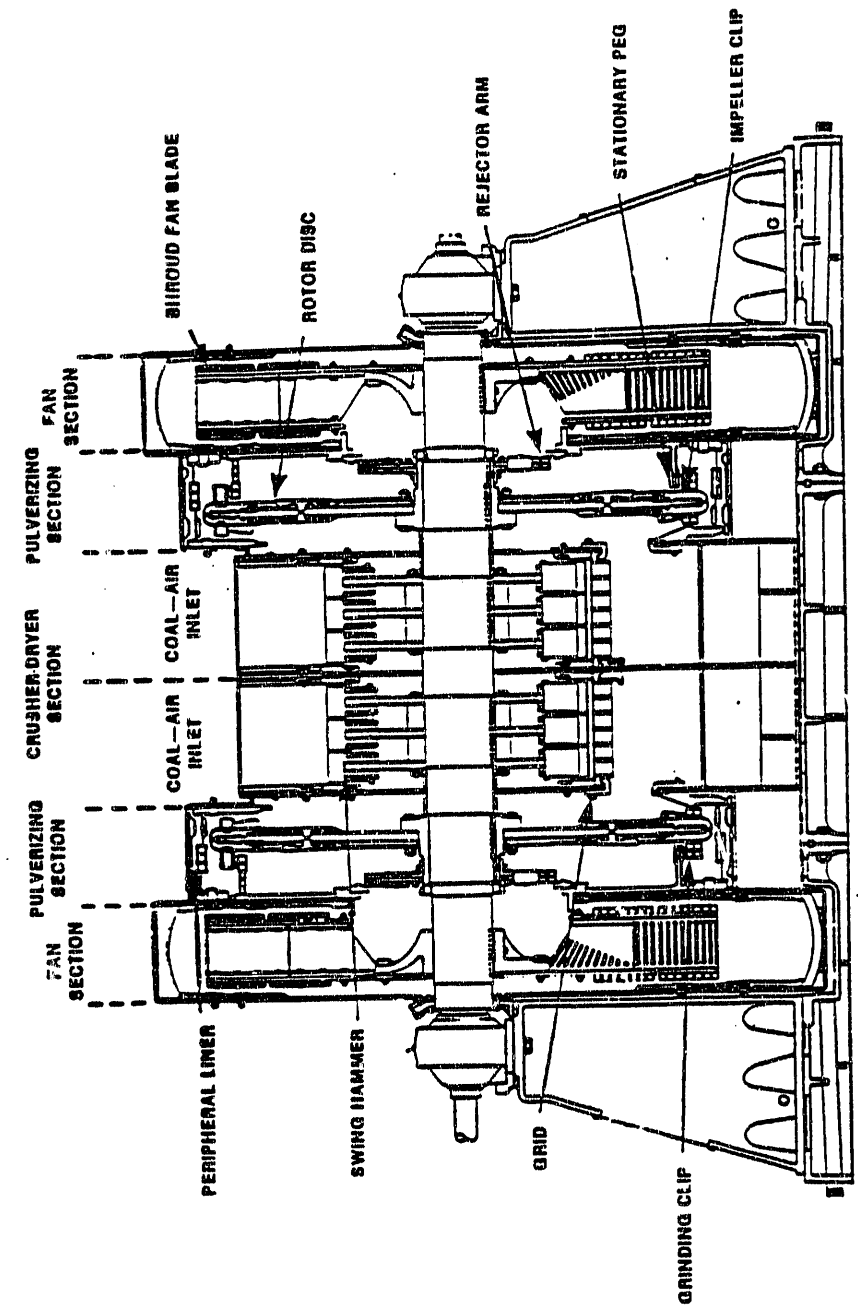

Figure 22. Riley Atrita Pulverizer - Duplex

Figure 23. Inside of Cyclone

Figure 24. Front Wall Tubing

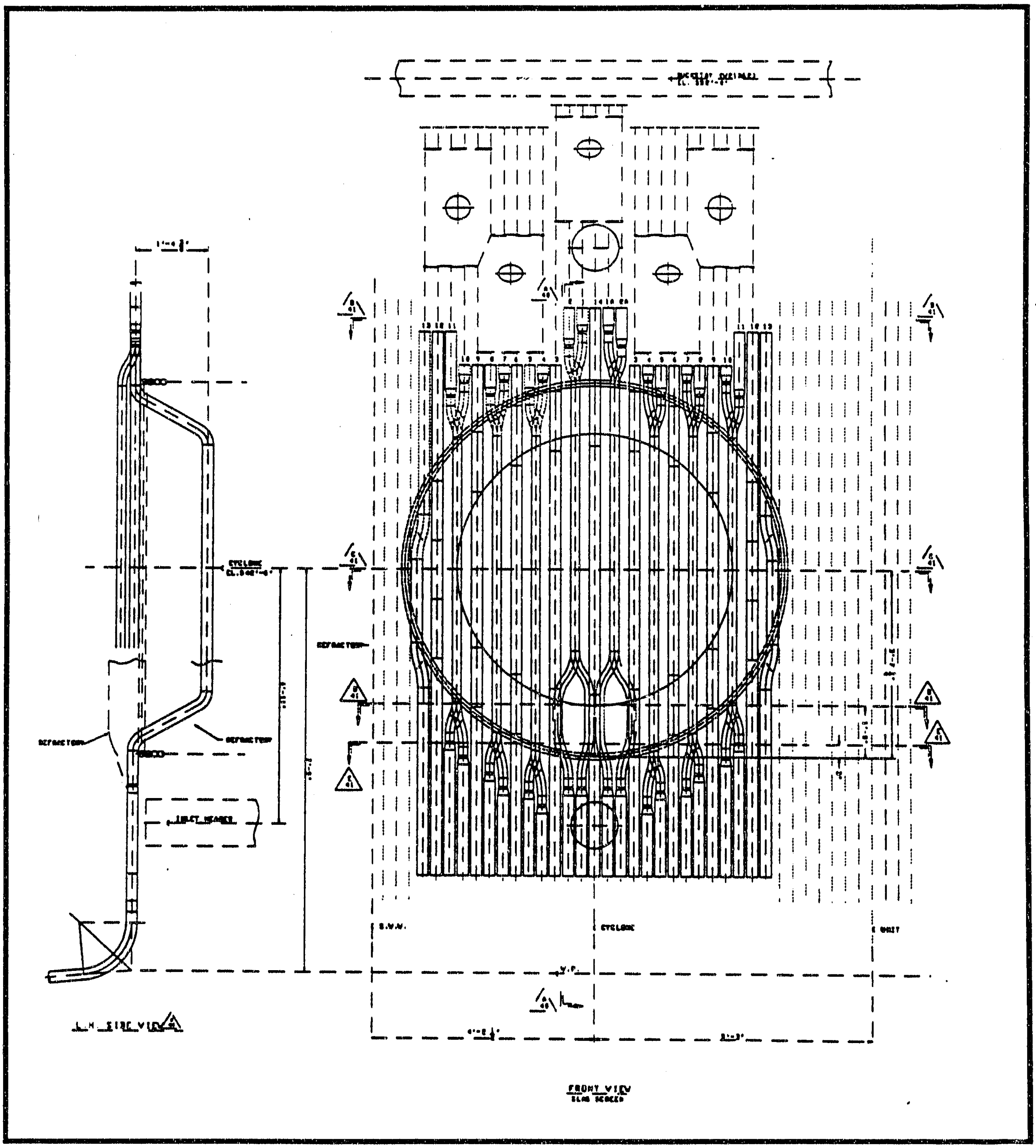

Figure 25. Slag Screen

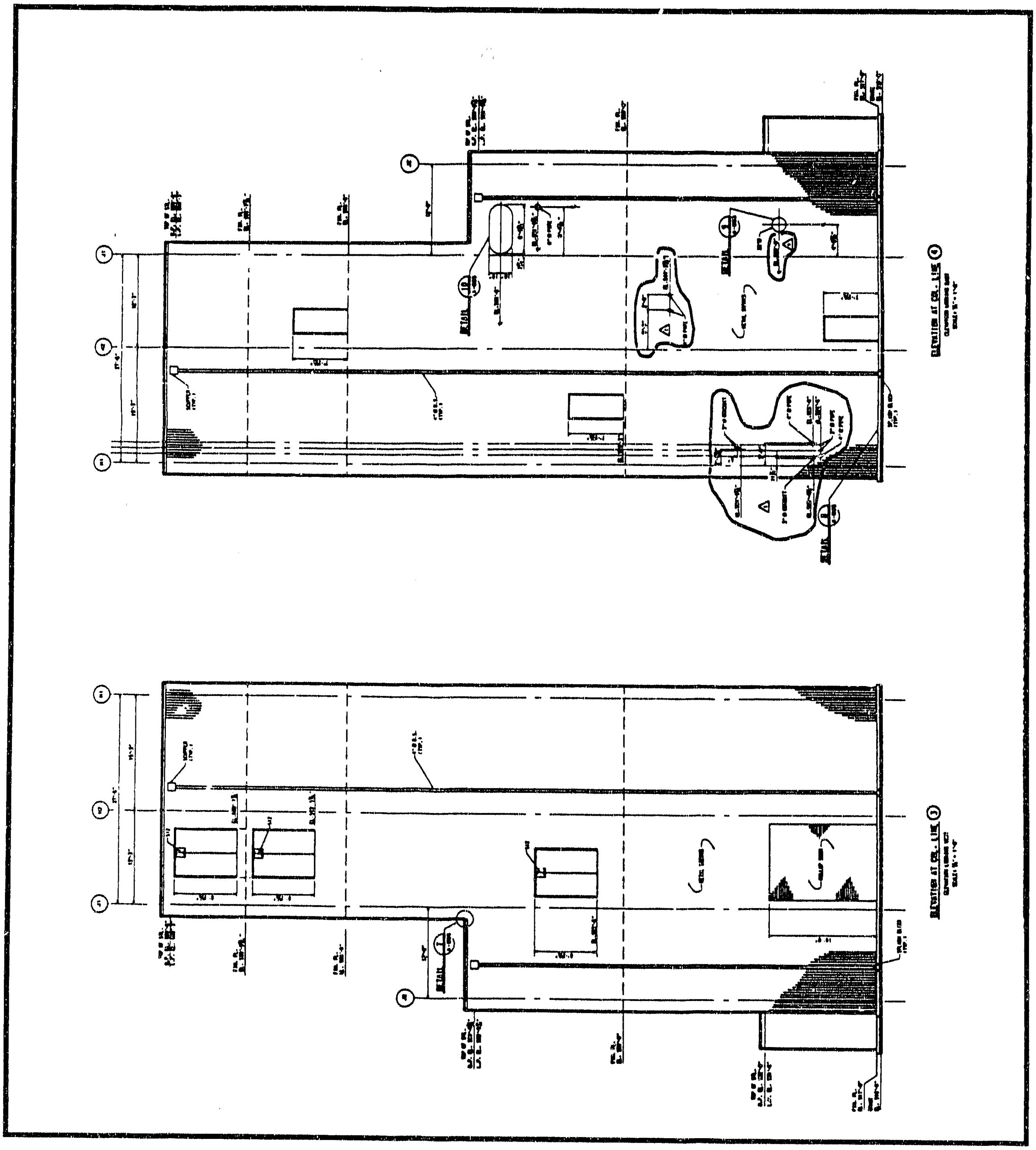

Figure 26. Architectural Elevations

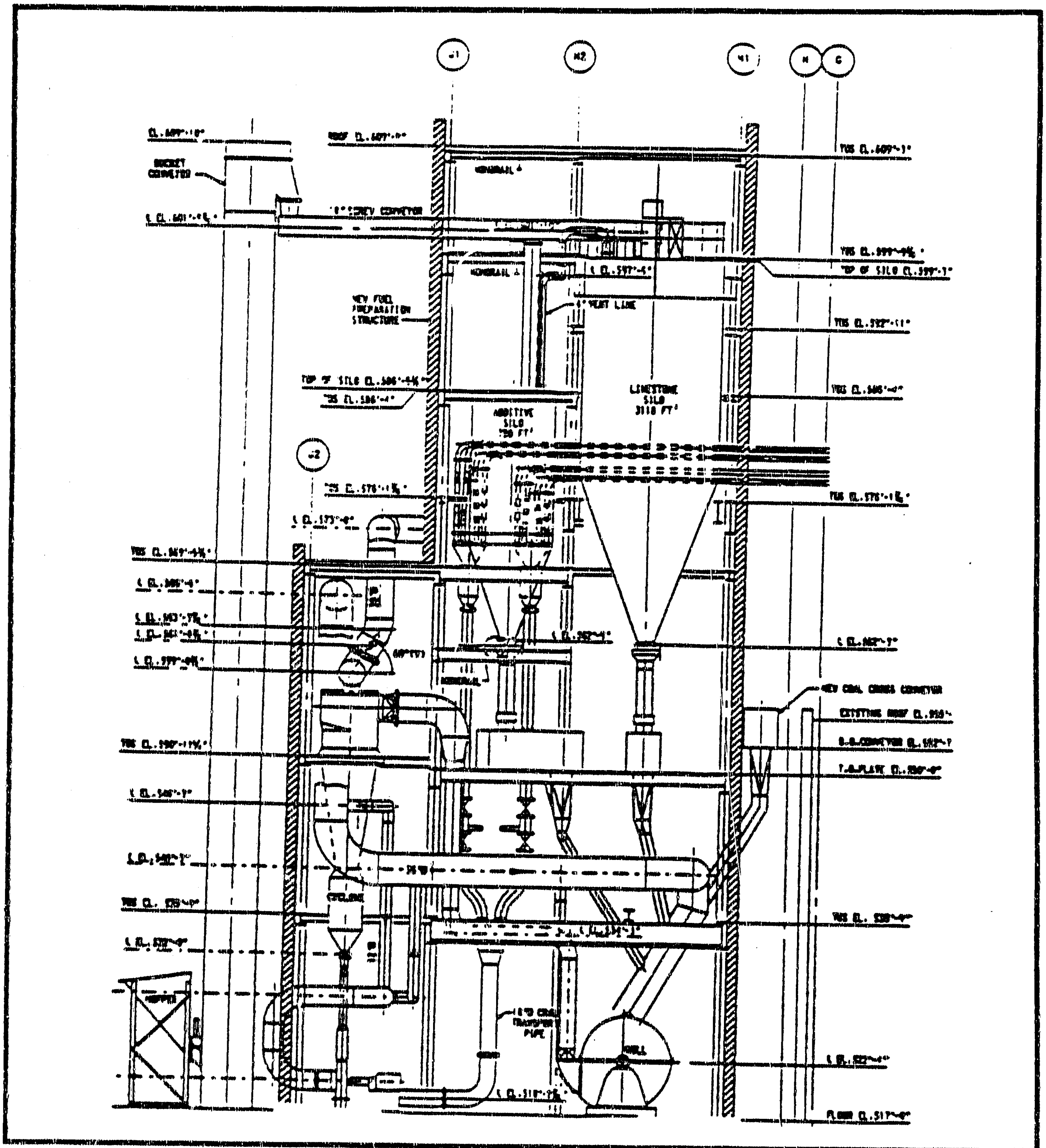

Figure 27. Fuel Preparation Building

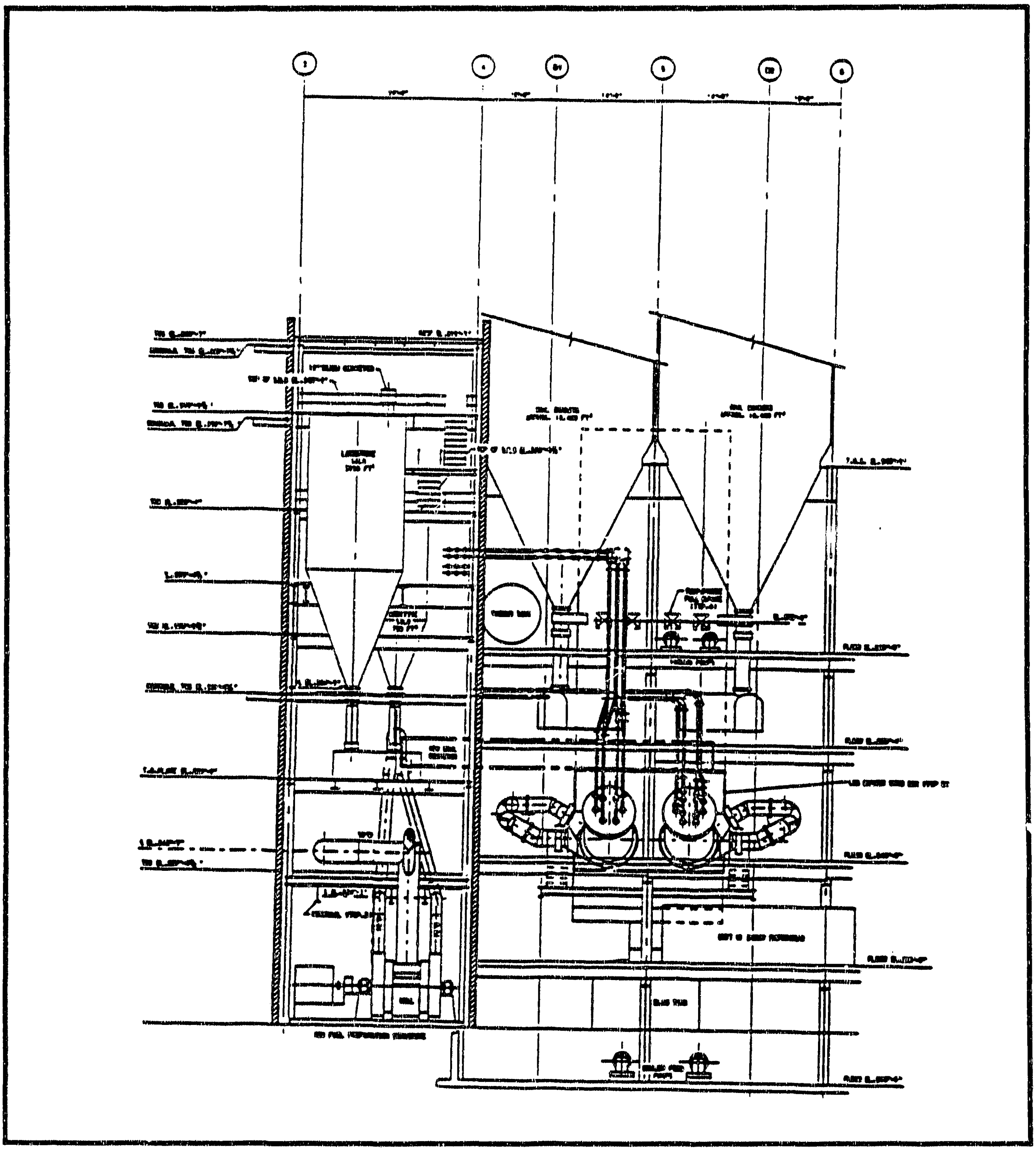

Figure 28. Elevation View After Retrofit

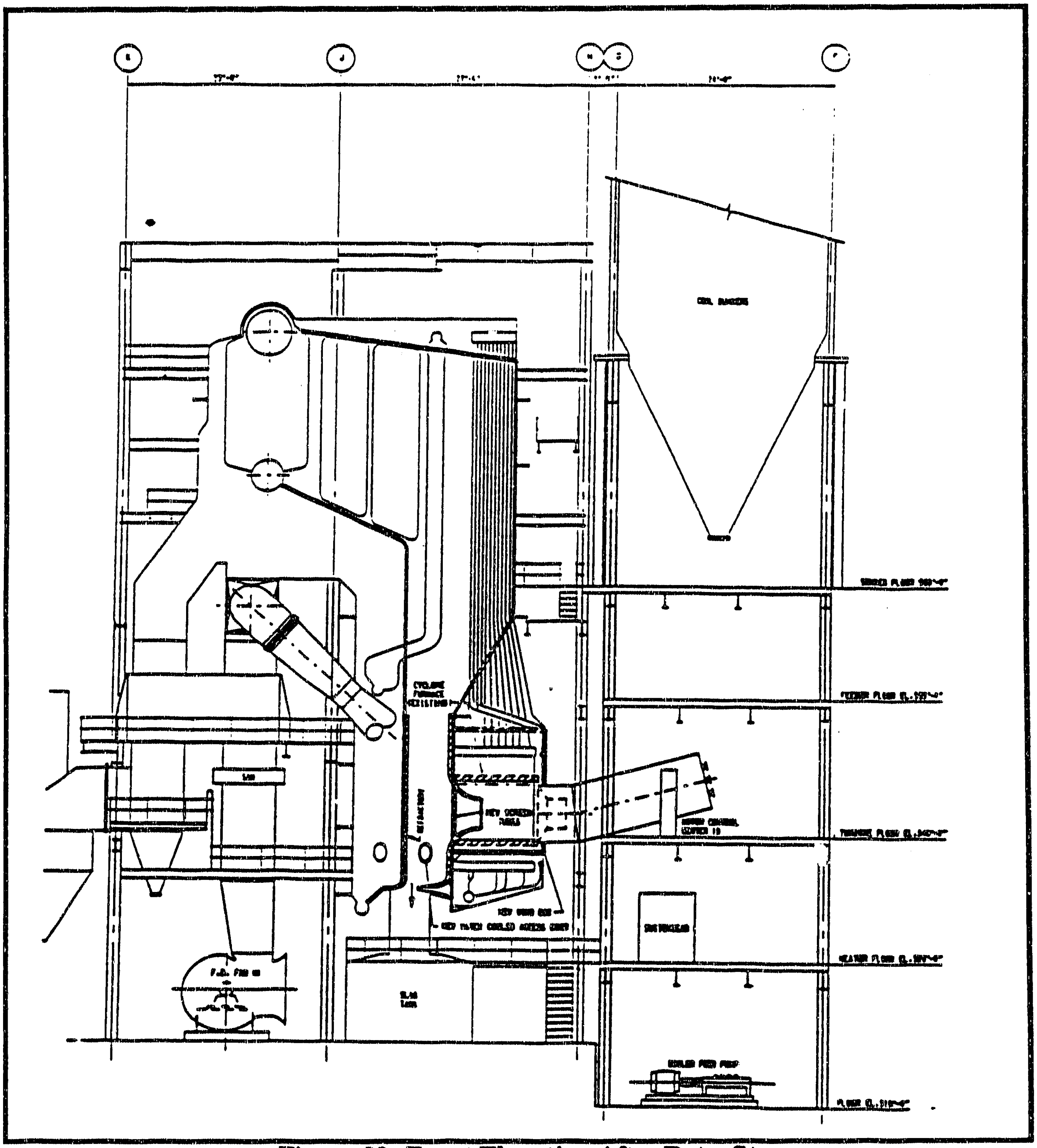

Figure 29. Front Elevation After Retrofit

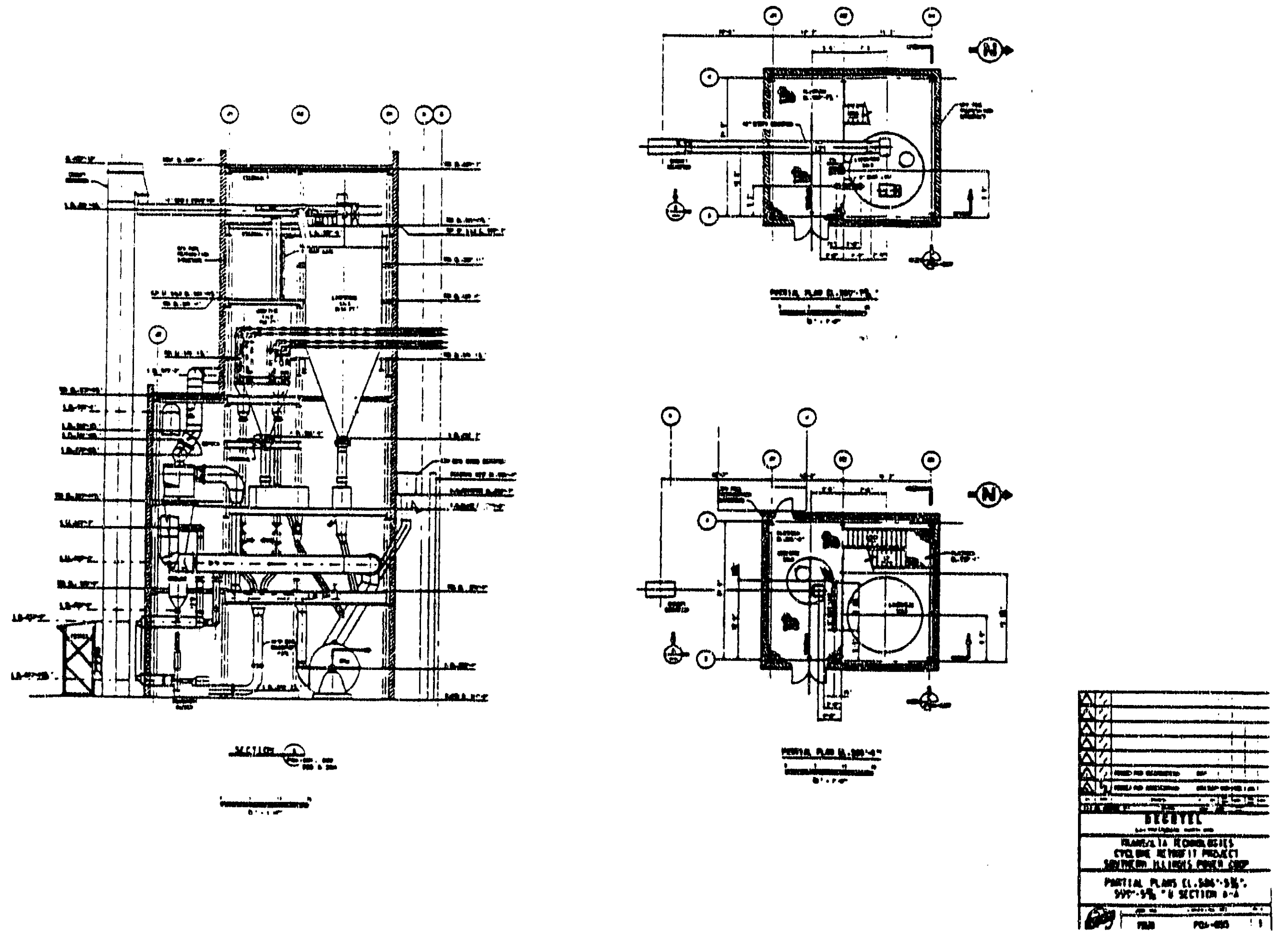

Figure 30. Fuel Preparation Building - Partial Plans

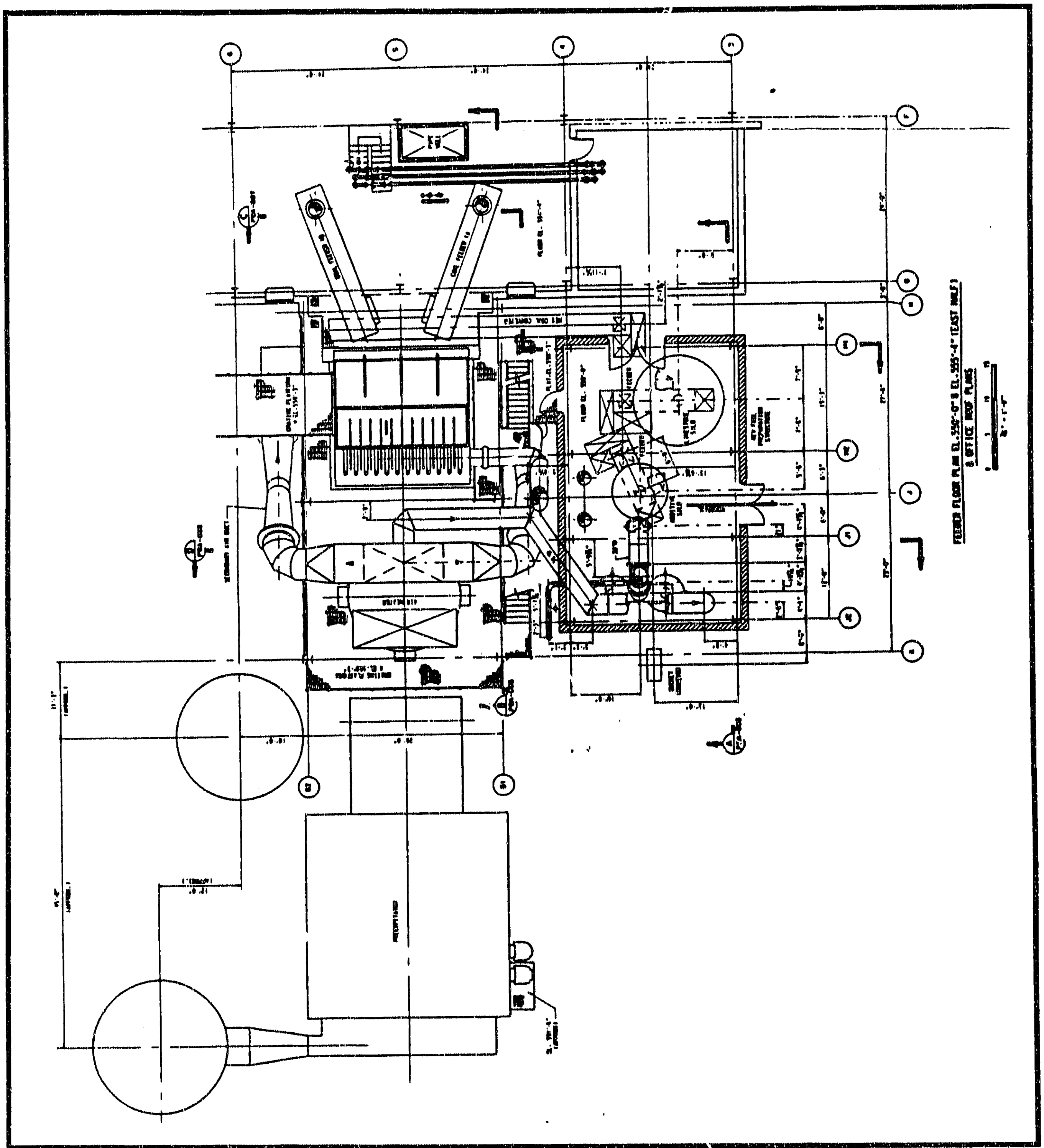

Figure 31. Coal Handling Arrangement

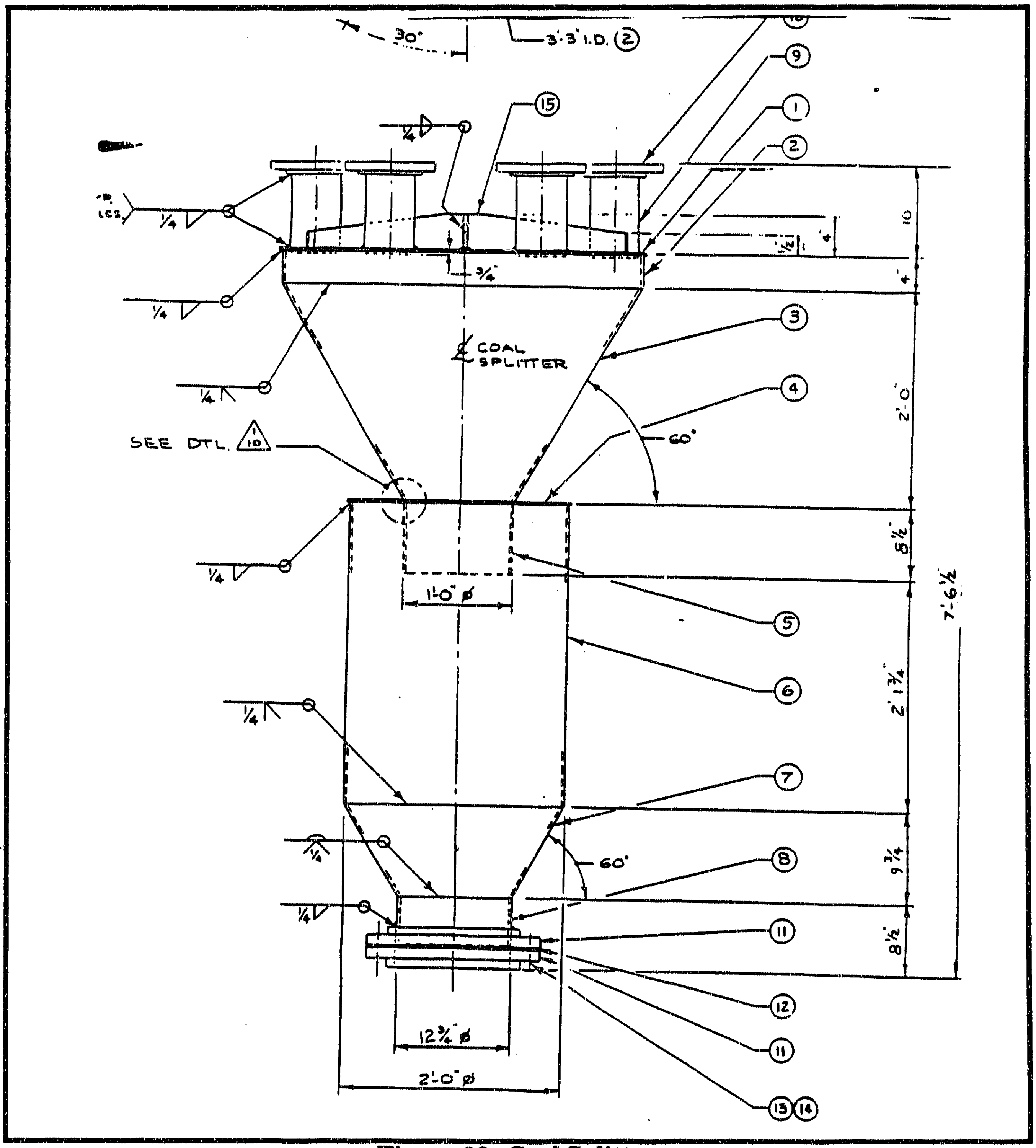

Figure 32. Coal Splitter

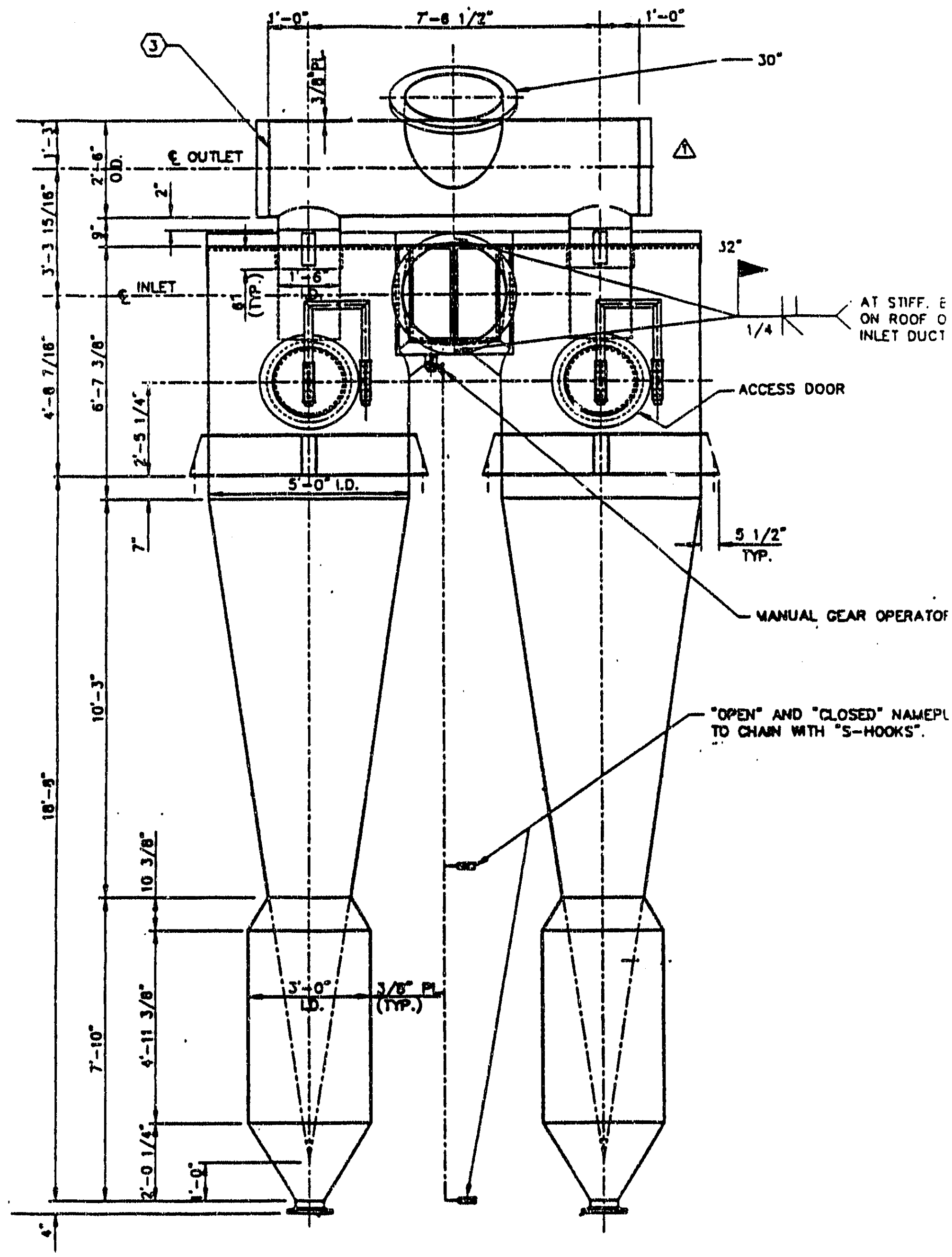

Figure 33. Coal Separator Cyclones

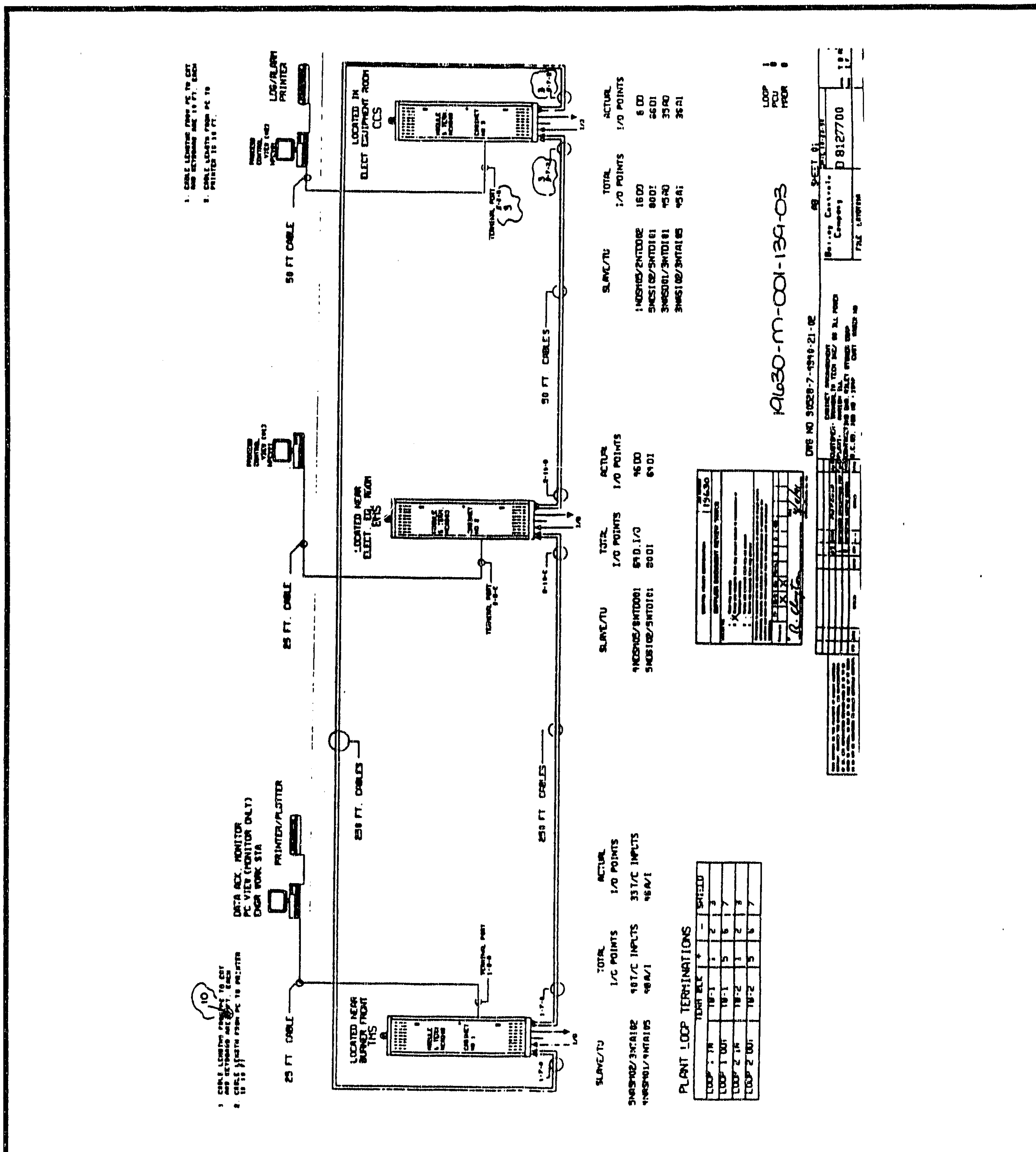

Figure 34. Control Cabinet Arrangement

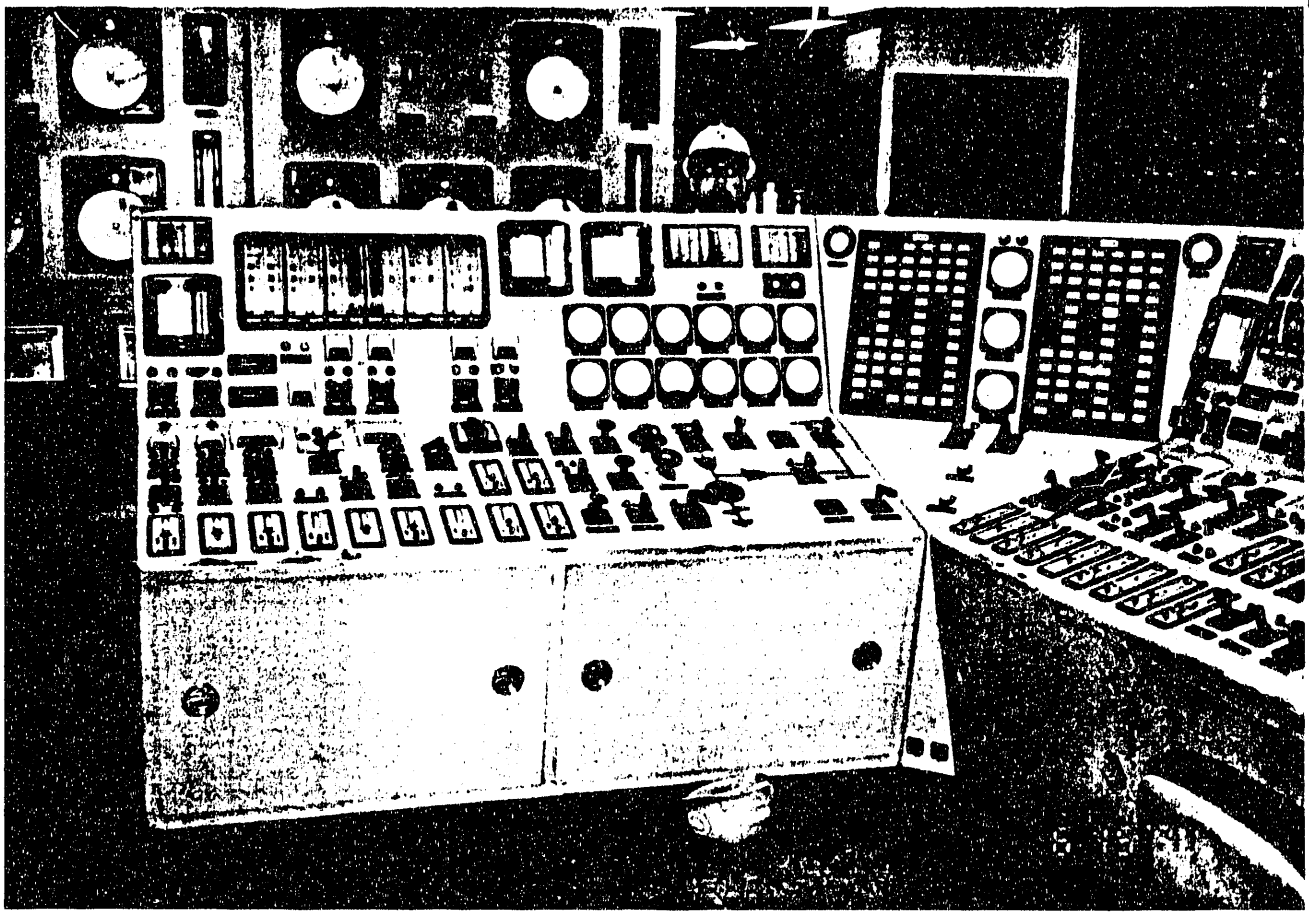

Figure 35. Existing Control Panel Prior to Modification

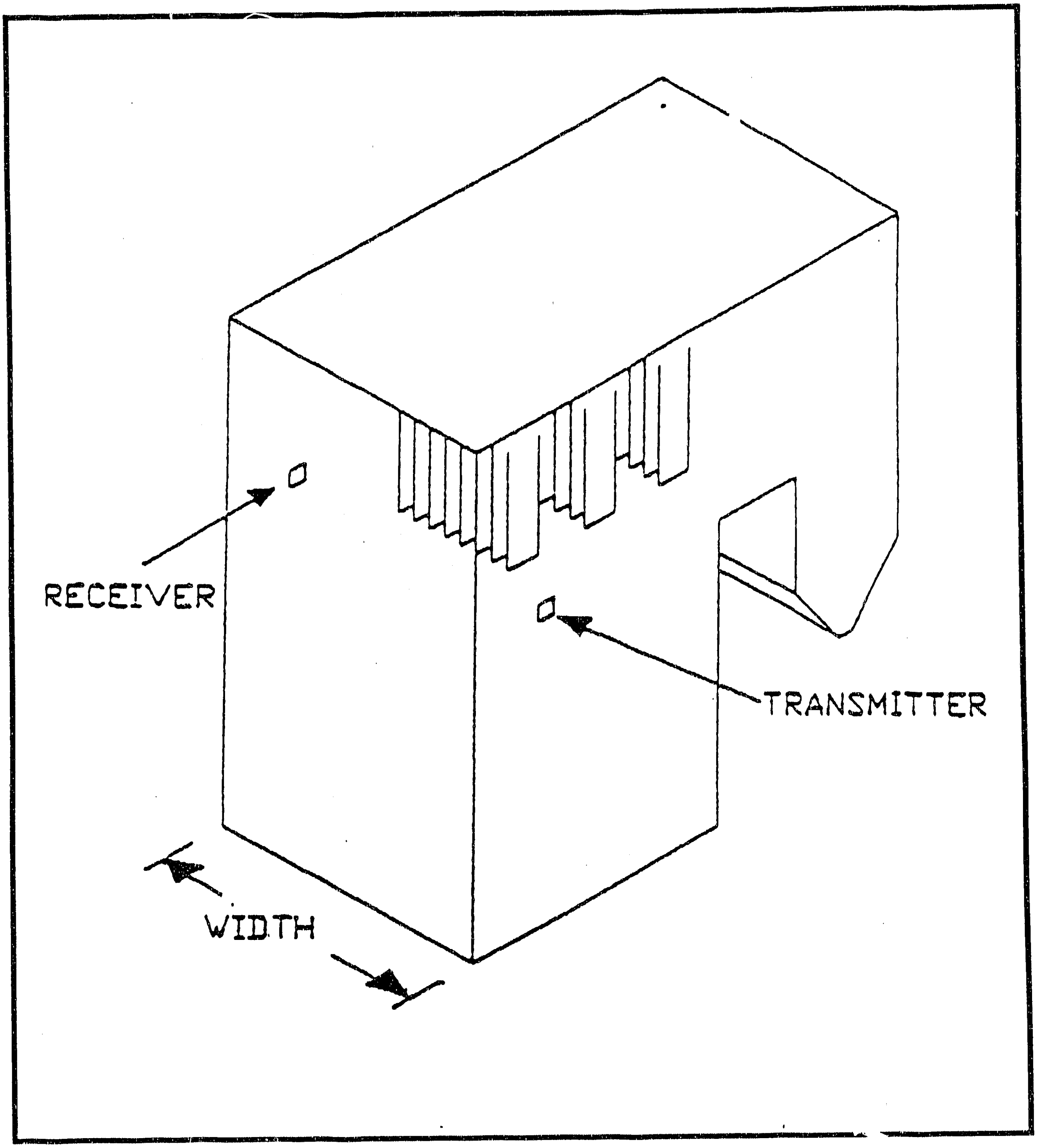

Figure 36. Gas Temperature Measurement Using Acoustic Methods

5. PLANT OPERATION

5.1 MANAGEMENT OF TEST PROGRAMS

The TransAlta project manager will coordinate all demonstration test activity and data analysis. Bechtel, reporting to the project manager, will coordinate and manage all host site activity and coordinate the testing and boiler operation with Southern Illinois Power Cooperative. An independent testing contractor, reporting to Bechtel will provide emissions monitoring and data gathering services. Riley Stoker will provide the boiler performance data gathering services.

A Project Management Plan has been issued to identify the responsibility and role of each participant in the project. Guidance and questions from the participants will be an important ingredient as the demonstration proceeds to assure that the needed information and end results are sufficiently documented to enable future commercial LNS Burner retrofits of utility boilers.

5.2 DEMONSTRATION TESTING

As directed by the Statement of Work, the Demonstration Test Program consists of two test series:

- Baseline testing of unit 1 boiler for actual performance and design information.
- Demonstration testing after retrofit.

This program will allow a comparison of the host unit's performance, emissions, and waste characteristics before and after retrofit with the LNS Burner.

Additionally, a materials monitoring program has commenced to collect information to enable assessment of the boiler materials of construction for long-term durability, operability, and reliability. When fully documented, this information will assist in determining the commercial retrofit economics of the LNS Burner for utility cyclone boilers.

The specific project objectives to be assessed during LNS Burner demonstration operation are the:

- Performance and reliability of all system components
- Emissions control capabilities
- Materials performance
- Solid waste characteristics

5.2.1 Baseline Testing

Baseline testing of the host unit has been completed. The host unit was operated at steady state conditions of 50, 75, and 100% of rated load to establish performance characteristics of the host unit, provide engineering design information, and minimize technical uncertainties in the application of the LNS Burner. Physical samples of coal, ash and slag, sluice water, etc., were taken and carefully identified with a full pedigree to provide a source of information should unanticipated questions arise at a later date.

Before the baseline tests, permanent and temporary emissions monitoring equipment was installed in the stack, checked out, and calibrated. Existing plant instrumentation, supplemented by new test instrumentation, was also calibrated and used to obtain the required test data.

The results of the baseline tests are summarized in Table 5-1.

Table 5-1. Baseline Performance of Marion Unit 1

Marion Unit 1	Original Design (Calculated)	Baseline Test (Measured)
Steam flow (lb/h)	335,000	315,000
Coal Flow (lb/h)	37,000	44,595
Additive (lb/h)	0	0
Excess air leaving air heater (%)	16	54.8
Flue gas leaving air heater (°F)	330	293
Air entering air heater (°F)	110	141
Ash tapped as slag (%)	60 [1]	60
Waste Disposal (lb/h)		
Slag	3780	
Fly ash	2440	
Emissions (lb/MBtu)		
SO_2	5.85	5.93
NO_x	1.35	0.84
Particulates	0.1	0.32
CO_2 %	11.3	
O_2 %	7.8	
SO_3 Dewpoint (°F)	274	
Flow rate (scfm)	151,733	
Efficiency Losses (%)		
Dry gas	4.89	4.26
$H_2 + H_20$ in fuel	4.56	4.76
Moisture in air	0.10	0.05
Unburned comb.	0.10	6.79
Radiation	0.40	0.35
Slag heat loss	0.85	0.64
Unaccounted & mfg. margin[2]	0.65	0.50
Total losses	11.55	18.12
Boiler efficiency (net)	88.45	82.65

1 Assumed
2 1.5% unaccounted for and manufacturer's margin less calculated slag heat loss.

5.2.2 Demonstration and Performance Testing

After LNS Burner retrofit installation, the host unit will be operated for a ten month period with an anticipated six months of continuous operation following the load management requirements of SIPC. The unit's operation will be greater than 75% of full power for approximately three months, with operation during the remainder of the period at 100% power. Weekend operation will be at reduced loads for minimum manpower requirements. During the demonstration period, performance testing will be conducted at the same steady state boiler operating conditions of 50, 75, and 100% rated loads (repeating the tests conducted at baseline).

The data will be compared to the baseline test results. Physical samples of coal, ash and slag, etc., will be taken and carefully identified with a full pedigree to provide a source of information should unanticipated questions arise at a later date.

5.2.3 Materials Monitoring Program

A materials monitoring program will be conducted at the beginning and end of the demonstration program. Further detail will be developed as required during the project if any unusual material conditions are noted and if any material failures occur.

5.3 INFORMATION MANAGEMENT AND REPORTING

The end product from this demonstration will be a Final Report. The data that comprise this report must have an assured pedigree and accuracy. Therefore, sufficient data will be gathered to allow a cross check of any data issued in the Final Report. It is a project requirement to impose a proprietary label on all raw data gathered. This procedure will be followed to avoid premature release of information before the appropriate quality control and data reduction procedures are complete. It is noted that in boiler performance reporting, a large number of calculations and laboratory analysis (such as coal and ash analysis) is required before the data (boiler efficiency, etc.) can be reliably reported.

5.4 PLANT START UP PROCEDURE AND SCHEDULE

A detailed start up plan and schedule will be developed before commencing checkout and start up activities. Presented below is an outline (example) of start up tasks developed to establish the LNS Burners operating setpoint and control philosophy.

5.4.1 Design Parameters

- Assure FD fan limitations: On the low-speed motor (300 hp), the FD fan appears capable of putting out 217,200 lb/h at about 27 iwg. On the high speed motor (1200 hp), the FD fan will be capable of putting out 414,500 lb/h at about 44.2 iwg.
- Confirm pulverizer sweep air (overfire air) set point.
- Confirm air flow to the boiler. NFPA requires a minimum of 85,000 lb/h.
- Assure FD fan capacity at high excess air to properly operate LNS Burner oil warm-up burners.
- Confirm LNS Burner air flows at minimum value required for thermal protection. Overfire air ports **do not** require a minimum air flow until temperatures in this region exceed 1200°F.
- Start both LNS Burners simultaneously. Each LNS Burner can be fired on oil.

5.4.2 Start Up

- Warm up LNS Burners on oil at a maximum 100°F/h rate to maintain refractory thermal limitations.
- Bring up temperatures in both LNS Burners simultaneously
  - within limitations of 8:1 turndown
  - by increasing firing rate of oil
  - decreasing stoichiometry to raise temperature.
- Increase heat to boiler by increasing oil rate. (Air flow will increase proportionally with oil flow up to limits on FD fan or limits on refractory temperature.)

- Turbines can roll when pressure at turbine stop valve (superheater outlet) pressure reaches 600 to 700 psi. With unit 1, this corresponds to about 3 to 4 MW.
- Beyond this point, three limitations apply:
  - SIPC wants to "run in" the turbine for a 1 h temperature soak. They do not want any sudden increase in load. To continue to increase system temperatures during this time is acceptable.
  - LNS Burner refractory temperature ramp limits still apply. (Maximum design T < 3200 °F)

    Note: it is probably preferable, from SIPC's requirements to start the turbines, to vent as much as possible of the overfire air to the multiclones to keep from quenching temperatures in the superheater.
- Increase oil fire to maximum value estimated at 15% of rated load (~°5 MWe).
- Increase LNS Burner temperatures by adjusting air flow.
- Start coal fuel flow under very oxidizing (excess air) conditions to minimize thermal shocks to the refractory. Coal will be started at **minimum** turndown possible to both burners:
  - Confirm additive flow.
  - Conveying air at minimum.
  - Adjust air flows.
  - Overfire air at (determined by pulverizer).
- Turn down oil to minimum fire as soon as stable coal fire is established and verified.
- Adjust LNS Burner coal fuel and air flows to establish design operating conditions.

5.4.3 System Status

- Confirm LNS Burner at operating temperatures.
- systems at about 15% coal.
- oil at minimum turndown.

- Turn off oil fire. Make minor readjustment to coal rates/air rates to compensate.
- Transition to design operating loads quickly. This will require a large increase in coal fuel rates and corrections to air flow (conveying air will stay constant until ~80% flow reached).

  Note: Limitation in rates are 1 MWe/min minimum (source SIPC)-(corresponds to about +3% load change/min maximum)

5.5 PLANT AND EMPLOYEE SAFETY

5.5.1 Safety and Security

Southern Illinois Power Cooperative has issued an plan titled *Safety & Health Action Plan* to ensure employee safety and security. This plan has been reviewed by affected employees. SIPC provides a full-time plant security service with controlled access to the plant through a main gate.

5.5.1.1 Safety Administration and Procedures

Southern Illinois Power Cooperative has an established *Safety & Health Action Plan* dated January 1991 to establish procedures and administration of employee conduct at the power plant site. During the on-site construction mobilization at the Marion Station, Bechtel has applied its standard *Employee Safety and Health Practices* procedures. Those employees of Bechtel were provided individual documentation and schooling in the following areas:

- General safety and health practices.
  - Including Safety Clearance and Tagging Procedures.
  - Start up and Lifted Wire and Jumper Tracking.
- First aid/medical care.
- Occupational health
- Personal protective equipment
- Scaffolding.
- Ladders.
- Floor/wall openings and stairways.
- Excavations and trenches.

- Housekeeping.
- Material handling, storage, and disposal.
- Hand and portable power tools.
- Cranes, hoist, motor vehicles, elevators and heavy equipment.
- Rigging practices.
- Applying wire rope clips.
- Fire prevention and protection.
- Welding and burning operations.
- Electrical equipment.
- Safe clearance procedure.
- Office safety and health practices.

5.5.2 Fire Protection

The Marion Station main plant, storage building, headquarters building and yard are served by a fire water system with a total capacity of 3280 gpm. The system consists of a fire system pump, two ash sluice and fire water pumps, hydro-pneumatic tank, yard hydrants, hose cabinets and sprinklers.

The new facilities for the fuel preparation and transport are designed to meet the National Fire Protection Association (NFPA) codes. The structure is also designed with dry stand pipe fire water system in accordance with the Fire Codes of the NFPA.

5.5.3 Emergency Plan

An emergency action plan has been implemented to ensure employee safety and other emergencies. This plan is in documented in SIPC's *Safety & Health Action Plan* and has been reviewed by affected employees. The plan contains the following elements for emergency action:

- Fire and Emergency calls.
- Emergency Telephone Numbers
- Response to Threatening Situations
- Procedure for fire or alarms.

- Procedure for shelter in high winds or tornado.
- Procedure for evacuation.
- Procedure for accountability.

5.5.4 Occupational Health Protection

SIPC has issued a comprehensive document titled *Safety & Health Action Plan*, dated January 1991 establishing guidelines for the implementation and administration of the occupational and health protection issues inherent in the operation of a utility power plant. The plan provides management and supervision with the recognition, evaluation and control of hazardous activities with in the areas of responsibility. This plan has been reviewed and implemented by affected employees.

6. LNS BURNER ECONOMICS

6.1 PROJECT COSTS

The current estimated cost for the project is $26,161,000 as used in the Continuation Application dated July 24, 1991. This cost consists of the planning, design, permitting, equipment retrofit, demonstration, and subsequent return to service of SIPC's 33-MW unit 1 cyclone boiler. The project is scheduled in two budget periods spanning four phases of work: preaward, designing and permitting, construction and start up, and operation and disposition. It may be instructive to identify that the engineering and retrofit cost portion of the project is about $14.0 million. A quick assumption suggests that the retrofit costs are about $420/kW. This cost reference may appear high but is reasonable when the economy of scale (33 MW compared to typical 500 MW utility size boilers) and the reasons for increase in the project costs including schedule delays, change in charges, expanded demonstration period, and increased technical support. A detailed summary of cost increase is included in the Continuation Application to the DOE dated July 24, 1991.

6.2 RETROFIT COST ESTIMATES

Engineering information has been developed from the demonstration program and from evaluation of the LNS Burner's retrofit application to large (500 MW) utility cyclone boilers. It is also of interest to compare the EPC (engineering, procurement, and construction) and O&M (operation and maintenance) costs of the LNS Burner with those of potential competing technologies. A key requirement is to provide sufficient equipment scope to achieve equivalent SO_2 and NO_x reduction as is provided by the LNS Burner.

Generally, most application studies indicate that the LNS Burner's fabrication cost is a very minor part of the total site-specific retrofit costs. Modifications to the boiler and other site specific auxiliary systems result in the major retrofit costs. Clearly, the retrofit scope for cyclone boilers is fairly modest when compared to other technologies of similar emissions performance. And when compared to retrofitted wet limestone scrubbers with a SCR system, the LNS Burner is significantly more cost effective. Table 6-1 and the list of assumptions/references in Table 6-2 compare the EPC and O&M costs for an LNS Burner/cyclone retrofit with those for a wet scrubber and SCR system to achieve comparable levels of emissions control on existing cyclone boilers.

To conduct this economic study, it was necessary to define a generic utility cyclone boiler to provide the basis for a realistic evaluation of the cost and performance when retrofitted with the LNS Burner. Table 6-3 lists the characteristics derived for a generic cyclone boiler. From these characteristics, an existing utility cyclone boiler was selected that most nearly matched the criteria for a generic unit. This boiler was used to perform the retrofit cost and performance analysis shown in Table 6-1.

To compare other Clean Coal Technologies with the LNS Burner as retrofitted to a new "conventional" pulverized coal fired boilers, the EPC and O&M cost were developed using EPRI TAG (technical assessment guidelines) and DOE publications.

Table 6-1 also shows these estimates. The EPC and O&M costs for a new 300-MW PC-fired plant built with conventional low NO_x burners and no SO_2 emissions control provide a base cost reference. Then the added costs for clean coal technology and their operation are shown for comparison. Note that these data represent order-of-magnitude costs to evaluate various alternatives. The data neither provide nor are intended to be used to determine the absolute cost of a specific technology. It is clear, however, that as the LNS Burner proves itself with reliability and emissions control performance, it will provide a significant new low-cost method for utility power plant emissions control.

Table 6-1 Technology Cost Comparisons[a]

Technology	Emission Control (%) (SO_x/NO_x)	EPC[b] Cost[c] ($/kW)	O&M Cost[c] ($$10^6$/year)
Cyclone retrofit–500 MW plant			
• Low NO_x/SO_x Burner	90/80	130	6.5
• Wet scrubber with SCR	90/80	320	33.2
• New 300-MW PC plant (with low NO_x Burners)	0/50	1150	10.7
Added cost for emissions control			
• PC plant with scrubber	90/50	170	8.2
• PC plant with scrubber and SCR	90/80	320	18.2
• Low NO_x/SO_x Burner	90/80	5	2.7
• Fluidized bed with SCR[d]	90/80	175	17.5
• IGCC[e]	90/80	350	16.7

a These data have been compiled and factored principally from EPRI and DOE publications. The data represent order-of-magnitude costs that may be useful for comparisons of various alternatives but not for absolute costs of the specific technology.

b EPC - engineering, procurement, construction.

c Order-of-magnitude costs adjusted to June 1988 dollars.

d SCR - selective catalytic reduction (required to achieve 80% NO_x removal).

e IGCC--Integrated Gasification Combined Cycle

Table 6-2 Assumptions and References Underlying Table

Assumptions

1. Capital costs are not site specific. Economic life is taken to be 30 years.
2. Operating costs are based on Electric Power Research Institute (EPRI) data published in Refs. 2 and 8 and exclude fuel costs. SCR O&M costs include replacing the catalysis bed after 3 years at 2/3 the cost of the original installation and include nominal costs for NH_3 at \$400/MW•year. SCR hazardous waste disposal costs have been excluded. O&M costs also include (1) scrubber power consumption at 2% gross power at \$0.05/kW•h and (2) IGCC oxygen power consumption at 11.5% gross power at \$0.05/kW•h.
3. New plant costs were obtained from Refs. 2 and 3. Costs for AFDC (interest during construction), start up, inventory, and land costs were backed out of the data so that all costs represented the basic EPC costs. EPRI costs were factored from 200-250 and 500 MW plants to obtain costs for a 300-MW plant. December 1985 EPRI costs were escalated by 2% for 1986, 2% for 1987, and 1% for half of 1988.
4. Repowering costs are based on DOE information (Ref. 5). The 500-MW unit in the reference has been factored and escalated in the same manner as used for new plant costs.
5. Retrofit costs are from estimates prepared for TransAlta's DOE clean coal proposal (Ref. 7) and from data in Ref. 4 that have been factored and escalated.
6. EPRI data basis:
   - PC steam cycle conditions are 2400 psig, 1000°F/1000°F. The steam generator is rated at 2620 psig and 1005 °F at the superheater outlet.
   - CFB steam-cycle conditions are 1990 psig, 1000 °F/1000°F. The steam generators are rated at 2400 psig and 1000°F at the superheater outlet. The 300-MWe CFB comprises two 150-MWe combined units, forming one plant.
   - IGCC design and cost are based on a prototype full-heat-recovery process.
7. Low NO_X/SO_X Burner costs are assumed to be the same as conventional PC burner costs.
8. Coal-burning applications use Eastern bituminous coal (3.5% sulfur by weight).
9. An SCR price of \$150/kW for the PC and cyclone plants was obtained by escalating the high range of the EPRI data (German currency rates) at 10%/year for 2 years. An SCR price of \$75/kW for the fluidized bed plant was obtained by similarly escalating the low range (less NO_X to be removed) of the EPRI data.
10. FGD costs are based on Bechtel's CT-121 process and were escalated to present dollars from Ref. 6.

References

1. EPRI, ***ECS Update, Summer 1987***, No. 9, Environmental Control System.
2. EPRI, ***Technical Assessment Guide***, Vol. 1, Electrical Supply, 1986.
3. EPRI, *Future Power Plants...Choosing among the Many Options*, a presentation by Stanley Vejtasa, 1 December 1987.
4. EPRI, ***Economic Evaluation of FGD Systems***, CS-3342, October 1986.
5. DOE, ***The role of Repowering in America's Power Generation Future***, November 1987.
6. Bechtel, ***Flue Gas Desulfurization, The Bechtel CT-121 Process.***
7. Bechtel/TransAlta, submittal to DOE (DE-PS01-88FE61530, Vol. II) and associated estimate.
8. EPRI projection for a mature IGCC facility, October 1987.

Table 6-3 Generic Cyclone Boiler

Item	Generic Boiler	Selected Boiler
Coal	High sulfur bituminous	Blended (1.71% S) coal
Capacity (MW)	360	500
Number of cyclones	8	10
Heat input/cyclone furnace	400 MBtu/h	329 MBtu/h
Type	Subcritical	Supercritical
Emissions (lb/MBtu)		
SO_2	>6.0	3.25
NO_x	>1.0	NA
Particulates	0.1	0.1
Age (years)	20 to 30	21

APPENDIX A: MAJOR CYCLONE BOILERS

Utility/Plant Name[a]	Oper.	MW	Steam (klb/h)	No. of Cyclones	Type of Fuel
AEP					
Tanners Creek 4	1964	580	3840	11	B
Breed 1	1961	450	2930	8	B
Kammer 1	1955	225	1523	5	B
Kammer 2	1955	225	1523	5	B
Kammer 3	1956	225	1523	5	B
Muskingum River 3	1954	225	1523	5	B
Muskingum River 3	1955	225	1523	5	B
Conesville 1	1958	136	1000	4	B
Conesville 1	1959	136	1000	4	B
Allegheny Power Sys.					
Willow Island 2	1961	165	1260	5	B
Associated Electric					
Thomas Hill 1	1964	175	1250	4	B
Thomas Hill 2	1965	270	2100	6	B
New Madrid 1	1973	580	4355	14	B
New Madrid 2	1977	600	4355	14	B
Atlantic Electric					
Deepwater	1957	80	560	3	O&G
B.L. England 1	1959	125	975	3	B
B.L. England 2	1965	150	1125	4	B
Baltimore G&E					
C.P. Crane 1	1961	190	1362	4	B
C.P. Crane 2	1963	191	1360	4	B
Basin Electric Power					
Leland Olds 2	1974	400	3075	12	L
Black Hills P&L					
Ben French	1961	30	210	1	S
Central Elec. Power					
Chamois Power Plant	1961	48	416	2	B
Central Illinois PS					
Coffeen 1	1965	365	2500	8	B
Coffeen 2	1972	600	4200	14	B
City of Springfield					
Dallman	1971	90	690	3	B
Dallman 31	1969	90	690	3	B
Dallman 32	1971	90	690	3	B
Lakeside 7	1960	40	320	2	B
Lakeside 8	1964	40	320	2	B
Commonwealth Edison					
Joliet 6	1960	360	2200	9	S
Kincaid 1	1967	660	4200	14	B
Kincaid 2	1968	660	4200	14	B

MAJOR CYCLONE BOILERS (2 of 4)

Utility/Plant Name	Oper.	MW	Steam (klb/h)	No. of Cyclones	Type of Fuel
Commonwealth Edison					
Powerton 5-1	1972	430	3037	10	S
Powerton 5-2	1972	430	3037	10	S
Powerton 6-1	1975	430	3037	10	S
Powerton 6-2	1975	430	3037	10	S
Stateline	1963	389	2200	9	S
Waukegan	1951	120	830	4	S
Will County 1	1954	170	1200	5	S
Will County 2	1954	170	1200	5	S
Dow Chemical					
Midland	1946	--	400	2	B
Midland	1946	--	400	2	B
Midland	1950	--	400	2	B
Midland	1964	--	400	2	B
Eastman Kodak					
Kodak Park 15	1956	--	400	2	B
Kodak Park 41	1964	--	400	2	B
Kodak Park 42	1966	--	400	2	B
Kodak Park 43	1968	--	550	2	B
Empire District					
Asbury 1	1970	200	1425	5	B
General Electric					
Erie, Penn.	1971	30	300	2	B
Illinois Power					
Baldwin 1	1970	605	4200	14	B
Baldwin 2	1972	600	4200	14	B
International Paper					
Mobile 1 & 2	1957	--	450	--	--
Iowa Electric L&P					
Sutherland	1962	75	575	3	S
Iowa Public Service					
Neal 1	1964	147	1050	3	S
Jersey Central P&L					
Sayreville 3	1952	140	900	4	O&G
Sayreville 4	1956	140	900	4	O&G
Kansas City P&L					
LaCygne 1*	1973	844	6193	18	B
Minnkota Power					
Milton Young 1	1970	235	1714	7	L
Milton Young 2*	1977	457	3200	12	L
Missouri Public Ser.					
Sibley 1	1960	50	450	2	B
Sibley 2	1963	50	450	2	B
Sibley 1	1968	5419	2584	8	B

MAJOR CYCLONE BOILERS (3 of 4)

Utility/Plant Name	Oper.	MW	Steam (klb/h)	No. of Cyclones	Type of Fuel
Montana-Dakota Util.					
Coyote 1*	1981	456	3250	12	L
Muscatine P&W					
Plant 1	1968	--	680	3	B
Nebraska Public Power					
Sheldon 1	1961	105	790	3	B
Sheldon 2	1968	120	760	3	B
Northeast Utilities					
Hartford Electric	1964	240	1675	5	O
Northern Indiana PS					
Baily 7	1962	194	1200	4	B
Baily 8	1968	422	2584	8	B
Michigan City 4	1950	45	375	2	B
Michigan City 5	1950	45	375	2	B
Michigan City 4	1950	45	375	2	B
Michigan City 12	1974	500	3230	10	B
Schahfer 14	1975	500	3230	10	S
Northern States Power					
King 1	1968	574	3873	12	S
Riverside 8	1964	228	1500	5	S
Nova Scotia Power					
Glace Bay 1	1964	80	550	2	B
Glace Bay 2	1964	80	550	2	B
Point Tupper	1966	85	600	2	B
Tuft's Cove 1	1962	100	725	3	O
Tuft's Cove 2	1964	80	550	2	B
Tuft's Cove 3	1964	80	550	2	B
Tuft's Cove 4	1969	90	669	3	O
Ohio Edison Co.					
Niles Station	1950	115	--	--	B
Otter Tail Power					
Big Stone 1	1974	400	3070	12	L
Owensboro Mun. Util.					
Elmer Smith	1965	150	1050	3	B
Public Ser. El. & Gas					
Hudson 1	1964	420	2450	8	O&G
Public Ser. of NH					
Merrimack 1	1961	114	815	3	B
Merrimack 2	1968	350	2332	7	B
So. Illinois Power					
Marion 1	1963	33	335	2	B
Marion 2	1963	33	335	2	B
Marion 3	1963	33	335	2	B
Marion 4*	1978	175	1250	4	B

MAJOR CYCLONE BOILERS (4 of 4)

Utility/Plant Name	Oper.	MW	Steam (klb/h)	No. of Cyclones	Type of Fuel
St. Joseph L&P					
Cake Road	1969	75	575	3	B
Tampa Electric					
Cannon 1	1957	105	910	3	B
Cannon 2	1959	115	950	3	B
Cannon 3	1960	160	1160	4	B
Cannon 4	1964	180	1260	4	B
TVA					
Allen 1	1964	330	2000	7	B
Allen 2	1964	330	2000	7	B
Allen 3	1964	330	2000	7	B
Paradise 1	1963	704	4900	14	B
Paradise 2	1963	704	4900	14	B
Paradise 3	1969	1150	8000	23	B
Thilmany Pulp & Paper					
Kaukauna, WI 9	1957	--	155	1	B
Kaukauna, WI 11	1966	--	350	2	B
Union Electric					
Sioux 1	1967	489	3290	10	B/S (blend)
Sioux 2	1968	489	3290	10	B/S (blend)
United Illuminating					
Bridgeport Harbor	1956	60	575	3	O
Bridgeport Harbor	1962	75	1150	5	O
Univ. of Notre Dame					
U. of Notre Dame 4	1968	--	170	1	B
Westvaco Corp.					
Luke, MD 24		--			B
Wisconsin P&L					
Nelson Dewey 1	1962	100	770	3	S-B
Nelson Dewey 2	1960	100	770	3	S-B
Edgewater 3	1948	90	600	3	B
Edgewater 4	1969	330	2155	7	B
Rock River	1964	85	525	3	B
Rock River	1952	85	525	3	B

[1]*Cyclone Inventory Summary*, Babcock & Wilcox Company

Bituminous coal	B	Oil	O
Subbituminous coal	S	Gas	G
Lignite	L	Scrubber installed	*

APPENDIX B: EQUIPMENT LIST AND DESCRIPTIONS FOR MARION STATION UNIT 1

CYCLONE BOILER

Unit 1 is a front-wall-fired Babcock & Wilcox cyclone boiler rated at 33 MW. The specific details of the cyclone furnace and the boiler are discussed in Section 2. The boiler design and operating specifications are provided in Table B-1. A pendent section extends down from the roof of the furnace to about midway between the top of the lower furnace and the bottom of the primary superheater. The high-temperature convective pass contains a primary and a secondary superheater. There is no economizer.

Table B-1 Boiler Design and Operating Specifications
(1 of 2)

Design Performance (Nameplate)	
Design capacity	
Continuous rating	335,000 lb/h
Four-hour peak rating	370,000 lb/h
Steam conditions at superheater outlet	905°F @ 875 psia
Fuel	Crushed coal
Firing equipment	Cyclone furnace, coal feeder
Overall design efficiency at full load	88.6%
Coal consumption at full load	32,500 lb/h
Excess air leaving boiler	16%
Boiler	
Type	2 drum
Heating surface	
Boiler	15,276 ft^2
Furnace	5,972 ft^2
Water capacity at normal level	
Boiler	139,000 lb
Hydrostatic test	193,535 lb
Upper drum diameter and wall thickness	60 in., <5 in.
Lower drum diameter and wall thickness	42 in., <5 in.

Table B-1. Boiler Design and Operating Specifications
(2 of 2)

Furnace	
Type	B&W cyclone, pressure type
Coal feed	Indirect or bin system
Primary Superheater	
Type	Pendant flow
Heating surface	8,242 ft^2
Secondary Superheater	
Type	Pendant flow
Heating surface	4,978 ft^2
Attemperator	
Type	Spray
Entering water temperature	315°F
Air Heater	
Type	Ljungstrom regenerative
Heating surface	38,600 ft^2
Cleaning medium	Steam and water
Steam Air Preheater	
Type	Finned-tube steam coil
Steam pressure range	5-130 psig
Soot Blowers	
Type	Diamond 1K300 retractable
Number installed	8
Cleaning medium	Steam from primary super-heater outlet
Forced Draft Fan	
Type	Buffalo Forge EL1200 DWDI
Air flow at 70°F	414,000 lb/h @44.5 in. H_2O
Air flow at 110°F	476,000 lb/h @57.7 in. H_2O
Dampers	Inlet vane
High speed motor	1,250 hp, 1775 rpm
Low speed motor	300 hp, 1180 rpm
Low speed air Flow	271,000 lb/h at 27 iwg

LNS BURNERS

Two LNS Burners, each 50% unit sized at 200 MBtu/h, will be added to the existing cyclone furnace. The LNS Burners are refractory lined and have an over all length of 16 ft and a diameter of about 6 ft Each LNS Burner is fed with six coal pipes.

TURBINE GENERATOR

The single 33-stage turbine generator (with single-flow exhaust; five extraction points; 850-psig, 900°F throttle steam; and 1.5-in. Hg exhaust pressure) is supplied by Allis-Chalmers. The turbine is coupled to a 3,600-rpm, 44,118-kV•A generator. The 18,000-V, 60-Hz, 3-phase generator has a 0.85 power factor and is hydrogen cooled. Design data for the turbine generator are shown in Table B-2.

CONDENSER

The condenser is a 27,500-ft^3 Elliott horizontal two-pass condenser with a 1,815-gal storage capacity hotwell. There are 5,460 tubes, 22 ft 3 in. long. Tube wall thickness is 18 BWG, material is admiralty metal, and the design pressure is 20 psig. The design inlet temperature is 75°F, and the outlet temperature is 81.6°F.

CIRCULATING WATER PUMPS

Four circulating water pumps are available to serve unit 1. All are vertical, wet pit pumps with mixed flow impellers, and all are located in a separate intake structure. Each of the two Allis-Chalmers pumps is rated at 29,000 gpm at 48 ft of head and has a motor horsepower of 450 hp. Each of the two Patterson pumps is rated at 74,000 gpm at 48 ft of head and has a motor horsepower of 1000 hp.

Table B-2 Turbine Generator Design Data

Steam inlet conditions: 850 psig, 900°F Air ejectors: 450 lb/h of steam				
Load on generator (kW)	7,492	14,999	29,998	34,307
Power factor	0.85	0.85	0.85	0.85
Exhaust pressure (in. Hg abs)	1.5	1.5	1.5	2.5
Mechanical losses (kW)	174	174	174	174
Electrical losses, (in. Hg abs)	269	308	466	564
Steam flow (lb/h)				
To throttle	69,750	131,600	263,800	298,500
To condenser	57,570	102,279	192,380	231,738
Heat rate (Btu/net kW•h)	11,009	9,958	9,437	9,741
Exhaust conditions				
Steam quality (% moisture)	6.94	9.32	10.45	9.83
Enthalpy (Btu/lb)	1029.4	1004.6	992.8	1007.5

CONDENSATE/FEEDWATER SYSTEM

Two 100% capacity condensate pumps are from Ingersol-Rand. Each takes suction from the condenser hot well and supplies condensate through the steam jet air ejector condenser, the drain coolers, and low-pressure feedwater heaters to the deaerator. The pumps are canned, 7-stage vertical pumps, rated at 600 gpm each at 375 ft of head. The motor is 75 hp.

FEEDWATER PUMP

Two 60% capacity Allis-Chalmers feedwater pumps take suction from the deaerator and supply feedwater through the high-pressure feedwater heaters to the boiler. The pumps are 8-stage, centrifugal, horizontally split, and rated at 436 gpm at 2680 ft Motor horsepower is 400 hp.

FEEDWATER HEATERS

The condensate and feedwater are heated by six stages of feedwater heaters, one drain cooler, two low-pressure heaters, one deaerator, and two high-pressure heaters.

FORCED DRAFT FAN

The FD fan draws in outside air through intake boxes. Two electric motors directly connected to the fan shaft through flexible couplings, one at each end, provide operating flexibility. See Table B-1 for design parameters.

COAL HANDLING SYSTEM

Two silos, one for each cyclone burner, store a total of 230 tons of coal. The maximum coal-feed capability is 25 tons/h. A single 250-ton/h coal feed belt supplies coal to the plant from active storage.

ASH SYSTEM

A UCC hydroejector bottom ash system is provided with a 5-h storage capacity and 10-ton/h transfer rate. A UCC hydrovactor fly ash system is provided with a 5-h storage capacity and a 4-ton/h transfer rate.

PLANT MAKEUP WATER

Makeup water is supplied by evaporators heated by extraction steam and an anion/cation demineralizer.

INSTRUMENT AND SERVICE AIR

Instrument air compressors with redundant units are provided from a common station system. Air is available at 100 psig.

STACK

A 200-ft high by 13.5-ft concrete stack is shared by units 1 and 2. Dampers are provided to isolate each unit from their common stack.

ELECTROSTATIC PRECIPITATOR

The existing electrostatic precipitator is a three field, weighted-wire type with 34,600 ft^2 of collection surface. The design gas flow rate is 176,000 acfm at 350°F.

CYCLONE SEPARATORS

Two 50% cyclones are used to separate pulverized coal from the sweep air. The units are 5 ft in diameter and are refractory-lined for abrasion protection. A shutoff damper permits one cyclone to be isolated for better turndown. The cyclones at full load have a design efficiency of 99.4% with the pulverizer size distribution.

TRANSPORT BLOWER

The coal transport blower, manufactured by Buffalo Forge, is rated at 38,600 lb/h of air at an increase in head from 35 iwg to 81 iwg. The blower is powered by a 125 hp motor.

LIMESTONE AND ADDITIVE SILOS

A 3118 ft^3 limestone silo and a 750 ft^3 additive silo will be installed in the fuel preparation area. The new limestone and additive silos provide for 45 and 73 h, respectively at full-load operation. Each silo has a weighbelt feeder manufactured by Stock Equipment, bin vents, and level switches and indicators. Air blasters have been added to each silo to insure material does not bridge the outlet of the silo.

BUCKET ELEVATOR

A bucket elevator (rated at 144 tons/h) is used to load the limestone and additive silos from a 240 ft^3 hopper located at grade level.

COAL CONVEYOR

A coal feed conveyor (rated at 25 tons/h) runs under the existing Stock weighbelt feeders to collect the coal and transport it to the fuel preparation building. The coal falls by gravity into the pulverizer inlet.

APPENDIX C

DESIGN CODES AND STANDARDS

CIVIL, STRUCTURAL AND ARCHITECTURAL DESIGN

a) Building Officials & Code Administrators (BOCA) National Building Code - 1987

b) American Institute of Steel Construction (AISC)

   Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, 1978

   Code of Standard Practice for Steel Buildings and Bridges, 1978

   Specification for Structural Joints Using ASTM A 325 or A 490 Bolts, 1978

   Manual of Steel Construction, 8th Edition

c) American Welding Society (AWS), Structural Welding Code, AWS D1.1 - 1988

d) American Concrete Institute (ACI), Building Code Requirements for Reinforced Concrete, ACI318-83

e) American Society for Testing and Materials (ASTM), Applicable standards for the various construction materials specified in the design document

f) American National Standards Institute (ANSI), Building Code Requirements for Minimum Design Loads in Buildings and Other Structures, ANSI A58.1 - 1982

g) American Iron and Steel Institute (AISI), Specification for the Design of Cold-Formed Steel Structural Members, Parts 1 and 2,1977

h) Occupational Safety and Health Administration (OPSHA), Department of Labor Occupational Safety and Health Standards, Title 29 - Labor, Part 1910

i) National Fire Protection Association (NFPA), NFPA 24 - 1981

j) AH applicable state and local codes and regulations

k) Specification 19630-C-010, Reinforced Concrete Work, Latest Revision

1) Specification 19630-C-011, Structural and Miscellaneous Steel Work, Latest Revision

2. MECHANICAL CODES AND STANDARDS

a) American National Standards Institute, ANSI, B31.1, Power Piping

b) National Fire Protection Association, NFPA 85F, Installation and Operation of Pulverized Fuel Systems

c) BOCA Building Code, Article 10, Fire Protection

3. ELECTRICAL CODES AND STANDARDS

Electrical Standards - (Applicable Sections of)

a) National Electrical Code

b) National Electrical Manufacturers Assoc. - NEMA Standards

c) ICEA (Cable Construction & Coding)

d) Underwriters' Laboratories Testing Requirements

e) IEEE Testing Requirements

f) IES Lighting Standards

4. CONTROL SYSTEMS

I & C Standards - (Applicable Sections of)

a) ISA S6.1 Instrumentation Symbols and Identification

b) ISA S51.1 Process Instrumentation Terminology

c) SAMA RC22-11 Functional Diagramming of Instrument and Control Systems

d) NFPA 85F National Fire Protection Assoc. Standard

APPENDIX D

LIST OF SUPPORTING DOCUMENTS

PARTIAL LIST OF EQUIPMENT AND MATERIAL SPECIFICATION

19630-A-003	Fuel Preparation Building Doors
19630-A-003A	Fuel preparation Building Doors
19630-A-151	Roof Personnel Hatch
19630-A-154	Aluminum Louvers
19630-E-003	Dry Type Distribution Power Center
19630-E-004	480 Volt Load Center Breaker
19630-E-005	480 Volt Bus Duct
19630-E-006	Electrical Bulk Commodities
19630-E-007	480 V MCC Bus Tie Breaker
19630-E-008	Electrical Grounding Materials
19630-E-009	Stack Platform Lighting Material
19630-J-003	Stack Monitoring Platform
19630-J-004	Silo Level Indicators and Switches
19630-J-005	Weld Pad Thermocouples
19630-J-007	Tanks for Instrument Calibration
19630-J-009	Instruments
19630-M-002	Bucket Elevator, Loading Hopper, Screw Conveyor
19630-M-004	Silo Dust Collector
19630-M-005	Martin Rig Blaster Air Cannon System
19630-M-010	Roof Ventilator Fans
19630-M-012	Elevator Hopper Winch

Partial List of Technical Specifications

19630-A-042	#Preformed Metal Siding
19630-A-051	#Single Ply Roofing
19630-C-010	#Reinforced Concrete Work
19630-C-011	Structural and Misc. Steel
19630-C-012	Limestone and Fuel Additive Silos
19630-C-1000	#Subsurface Investigation & Lab. Testing
19630-E-001	Motor Control Center
19630-E-002	2.4kV Metal Clad Switchgear
19630-J-001	Continuous Emissions Monitoring System
19630-J-003	Stack Monitoring Platform
19630-J-006	Bucket Elevator Control panel
19630-M-002	Bucket Elevator
19630-TSC-001	#Environmental Monitoring Program
19630-TSC-002	#Instrument Calibration, Testing & Maint.
19630-TSC-003	#Boiler Materials for Monitoring Inspection
19630-TSC-003A	#Boiler Tube Materials Monitoring Inspect.
19630-TSC-004	#ESP Materials Monitoring Sys.
19630-TSC-005	#Engineering/Technical/Craft personnel, Etc.

Used in development of construction package for outside contractor. All other construction work performed within Project by Bechtel Construction or Riley Construction.

Partial List of Balance of Plant Drawings

19630-A-001	Architectural Floor Plans El. 517'-0", El. 550'-0"
19630-A-002	Architectural Roof Plan, Door Schedule & Spec.

19630-A-003	Architectural Elevations
19630-A-004	Architectural Elevations
19630-A-005	Architectural Details and Sections
19630-C-001	Structural Steel Framing Plan El. 576'-49/16"
19630-C-002	Structural Steel Framing Plan El. 535'-9", Etc.
19630-C-003	Structural Steel Framing Els. @ Col. Lines 3 & 4
19630-C-004	Struct. Steel Framing Els. @ Col. Lines H1 & H2
19630-C-005	Structural Steel Framing Elevs. At Col. Lines J1 & J2
19630-C-009	Misc. Steel Platforms and Details
19630-C-010	Fuel Preparation Building Reinforced Concrete Plan
19630-C-011	Continuous Emissions Monitoring System
19630-C-012	Bucket Elevator Support Tower Plan, Sec. & Details
19630-C-013	Bucket Elevator and Inlet Loading Hopper Found.
19630-C-014	Structural Steel Framing partial plans
19630-C-015	Structural Steel Framing partial Plans
19630-C-016	Supplemental Steel Framing plan Views
19630-C-017	Supplemental Steel Framing Sections and Details
19630-C-018	Supplemental Steel Framing Sections and Details
19630-E-001	Motor Control Center Frame Spec.
19630-E-002	Modification Drawing Grounding Plan E1. 517'0
19630-E-003	Modification Dwg. Plan El. 526'0" Cable Tray
19630-E-004	Modification Drawing 480V One-Line Diagram Unit 1
19630-E-005	Modification Drawing Main One-Line Diagram

19630-E-010	Cable Tray layout Turbine Floor El. 540'-0" Unit 1
19630-E-020	lighting General Notes and Details Unit 1
19630-E-021	Lighting Layout Fuel Prep Bldg. Unit 1
19630-E-022	Lighting layout Fuel Prep Bldg. Unit 1
19630-M74-BA01	Demonstration Program Test Data Acquisition Measurements
19630-M74-BA02	Demonstration Program Test Data Acquisition Measurements
19630-POA-001	Ground Floor Plan @ El. 517'0", F.P. @ El. 526'0"
19630-POA-002	Turbine Floor Plan El. 540'-0"
19630-POA-003	Feeder Floor Plan @ El. 550'-0" @ El. 555'-4"
19630-POA-004	Floor Plan @ 568'-0"
19630-POA-005	Partial plans El. 568'-5 3/4". 599'-5 13/16"
19630-POA-006	Fuel preparation Building Section B-B
19630-POA-007	Fuel preparation Building Section C-C
19630-POA-008	Fuel preparation Building Section D-D
19630-SK-E-011	Scope of Work Single Line
19630-SK-M-001	Ground Floor Plans at El. 517'-0
19630-SK-M-001	Ground Floor Plan @ Elv. 517'0" Fl Plan @ Elv. 526'0"
19630-SK-M-002	Turbine Floor Plan El. 540'-0
19630-SK-M-002	Turbine Floor Plan @ Elv. 540'-0" Unit 1
19630-SK-M-003	Feeder Floor Plan @ Elv. 550'-0" & Elv. 555'4" Unit 1
19630-SK-M-005	Partial Plans El. 586'-3 5/16, & Section A-A
19630-SK-M-006	Fuel Preparation Building Section B-B
19630-SK-M-007	Fuel Preparation Building Section C-C

19630-SK-M-008	Fuel preparation Building Section D-D
19630-SKC-001	Limestone Silo
19630-SKC-002	Fuel Additive Silo

List of Piping Drawings

90528-7-1882-10	Coal Piping/Looking South
90528-7-1882-11	Coal Piping/Looking West
90528-7-1882-20	Coal Piping/Splitter-Burner
90528-7-1882-21	Coal Piping/Splitter-Burner
90528-7-1882-22	Coal Piping/Splitter-Burner
90528-7-1882-23	Coal Piping/Splitter-Burner
90528-7-1882-24	Coal Piping/Splitter-Burner
90528-7-1882-25	Coal Piping/Splitter-Burner
90528-7-1882-30	Coal Pipe - 90°Elbow
90528-7-1882-31	Coal Pipe - 75°Elbow
90528-7-1882-40	Coal Piping/Splitter-Burner
90528-7-1882-41	Coal Piping/Splitter-Burner
90528-7-1885-10	Seal Air System/Plan View
90528-7-1885-11	Seal Air System/Looking South
90528-7-1885-12	Seal Air System/Looking West
90528-7-1885-15	Seal Air Piping
90528-7-2361-10	Primary Air System
90528-7-2361-11	Primary Air System
90528-7-2361-12	Primary Air System
90528-7-2365-20	Coal Transport/Tempering Air

90528-7-2365-21	Coal Transport/Tempering Air
90528-7-2365-22	Coal Transport/Tempering Air
90528-7-2371-10	Overfire Air Duct
90528-7-2371-11	Overfire Air Duct
90528-7-2371-12	Overfire Air Duct
90528-7-2371-20	*Air Duct/LNS
90528-7-2371-25	*Air Duct/LNS
90528-7-2371-26	*Air Duct/LNS
90528-7-2371-30	*Air Duct
90528-7-2371-35	*Air Duct
90528-7-2371-36	*Air Duct
90528-7-2371-37	*Air Duct
90528-7-4035-10	Fuel Arrgmt./Feed Sys. Piping
90528-7-4035-11	Fuel Arrgmt./Feed Sys. Piping
90528-8-3451-10	Spring Hanger/LNS Burner

* Abbreviated title to make non-proprietary

List of Proprietary LNS Burner Drawings

90528-7-9000-10	LNS Burner Arrgmt.
90528-7-9000-20	Burner Injector Ass'y
90528-7-9000-21	LNS Burner Barrel
90528-7-9000-22	LNS/Barrel Plenum Section
90528-7-9000-23	Burner Perspective
90528-7-9000-24	LNS Burner

Boiler and Slag Screen Drawings

90528-5-0900-20	Overfire Air Openings
90528-5-0900-40	Slag Screen
90528-5-0900-41	Slag Screen
90528-5-0900-42	Slag Screen Tube List
90528-5-0900-90	Slag Screen/Bottom Cyclone
90528-5-0900-91	Slag Screen/Bottom Cyclone
90528-5-0900-92	Slag Screen/Bottom Cyclone
G-333	Water Wall Tubes

Partial List of Vendor Drawings

90528-7-9000-90	Ignitor Layout
C17154	Control Cabinet - NEMA 4
C19957	Airlock
D24182	Coal Feeder Conversion
D27010	Schematic Diagram
D27011	Feeder Connection
D27012	Feeder Power Cabinet
D27013 -1	Additive Feeder Schematic
D27013 -2	Additive Feeder Schematic
D27014 -1	Additive Feeder Schematic
D27014 -2	Additive Feeder Schematic
D27014 -3	Additive Feeder Schematic
D27015 -1	Limestone Feeder Schematic
D27015 -2	Limestone Feeder Schematic

D27016 -1	Limestone Feeder Schematic
D27016 -2	Limestone Feeder Schematic
D27016 -3	Limestone Feeder Schematic
D27024	Additive Feeder
D27025	Limestone Feeder
D27026	Transfer Feeder
D27027	Feeder Arrangement
D27275	Hopper-Trans.
D27376	Feeder Connection
D27376	Feeder Connection
D27377	Feeder Connection
D27377	Feeder Connection
D27378	Feeder Connection
L-D8670	S-E-Co. Type VB Coal Valve

List of Instrumentation and Control Drawings

19630-M74-JL01	P&ID - Limestone/Fuel Additive Handling System
19630-M74-KA01	P&ID - Instrument and Service Air System (Modifications)
90528-4-4913-XX1	Instrument Data Sheets
90528-7-4900-10	Process Flow Control
90528-7-4900-20	Drawing Index
90528-7-4900-21	Process Symbols
90528-7-4900-22	Control Symbols
90528-7-4900-23	P&ID - Air & Gas
90528-7-4900-24	P&ID - Light Oil Ignitors

90528-7-4900-25	P&ID - Feedwater and Steam
90528-7-4900-26	P&ID - LNSB
90528-7-4900-27	P&ID - Gas Side-Boiler Outlet to Stack
90528-7-4904-XX	DCS Analog Terminations
90528-7-4907-01	SAMA Logic Boiler Control
90528-7-4908-01	Logic Diagrams
90528-7-4908-02	Logic Diagrams
90528-7-4923-XX	DCS Digital Terminations
90528-7-4939-XX	DCS Logic
90528-7-4940-XX	DCS Module Locations
90528-7-4950-01	Graphic Display
90528-7-4950-02	Graphic Display
90528-7-4950-03	Graphic Display
90528-7-4950-04	Graphic Display
90528-7-4950-05	Graphic Display
90528-7-4950-06	Graphic Display
90528-7-4950-07	Graphic Display
90528-7-4950-08	Graphic Diaplay

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