DOE/PC/89653--T1

DOE/PC/89653--T1

DE92 005266

INNOVATIVE CLEAN COAL TECHNOLOGY (ICCT)

180 MW DEMONSTRATION OF ADVANCED TANGENTIALLY-FIRED COMBUSTION TECHNIQUES FOR THE REDUCTION OF NITROGEN OXIDE (NOx) EMISSIONS FROM COAL-FIRED BOILERS

Technical Progress Report
Second Quarter 1991

DOE Contract Number:
DE-FC22-90PC89653

SCS Contract Number
C-91-000028

Prepared by:

Southern Company Services, Inc.
800 Shades Creek Parkway
Birmingham, Alabama 35209

Patents Cleared by Chicago on October 9, 1991

LEGAL NOTICE

EXECUTIVE SUMMARY

This quarterly report discusses the technical progress of a U. S. Department of Energy (DOE) Innovative Clean Coal Technology (ICCT) Project demonstrating advanced tangentially-fired combustion techniques for the reduction of nitrogen oxide (NOx) emissions from a coal-fired boiler. The project is being conducted at Gulf Power Company's Plant Lansing Smith Unit 2 located near Panama City, Florida. The primary objective of this demonstration is to determine the long-term effects of commercially available tangentially-fired low NOx combustion technologies on NOx emissions and boiler performance. A target of achieving fifty percent NOx reduction using combustion modifications has been established for the project.

The stepwise approach that is being used to evaluate the NOx control technologies requires three plant outages to successively install the test instrumentation and the different levels of the low NOx concentric firing system (LNCFS). Following each outage, a series of four groups of tests are performed. These are (1) diagnostic, (2) performance, (3) long-term, and (4) verification. These tests are used to quantify the NOx reductions of each technology and evaluate the effects of those reductions on other combustion parameters such as particulate characteristics and boiler efficiency.

This quarterly update provides a description of the flow modeling study conducted by Asea Brown Boveri Combustion Engineering (ABB CE). This modeling effort centers on evaluating the in-furnace flow and mixing phenomena for the various low NOx firing systems being demonstrated at Plant Lansing Smith. During this quarter, testing of the 1/12 scale model of the Plant Lansing Smith boiler was completed.

In April 1991, ABB CE's LNCFS Level II was installed during a twenty-one day outage. A discussion of the installation is presented.

This report also contains results from the Phase II short-term testing conducted in May and June 1990. NOx emissions data from the diagnostic and performance tests are presented. In addition, flyash LOI levels and CO emissions are discussed. Preliminary NOx emissions profiles collected during the first few weeks of long-term testing are also reported. In general, unit NOx emissions tend to increase with decreases in unit generation when operating with LNCFS Level II.

TABLE OF CONTENTS

1. INTRODUCTION

This document discusses the technical progress of a U. S. Department of Energy (DOE) Innovative Clean Coal Technology (ICCT) Project demonstrating advanced tangentially-fired combustion techniques for the reduction of nitrogen oxide (NOx) emissions from coal-fired boilers. The project is being conducted at Gulf Power Company's Plant Lansing Smith near Panama City, Florida.

The project is being managed by Southern Company Services, Inc. (SCS) on behalf of the project co-funders: The Southern electric system, the U. S. Department of Energy (DOE), and the Electric Power Research Institute. In addition to SCS, The Southern electric system includes five electric operating companies: Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric and Power. SCS provides engineering and research services to the Southern electric system. Through cost sharing in the installed low NOx retrofit technology, Asea Brown Boveri Combustion Engineering (ABB CE) is also participating as a project co-funder.

The Clean Coal Technology Program is a jointly funded effort between government and industry to move the most promising advanced coal-based technologies from the research and development stage to the commercial marketplace. The Clean Coal effort sponsors projects which are different from traditional research and development programs sponsored by the DOE. The traditional projects focused on long-range, high-risk, high-payoff technologies with the DOE providing the majority of the funding. In contrast, the goal of Clean Coal Projects is to demonstrate commercially feasible advanced coal-based technologies which have already reached the "proof-of-concept" stage. As a result, the Clean Coal Projects are jointly funded endeavors between the government and the private sector which are conducted as Cooperative Agreements in which the industrial participant contributes at least fifty percent of the total project cost.

ABB CE's Low NOx Bulk Furnace Staging (LNBFS) System and Low NOx Concentric Firing System (LNCFS) are demonstrated in stepwise fashion. These systems incorporate the concepts of advanced overfire air (AOFA), clustered coal nozzles, and offset air. A complete description of the installed technologies is provided in the following section.

The primary objective of the Plant Lansing Smith demonstration is to determine the long-term effects of commercially available tangentially-fired low NOx combustion technologies on NOx emissions and boiler performance. Short-term tests of each technology are also being performed to provide engineering information about emissions and performance trends. A target of achieving fifty percent NOx reduction using combustion modifications has been established for the project. Through modifications shown in Figure 1, the project seeks to address the following objectives:

1. Demonstrate in a logical stepwise fashion the short-term NOx reduction capabilities of the following advanced low NOx combustion technologies:

   a. Low NOx Bulk Furnace Staging (LNBFS)
   b. Low NOx Concentric Firing System (LNCFS) Levels I, II, and III

2. Determine the dynamic long-term emissions characteristics of each of these combustion NOx reduction methods using sophisticated statistical techniques.

3. Evaluate the progressive cost effectiveness (i.e., dollars per ton NO_x removed) of the low NOx combustion techniques tested.

4. Determine the effects on other combustion parameters (e.g., CO production, carbon carryover, particulate characteristics) of applying the NOx reduction methods listed above.

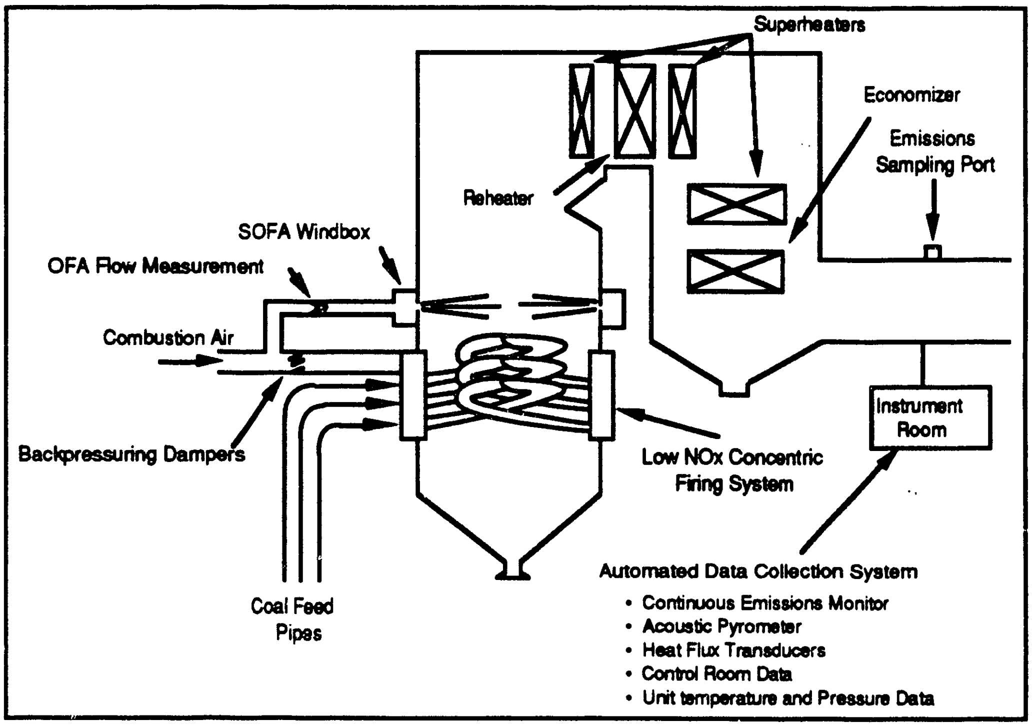


Figure 1. Plant Lansing Smith Unit 2 Boiler

2. DEMONSTRATED TECHNOLOGIES

As shown in the Statement of Work (SOW) revised in February 1991, four different low NOx combustion technologies offered by ABB Combustion Engineering (ABB CE) for tangentially-fired boilers are planned for this demonstration. The demonstration of these technologies progresses in the most logical manner from an engineering and construction viewpoint. During Phase I of the project, the baseline conditions of the unit will be studied. During Phase II, the Low NOx Bulk Furnace Staging (LNBFS) system and the Low NOx Concentric Firing System (LNCFS) Level II will be demonstrated. Finally, LNCFS Levels I and III will be demonstrated during Phase III.

The concept of overfire air is demonstrated in all of these systems. In LNCFS Level I, a Close-Coupled Overfire Air (CCOFA) system is integrated directly into the windbox. Compared to the baseline configuration, LNCFS Level I is arranged by exchanging the highest coal nozzle with the air nozzle immediately below it. This configuration provides the NOx reducing advantages of an overfire air system without major pressure part modifications to the boiler.

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

In addition to overfire air, the LNCFS incorporates other NOx reducing techniques into the combustion process. Using offset air, two concentric circular combustion regions are formed. The inner region contains the majority of the coal thereby being fuel rich. This region is surrounded by a fuel lean zone containing combustion air. For this demonstration, the size of this outer circle of combustion air will be varied using adjustable offset air nozzles. The separation of air and coal at the burner level further reduces the production of NOx.

The LNBFS consists of a standard tangentially-fired windbox with a SOFA system. This technology will be demonstrated by repositioning the offset air nozzles in the main windbox to be in line with the fuel nozzles. No other modifications to the windbox will be required. Due to the limits of the project schedule, LNBFS will be demonstrated using short-term diagnostic tests only.

When the Statement of Work (SOW) for this project was prepared in June 1990, ABB CE offered the following low NOx combustion systems:

1) Low NOx Concentric Firing System (LNCFS)
2) Concentric Clustered Tangential Firing System (CCTFS)

Since that time, the technologies which ABB CE offers to the public have evolved to reflect the results of their most recent knowledge. The equipment that is presently offered comprises a family of technologies called the Low NOx Concentric Firing System Levels I, II, and III as discussed above. These technologies provide a stepwise reduction in NOx emissions with LNCFS Level III providing the greatest reduction.

Although the names of these technologies have changed, the basic concepts for the reduction of NOx emissions have remained constant. The Low NOx Concentric Firing System (LNCFS) included the NOx reduction techniques of overfire air and adjustable offset air nozzles as part of its design. These features are now incorporated into the design of LNCFS Level II.

The Concentric Clustered Tangential Firing System (CCTFS) included two sets of overfire air and clustered coal nozzles. Both LNCFS Levels I and III utilize clustered coal nozzles and overfire air in their design. Research by ABB CE has shown that the use of clustered coal nozzles does not positively or negatively affect the production of nitrogen oxides in a coal-fired boiler. As a result, one set of coal nozzles at the top of the main windbox are clustered to facilitate the addition of the CCOFA system discussed in the section above. This modification allowed the low pressure overfire air system (now designated the CCOFA) to be integrated directly into the windbox. This design change reduced the number of pressure part modifications required to install this low NOx combustion technology. No significant design changes to the high pressure overfire air system (now designated the SOFA) were made.

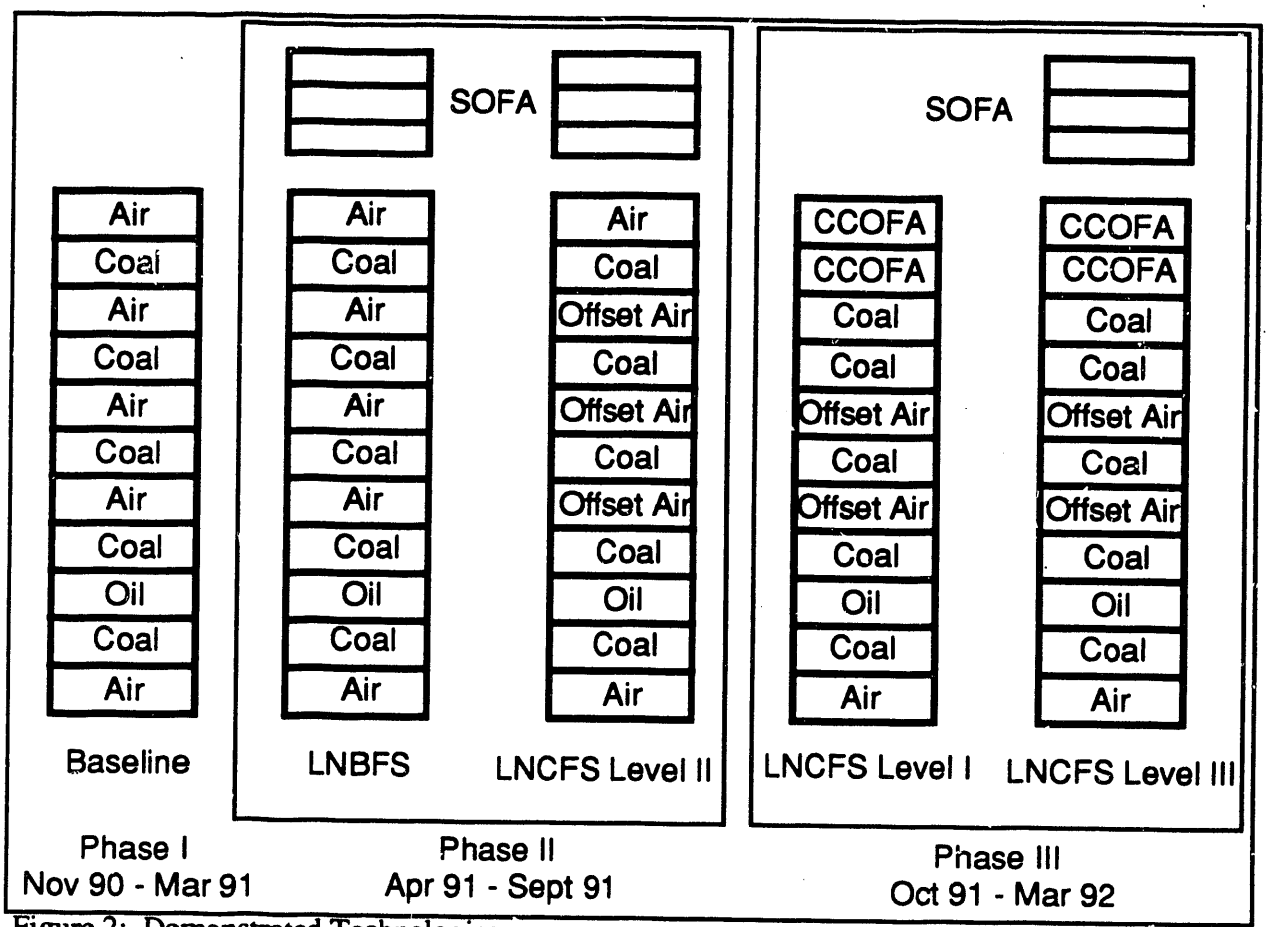


Figure 2: Demonstrated Technologies

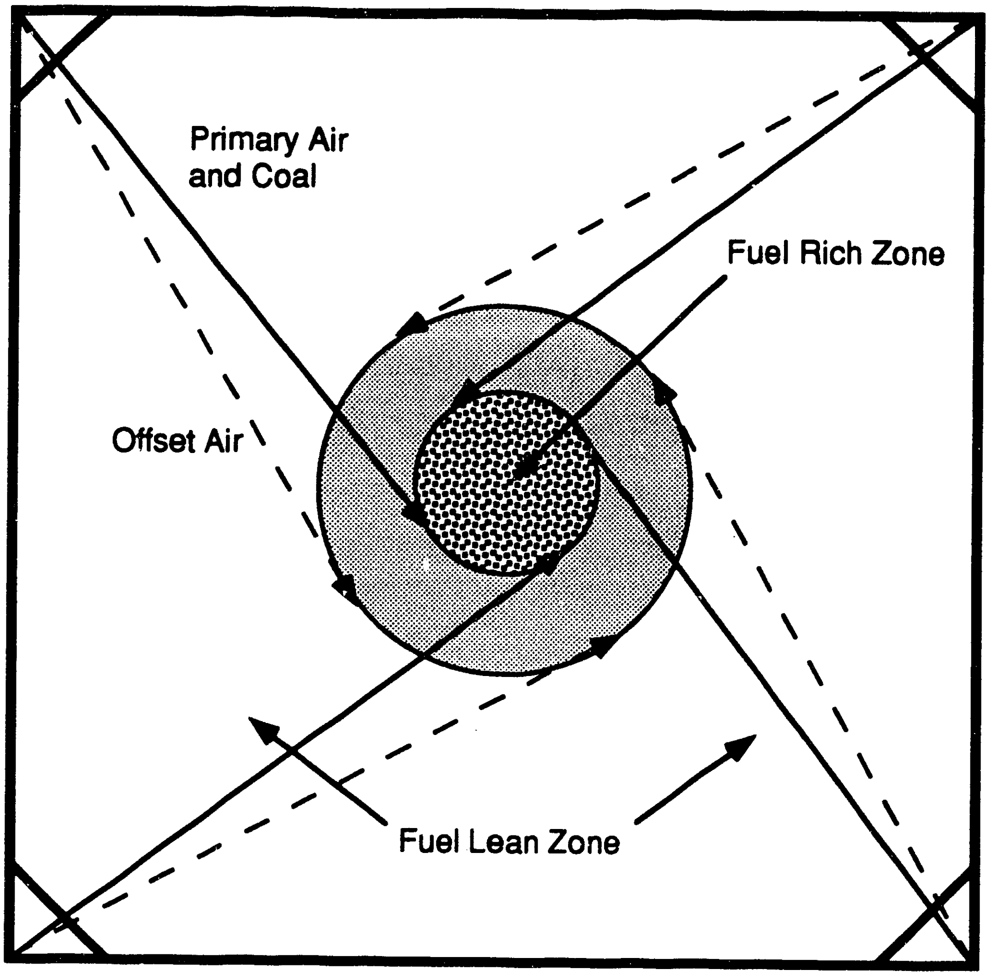


Figure 3: Concentric Firing System

3. UNIT DESCRIPTION

Plant Lansing Smith Unit 2 is a 180 MWe tangentially-fired boiler owned and operated by Gulf Power Company. The unit is located in Lynn Haven, Florida, near Panama City. The boiler is a Combustion Engineering radiant reheat, natural circulation steam generator. It is designed for continuous indoor service to deliver 1,306,000 pounds of steam per hour at normal rated load, a pressure of 1800 psig, and a temperature of 1000°F at the superheater and the reheater outlets. It is fired with pulverized coal through twenty tangential coal nozzles with five nozzles at each corner. Five Combustion Engineering Raymond Bowl mills equipped with exhausters at the outlet of each mill deliver coal to the furnace. The unit is equipped with Ljungstrom air preheaters and two forced-draft fans which deliver all the combustion air to the boiler. Although originally designed for pressurized furnace operation, the unit was converted to balanced-draft operation in 1976.

4. PROJECT DESCRIPTION

In order to accomplish the project objectives, a Statement of Work (SOW) was developed which included the Work Breakdown Structure (WBS) found in Table 1. The WBS is designed around a chronological flow of the project. The chronology requires design, construction, and operation activities in each of the first three phases following project award. Although this project structure is inconsistent with the typical ICCT project phase structure of (1) permitting and design, (2) construction, and (3) operation, it prevents phases from starting and stopping several times during the project.

The stepwise approach to evaluating the NOx control technologies requires that three plant outages be used to successively install (1) the test instrumentation and new air heater baskets, (2) the LNCFS Level II, and (3) the LNCFS Levels I and III. These outages are scheduled to coincide with existing plant outages in the fall of 1990, spring of 1991, and the fall of 1991.

The Data Acquisition System (DAS) for the Lansing Smith Unit 2 ICCT project is a custom designed microcomputer based system used to collect, format, calculate, store, and transmit data derived from power plant mechanical, thermal, and fluid processes. The extensive process data selected for input to the DAS has in common a relationship with either boiler performance or boiler exhaust gas properties. This system includes two continuous emissions monitoring systems (NOx, SO2, O2, THC, CO) with a multi-point flue gas sampling and conditioning system, an acoustic

Table 1: Work Breakdown Structure			
Phase	Task	Description	Scheduled Date
0		Pre-Award Activities	
I		Setup and Pre-Retrofit	
	1.1.1	Project Management and Reports	9/90 - 3/91
	1.1.2	Site Preparation	10/90 - 11/90
	1.1.3	Flow Modeling	9/90 - 7/91
	1.1.4	Instrumentation	8/90 - 12/90
	1.1.5	Baseline Characterization	11/90 - 3/91
II		LNCFS Level II Retrofit	
	1.2.1	Project Management and Reports	4/91 - 9/91
	1.2.2	LNCFS Level II Installation	4/91 - 5/91
	1.2.3	LNBFS and LNCFS Level II Characterization	5/91 - 9/91
III		LNCFS Levels I and III Retrofit	
	1.3.1	Project Management and Reports	9/91 - 1/93
	1.3.2	LNCFS Level III Installation	9/91 - 10/91
	1.3.3	LNCFS Levels I and III Characterization	10/91 - 8/92
IV		Final Reporting and Disposition	
	1.4.1	Project Management and Reports	8/92 - 9/93
	1.4.2	Disposition	11/92

pyrometry and thermal mapping system, furnace tube heat flux transducers, and boiler efficiency instrumentation. The instrumentation system is designed to provide data collection flexibility to meet the schedule and needs of the various testing efforts throughout the demonstration program. A summary of the type of data collected is shown in Table 2.

Following each outage, a series of four groups of tests are performed. These are (1) diagnostic, (2) performance, (3) long-term, and (4) verification. The diagnostic, performance, and verification tests consist of short-term data collection during carefully established operating conditions. The diagnostic tests are designed to map the effects of changes in boiler operation on NOx emissions. The performance tests evaluate a more comprehensive set of boiler and combustion performance indicators. The results from these tests will include particulate characteristics, boiler efficiency, and boiler outlet emissions. Mill performance and air flow distribution are also tested. The verification tests will be used to characterize any changes that might have occurred during long-term testing.

As stated previously, the primary objective of the demonstration is to collect long-term, statistically significant quantities of data under normal operating conditions with and without the various NOx reduciion technologies. Earlier demonstrations of emissions control technologies have relied solely

Table 2: Plant Data Points	
Boiler Drum Pressure	Superheat Outlet Pressure
Cold Reheat Pressure	Hot Reheat Pressure
Barometric Pressure	Superheat Spray Flow
Reheat Spray Flow	Main Steam Flow
Feedwater Flow	Coal Flows
Secondary Air Flows	Tempering Air Flows
Main Steam Temperatures	Cold Reheat Temperature
Hot Reheat Temperature	Feedwater Temperature
Desuperheater Outlet Temp.	Desuperheater Inlet Temp.
Economizer Outlet Temp.	Air Heater Air Inlet Temp.
Air Heater Air Outlet Temp.	Ambient Temperature
BFP Discharge Temperature	Relative Humidity
Stack NOx	Stack SO2
Stack O2	Stack Opacity

on data from a matrix of carefully established short-term (one to four hour) tests. However, boilers are not typically operated in this manner considering plant equipment inconsistencies and economic dispatch strategies. Therefore, statistical analysis methods for long-term data have been developed that can be used to determine the achievable emissions limit or emission tonnage of a control technology. These analysis methods have been developed over the past fifteen years by the Control Technology Committee of the Utility Air Regulatory Group (UARG). Because the uncertainty in the analysis methods is reduced with increasing data set size, UARG recommends that acceptable results can be achieved with data sets of at least 51 days with each day containing at least 18 valid hourly averages.

5. PROJECT STATUS

5.1. Phase I Setup and Pre Retrofit

5.1.1. Task 1.1.3 Flow Modeling

The objective of the isothermal flow model study is to assure optimum performance of the low NOx tangential firing system. The modeling effort centers on the understanding of in-furnace flow and mixing phenomena for the various low NOx firing systems being demonstrated at Plant Lansing Smith. This is accomplished through an evaluation of the baseline configuration and the proposed firing systems.

The 1/12 scale flow model of the Plant Lansing Smith Unit 2 boiler encompasses the entire furnace from the hopper through the economizer outlet including all radiant and convective heat transfer surfaces within the first sections of the upper furnace. The furnace shell is constructed of 1/2 inch plexiglass. The heat transfer surfaces are constructed of perforated metal plate and paper tubing. The free areas of the plates and their spacing within the model were determined such that axial and transverse pressure drop coefficients were accurately simulated. The airflow paths are modeled from the inlet of individual windboxes at the corners to the economizer outlet. Testing evaluations included flow visualization and three dimensional velocity mapping.

In addition, a separate one-sixth scale model of the overfire air ductwork from the secondary air ducts to the overfire air windboxes has been evaluated. The purpose of this effort was to develop flow control devices which minimize pressure drop and provide uniform flow profiles entering the flow measurement devices.

During this quarter, the LNCFS Level III configuration was tested. Results of these tests are compiled into the report:

Test Report Physical Flow Modeling - Task V LNCFS-III Operating Conditions

This document is included in the Topical Report, **Physical Flow Modeling**, (transmitted separately to the DOE in August 1991) which presents the results of the flow modeling effort.

The tests of the LNCFS Level III operating condition began with of an evaluation of windbox penetrations, flow swirl, and mixing characteristics using smoke visualization techniques. During these tests the flow pattern was observed as it entered the windbox through different elevations. Twenty different boiler configurations were tested using the flow visualization techniques. Based on those tests, five model conditions were chosen for further study.

Detailed tests of the five best model configurations were conducted to determine a recommended operating condition. These tests included three dimensional velocity characterizations and methane gas mixing analysis. These characterizations were conducted in four horizontal planes in the model. One of these planes was below the SOFA air nozzles and the other three were above the SOFA nozzles.

The following conclusions from the modeling of the LNCFS Level III were reached:

- The overall mixing performance of the OFA systems were found to be fairly well mixed at the furnace outlet plane for the five final model configurations. That is, the RMS deviation of the mixing was typically less than twenty percent. It was determined that mixing could be optimized with adjustments of the OFA firing angles.

- A recommended configuration for OFA operation was presented. This configuration included nozzles angles which directed the overfire air both in the direction and against the direction of the main windbox air flow in the furnace.

- For the design operating conditions (20 percent SOFA and 15 percent CCOFA), the jets do not completely penetrate the centerline of the furnace. Instead, they are redirected by cross flows and dispersed along the outer perimeter of the furnace. The penetration of the OFA flow can be increased or decreased by respectively increasing or decreasing the OFA air flow rate.

- A downward tilt of the OFA nozzles improves the overall mixing level of the OFA jets. However, separation between OFA and windbox flow is reduced in such a configuration. For the final configuration, no tilt in the OFA nozzles is recommended.

- At minimum OFA flow rates, a down tilt is necessary to provide adequate mixing. This down tilt is limited to approximately ten degrees.

- The side to side velocity distribution generally shows higher flow rates along side walls of the furnace at the furnace outlet plane. There is also a side to side flow imbalance in which there is more flow along the side walls, with reduced flow at the center of the furnace.

5.1.2. Task 1.1.4 Instrumentation

Certification tests of the KVB extractive continuous emissions monitoring system were conducted in June 1991, by Spectrum Systems. The entire system passed certification. A copy of the certification report and the Notice of Field Certification are contained in Appendix A.

5.1.3. Task 1.1.5 Baseline Characterization

Phase I baseline tests were completed in previous quarters. Eighty-four different short-term tests (55 diagnostic, 7 performance, and 22 verification) were completed during the baseline test program. Seventy-five days of statistically significant long-term data were collected from

December 1990 to March 1991. Figure 4 presents the short- and long-term NOx emissions results collected during all of these tests. Each mark on the graph represents NOx emissions data collected during a short-term test. The upper and lower bands of the shaded region designate the upper 95 percent and lower 5 percent confidence levels for the long-term data. A summary of pertinent data collected during long-term testing is presented in Table 3.

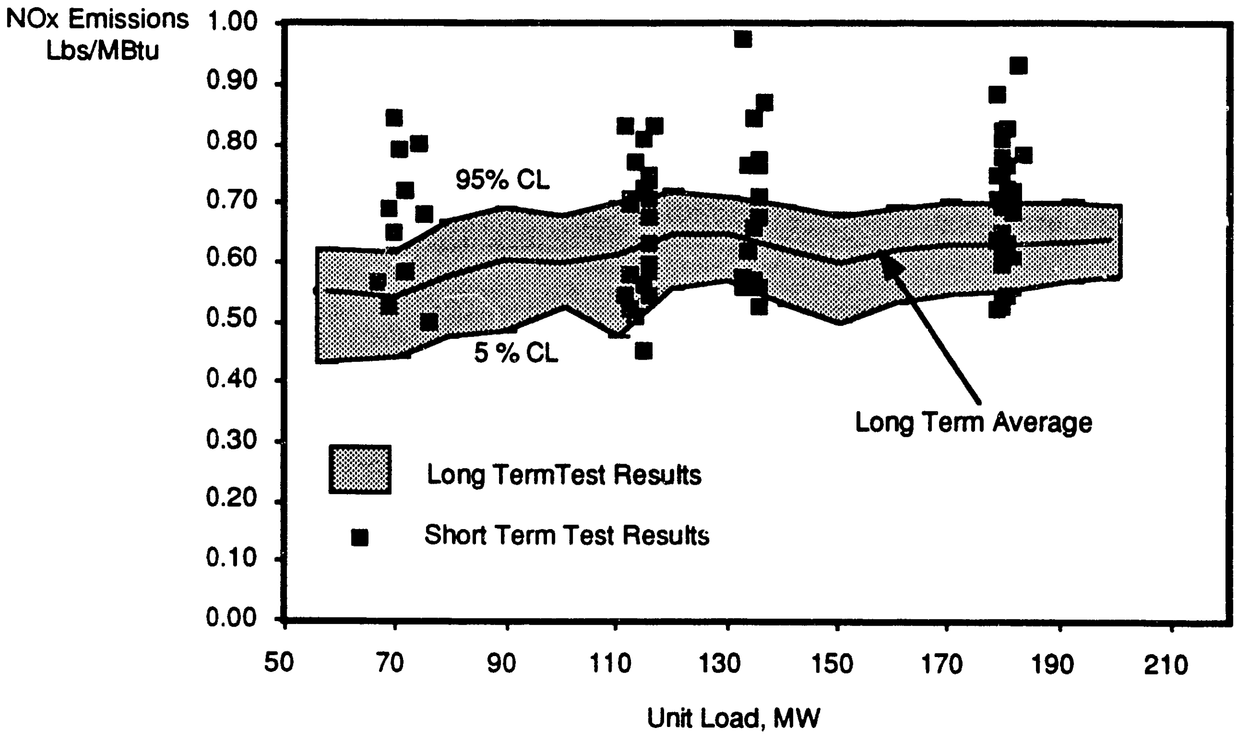


Figure 4: Baseline NOx emissions characteristics

TABLE 3. Phase I Long-Term Testing - Average NOx Emissions	
Number of Daily Averaged Values	75
Average Emissions (lb NOx/mBtu)	0.62
Standard Deviation (lb NOx/mBtu)	0.036
Distribution	Normal
Average Load (MW)	156
Achievable Emission Limit (lb NOx/mBtu)	0.68

5.2. Phase II LNCFS Level II Retrofit

5.2.1. Task 1.2.2 LNCFS Level II Installation

Level II of ABB CE's Low NOx Concentric Firing System was installed during a three week outage that began on March 29, 1991. During that outage, craft labor worked seven days a week with two ten-hour shifts per day. The remaining four hours of the day were reserved for x-raying welds in the furnace walls. During peak work loads, as many as seventy craft laborers per shift were involved in the retrofit. A full furnace scaffold was installed to expedite the job.

Due to the scope of the work required to be performed during the outage, the SOFA ductwork was hung in place prior to the unit coming off line. The installation of the SOFA windboxes required significant pressure part modifications to each corner of the boiler above the main windbox. Preassembled bent tube panels were welded into the four 10 feet high by 4 feet wide holes cut in the boiler. The overfire air windboxes with three sets of air nozzles are inserted into the 5 feet high by 2 feet wide openings in the tube panels. Each nozzle has its own automatically controlled damper to provide regulation of the flow to the overfire air ports. The yaw adjustment on each SOFA nozzle is manually adjustable. The three nozzles tilt in unison via automatic controls tied to the tilting of the main nozzles in the secondary air windbox.

The critical path for this outage was the modification to the main windboxes. The windboxes were completely stripped of coal nozzles, auxiliary air nozzles, tilt linkages, and all bearings and bushings. After removing this equipment, the partition plates and windbox turning vanes were inspected for warpage and general wear. When necessary, these parts were replaced or refurbished. Additional partition plates were installed in the top and bottom auxiliary air compartments. All of the partition plates were cut back approximately three inches to allow greater tilting mobility of the new coal and air nozzles. All coal nozzles and tips were replaced, Rockwell couplings were installed in the fuel lines to relieve fuel pipe loadings on the windbox, and four elevations of flame scanners were installed including a cooling air system with a dedicated fan. The windbox tilting mechanism was completely replaced. The offset air nozzles in the main windbox have the capability to move in the horizontal direction by a manual adjustment. The air nozzles and coal nozzles are tilted in unison using automatic controls.

During the outage, two unexpected events occurred which could have impacted unit start up following the outage. First, asbestos insulation was inadvertently uncovered and removed from a section of the secondary air ductwork by craft laborers. Upon discovery and identification of the uncovered asbestos, the building was cleared of all personnel and the area was properly cleaned. Four working shifts were lost as a result of this incident. Second, the main boiler feedwater line required relocation to clear the overfire air ductwork. The relocation of this line required welds in ten different locations. Because one of the welds was located in a tight area, it had to be rewelded five times before passing inspection the night before unit start up.

A complete description of the activities which occurred during the April outage is included the following reports prepared by ABB CE:

- *Technical Services Activity Report* (Appendix B)
- *Construction Services Activity Report* (Appendix C).

5.2.2. Task 1.2.3 LNBFS and LNCFS Level II Characterization

Phase II Characterization tests of the LNCFS Level II were conducted during this quarter. Twenty eight diagnostic tests were conducted from May 7 to June 6, 1991. Seven performance tests were conducted from May 29 to June 6, 1991. Table 4 provides the pertinent data collected during the short-term tests conducted this quarter. Long-term testing was begun on June 23, 1991 and will continue through September 1991.

5.2.2.1. Short-Term Testing

The LNCFS Level II diagnostic tests consisted of characterizing the boiler operating conditions. These tests were conducted at nominal loads of 75, 115, 140, 180, and 200 megawatts. The tests were organized to study various combinations of mill arrangements, furnace oxygen levels, and unit loads. During each test, manual data was collected from the control room, automated boiler operational data were recorded on the data acquisition system, and coal and flyash samples were collected.

The seven performance tests were conducted at nominal loads of 115, 135, 180 and 200 megawatts with each test lasting from ten to twelve hours. Manual and automated boiler operational data were recorded, fuel and ash samples were acquired, gaseous and solid emissions measurements were made, and engineering performance tests were conducted for each test. At each load level (except 200 MW), two tests were performed over a two day test period to accommodate the test requirements.

Figure 5 presents the short-term NOx emissions characteristics of the boiler in comparison to the baseline results. As with the baseline results, NOx emissions increased with increasing furnace oxygen levels. These results also show that, unlike the baseline results, unit NOx emissions increase as unit load decreases. This can be attributed to the operation of the SOFA system. At full load, the dampers in the SOFA are open 100 percent. However, as unit load is decreased, these are closed until there is no overfire air flow at minimum load. Based on the short-term test data, a NOx reduction of approximately 35 percent has been attained at full load.

TABLE 4: Summary of LNCFS Level II Test Results and Operating Conditions

Test No.	Date	Load MW	moos	SOFA upper	SOFA middle	SOFA lower	O2	NOx ppm	NOx lb/mBtu	CO ppm	TEST TYPE
25-1	7-May	181	None	101	100	100	3.9	296	0.40	8	Diagnostic
25-2	7-May	180	None	101	100	100	3.6	246	0.34	70	Diagnostic
25-3	7-May	181	None	101	100	100	4.3	288	0.39	16	Diagnostic
26-1	8-May	180	None	101	100	100	5.2	288	0.39	9	Diagnostic
26-2	8-May	180	None	101	100	100	4.3	274	0.37	17	Diagnostic
27-1	9-May	180	None	100	100	100	3.8	264	0.36	6	Diagnostic
27-2	9-May	180	None	100	100	100	3.8	262	0.36	4	Diagnostic
27-4	9-May	200	None	60	100	100	3.2	260	0.35	80	Diagnostic
28-1	14-May	201	A	0	0	0	3.4	399	0.54	8	Diagnostic
28-2	14-May	200	A	60	100	100	3.3	282	0.38	94	Diagnostic
29-1	14-May	140	A	20	101	100	2.4	245	0.33	22	Diagnostic
29-2	15-May	140	A	20	101	100	3.7	278	0.38	7	Diagnostic
29-3	15-May	140	A	20	101	100	5.3	318	0.43	5	Diagnostic
29-4	15-May	140	A	0	0	100	3.9	298	0.41	3	Diagnostic
29-5	15-May	140	A	0	0	0	4.1	379	0.52	4	Diagnostic
30-1	16-May	141	AB	20	100	100	2.4	251	0.34	18	Diagnostic
30-2	16-May	142	AB	20	100	100	3.0	230	0.31	16	Diagnostic
30-3	16-May	143	AB	20	100	100	4.2	265	0.36	4	Diagnostic
30-4	16-May	142	AB	20	100	100	5.4	292	0.40	6	Diagnostic
30-5	16-May	142	A	20	100	100	4.7	293	0.40	4	Diagnostic
30-6	16-May	142	A	20	100	100	3.2	248	0.34	3	Diagnostic
31-1	16-May	115	AB	0	0	0	2.4	282	0.38	15	Diagnostic
31-2	17-May	117	AB	0	60	100	2.4	250	0.34	148	Diagnostic
31-3	17-May	117	AB	0	60	100	3.9	266	0.36	6	Diagnostic
31-4	17-May	114	AB	0	60	100	4.7	286	0.39	7	Diagnostic
31-5	17-May	181	None	100	100	100	3.2	257	0.35	8	Diagnostic
32-1	17-May	115	AB	0	60	100	2.4	250	0.34	118	Diagnostic
32-2	18-May	116	AB	0	60	100	3.7	283	0.39	25	Diagnostic
32-3	18-May	116	AB	0	60	100	4.8	288	0.39	10	Diagnostic
33-1	18-May	75	ABC	0	0	0	5.4	330	0.45	9	Diagnostic
33-2	18-May	76	ABC	0	0	50	4.8	269	0.37	10	Diagnostic
33-3	18-May	76	ABC	0	0	50	6.5	311	0.42	10	Diagnostic
33-4	18-May	76	ABC	0	0	50	7.7	338	0.46	12	Diagnostic
33-5	19-May	76	ABC	0	0	0	7.8	398	0.54	12	Diagnostic
34-1	28-May	181	None	100	100	100	3.7	252	0.34	74	Diagnostic
34-2	28-May	181	None	100	100	100	2.7	204	0.28	74	Diagnostic
34-3	28-May	181	None	100	100	100	3.0	221	0.30	12	Diagnostic
34-4	28-May	181	None	100	100	100	3.5	249	0.34	7	Diagnostic
34-5	28-May	181	None	100	100	100	4.1	276	0.38	9	Diagnostic
34-6	28-May	181	None	100	100	100	3.7	252	0.34	9	Diagnostic
35-1	29-May	181	None	100	114	114	3.9	245	0.33	24	Performance
35-2	29-May	181	None	100	114	114	3.7	255	0.35	5	Diagnostic
35-3	29-May	181	None	100	114	114	3.7	255	0.35	5	Diagnostic

TABLE 4 (continued): Summary of LNCFS Level II Test Results and Operating Conditions											
Test No.	Date	Load MW	moos	SOFA upper	SOFA middle	SOFA lower	O2	NOx ppm	NOx lb/mBtu	CO ppm	TEST TYPE
36-1	30-May	181	None	100	114	114	3.4	229	0.31	75	Diagnostic
36-2	30-May	181	None	100	114	114	3.9	243	0.33	15	Performance
36-3	30-May	180	None	100	114	114	3.9	243	0.33	15	Diagnostic
37-1	31-May	201	None	114	114	114	3.8	272	0.37	21	Performance
37-2	31-May	201	None	114	114	114	3.9	309	0.42	8	Diagnostic
37-3	31-May	200	None	114	114	114	4.7	351	0.48	8	Diagnostic
38-1	1-Jun	115	A,B	0	53	114	3.7	251	0.34	6	Diagnostic
38-2	1-Jun	115	A,B	0	54	114	4.3	261	0.36	5	Performance
38-3	1-Jun	115	A,B	0	54	114	4.6	256	0.35	5	Diagnostic
38-4	1-Jun	115	A,B	0	57	114	5.3	265	0.36	6	Diagnostic
39-1	2-Jun	115	A,B	0	54	114	4.5	255	0.35	4	Performance
39-2	2-Jun	115	A,B	0	55	114	4.4	257	0.35	4	Diagnostic
39-3	2-Jun	115	A,B	0	56	114	3.7	239	0.33	6	Diagnostic
39-4	2-Jun	115	A,B	0	56	114	5.4	279	0.38	6	Diagnostic
40-1	3-Jun	137	A	15	104	114	3.9	248	0.34	10	Performance
40-2	3-Jun	137	A	15	105	114	3.8	255	0.35	7	Diagnostic
40-3	3-Jun	137	A	15	105	114	3.0	242	0.33	11	Diagnostic
40-4	3-Jun	137	A	15	105	114	5.0	272	0.37	11	Diagnostic
41-1	4-Jun	135	A	11	97	114	4.9	284	0.39	9	Performance
41-2	4-Jun	136	A	11	100	114	4.1	266	0.36	9	Diagnostic
41-3	4-Jun	136	A	12	100	114	3.9	266	0.36	8	Diagnostic
41-4	4-Jun	136	A	100	100	114	3.8	245	0.33	8	Diagnostic
41-5	4-Jun	136	A	100	100	114	3.9	259	0.35	8	Diagnostic
41-6	4-Jun	136	A	13	100	114	4.2	274	0.37	7	Diagnostic
42-1	5-Jun	182	None	101	114	114	3.9	253	0.34	46	Diagnostic
42-2	5-Jun	182	None	75	75	75	3.9	258	0.35	46	Diagnostic
42-3	5-Jun	181	None	50	50	50	4.0	275	0.37	22	Diagnostic
42-4	5-Jun	182	None	25	25	25	4.0	321	0.44	22	Diagnostic
42-5	5-Jun	182	None	0	0	0	4.0	412	0.56	12	Diagnostic
42-6	5-Jun	181	None	100	0	0	4.2	384	0.52	8	Diagnostic
42-7	5-Jun	181	None	100	100	0	4.0	305	0.42	11	Diagnostic
42-8	5-Jun	182	None	100	100	100	4.0	256	0.35	16	Diagnostic
43-1	6-Jun	182	None	100	114	114	4.0	247	0.34	49	Diagnostic
43-2	6-Jun	181	None	100	114	114	3.8	245	0.33	42	Diagnostic
43-3	6-Jun	182	None	100	114	114	4.0	252	0.34	6	Diagnostic
43-4	6-Jun	182	None	100	114	114	4.0	275	0.37	5	Diagnostic
43-5	6-Jun	181	None	100	114	114	4.0	287	0.39	6	Diagnostic
43-6	6-Jun	182	A	100	114	114	2.9	243	0.33	10	Diagnostic
43-7	6-Jun	182	A	100	114	114	5.2	323	0.44	7	Diagnostic
43-8	6-Jun	181	A	100	114	114	4.0	285	0.39	5	Diagnostic

Legend:
- moos: Mills Out Of Service
- SOFA: Separated Overfire Air
- upper: percentage of flow through the upper SOFA nozzle
- middle: percentage of flow through the middle SOFA nozzle
- lower: percentage of flow through the lower SOFA nozzle
- NOx (ppm): NOx emissions corrected to 3 % O2

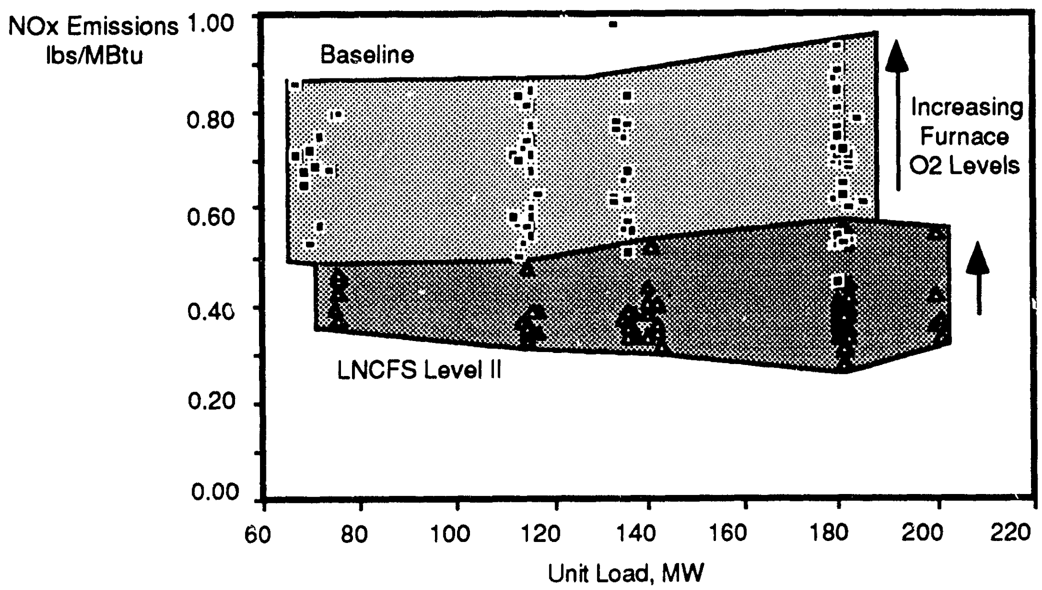


Figure 5: Short-term LNCFS Level II NOx emissions compared to short-term baseline NOx emissions

Figure 6 shows the baseline and LNCFS Level II CO emissions for this unit. Baseline CO emission maintained a tight band in the 5 to 20 ppm range. Post retrofit CO emissions were not as predictable. CO emissions with LNCFS Level II are highly dependant upon unit excess oxygen levels. As the excess oxygen level decreases, unit CO emissions increase. During some tests, reductions of only 0.75 percent in excess oxygen levels have caused CO emissions to increase over 60 ppm.

A comparison of pre- and post-retrofit combustibles loss-on-ignition (LOI) data measured during short-term testing is presented in Table 5.

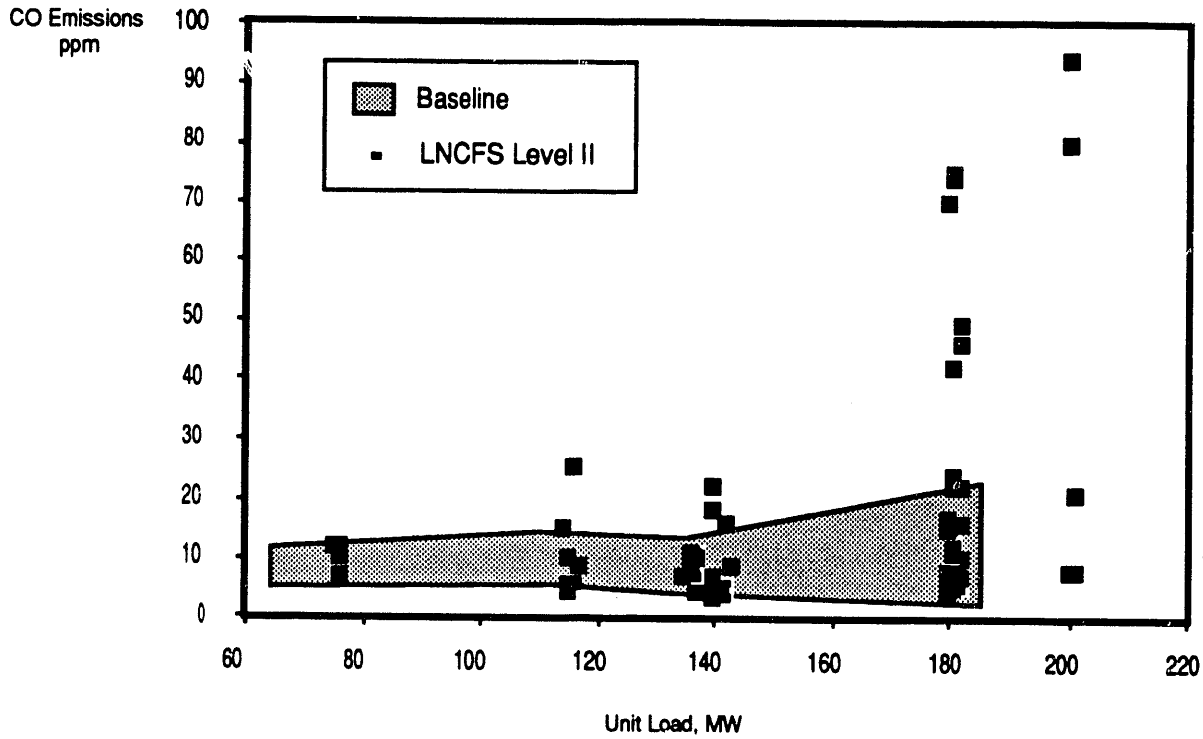


Figure 6: Comparison of baseline and LNCFS Level II CO emission levels during short-term testing

Table 5: Comparison of short-term baseline and LNCFS Level II LOI values

Boiler Load MW	Baseline LOI Results %	LNCFS Level II LOI Results %
200	*	5.4
180	5.0	4.2
135	4.2	3.9
115	4.0	3.8

* No baseline tests were conducted at 200 MW.

5.2.2.2. Long-Term Testing

As stated previously, the objective of this project is to determine the long-term NOx emissions for a T-Fired boiler retrofit with low NOx combustion equipment. Long-term data collection is the definitive method to determine the actual NOx reduction characteristics of a low NOx combustion system. Based on the limited amount of LNCFS Level II long-term data collected between June 24 and July 14, 1991, Figure 7 presents the long-term NOx emissions data. These data show that at full load (200 MW), the unit is able to meet a 0.45 lb/mBtu standard f›r NOx emissions with a NOx reduction of approximately 35 percent compared to the baseline values. However, this is not the case for low load operation. NOx emissions during off peak hours when the unit is at minimum load are well above the 0.45 lb/mBtu limit. At minimum load, NOx emissions exceed 0.60 lb/mBtu which equates to 15 percent increase in NOx emissions.

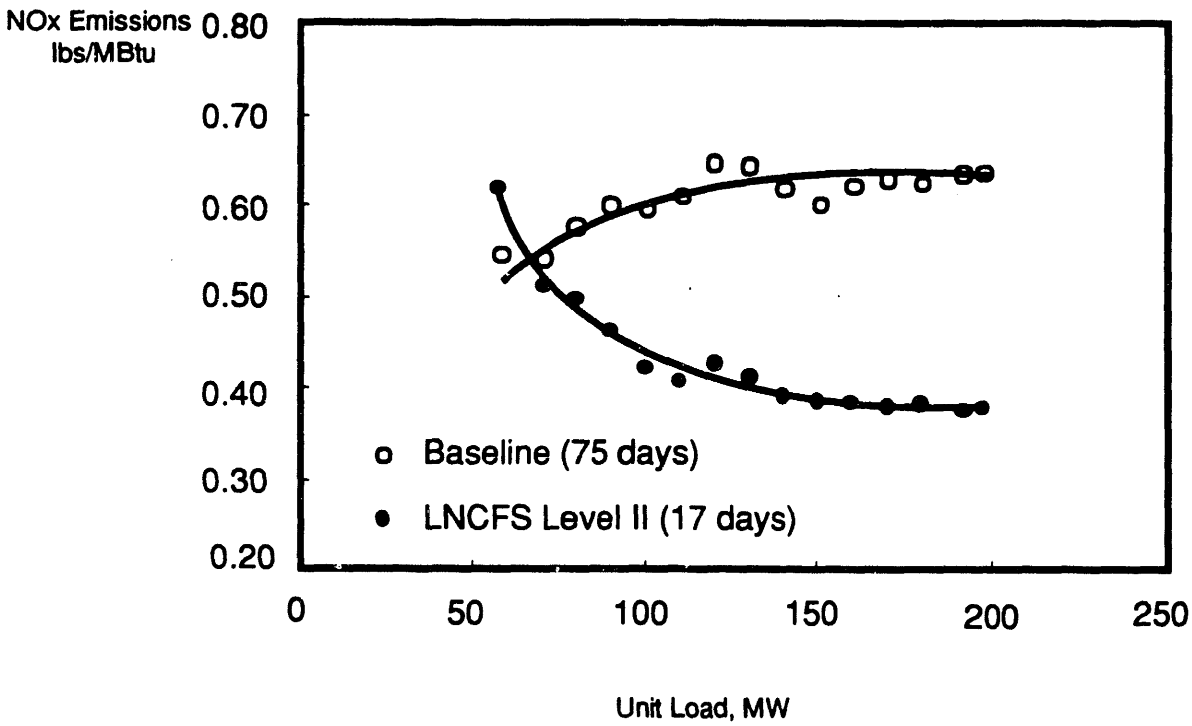


Figure 7: Comparison of baseline and LNCFS Level II long-term NOx emissions

6. FUTURE PLANS

The following is a quarterly outline of the activities scheduled during the remainder of the project:

QUARTER	ACTIVITY
Third Quarter 1991	Continue Long-Term LNCFS Level II Tests
Forth Quarter 1991	Complete Long-Term LNCFS Level II Tests Verification Tests of LNCFS Level II Configuration Complete LNCFS Level I and III Retrofit Diagnostic Tests of LNCFS Level I and III Performance Tests of LNCFS Level I and III Begin Long-Term LNCFS Level I and III Tests
First Quarter 1992	Continue Long-Term LNCFS Level I and III Tests
Second Quarter 1992	Complete Long-Term LNCFS Level I and III Tests Verification Tests of LNCFS Level I and III Configuration
Third and Fourth Quarters 1992 1993	Complete Final Reporting Disposition Project Completion

7. ACKNOWLEDGEMENTS

The management of this project wish to gratefully acknowledge the support and dedication of the following personnel for their work at the tangentially-fired test site: Mr. J. D. McDonald, Gulf Power Company, and Mr. Lamar Sumerlin, Southern Company Services, for their coordination of the design and retrofit efforts and Mr. James Gibson, full-time Instrumentation Specialist from Spectrum Systems, Inc. We also thank Messrs Jim Witt, John Sorge, and Jimmy Horton of Southern Company Services for their work coordinating the procurement and installation of the instrumentation at this site. We would also like to recognize the following companies for their outstanding testing and data analysis efforts: Energy Technology Consultants, Inc., Flame Refractories, Inc., Southern Research Institute, W. S. Pitts Consulting, and Radian Corporation.

APPENDIX A

Continuous Emissions Monitor
Certification Test Report

CERTIFICATION TESTING

UNIT #2

GULF POWER COMPANY

PLANT SMITH

June 23, 1991

Prepared by:

Spectrum Systems, Inc.
Pensacola, Florida

AMETEX/TERMOX O2 ANALYZER S/N C068052B-2

WESTERN RESEARCH SO2 ANALYZER S/N 90-721AT2-7629-6

TECO NOx ANALYZER S/N 28345-231

TABLE OF CONTENTS

I. INTRODUCTION

Spectrum Systems, Inc. was contracted by Southern Company Services, Inc., to conduct a Performance Evaluation of the Plant Smith Continuous Emission Monitoring Systems (CEMS), comprised of an Ametex/Thermox Model FCA-LX O2 Analyzer, Serial Number CO68052B-2; Western Research Model 721AT2 SO2 Analyzer, Serial Number 90-721AT2-7629-6; and a Thermo Environmental Model 10 NOx Analyzer, Serial Number 10 A/R-28345-231. The KVB extractive system monitors the exhaust gas duct as well as several intermediate ducts, on command. Reference Method Tests were performed on the stack gas stream at a point adjacent to the extractive analyzer probes to determine instrument accuracies. The installation was made on the multi-fuel boiler located on Unit #2 at the Plant Smith facility. This certification was performed in accordance with the emission monitoring requirements as promulgated on May 25, 1984, by the Environmental Protection Agency. Field tests were conducted from 06/11/91 through 06/23/91. The instrument operated continuously throughout the operational test period without maintenance or service. During the relative accuracy test period, the boiler was operated at greater than 50% of normal load. Results in this report include data from a diluent monitor since reporting is required in a mass emission output format. The diluent monitors were also certified during this test.

II. INSTALLATION DESCRIPTION

The instruments were installed on the exhaust stack and main exhaust duct of the Unit #2 Boiler located at the Plant Smith facility. Further installation information can be obtained from the affected facility. The initial start-up was on October, 30, 1990, for the KVB system. The effluent gases are assumed to be representative in accordance with para. 3.1.1. of the referenced specification since the monitor location is more than eight diameters downstream of the nearest control device and in the centroid into the effluent stream. These monitoring systems are used to evaluate the effects of NOx reduction procedures under test at the facility.

III. SUMMARY

Test results of the Performance Evaluation are presented in Table III-1 A and B. These results are based on data obtained in Panama City, Florida, during normal operation at the facility. The test results clearly show that the KVB continuous emissions monitor is in conformance with all requirements of "Performance Specifications and Specification Test Procedures for Sulphur Dioxide and Nitrogen Oxides Continuous Emission Monitoring Systems in Stationary Sources."

IV. DISCUSSION OF RESULTS

Calibration Drift Test

Calibration drift was tested in accordance with paragraph 1 of Performance Specification 2. Both SO2/NOx monitors are designed to provide automatically timed zero and span calibration checks at 24 hour intervals throughout the required 7 consecutive days. The zero value is determined by mechanically introducing to the probe measurement cavity or sample probe a supply of zero air, thereby producing a zero condition that checks the analyzer's internal components and all electronic circuitry including the radiation source and detector assembly. The span of the system is checked with a calibration gas equivalent to between a 50 and 90 percent deflection of span concentration, utilizing the probe measurement cavity in a manner similar to that described above. Adjustments were not made on the gas monitor or the diluent monitor during the Calibration Drift Test. Twenty-four (24) hour results were calculated by taking the daily recorded monitor response and subtracting this reading from the reference value. Daily calibration drift tests are contained in the reports entitled, "Lansing Smith Unit 2 Clean Coal Project", Valve Group 199, 200 and 201, taken from the plant reporting data acquisition system and found in Appendix D of this report.

Calibration Drift Test Results

Results of the two (2) point Calibration Drift Test are as follows:

> Sulphur Dioxide and Nitrogen Oxide stack gas monitor and the oxygen diluent monitor calibration drift for the seven (7) consecutive day period did not exceed 2.5% of the zero or span value for pollutant parameters, or 0.5% oxygen by volume for the diluent monitor for any given day. Drift test results are displayed in tabular formats (see Table IV-1 and IV-1A through IV-3 and IV-3A).

Federal Register specifications permit calibration drift to be less than equal to 2.5% of span for sulphur dioxide and nitric oxide and 0.5 % O2 by volume for diluent oxygen for each 24 hour period of the seven (7) day calibration drift test. The test data used in calculating these results is presented on Table IV-1 and IV-1A through IV-3 and IV-3A.

Calibration Error Test

A calibration error test or cylinder gas audit was performed in accordance with the QA guideline contained in the Title 40 Part 60 Appendix F of Code of Federal Regulations. This test was used to access the accuracy of each CEMS prior to the reference method testing procedures. No adjustments were made to the CEMS as a result of the gas audits.

A secondary purpose of this procedure was to validate the calibration procedures used by contractor personnel to maintain instrument accuracy. Although a manufacturer's specification of ±5% relative error is advised against the LSI SO2/NO monitor, a federal guideline of ±15% relative is acceptable for accessing the accuracy of a cylinder gas audit.

Relative Accuracy

Relative Accuracy is defined in the Federal Register as "the degree of correctness with which the continuous monitoring system yields the value of gas concentration of a sample relative to the value given by a defined reference method." The defined reference method, in this case, is EPA Reference Methods 3A, 6 and 7E. Nine sets of tests were performed on June 11, 1991, at a point established in accordance with Section 7.1 of the Federal Register. Additional details can be found in the appendix of this report.

The accuracy is reported as an error and is the sum of the absolute mean value of the difference between the reference test and the combined readings, plus a 95% confidence interval of the differences, expressed as a percentage of the mean combined reference value. The analyzer's average response was determined from the computer printouts corresponding to the time period the relative accuracy tests were performed.

When using computer printouts for comparisons to the reference methods, one minute instrument averages were used, corresponding to the time frame of stack gas samples. The method for arriving at the comparison of LBS/MBTU is obtained by using a formula that calculates the emission output based on raw PPM the percent of oxygen and moisture factor. The formulas used for conversion are explained in the Appendix, under the section entitled, "Mathematical Explanation."

The relative accuracy is displayed in Table IV-4 and IV-5. Federal Register specifications limit the allowable error to 20% of the mean calculated reference method value.

DOE/SOUTHERN COMPANY SERVICES, INC.
INNOVATIVE CLEAN COAL TECHNOLOGY PROJECT
GULF POWER - PLANT LANSING SMITH - UNIT TWO

EQUIPMENT INVENTORY - CEM SYSTEM

SYSTEM	*MANUFACTURER*	*SERIAL NUMBER*	*MODEL*	*RANGE*
KVB-02	Ametex/Thermox	CO68052B-2	FCA-LX	0-25PCT
KVB-SO2	Western Research	90-721AAT2-7629-6	721AT2	0-2500PPM
KVB-NOX	TECO	28345-231	10A/R	0-1000PPM
KVB-THC	Beckman Ind.	1001234	400A	0-100PPM
KVB-CO	Siemens	7HB1L22-1CA13-1BA1	21P	0-300PPM
CABINET	KVB	EN505270		
DATA LOGGER	Kaye 1	0008329	L4PM	NEMA-LINK 4+
DATA LOGGER	Kaye 2	008330	L4PM	NEMA-LINK 4+
DAS	Gateway 200	82922/AG424R	386 PC	
OFFICE	Gateway 200	82921/AG424R	386 PC	
TAPE DRIVE	Irwin	C20020646 DM-21	445	40 MEG.
YOKOGAWA O2	Yokogawa	8076JAO38	AV8G	0-25%
PYROMETERS	S.E.I.	05	31AP	P/N 000455

LOG OF OPERATIONS

KVB SYSTEM S/N 505270

Model and Manufacturer	KVB Model 50 Extractive
Instrument Serial Number	505270 - Cabinet 90-721AT27629-6-SO2 10A/R-28345-231-NOx
Diluent Serial Number	Ametek CO68052B-2
Initial Start-up	10/30/90
Start of Performance Calibration	06/16/91
Start of Calibration Drift Test	06/16/91
End of Calibration Drift Test	06/23/91
Start of Relative Accuracy Test	06/11/91
End of Relative Accuracy Test	06/11/91

TABLE III-1A

PERFORMANCE TEST RESULTS

KVB SYSTEM (S/N 505270)

	Monitor Performance	EPA Specifications
SO2 Instrument Serial Number	90-721AT2-7629-6	
NOx Instrument Serial Number	10 A/R-28345-231	
Diluent Serial Number	CO68052B-2	
Calibration Period	seven (7) consecutive days	seven (7) consecutive days
NOx Analyzer Cal. Drift (Lo pt. 0-20%)	-0.08% largest daily difference (NOx)	less than or equal to 2.5% span per day
SO2 Analyzer Cal. Drift (Lo pt. 0-20%)	0.88% largest daily difference (NOx)	less than or equal to 2.5% span per day
Diluent Oxygen Analyzer (Downscale checkpoint)	0.00% largest daily difference (O2)	less than or equal to 0.5% O2 by volume per dat
SO2 Analyzer Cal. Drift (Hi pt. 50-100%)	0.52% largest daily difference (NOx)	less than or equal to 2.5% span per day
NOx Analyzer Cal. Drift (Hi pt. 50-100%)	-1.00% largest daily difference (NOx)	less than or equal to 2.5% span per day
Diluent Oxygen Analyzer (Upscale checkpoint)	-0.20% largest daily difference (O2)	less than or equal to 0.5% O2 by volume per day
System Relative Accuracy computed in lbs/Mbtu (SO2)	8.95%	less than or equal to 20%
System Relative Accuracy computed in lbs/Mbtu (NOx)	9.00%	less than or equal to 20%

CALIBRATION DRIFT DETERMINATION
DOE/SOUTHERN COMPANY SERVICES, INC.
INNOVATIVE CLEAN COAL TECHNOLOGY PROJECT
GULF POWER COMPANY - PLANT LANSING SMITH UNIT TWO

SYSTEM	KVB	GAS	SO2
MANUFACTURER	WESTERN RESEARCH	SPAN VALUE	2500PPM
MODEL	721-AT	OPERATOR	JW GIBSON
SERIAL NUMBER	90-721AT2-7629-6		

SPAN DRIFT

DAY	DATE	TIME	CALIBRATION VALUE PPM	MONITOR VALUE PPM	DIFFERENCE IN PPM	PERCENT OF SPAN VALUE
START	16-Jun-91	06:21 PM	1500	1498	-2	-0.08%
1	17-Jun-91	07:32 AM	1500	1499	-1	-0.04%
2	18-Jun-91	07:26 AM	1500	1500	0	0.00%
3	19-Jun-91	07:39 AM	1500	1500	0	0.00%
4	20-Jun-91	05:23 AM	1500	1493	-7	-0.28%
5	21-Jun-91	07:59 AM	1500	1499	-1	-0.04%
6	22-Jun-91	08:09 AM	1500	1513	13	0.52%
7	23-Jun-91	06:02 AM	1500	1500	0	0.00%

ZERO DRIFT

DAY	DATE	TIME	CALIBRATION VALUE PPM	MONITOR VALUE PPM	DIFFERENCE IN PPM	PERCENT OF SPAN VALUE
START	16-Jun-91	10:54 PM	0	0	0	0.00%
1	17-Jun-91	07:21 AM	0	17	17	0.68%
2	18-Jun-91	07:15 AM	0	22	22	0.88%
3	19-Jun-91	07:25 AM	0	17	17	0.68%
4	20-Jun-91	05:11 AM	0	20	20	0.80%
5	21-Jun-91	07:47 AM	0	18	18	0.72%
6	22-Jun-91	07:38 AM	0	20	20	0.80%
7	23-Jun-91	05:51 AM	0	22	22	0.88%

%SPAN = ((INSTRUMENT RESPONSE - EXPECTED CONCENTRATION)/SPAN VALUE)*100

CALIBRATION DRIFT DETERMINATION
DOE/SOUTHERN COMPANY SERVICES, INC.
INNOVATIVE CLEAN COAL TECHNOLOGY PROJECT
GULF POWER COMPANY - PLANT LANSING SMITH UNIT TWO

SYSTEM	KVB		
MANUFACTURER	THERMO ENVIRONMENTAL	GAS	NOx
MODEL	10	SPAN VALUE	1000PPM
SERIAL NUMBER	10A/R-28345-231	OPERATOR	JW GIBSON

SPAN DRIFT

DAY	DATE	TIME	CALIBRATION VALUE PPM	MONITOR VALUE PPM	DIFFERENCE IN PPM	PERCENT OF SPAN VALUE
START	16-Jun-91	06:21 PM	762	762	0	0.00%
1	17-Jun-91	07:26 AM	762	763	1	0.10%
2	18-Jun-91	07:32 AM	762	758	-4	-0.40%
3	19-Jun-91	07:39 AM	762	756	-6	-0.60%
4	20-Jun-91	05:23 AM	762	756	-6	-0.60%
5	21-Jun-91	07:59 AM	762	752	-10	-1.00%
6	22-Jun-91	08:09 AM	762	763	1	0.10%
7	23-Jun-91	06:02 AM	762	761	-1	-0.10%

ZERO DRIFT

DAY	DATE	TIME	CALIBRATION VALUE PPM	MONITOR VALUE PPM	DIFFERENCE IN PPM	PERCENT OF SPAN VALUE
START	16-Jun-91	06:21 PM	0	-2	-2	-0.08%
1	17-Jun-91	07:21 AM	0	-2	-2	-0.08%
2	18-Jun-91	07:15 AM	0	-2	-2	-0.08%
3	19-Jun-91	07:25 AM	0	-2	-2	-0.08%
4	20-Jun-91	05:11 AM	0	-2	-2	-0.08%
5	21-Jun-91	07:47 AM	0	-2	-2	-0.08%
6	22-Jun-91	07:38 AM	0	-1	-1	-0.04%
7	23-Jun-91	05:51 AM	0	-2	-2	-0.08%

%SPAN = ((INSTRUMENT RESPONSE-EXPECTED CONCENTRATION)/SPAN VALUE)*100

CALIBRATION DRIFT DETERMINATION
DOE/SOUTHERN COMPANY SERVICES, INC.
INNOVATIVE CLEAN COAL TECHNOLOGY PROJECT
GULF POWER COMPANY - PLANT LANSING SMITH UNIT TWO

SYSTEM	KVB
MANUFACTURER	AMETEK
MODEL	FCA-LX
SERIAL NUMBER	C068052B-2

GAS	02
SPAN VALUE	25PCT
OPERATOR	JW GIBSON

SPAN DRIFT

DAY	DATE	TIME	CALIBRATION VALUE PCT	MONITOR VALUE PCT	DIFFERENCE	TOTAL ERROR
START	16-Jun-91	06:21 PM	20.10	20.10	0.00	0.00%
1	17-Jun-91	07:21 AM	20.10	20.10	0.00	0.00%
2	18-Jun-91	07:15 AM	20.10	20.10	0.00	0.00%
3	19-Jun-91	07:25 AM	20.10	20.00	-0.10	-0.10%
4	20-Jun-91	05:11 AM	20.10	20.00	-0.10	-0.10%
5	21-Jun-91	07:45 AM	20.10	19.90	-0.20	-0.20%
6	22-Jun-91	07:38 AM	20.10	19.90	-0.20	-0.20%
7	23-Jun-91	05:51 AM	20.10	20.10	0.00	0.00%

ZERO DRIFT

DAY	DATE	IME	CALIBRATION VALUE PCT	MONITOR VALUE PCT	DIFFERENCE	TOTAL ERROR
START	16-Jun-91	06:21 PM	0.00	0.00	0.00	0.00%
1	17-Jun-91	07:32 AM	0.00	0.00	0.00	0.00%
2	18-Jun-91	07:26 AM	0.00	0.00	0.00	0.00%
3	19-Jun-91	07:39 AM	0.00	0.00	0.00	0.00%
4	20-Jun-91	05:23 AM	0.00	0.00	0.00	0.00%
5	21-Jun-91	07:59 AM	0.00	0.00	0.00	0.00%
6	22-Jun-91	08:09 AM	0.00	0.00	0.00	0.00%
7	23-Jun-91	06:02 AM	0.00	0.00	0.00	0.00%

MAXIMUM ALLOWANCE ERROR = PLUS OR MINUS 0.5% O2 BY VOLUME

CEM RELATIVE ACCURACY DATA

Relative Accuracy Determination

CEM-DRY RM-DRY

DATE ---- 06/11/91
SOURCE -- G.P.C. SMITH PLANT
UNIT 2
SO2 s/n - 90-721AT2-7629-6
NOx s/n - 10A/R-28345-231
O2 s/n - C068052B-2

SPECTRUM SYSTEMS INC.
3410 W. 9 MILE ROAD
PENSACOLA, FLORIDA 32526-7808
1-904-944-3392

Fd = 9780

Run No.	RUN START TIME	SO2 RM-6 (PPM)	SO2 CEM (PPM)	SO2 DIFF (PPM)	NOx RM-7E (PPM)	NOx CEM (PPM)	NOx DIFF (PPM)	OXYGEN RM-3A (%)	OXYGEN CEM (%)	SO2 RM-6 (Lbs/Mbtu)	SO2 CEM (Lbs/Mbtu)	SO2 DIFF (Lbs/Mbtu)	NOx RM-7E (Lbs/Mbtu)	NOx CEM (Lbs/Mbtu)	NOx DIFF (Lbs/Mbtu)
1	09:18	1692.7	2005.5	312.8	227.9	226.3	-1.6	6.94	6.20	4.1147	4.6291	0.5144	0.3985	0.3757	-0.0228
2	11:03	1733.3	1998.5	265.2	234.7	230.8	-3.9	6.91	6.18	4.2033	4.6054	0.4022	0.4095	0.3826	-0.0269
3	12:12	1706.5	1916.9	210.4	262.4	255.9	-6.5	7.30	6.60	4.2564	4.5468	0.2904	0.4707	0.4365	-0.0342
4	12:51	1730.2	1922.4	192.2	262.9	255.1	-7.8	7.28	6.54	4.3091	4.5432	0.2341	0.4709	0.4336	-0.0372
5	13:31	1711.6	1911.4	199.8	265.1	255.3	-9.8	7.28	6.54	4.2655	4.5157	0.2502	0.4752	0.4339	-0.0413
6	14:06	1723.1	1909.7	186.6	266.2	256.0	-10.1	7.25	6.49	4.2832	4.4969	0.2137	0.4759	0.4337	-0.0422
7	14:40	1728.1	1944.1	216.0	268.8	261.8	-7.0	7.10	6.33	4.2490	4.5271	0.2781	0.4753	0.4384	-0.0369
8	15:17	1718.8	1947.3	228.5	272.0	261.5	-10.5	7.10	6.30	4.2261	4.5256	0.2995	0.4810	0.4371	-0.0439
9	15:56	1714.4	1935.1	220.7	268.4	261.8	-6.6	7.09	6.28	4.2127	4.4900	0.2773	0.4744	0.4369	-0.0375
Average		1717.6	1943.4	225.8	258.7	251.6	-7.1	7.14	6.38	4.2355	4.5422	0.3067	0.4590	0.4232	-0.0359
Confidence Interval												0.0726			0.0054
Accuracy												8.95			9.00

APPENDIX B
Technical Services Activity Report

ASEA BROWN BOVERI

May 31, 1991

Southern Company Services, Inc.
Gulf Power, Lansing Smith, Unit 2
180 MW Low NO_x Demonstration
Technical Services Activity Report

INTRODUCTION

ABB CE Technical Services arrived on site on March 4, 1991, to assist in the Low NO_x retrofit at Lansing Smith Station, Unit 2.

This retrofit consisted of:

(1) Installing four (4) overfire air registers and associated ductwork and equipment.

(2) Refurbishing the main windbox tilt system.

(3) Installing SAFE FLAME I flame scanners and associated scanner cooling system.

(4) Installing a Diamond Electronic Television flame monitor system.

(5) Installing a MOD 30 Control System to control the OFA tilt and damper drives.

All construction was performed by ABB CE Construction Services. All electrical work was performed by R. N. Pyle Contractors, INC.

This report will detail:

(1) Technical Service's function and duties.
(2) The commissioning of the new equipment.
(3) General description of the optimization tests and results of the tests.

ABB Combustion Engineering Services

Combustion Engineering, Inc.
31 Inverness Center Parkway
Post Office Box 43020
Birmingham, Alabama 35243-0020
Telephone (205) 991-2832

Technical Service Responsibilities

During this retrofit, Technical Services was responsible for:

(1) Overseeing the installation of new equipment.

While Technical Services did not instruct Construction Services on the installation of this equipment, it was Technical Services responsibility to "sign off" on the installation of several components of this system. Technical Services worked closely with the pipefitters on the rockwell coupling installation and coal piping alignment, with the boilermakers on the windbox repairs, and installation of the burner corner components (auxiliary air nozzles, belcrank assemblies, coal nozzles, etc.), and with the electricians on installing the TV camera, MOD 30, and the scanner fan control station.

(2) Commissioning the new equipment.

Technical Services commissioned all new equipment. Specifically, this equipment is the MOD 30 control system, flame scanners and scanner air cooling system, main windbox and overfire air windbox tilt drive system, overfire air dampers and damper drives, and TV camera system.

(3) Inspecting the main windbox auxiliary air and fuel air compartments.

As part of the windbox tilt upgrade, it was necessary to thoroughly inspect the fuel air and auxiliary air compartments for any interferences that might prevent the coal or auxiliary air nozzle from tilting. Ron Tenerowicz (Firing Systems - Windsor) led this inspection with Technical Services assisting. Refer to appendix I for the results of this inspection. Furthermore, during the windbox upgrade, it was necessary for Technical Services to closely follow the installation to note for potential interferences.

(4) Coordinating the optimization tests for the new system.

After the boiler had been brought to full load, it was necessary to perform a series of optimization tests to determine the best settings for the secondary air dampers, OFA dampers, OFA and main windbox auxiliary air nozzle yaw position and OFA tilt position. Also, hot air traverses were taken at the OFA annular venturi to assure that the predicted air flow was going to the OFA nozzles. Refer to appendix II for the test results and final damper settings and appendix III for the results of the hot air traverse.

(5) Training the plant personnel on the new equipment.

Technical Services provided classroom training as well as "hands on" training for the plant operators and maintenance workers.

(6) Solving any problems related to the equipment, drawings, etc. .

During this job, Technical Services was required to address any problem related to the new equipment. Furthermore, both Technical Services and Construction Services worked closely with the support groups in Windsor and Chattanooga solving any problems with drawings or job materials.

New Equipment Start Up

The new equipment installed on this job were:

- Six (6) MOD 30 Controllers.
- Four (4) OFA tilt drive electric motors (BECK).
- Four (4) main windbox tilt drive motors (BECK).
- Twelve (12) OFA damper drive motors (Foxboro Jorden).
- One (1) Diamond Electronic furnace TV monitoring system.
- Sixteen (16) Safe Flame I flame scanners.
- One (1) flame scanner air cooling system.

Taylor MOD 30 Controller - Model 1701R

There were six MOD 30 controllers installed during this retrofit. These controllers were provided to control:

- OFA tilt drive motors (one controller).
- OFA damper drive motor (one controller per overfire air elevation, total of three controllers).
- Main windbox overfire air damper drive motors (one controller per elevation, total of two controllers).

These controllers can be operated in manual or automatic mode. In the automatic mode, the OFA damper drive controllers receives a Main Steam Flow signal from the the plant logic system (Westinghouse). The OFA tilt drive controller receives a feedback signal from the main tilt drive motor (right front corner) through the plant logic system.

The commissioning process was simplified because this system was assembled and "debugged" in the shop. The MOD 30 controllers were installed and hardwired to terminal blocks in a NEMA 12 cabinet. This cabinet was mounted inside the control room and the electricians wired to the other side of the terminal blocks. After all the wiring was checked out, Technical Services powered the system and put the controllers through the diagnostic tests provided in the software.

After the optimization tests were complete, it was necessary to "customize" the input/output signal such that (in automatic operation) the desired OFA damper and tilt position would correspond to a particular steam flow or main tilt position.

In order to do this, it was necessary to change the input/output parameters in the Linearzation Block (piecewise table) of the software program. The default program had a one to one ratio for input/output (i.e. 10% input, 10% output, etc.). Listed below are the customized input/output parameters for the OFA damper drive controllers and OFA tilt drive controller. Refer to figures 1 and 2 for the damper position vs. load curve and damper position vs. steam flow signal. Note that there was a +/- 7 degree bias programmed for the OFA tilt drives, i.e. the OFA tilt drives do not tilt lower/higher than +/-7 degrees.

Damper Drive Controllers

Lower Elevation		Middle Elevation		Upper Elevation	
Input (%)	Output (%)	Input (%)	Output (%)	Input (%)	Output (%)
					0
30.0	0	37.0	0	57.0	11
31.1	11	39.6	11	59.7	22
32.2	22	42.2	22	62.4	33
33.3	33	44.8	33	65.1	44
34.4	44	47.4	44	67.8	55
35.5	55	50.0	55	70.5	66
36.6	66	52.6	66	73.2	77
37.7	77	55.2	77	75.9	88
38.8	88	57.8	88	78.6	99
40.0	100	60.0	100	82.0	100

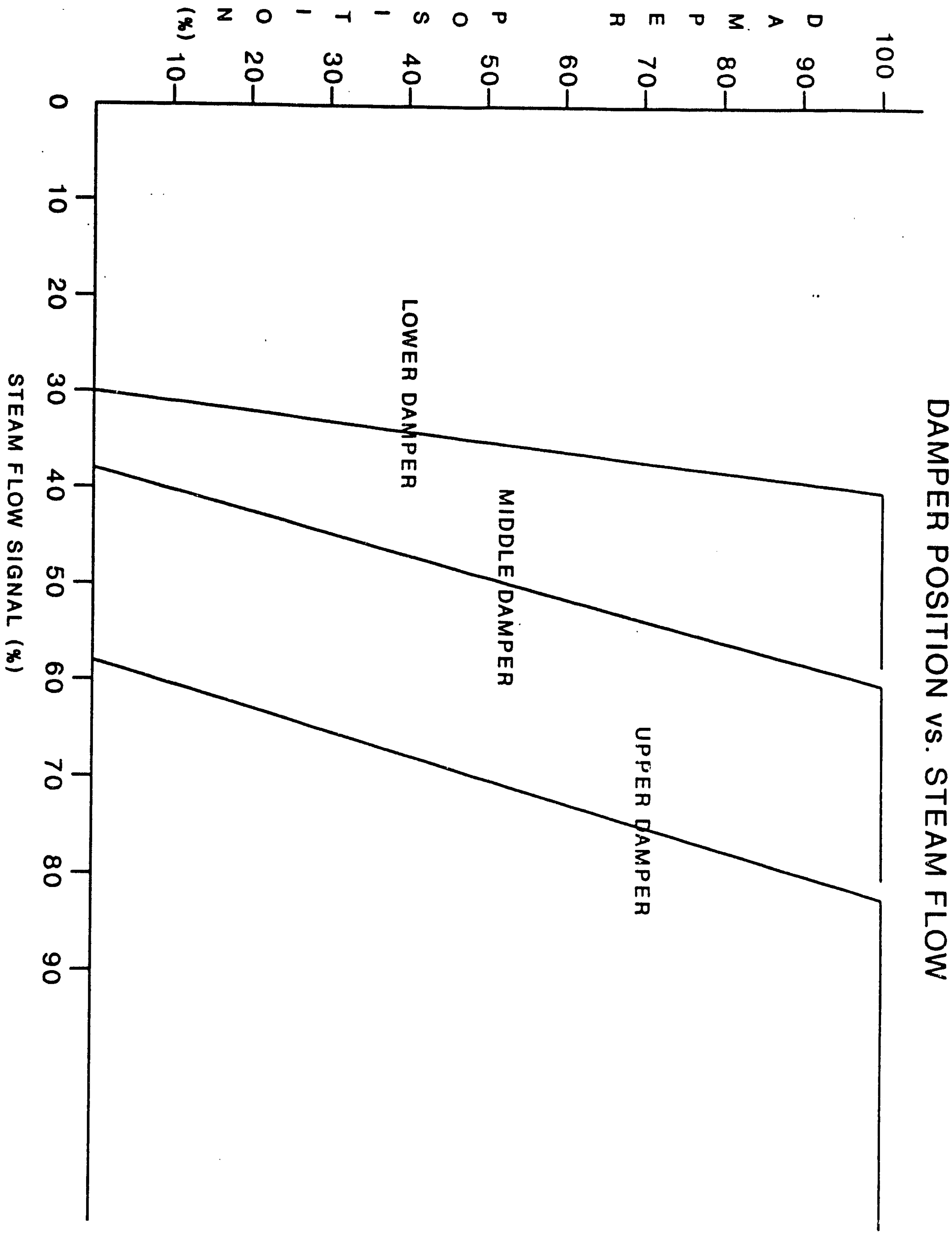

DAMPER POSITION vs. STEAM FLOW
DAMPER POSITION (%)
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
LOWER DAMPER
MIDDLE DAMPER
UPPER DAMPER
STEAM FLOW SIGNAL (%)

FIGURE 1

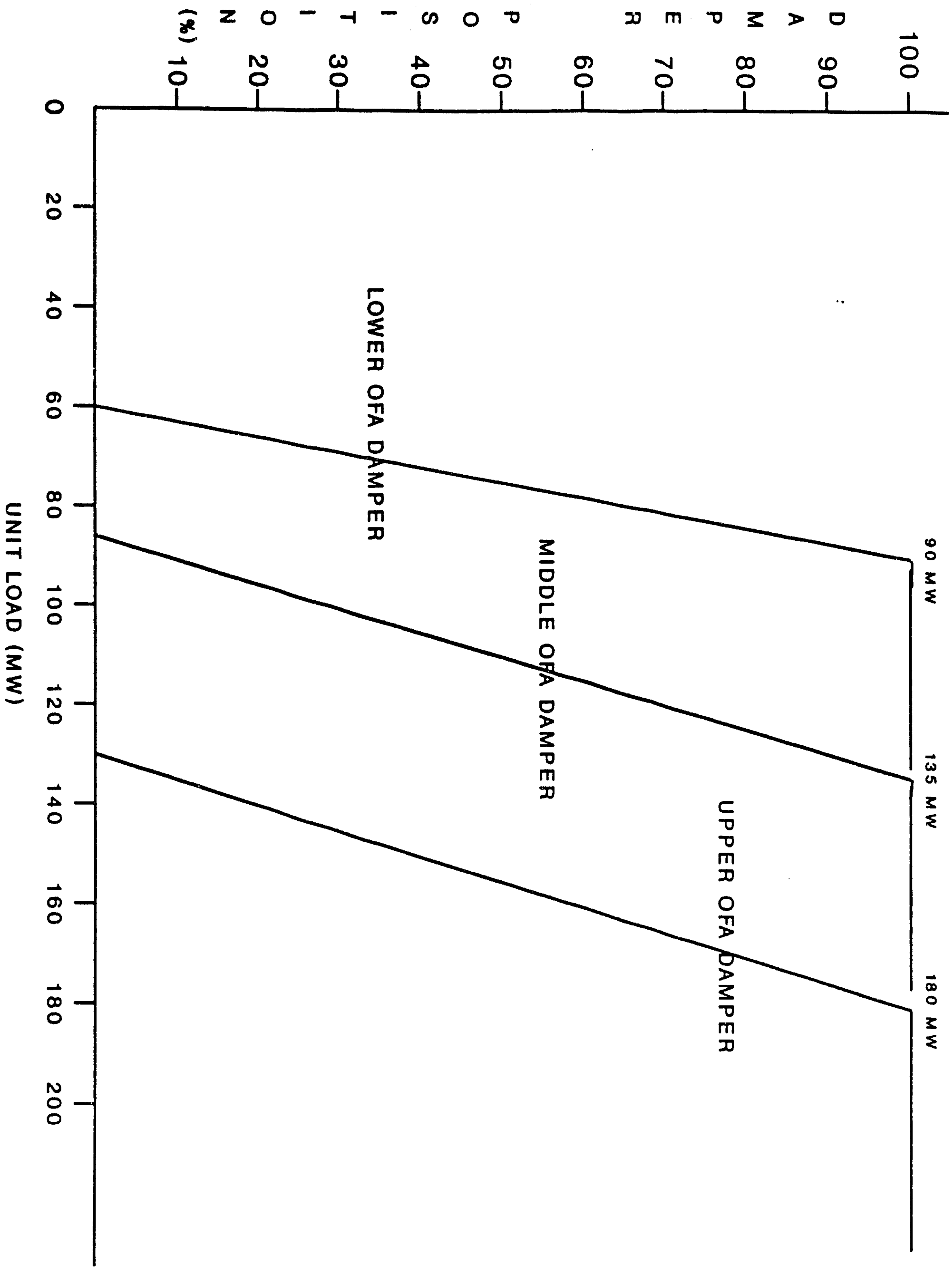

DAMPER POSITION (%)
100
90
80
70
60
50
40
30
20
10
0
20
40
60
80
100
120
140
160
180
200
UNIT LOAD (MW)
LOWER OFA DAMPER
MIDDLE OFA DAMPER
UPPER OFA DAMPER
90 MW
135 MW
180 MW

FIGURE 2

OFA Tilt Drive Controller

Input (%)	Output (%)
0	37.5
12.5	40.6
25.0	43.8
37.5	46.9
50.0	50.0
62.5	53.1
75.0	56.3
87.5	59.4
100.0	62.5

<u>Main Windbox and OFA Tilt Drive Motors</u>
(BECK models 11-408-1800-60, and 11-408-0550-40)

To commission the tilt drive motors, it was necessary to:

- check for correct rotation (CW of CCW) for each corner.
- check foundation bolts for a secure fit.
- attach the linkage from the motor drive arm to the belcrank assembly.
- adjust the linkage arm to produce a 60 degree nozzle stroke (+/- 30 degrees) from the 100 degree (+/- 50 degrees) motor drive arm stroke. The motor limit switches were adjusted at the factory to a 100 degree stroke.
- check tilt operation for smooth stroke.

As stated earlier, the OFA tilt drive is (intentionally) limited (in the MOD 30) to a +/-7 degree stroke. This stroke will track the main windbox tilt position.

<u>OFA Damper Drive Motors</u>
(Foxboro Jorden model SM-1710)

The damper drive motors were shipped with the limit switch set at a stroke settings of 0 degrees and 90 degrees. During the commissioning, it was necessary to:

- check for proper shaft rotation per increasing input signal.
- check the damper drive mount for a secure foundation.
- adjust the damper position with the damper drive and couple the damper drive to the damper shaft. Note that the damper shaft was positioned such that the damper drive limit switch would activate before the

damper was completely opened or closed. This would prevent stalling the motor when the damper was completely closed.

Diamond Electronic TV Monitoring System

As part of this retrofit, an additional TV camera was installed.

A cooling system was installed to provide filtered (60 psi to 70 psi) station air to the High Temperature Housing and (6 psi to 15 psi) air to the lens tube. Because of problems with high temperature alarms (>110 F) in the camera housing, it was necessary to insulate the air line to the High Temperature Housing. This insulation was installed to keep the air inlet temperature (to the DEMON III vortex cooler) below 90 F. If the temperature exceeds 110 F at full load operation during the summer, it may be necessary reroute the cooling air lines.

Commissioning the TV camera consisted of:

- mounting the lenstube and High Temperature Housing in the wallbox.
- Connecting all cooling air hoses and adjusting the air pressure to the lenstube at 7 psi (6 psi to 10 psi recommended), and air pressure at 65 psi to the High Temperature Housing.
- Focusing and aligning the TV camera by shimming at the support bolts.

During startup there were problems with flyash pitting and depositing on the lenstube nose cone. Note that lenstube air pressure settings were as recommended in the manual. Technical Services consulted Diamond Electronic and decided that it was necessary that Diamond Electronic visit the station to determine the problem and solution. This problem is pending and the camera system is not operational at this time.

Post Outage Optimization Tests

After the unit was brought to full load (200 MW), all new systems were operated to assure proper operation. It was noted that the main windbox tilts stroked freely +/-30 degrees, all OFA damper drives moved freely, all scanners operated per design, and all auxiliary air and OFA air nozzle Yaw adjustment could operated.

As part of this retrofit, it was necessary to perform tests at several loads with different damper, yaw and tilt position. Specifically, tests were performed at 200, 180, 135, 115 & 80 megawatts with different main windbox and OFA yaw positions. Using Southern Company Services emission testing equipment, Technical Services/Firing Systems-Windsor was able to obtain the following final emissions data:

Unit Load:	200 MW
% O2 :	5.1 %
CO :	8.4 ppm
NOx (UC) :	224 ppm
NOx (C) :	254 ppm
NOx (C) :	0.343 lb/MBtu

This represents approximately a 40% reduction in NOx with the CO level under the guaranteed limit of 50 ppm. Note that flyash samples were taken from the economizer outlet and visually examined for carbon in the flyash. No samples were taken for carbon loss as the sampling method available is not an accurate method.

The final main windbox and OFA yaw positions are:

Main Windbox (all corners & elevations): 15 degrees right.

OFA Windbox - RF corner,	Top elev.	:	15 degrees right.
	Middle elev.	:	0 degrees.
	Lower elev.	:	15 degrees left.
- RR corner,	All elev.	:	15 degrees right.
- LF corner,	Top elev.	:	15 degrees left.
	Middle elev.	:	0 degrees.
	Lower elev.	:	15 degrees right.
- LR corner,	Top elev.	:	15 degrees right.
	Middle elev.	:	0 degrees.
	Lower elev.	:	15 degrees left.

The final OFA tilt position full load is 0 degrees.

Refer to the board data for additional data (appendix II).

As part of the optimization tests, a hot air traverse was performed at the OFA annular venturi to check total air flow through the OFA duct. At 180 MW, with the OFA damper position at 100%, 100%, 40%, the total air flow through the OFA duct to be 302,937 lb/hr. The percent error between the measured air flow and calculated air flow is approximately 2%. Refer to appendix III for the results of this test.

APPENDIX I

WINDBOX COMPARTMENT INSPECTION

R.H.R. D.E. Burner Corner 4/2/91
Repair Recom.

1. REPLACE FRONT I SECTION ON LEFT (SEE SK. 1)
2. GRIND TUBE FRAME BAR FLUSH (~~Bo...~~
3. TRIM CROTCH PLATE AWAY FROM COOLING
AIR COMPARTMENT
4. REPLACE PART. PL BACK 20" AT "C" ELEV.
5. FINISH REMOVING SLAG & REFRACTORY

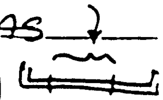
R.H.F.

1. TRIM CROTCH PLATES IN COOLING AIR COMPT.
2. GRIND TUBE FRAME BAR (BOT COMPT.)
3 REMOVE RAMP PLATE (CD ELEV,
4 REPLACE PARTITION PL -16" BACK ~~Above~~ Bottom BE
5 FINISH REMOVING SLAG & REFRACTORY

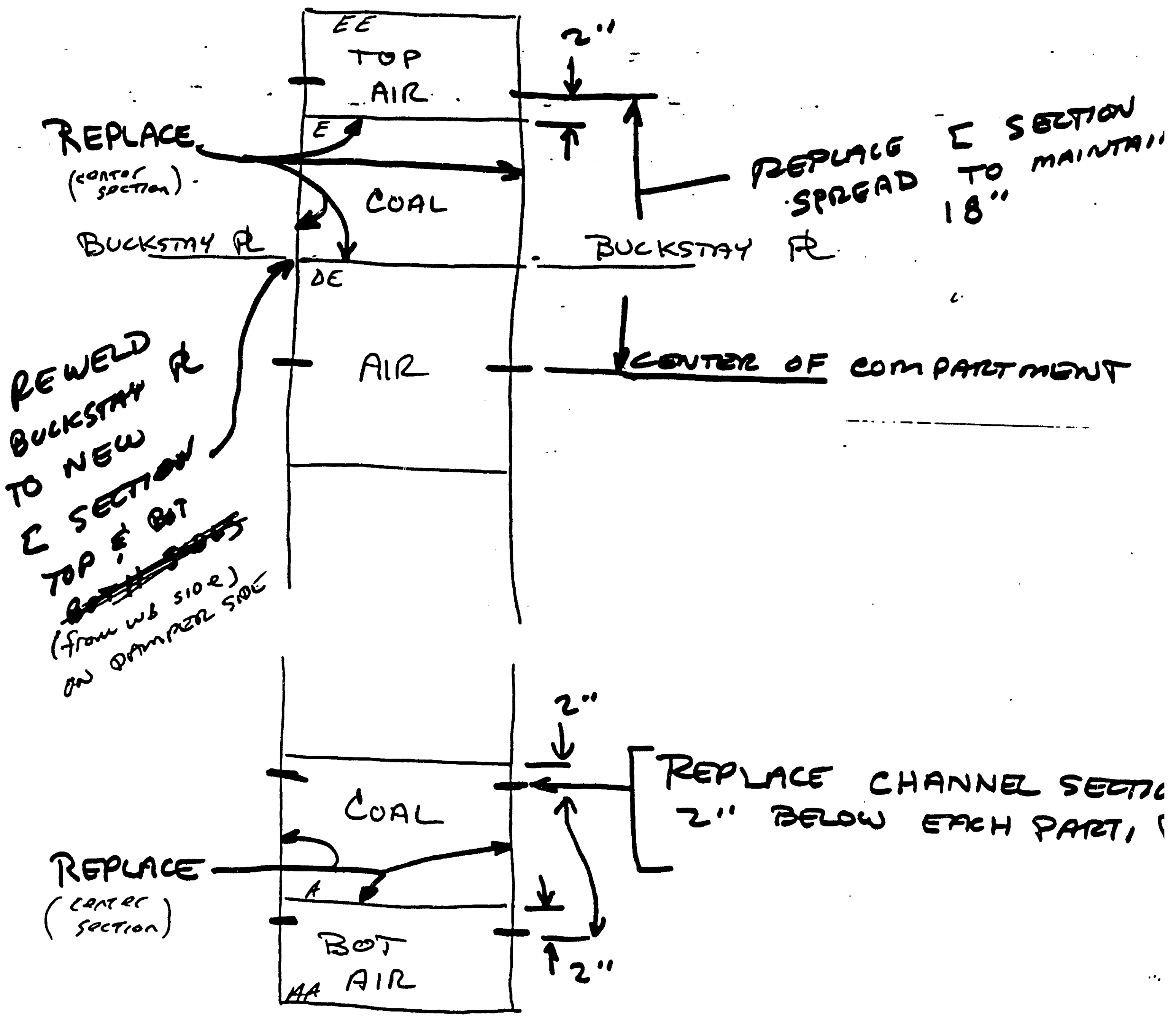
L.H.F.

1. TRIM CROTCH PLATE IN COOLING AIR COMPT.
TOP & BOTTOM
2. FINISH REMOVING SLAG & REFRACTORY

L.H.R.

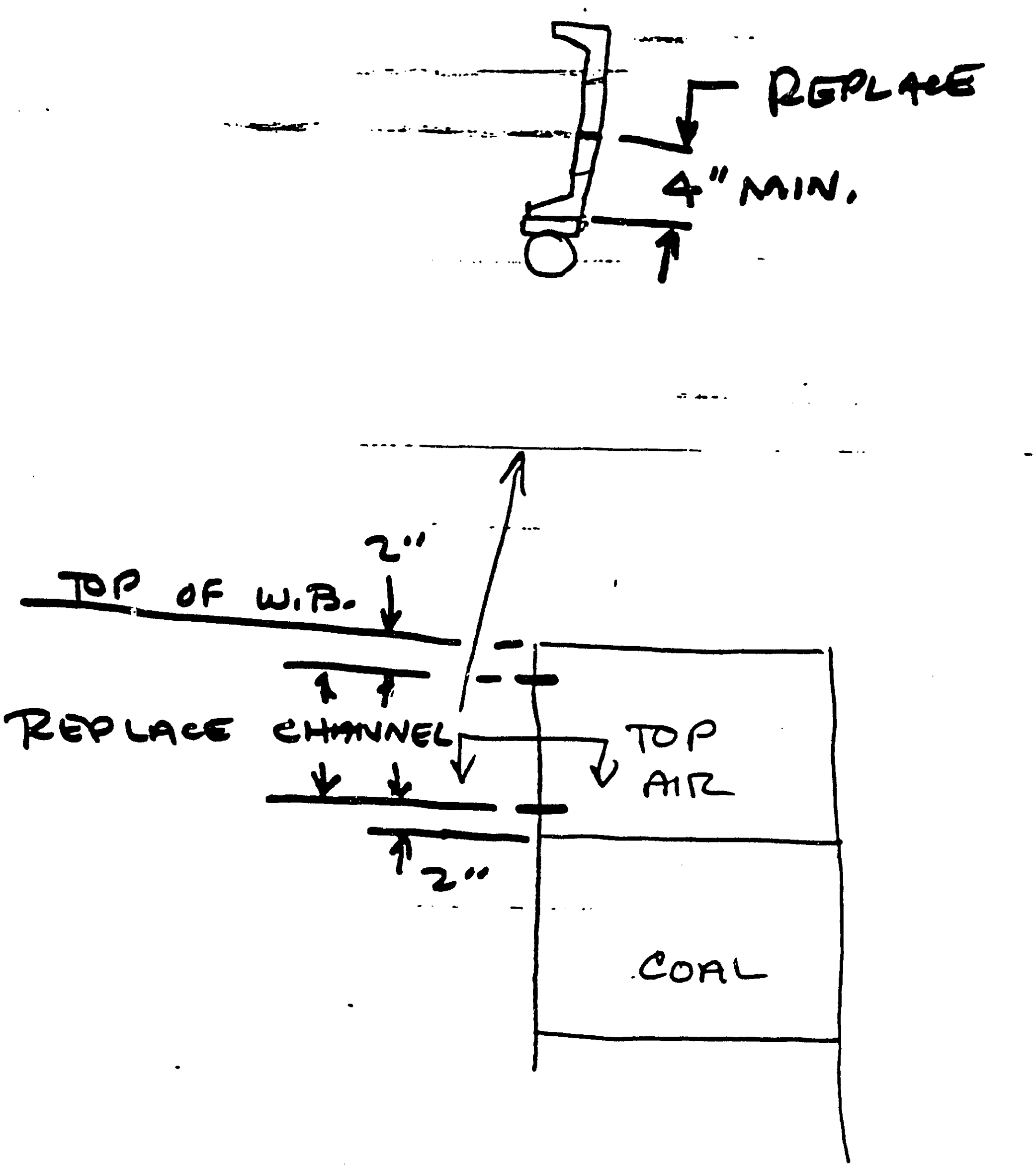
1. REMOVE PART. PL'S & CHANNEL SECTIONS AS
SHOWN IN SKETCH NO. 2 (REMOVE THE LEAST AMT. POSSIBLE - CENTER OF CHANNEL)

2. TRIM CROTCH PLATES
3. FINISH REMOVING SLAG & REFRACTORY
4 SPREAD CHANNELS IN UPPER SECTION AS SHOWN IN SK. 2
5. GRIND TUBE FRAME BAR

L.H.R.



SKETCH NO. 2

R.H.R.



SKETCH NO. 1

APPENDIX II

OPTIMIZATION TEST BOARD DATA

LANSING SMITH UNIT 2
LOW NOx DEMONSTRATION
OPTIMIZATION TEST

TEST NO. DATE TIME		1A 4/23/91 11:30	1B 4/23/91 16:40	2A 4/24/91 14:10
LOAD	MW	200	200	180
THROTTLE PRESSURE	LB/IN2	1800	1804	1800
ECON (FW) IN TEMP	F	478	479	466
ECON OUT TEMP	F	NA	NA	NA
SH OUT TEMP	F	1000/1000	1001/997	1000/997
SH DESH IN TEMP	F	828/810	908/910	870/910
SH DESH OUT TEMP	F	796	808/818	815/825
RH OUT TEMP	F	1002	1004	988
RH DESH IN TEMP	F		711	700
RH DESH OUT TEMP	F	678/688	685	690
O2 (BOARD)	%	4.4	4.4	NA
TOTAL AIR FLOW	%	88	88	83
TILT POS	DEG	0	0	0
ELEV. IN SERVICE	---	5	5	5
WINDBOX/FURN dP	"H2O	6	5.5	5
WINDBOX PRESSURE	"H2O	5.5	5	4.5
FURNACE PRESSURE	"H2O	-0.5	-0.5	-0.5
TOTAL FUEL FIRED	KLB/HR	149.4	151.5	135.5
FLOWS				
FEEDWATER	KLB/HR	1368	1333	1210
MAIN STEAM	KLB/HR	1479	1478	1320
FW MAKEUP	LB/MIN	120	70	45
SH DESH SPRAY	KLB/HR	79	93	58
RH DESH SPRAY	KLB/HR	9	11.4	3

PRESSURES				
ECON IN PRESS	LB/IN2	NA	2100	NA
STEAM DRUM	LB/IN2	2088	2091	2035
SH OUT	LB/IN2	1803	1800	1820
RH IN (COLD RH @ TURB)	LB/IN2	697	549	482
RH OUT (HOT RH @ TURB)	LB/IN2	982	522	458
SH SPRAY VALVE POS.	%	47.8	72.2	48.6/34.5
RH SPRAY VALVE POS.	%	4.1	1.6	0.4
APH TEMPERATURES				
GAS IN	F	657/654	665/661	649/646
GAS OUT	F	317/312	318/313	316/310
AIR IN	F	139/158	138/157	140/160
AIR OUT	F	560/549	566/555	556/545
AMBIANT AIR TEMP	F	81	80	84
PULVERIZER DATA				
MILL OUT TEMPS				
A	F	149	150	150
B	F	150	150	151
C	F	149	150	150
D	F	148	149	150
E	F	149	150	151
MILL LOADING				
A	KLB/HR	35	29	27.3
B	KLB/HR	38	32	29.9
C	KLB/HR	35	28.8	26.8
D	KLB/HR	37	29.5	28.4
E	KLB/HR	31	30.2	28
MILL POWER				
A	AMPS	32	35	35
B	AMPS	32	37	34.5
C	AMPS	31	36	34.5
D	AMPS	32	36	34.5
E	AMPS	27	35	33

BOWL dP				
A	"H2O	8.3	8.3	8.5
B	"H2O	8.5	8.3	8.6
C	"H2O	7.6	7.5	7.6
D	"H2O	5.4	5.2	5
E	"H2O	7.6	7.6	7.6
MILL IN TEMPS				
A	F	NA	NA	NA
B	F	NA	NA	NA
C	F	NA	NA	NA
D	F	NA	NA	NA
E	F	NA	NA	NA
HOT AIR DAMPER POS (PRIMARY AIR)				
A	%	100	100	85.5
B	%	100	100	98
C	%	90	90	98.4
D	%	100	100	98.4
E	%	100	100	94.9
COLD AIR DAMPER POS (TEMPERING AIR)				
A	%	70	70	60
B	%	80	80	68
C	%	70	70	60
D	%	70	70	70
E	%	80	65	56
MILL AIR FLOW				
A	LB/HR	NA	NA	NA
B	LB/HR	NA	NA	NA
C	LB/HR	NA	NA	NA
D	LB/HR	NA	NA	NA
E	LB/HR	NA	NA	NA
MILL CLASSIFIER POSITION				
A		3-1/3 to 3-2/3	|	|
B		3-1/3 to 4	Same as	Same as
C		3-2/3	test 1a	test 1a
D		3-1/3 to 3-2/3	|	|
E		3-1/3 to 3-2/3	|	|

MILL EXH/FURN dP				
A	"H2O	15	15.9	15
B	"H2O	15	15.5	15
C	"H2O	15	15.7	15
D	"H2O	15	16	14.8
E	"H2O	13	12.9	13
COAL FINENESS				
A % ON 50	%	2.2		
A % THRU 100	%	87.1		
A % THRU 200	%	68.4		
B % ON 50	%	2		
B % THRU 100	%	87		
B % THRU 200	%	66.4		
C % ON 50	%	1	Same as	Same as
C % THRU 100	%	92.4	test 1a	test 1a
C % THRU 200	%	75.6		
D % ON 50	%	1.6		
D % THRU 100	%	89.4		
D % THRU 200	%	71.6		
E % ON 50	%	2		
E % THRU 100	%	89		
E % THRU 200	%	72.4		
FD FAN DATA				
DAMPER POS	%	100	100	100
FAN SPEED	RPM	909/955	904/935	881/883
OUTLET PRESS	"H2O	12	12	NA
AMPS			110	100/100
ID FAN DATA				
INLET VANE POS	%	66/72	65/72	58/64
OUT VANE POS	%	100/100	100/100	100/100
IN PRESS	"H2O	-18/18	-18/17	-14
OUTLET PRESS	LB/IN2	NA	NA	NA
AMPS		NA	NA	NA
BFP MOTOR SPEED	RPM	3369	3358/3361	3236/3242
BFP AMPS		320	300	280

SECONDARY AIR/ FUEL AIR DAMPER POSITION				
EE	%	100	100	100
E	%	56	55	30
DE	%	30	32	30
D	%	56	54	30
CD	%	34	32	30
C	%	58	54	30
BC	%	30	30	30
B	%	56	54	30
AB	%	30	32	30
A	%	56	56	30
AA	%	34	32	30
OFA DAMPER POS				
UPPER	%	0	60	40
CENTER	%	100	100	100
LOWER	%	100	100	100
MAIN STM FLOW INPUT SIGNAL (for OFA dmpr bias)	%	92.4	92.1	82.5
OFA TILT POS	DEG	0	0	0
OFA YAW POS (T,M,B)				
RF	DEG	0	15L	15L,0,15R
RR	DEG	0	8L	15L
LF	DEG	0	8L	8L
LR	DEG	0	10L	8L
AUX AIR YAW POS				
RF	DEG	+7	15R	15R
RR	DEG	+7	15R	15R
LF	DEG	+7	15R	15R
LR	DEG	+7	15R	15R
MAIN TILT INPUT SIGNAL (for OFA tilt bias)	%	50	50	50

GAS DATA (local)				
O2	%	5.8	5.4	6.9
CO	PPM	9	52	18
NOx (UC)	PPM	235	225	231
NOx (CORR)	PPM	278	260	295
NOx (CORR)	LB/MBTU	0.376	0.351	0.399
SO2 (UC)	PPM		2090	1894
THC	%	NA	63.8	NA
FURNACE CONDITIONS	—	good	NA	bright
IGNITIONS POINTS				
RF CORNER	FT	2	2	2
RR CORNER	FT	3	3	3
LR CORNER	FT	3	2	2
LF CORNER	FT	2	2	3

TEST NO.		2B	2C	3A
DATE		4/24/91	4/25/91	4/25/91
TIME		16:35	7:00	14:45
LOAD	MW	180	182	183
THROTTLE PRESSURE	LB/IN2	1800	1808	1800
ECON (FW) IN TEMP	F	467	467	NA
ECON OUT TEMP	F	NA	NA	NA
SH OUT TEMP	F	1000/1000	1000/990	1001/1000
SH DESH IN TEMP	F	900/920	835/875	837/864
SH DESH OUT TEMP	F	806/823	829/830	839/826
RH OUT TEMP	F	1005	965	973
RH DESH IN TEMP	F	700	695	701
RH DESH OUT TEMP	F	695	690	681/685
O2 (BOARD)	%	4.5	4.6/5.1	3.8/4.2
TOTAL AIR FLOW	%	81	80	79
TILT POS	DEG	+1	0	0
ELEV. IN SERVICE	---	5	5	5
WINDBOX/FURN dP	"H2O	5	6	5.3
WINDBOX PRESSURE	"H2O	4.5	5.5	4.8
FURNACE PRESSURE	"H2O	-0.5	-0.5	-0.5
TOTAL FUEL FIRED	KLB/HR	134.1	139.1	138.2
FLOWS				
FEEDWATER	KLB/HR	1183	1289	1296
MAIN STEAM	KLB/HR	1300	1357	1357
FW MAKEUP	LB/MIN	35	0	80
SH DESH SPRAY	KLB/HR	77.6	26.5	25.4
RH DESH SPRAY	KLB/HR	26.5	2.7	2.7

PRESSURES				
ECON IN PRESS	LB/IN2	NA	NA	NA
STEAM DRUM	LB/IN2	2032	2075	2075
SH OUT	LB/IN2	1800	1850	1830
RH IN (COLD RH @ TURB)	LB/IN2	481	489	493
RH OUT (HOT RH @ TURB)	LB/IN2	456	465	468
SH SPRAY VALVE POS.	%	60.0/55.5	0.8/22.4	1.2/20
RH SPRAY VALVE POS.	%	0.4	0.4	0.4
APH TEMPERATURES				
GAS IN	F	654/650	619/616	637/633
GAS OUT	F	318/311	294/288	302/295
AIR IN	F	140/159	125/146	128/148
AIR OUT	F	562/550	525/616	544/532
AMBIANT AIR TEMP	F	82	66	69
PULVERIZER DATA				
MILL OUT TEMPS				
A	F	151	152	150
B	F	150	151	150
C	F	150	152	150
D	F	151	150	149
E	F	150	151	150
MILL LOADING				
A	KLB/HR	26.5	27.6	28.8
B	KLB/HR	29	27.7	28.4
C	KLB/HR	25.6	26.4	27.2
D	KLB/HR	27.3	27.9	28.8
E	KLB/HR	26.8	27.7	28
MILL POWER				
A	AMPS	35	33.5	35
B	AMPS	34	32	34
C	AMPS	34	34.5	34.5
D	AMPS	34.5	35	35.5
E	AMPS	32.5	34.5	32.5

BOWL dP				
A	"H2O	8.4	8.7	8.4
B	"H2O	8.3	9	8.6
C	"H2O	7.5	7.8	7.6
D	"H2O	4.8	5.6	5.1
E	"H2O	7.4	8	8
MILL IN TEMPS				
A	F	NA	NA	NA
B	F	NA	NA	NA
C	F	NA	NA	NA
D	F	NA	NA	NA
E	F	NA	NA	NA
HOT AIR DAMPER POS (PRIMARY AIR)				
A	%	85	85	85
B	%	100	100	100
C	%	90	90	91
D	%	100	100	100
E	%	100	98	97
COLD AIR DAMPER POS (TEMPERING AIR)				
A	%	62	62	71
B	%	66	72	74
C	%	62	75	70
D	%	50	74	74
E	%	55	65	62
MILL AIR FLOW				
A	LB/HR	NA	NA	NA
B	LB/HR	NA	NA	NA
C	LB/HR	NA	NA	NA
D	LB/HR	NA	NA	NA
E	LB/HR	NA	NA	NA
MILL CLASSIFIER POSITION				
A		|	|	|
B		Same as	Same as	Same as
C		test 1a	test 1a	test 1a
D		|	|	|
E		|	|	|

MILL EXH/FURN dP				
A	"H2O	15	16	14.8
B	"H2O	16	16	14.6
C	"H2O	15	15.4	14.6
D	"H2O	14	16.5	16.2
E	"H2O	13	13.3	12.2
COAL FINENESS				
A % ON 50	%			
A % THRU 100	%			
A % THRU 200	%			
B % ON 50	%			
B % THRU 100	%			
B % THRU 200	%			
C % ON 50	%	Same as	Same as	Same as
C % THRU 100	%	test 1a	test 1a	test 1a
C % THRU 200	%			
D % ON 50	%			
D % THRU 100	%			
D % THRU 200	%			
E % ON 50	%			
E % THRU 100	%			
E % THRU 200	%			
FD FAN DATA				
DAMPER POS	%	100/100	100/100	100/100
FAN SPEED	RPM	858/846	890/877	842/830
OUTLET PRESS	"H2O	10	11.5	10
AMPS		100	105	100
ID FAN DATA				
INLET VANE POS	%	56/61	55/62	52/58
OUT VANE POS	%	100/78	100/98	100/98
IN PRESS	"H2O	-16/16	-16.5/16	-16
OUTLET PRESS	LB/IN2	NA	NA	NA
AMPS		NA	245/255	230/250
BFP MOTOR SPEED	RPM	3228	3280	3275
BFP AMPS		275	285/280	290/285

SECONDARY AIR/ FUEL AIR DAMPER POSITION				
EE	%	100	37	30
E	%	30	68	20
DE	%	30	35	30
D	%	30	69	22
CD	%	30	35	29
C	%	30	68	22
BC	%	30	35	22
B	%	30	69	26
AB	%	30	35	30
A	%	30	69	20
AA	%	30	36	30
OFA DAMPER POS				
UPPER	%	100	0	100
CENTER	%	100	0	100
LOWER	%	100	0	100
MAIN STM FLOW INPUT SIGNAL (for OFA dmpr bias)	%	81.7	84.5	85
OFA TILT POS	DEG	0	0	0
OFA YAW POS (T,M,B)				
RF	DEG	15L,0,15R	15L,0,15R	15L,0,15R
RR	DEG	15L	15L	15L
LF	DEG	8L	8L	8L
LR	DEG	8L	8L	8L
AUX AIR YAW POS				
RF	DEG	15R	15R	15R
RR	DEG	15R	15R	15R
LF	DEG	15R	15R	15R
LR	DEG	15R	15R	15R
MAIN TILT INPUT SIGNAL (for OFA tilt bias)	%	50	47.8	47.8

GAS DATA (local)				
O2	%	6.5	6.6	4.2
CO	PPM	9	8.8	9
NOx (UC)	PPM	230	NA	NA
NOx (CORR)	PPM	286	376	239
NOx (CORR)	LB/MBTU	0.386	0.508	0.323
SO2 (UC)	PPM	2004	2420	2238
THC	%			
FURNACE CONDITIONS	—	NA	good	good
IGNITIONS POINTS				
RF CORNER	FT	2	2	2
RR CORNER	FT	1.5	2	2
LR CORNER	FT	1	2	2
LF CORNER	FT	2	2	2

TEST NO.		4A	5A	6A
DATE		4/26/91	4/27/91	4/27/91
TIME		~21:30	~2:30	~5:00
LOAD	MW	135	115	80
THROTTLE PRESSURE	LB/IN2	1800	1800	1800
ECON (FW) IN TEMP	F	436	418	387
ECON OUT TEMP	F	NA	NA	NA
SH OUT TEMP	F	999/1005	981	1010
SH DESH IN TEMP	F	855/884	846/864	848/884
SH DESH OUT TEMP	F	764/759		750/779
RH OUT TEMP	F	969	929	935
RH DESH IN TEMP	F	646	632	NA
RH DESH OUT TEMP	F	627	604/596	NA
O2 (BOARD)	%	4.35	5.1	6.9
TOTAL AIR FLOW	%	60	54	46
TILT POS	DEG	+30	+30	+27
ELEV. IN SERVICE	---	4	3	2
WINDBOX/FURN dP	"H2O	4.5	4.5	4.5
WINDBOX PRESSURE	"H2O	4	4	4
FURNACE PRESSURE	"H2O	-0.5	-0.5	-0.5
TOTAL FUEL FIRED	KLB/HR	102.6	85.8	70.1
FLOWS				
FEEDWATER	KLB/HR	837.7	707.5	486.8
MAIN STEAM	KLB/HR	945.6	780	557.9
FW MAKEUP	LB/MIN	37	89	46
SH DESH SPRAY	KLB/HR	61.6	34	22
RH DESH SPRAY	KLB/HR	2.9	3	3

PRESSURES				
ECON IN PRESS	LB/IN2	NA	NA	NA
STEAM DRUM	LB/IN2	1934	1899	1860
SH OUT	LB/IN2	1800	1800	1800
RH IN (COLD RH @ TURB)	LB/IN2	629	606	583/587
RH OUT (HOT RH @ TURB)	LB/IN2	968	930/935	927/932
SH SPRAY VALVE POS.	%	98/76	38/40	47.8/42.7
RH SPRAY VALVE POS.	%	0/0.4	0/0.4	0/0.8
APH TEMPERATURES				
GAS IN	F	572/577	574/568	539/543
GAS OUT	F	271/279	277/262	258/265
AIR IN	F	147/126	146/126	143/123
AIR OUT	F	495/503	494/499	479/483
AMBIANT AIR TEMP	F	69	69	69
PULVERIZER DATA				
MILL OUT TEMPS				
A	F	NA	NA	NA
B	F	149	NA	NA
C	F	149	145	NA
D	F	146	145	142
E	F	147	145	145
MILL LOADING				
A	KLB/HR	0	0	0
B	KLB/HR	30	0	0
C	KLB/HR	29.9	30	0
D	KLB/HR	29.9	30	36
E	KLB/HR	30	30	36
MILL POWER				
A	AMPS	0	0	0
B	AMPS	33	0	0
C	AMPS	34	35	0
D	AMPS	33	34	37
E	AMPS	32	31	29

BOWL dP				
A	"H2O	0	0	0
B	"H2O	8.4	0	0
C	"H2O	7.6	7.4	0
D	"H2O	4.6	4.6	4.6
E	"H2O	7.6	7.6	7.2
MILL IN TEMPS				
A	F	NA	NA	NA
B	F	NA	NA	NA
C	F	NA	NA	NA
D	F	NA	NA	NA
E	F	NA	NA	NA
HOT AIR DAMPER POS (PRIMARY AIR)				
A	%	5	4	10
B	%	84	7	10
C	%	86	85	5
D	%	80	87	86
E	%	88	90	90
COLD AIR DAMPER POS (TEMPERING AIR)				
A	%	4	3	3
B	%	67	0	0
C	%	64	65	0
D	%	64	67	84
E	%	60	60	73
MILL AIR FLOW				
A	LB/HR	NA	NA	NA
B	LB/HR	NA	NA	NA
C	LB/HR	NA	NA	NA
D	LB/HR	NA	NA	NA
E	LB/HR	NA	NA	NA
MILL CLASSIFIER POSITION				
A		|	|	|
B		Same as	Same as	Same as
C		test 1a	test 1a	test 1a
D		|	|	|
E		|	|	|

MILL EXH/FURN dP				
A	"H2O	0	0	0
B	"H2O	15	0	0
C	"H2O	14.4	14.7	0
D	"H2O	14.6	14.8	NA
E	"H2O	12	12	NA
COAL FINENESS				
A % ON 50	%			
A % THRU 100	%			
A % THRU 200	%			
B % ON 50	%			
B % THRU 100	%			
B % THRU 200	%			
C % ON 50	%	Same as	Same as	Same as
C % THRU 100	%	test 1a	test 1a	test 1a
C % THRU 200	%			
D % ON 50	%			
D % THRU 100	%			
D % THRU 200	%			
E % ON 50	%			
E % THRU 100	%			
E % THRU 200	%			
FD FAN DATA				
DAMPER POS	%	100/100	100/100	100/100
FAN SPEED	RPM	658/641	600/593	560/549
OUTLET PRESS	"H2O	7/7	7/7	6.5/6.5
AMPS		65/65	60/60	55/55
ID FAN DATA				
INLET VANE POS	%	40/46	35/42	28/36
OUT VANE POS	%	91/98	91/98	91/98
IN PRESS	"H2O	-10.5	-9.5	-12.5
OUTLET PRESS	LB/IN2	NA	NA	NA
AMPS		150/160	145/150	130/150
BFP MOTOR SPEED	RPM	2996	2920	2820
BFP AMPS		220/215	200/200	175/175

SECONDARY AIR/ FUEL AIR DAMPER POSITION				
EE	%	20	20	27
E	%	18	5	0
DE	%	11	18	0
D	%	20	9	0
CD	%	10	27	28
C	%	20	7	0
BC	%	11	24	0
B	%	20	0	0
AB	%	8	0	0
A	%	0	0	0
AA	%	0	0	0
OFA DAMPER POS				
UPPER	%	20	0	0
CENTER	%	100	100	0
LOWER	%	100	100	75
MAIN STM FLOW INPUT SIGNAL (for OFA dmpr bias)	%	59	48.5	34.8
OFA TILT POS	DEG	0	0	0
OFA YAW POS (T,M,B)				
RF	DEG	15L,0,15R	15L,0,15R	15L,0,15R
RR	DEG	15L	15L	15L
LF	DEG	8L	8L	8L
LR	DEG	8L	8L	8L
AUX AIR YAW POS				
RF	DEG	15R	15R	15R
RR	DEG	15R	15R	15R
LF	DEG	15R	15R	15R
LR	DEG	15R	15R	15R
MAIN TILT INPUT SIGNAL (for OFA tilt bias)	%	96.9	97	97.2

GAS DATA (local)				
O2	%	6.7	7.8	9
CO	PPM	8	9	11
NOx (UC)	PPM	234	233	236
NOx (CORR)	PPM	295	318	354
NOx (CORR)	LB/MBTU	0.398	0.429	0.478
SO2 (UC)	PPM			
THC	%			
FURNACE CONDITIONS	---	good	good	good
IGNITIONS POINTS				
RF CORNER	FT	1	1	1
RR CORNER	FT	1	1	1
LR CORNER	FT	1	1	1
LF CORNER	FT	1	1	1

TEST NO. DATE TIME		7A 4/29/91 15:02	8A 4/29/91 17:30
LOAD	MW	200	200
THROTTLE PRESSURE	LB/IN2	1800	1800
ECON (FW) IN TEMP	F	476	476
ECON OUT TEMP	F	NA	NA
SH OUT TEMP	F	1000/1001	1000/1000
SH DESH IN TEMP	F	845/862	846/876
SH DESH OUT TEMP	F	818/799	822/824
RH OUT TEMP	F	998	1001
RH DESH IN TEMP	F	709	711
RH DESH OUT TEMP	F	694/695	692/693
O2 (BOARD)	%	3.5	3.7
TOTAL AIR FLOW	%	82	82
TILT POS	DEG	-5	-10
ELEV. IN SERVICE	---	5	5
WINDBOX/FURN dP	"H2O	5.5	5.25
WINDBOX PRESSURE	"H2O	5	4.75
FURNACE PRESSURE	"H2O	-0.5	-0.5
TOTAL FUEL FIRED	KLB/HR	149.1	149.9
FLOWS			
FEEDWATER	KLB/HR	1389	1380
MAIN STEAM	KLB/HR	1472	1466
FW MAKEUP	LB/MIN	141	70
SH DESH SPRAY	KLB/HR	39.5	31
RH DESH SPRAY	KLB/HR	3.1	3.2

PRESSURES			
ECON IN PRESS	LB/IN2	NA	NA
STEAM DRUM	LB/IN2	2000	2082
SH OUT	LB/IN2	1850	1850
RH IN (COLD RH @ TURB)	LB/IN2	696/695	NA
RH OUT (HOT RH @ TURB)	LB/IN2	979/984	NA
SH SPRAY VALVE POS.	%	27.1/23.7	28/30
RH SPRAY VALVE POS.	%	0.8/0.8	0/0
APH TEMPERATURES			
GAS IN	F	646/649	653/648
GAS OUT	F	304/312	316/307
AIR IN	F	153/136	138/154
AIR OUT	F	539/552	560/546
AMBIANT AIR TEMP	F	86	80
PULVERIZER DATA			
MILL OUT TEMPS			
A	F	148	148
B	F	149	149
C	F	149	150
D	F	148	150
E	F	146	151
MILL LOADING			
A	KLB/HR	35	29.8
B	KLB/HR	35	31.5
C	KLB/HR	34.5	30
D	KLB/HR	34.5	29.7
E	KLB/HR	32	28.4
MILL POWER			
A	AMPS	37	36.5
B	AMPS	37	35.5
C	AMPS	38	37
D	AMPS	32	36
E	AMPS	33	33

BOWL dP			
A	"H2O	8.4	8.2
B	"H2O	8.4	8.3
C	"H2O	8.6	7.5
D	"H2O	5	4.6
E	"H2O	7.6	7.2
MILL IN TEMPS			
A	F	NA	NA
B	F	NA	NA
C	F	NA	NA
D	F	NA	NA
E	F	NA	NA
HOT AIR DAMPER POS (PRIMARY AIR)			
A	%	88	88
B	%	90	90
C	%	90	90
D	%	88	88
E	%	76	74
COLD AIR DAMPER POS (TEMPERING AIR)			
A	%	70	74
B	%	75	76
C	%	71	72
D	%	70	72
E	%	62	60
MILL AIR FLOW			
A	LB/HR	NA	NA
B	LB/HR	NA	NA
C	LB/HR	NA	NA
D	LB/HR	NA	NA
E	LB/HR	NA	NA
MILL CLASSIFIER POSITION			
A		|	|
B		Same as	Same as
C		test 1a	test 1a
D		|	|
E		|	|

MILL EXH/FURN dP			
A	"H2O	15.6	15.3
B	"H2O	16.2	16
C	"H2O	15.2	15
D	"H2O	16.8	16.7
E	"H2O	12.7	12
COAL FINENESS			
A % ON 50	%		
A % THRU 100	%		
A % THRU 200	%		
B % ON 50	%		
B % THRU 100	%		
B % THRU 200	%		
C % ON 50	%	Same as	Same as
C % THRU 100	%	test 1a	test 1a
C % THRU 200	%		
D % ON 50	%		
D % THRU 100	%		
D % THRU 200	%		
E % ON 50	%		
E % THRU 100	%		
E % THRU 200	%		
FD FAN DATA			
DAMPER POS	%	100/100	100/100
FAN SPEED	RPM	869/863	849/842
OUTLET PRESS	"H2O	10.5/10.5	10.5/10
AMPS		100/105	100/100
ID FAN DATA			
INLET VANE POS	%	58/62	56/60
OUT VANE POS	%	91/98	91/98
IN PRESS	"H2O	-17	-16.5
OUTLET PRESS	LB/IN2	NA	NA
AMPS		NA	240/250
BFP MOTOR SPEED	RPM	3365	3353
BFP AMPS		315/310	305/300

SECONDARY AIR/ FUEL AIR DAMPER POSITION			
EE	%	74	74
E	%	15	15
DE	%	40	40
D	%	15	15
CD	%	40	40
C	%	15	15
BC	%	40	40
B	%	15	15
AB	%	40	40
A	%	15	15
AA	%	40	40
OFA DAMPER POS			
UPPER	%	0	100
CENTER	%	100	100
LOWER	%	100	100
MAIN STM FLOW INPUT SIGNAL (for OFA dmpr bias)	%	92.4	91.7
OFA TILT POS	DEG	0	0
OFA YAW POS (T,M,B)			
RF	DEG	15L,0,15R	15R,0,15L
RR	DEG	15L	15R
LF	DEG	8L	15L,0,15R
LR	DEG	8L	15R,0,15L
AUX AIR YAW POS			
RF	DEG	15R	15R
RR	DEG	15R	15R
LF	DEG	15R	15R
LR	DEG	15R	15R
MAIN TILT INPUT SIGNAL (for OFA tilt bias)	%	40.6	33.3

GAS DATA (local)			
O2	%	2.6	5.1
CO	PPM	14.2	8.4
NOx (UC)	PPM	268	224
NOx (CORR)	PPM	262	254
NOx (CORR)	LB/MBTU	0.354	0.343
SO2 (UC)	PPM	2470	2147
THC	%		
FURNACE CONDITIONS	—	good	good
IGNITIONS POINTS			
RF CORNER	FT	1	1
RR CORNER	FT	1	1
LR CORNER	FT	1	1
LF CORNER	FT	1	1

APPENDIX III

HOT AIR TRAVERSE TEST RESULTS

ANNULAR VENTURI PERFORMANCE DATA

SOUTHERN COMPANY SERVICES
GULF POWER COMPANY
LANSING SMITH, UNIT #2

DATE : APRIL 24,1991

TEST #1: RHS OFA DUCT

TEST ENGINEER : M.HAGARTY

ANNULAR VENTURI dP (in.w.g.) : BEFORE : 1.90 AFTER : 1.90 AVG : 1.9

UPSTREAM Pstat (psig) : 0.30324 in.w.g. x 0.0361

BAROMETRIC PRESSURE (psia): 14.783 in.Hg x 0.49

AREA DUCT (ft^2) : 17

TAP #1

	#1	#2	#3	#4	#5	#6
dP (in.w.g.)	0.47	0.38	0.4	0.43	0.46	0.44
T (deg R)	1025	1025	1025	1025	1025	1025
v (ft/sec)	63.98076	57.52972	59.02425	61.19764	63.29645	61.90515
v avg. (ft/sec)	61.15566					
T avg. (deg R)	1025					

TAP #2

	#1	#2	#3	#4	#5	#6
dP (in.w.g.)	0.47	0.47	0.44	0.45	0.47	0.52
T (deg R)	1025	1025	1025	1025	1025	1025
v (ft/sec)	63.98076	63.98076	61.90515	62.60467	63.98076	67.29800
v avg. (ft/sec)	63.95835					
T avg. (deg R)	1025					

TAP #3

	#1	#2	#3	#4	#5	#6
dP (in.w.g.)	0.49	0.4	0.38	0.4	0.43	0.5
T (deg R)	1025	1025	1025	1025	1025	1025
v (ft/sec)	65.32787	59.02425	57.52972	59.02425	61.19764	65.99111
v avg. (ft/sec)	61.34914					
T avg. (deg R)	1025					

TAP #4

	#1	#2	#3	#4	#5	#6
dP (in.w.q.)	0.49	0.46	0.41	0.41	0.44	0.52
T (deg R)	1025	1025	1025	1025	1025	1025
v (ft/sec)	65.32787	63.29645	59.7575	59.7575	61.90515	67.29800
v avg. (ft/sec)	62.89041					
T avg. (deg R)	1025					

SUMMARY

ANNULAR VENTURI (in.w.g.)	1.9	CALC. MASS FLOW (lb/hr)	151840.2
AVERAGE VELOCITY (ft/sec)	62.33839	MEASURED MASS FLOW (lb/hr)	154878.2
AVERAGE TEMP (DEG R)	1025	ERROR (%)	-2.00076

PLANT DHS: 58% OF 196,000 = 113,680 LB/HR

ANNULAR VENTURI PERFORMANCE DATA

SOUTHERN COMPANY SERVICES
GULF POWER COMPANY
LANSING SMITH, UNIT #2

DATE : APRIL 24,1991

TEST #1: LHS OFA DUCT

TEST ENGINEER : M.HAGARTY

ANNULAR VENTURI dP (in.w.g.) : BEFORE : 1.74 AFTER : 1.74 AVG : 1.74

UPSTREAM Pstat (psig) : 0.2527 (in.w.g. x 0.0361)

BAROMETRIC PRESSURE (psia): 14.783 (in.Hg x 0.49)

AREA DUCT (ft^2) : 17

TAP #1

	#1	#2	#3	#4	#5	#6
dP (in.w.g.)	0.46	0.38	0.36	0.4	0.43	0.49
T (deg R)	1025	1025	1025	1025	1025	1025
v (ft/sec)	63.29645	57.52972	55.99532	59.02425	61.19764	65.32787
v avg. (ft/sec)	60.39521					
T avg. (deg R)	1025					

TAP #2

	#1	#2	#3	#4	#5	#6
dP (in.w.g.)	0.45	0.46	0.43	0.43	0.45	0.52
T (deg R)	1025	1025	1025	1025	1025	1025
v (ft/sec)	62.60467	63.29645	61.19764	61.19764	62.60467	67.29800
v avg. (ft/sec)	63.03318					
T avg. (deg R)	1025					

TAP #3

	#1	#2	#3	#4	#5	#6
dP (in.w.g.)	0.43	0.37	0.35	0.4	0.42	0.39
T (deg R)	1025	1025	1025	1025	1025	1025
v (ft/sec)	61.19764	56.76770	55.21213	59.02425	60.48185	58.28177
v avg. (ft/sec)	58.49422					
T avg. (deg R)	1025					

TAP #4

	#1	#2	#3	#4	#5	#6
dP (in.w.g.)	0.46	0.44	0.4	0.4	0.43	0.48
T (deg R)	1025	1025	1025	1025	1025	1025
v (ft/sec)	63.29645	61.90515	59.02425	59.02425	61.19764	64.65782
v avg. (ft/sec)	61.51759					
T avg. (deg R)	1025					

SUMMARY

ANNULAR VENTURI (in.w.g.)	1.74	CALC. MASS FLOW (lb/hr)	147742.7
AVERAGE VELOCITY (ft/sec)	60.86005	MEASURED MASS FLOW (lb/hr)	148059.2
AVERAGE TEMP (DEG R)	1025	ERROR (%)	-0.21421

PLANT DHS: 56% OF 196,000 = 109,760 LB/HR

APPENDIX IV

SAFE FLAME I FLAME SCANNER REPORT
FLAME SCANNER COOLING AIR SYSTEM REPORT

SAFE FLAME I FLAME SENSING SYSTEM

The Safe Flame I flame sensing system was installed this outage. The purpose of this system is to detect coal fireball flame at all loads. The system does not discriminate between oil and coal flames.

System Components

Sixteen (16) scanner assemblies were installed at elevations AB (oil), BC, CD, and DE in all four (4) corners. One (1) cabinet was supplied which contains four (4) card rack assemblies, one for each elevation of scanners. Each card rack assembly consists of three (3) cards for each scanner (channel) - an Intensity and Fault Detection Card, a Frequency Detection Card, and a Lamp and Meter Card. Each card rack assembly also consists of one 2/4 Flame Indication and Fault Alarm Card for the elevation. Junction boxes were installed in each corner of the unit at elevation 56'-6" that house the terminal strips and wiring connections for four (4) scanners per corner. Shielded four conductor cables are run from these junction boxes to the scanner cabinet.

Sixteen (16) scanner lights, four (4) 2/4 indicating lights, and one (1) fault light are installed above the T.V. monitors located in the control room. The logic for the indicating lights will be revised to the following, based on plant request:

- Green scanner lights will be lit when the scanners prove flame.
- Red 2/4 lights will be lit when at least 2/4 scanners are not proving flame.
- When a system fault exists with the scanner housing electronics, the scanner card electronics, or the intensity signal, an amber fault light will be lit.

These modifications will be performed entirely by Southern Company.

An annunciator alarm light has been installed on the benchboard which will sound and light should all but one (1) scanner prove flame. The indication is a "NO FLAME" signal.

Pre-Operation System Check

Each scanner was checked before installation by placing a 100 watt light bulb as a simulated flame source in front of each scanner head. The frequency sensitivity was set for 103 Hz by changing the dip switch settings located on the Frequency Detection Card all in the "on" position. These switches are located on the front of the card (refer to drawing D-984-0579-07 in the Instruction Manual). These settings are only set for checkout function, not normal operation. The

Pre-Operation System Check (cont'd.)

intensity component was satisfied with the red light indication on the Intensity and Fault Detection card. The intensity meter reading was approximately 60% on the Lamp and Meter Card. The red frequency light was lit on the Frequency Detection Card. The flame light was lit on the Lamp and Meter Card to indicate Flame exists. This was performed on all scanners to ensure that the scanners were operational. No problems were found.

Installation

The scanner guide tube assemblies are installed in the bottom auxiliary air tips in elevations BC, CD, and DE. In elevation AB, the assemblies are installed in the center tip adjacent to the oil compartment. The assemblies house the scanners and provide a passage for the required airflow to the scanners to prevent overheating. The guide pipes are welded to the tips three inches (3") from the front face.

The assemblies are secured in the windbox by a flanged connection in the backplate. Approximately fourteen inches (14") of the guide pipes extend on the outside of the windbox.

Between the two (2) sections of guide pipes, flexible hoses allow for freedom of movement of the tilts. The flex hoses were checked over the full stroke of the tips, +/- 30^{o}.

The scanner assemblies were installed so that the end of the scanner heads were bottomed in the guide tube assemblies. A stop plate at the end of the guide tubes secures the scanner heads. Some of the guide tube assemblies were cut to properly fit the scanners. Again, the tips were stroked to ensure that the scanners remained in place through their full travel.

After the field wiring was complete, the scanners were again checked by: covering the scanner heads to ensure no flame, placing a flashlight in front of the heads to detect an intensity signal, and placing a light bulb in front of the heads to detect both the intensity and frequency signals. The appropriate indications on the three (3) cards for each scanner were satisfied. A blown fuse (B-) on the Lamp and Meter card at one of the channels was found. Each card contains a spare fuse which was used to replace this fuse. Refer to the schematic drawing for the Lamp and Meter Card (D-984-0721-07) in the instruction manual for location of the fuses.

SCANNER COOLING AIR FANS

SYSTEM DESCRIPTION

Two (2), 100% capacity, Buffalo Forge scanner air fans, Model 5E, were installed to supply cooling air to 16 Safe Flame I flame scanners. The fans were mounted in front of the unit at elevation 73'-0". They are installed side by side and rotate in the counterclockwise and clockwise direction to discharge to a common duct supplied with an air filter. A remote control station was installed adjacent to the fans for local start and stop of fans as necessary and for indication of their operation and alarms.

OPERATIONAL SUMMARY

The scanner fan control station consists of five (5) time delay relays and a control relay. The function of these six (6) relays are:

- "A" Fan start, 2 second time delay upon start command
- "A" Fan "ON" light, 5 second time delay to verify start and scanner duct/furnace delta P satisfied
- "B" Fan start, 2 second time delay upon start comm d
- "B" Fan "ON" light, 5 second time delay to verify start and scanner duct/furnace delta P satisfied
- Scanner duct/furnace delta P "LOW" light, 5 second time delay to prove that the delta P is not below 6" WG
- Scanner air filter delta P "HIGH" light, control relay to prove that the delta P across the filter is above 0.6" WG

A signal for the scanner duct/furnace delta P "LOW" and scanner air filter delta P "HIGH" is wired to an annunciator alarm in the control room.

"AS OPERATING" STATUS

Both fans were checked for correct rotation and balance. Vibration readings were taken up on start-up and shut-down of each fan and the results are listed in the following table.

SCANNER COOLING AIR FANS

"AS OPERATING" STATUS (cont'd.)

	Initial Operation		Shut-down	
Fan	**Specified**	**Actual**	**Specified**	**Actual**
"A"	0.53 mils	0.30 mils	2.39 mils	<0.10 mils
"B"	0.53 mils	0.30 mils	2.39 mils	0.20 mils

Both fans rotated per design, counter-clockwise on "A" fan and clockwise on "B" fan.

A complete functional check was performed on the system by ABB-CE Technical Services per the Instruction Manual. Off-line checkouts included verifying mechanical and wiring installation. An operational checkout was performed to ensure the following logic is satisfied:

- With the F.D. Fan on, "A" fan starts automatically.
- If scanner duct/furnace delta P is low, the idle fan ("B" fan if no problems exist mechanically with "A" fan)) starts automatically.
- Once scanner duct/furnace delta P is satisfied, the second fan must be stopped locally by the pushbutton.

The local indications and control room indications were verified on operating fans.

APPENDIX C

Construction Services Activity Report

ABB COMBUSTION ENGINEERING SERVICES, INC.

GULF POWER - LANSING SMITH PLANT

SOUTHPORT,FLORIDA

CONTRACT-13790

UNIT # 2

LOW NOX DEMONSTRATION PROJECT - PHASE II

I. Introduction

During the period of March 4, 1991 to May 6, 1991 ABB-CE Construction Services successfully completed the LNCFS Phase II retrofit of Gulf Power Company's Lansing Smith Unit #2. This report will summarize all Phases of the outage from receiving material to demobilization.

II. Scope   Ref: Appendix A

The LNCFS Phase II retrofit consisted of the installation of the following equipment:

Burner Systems

1. Twenty (20) coal nozzle assemblies, constructed of cast ductile iron.
2. Twenty (20) two-piece flame-holder adjustable coal nozzle tips, constructed of 309ss or better.
3. Twenty (20) sets of adjustable auxiliary air nozzle tips, constructed of 309ss, complete with associated linkage and hardware.
4. Twenty Four (24) sets of variable offset (w/manual yaw adjustment) adjustable auxiliary air nozzle tips, constructed of 309ss, complete with associated linkage and hardware.
5. One (1) Lot of miscellaneous adjusting mechanisms, pivot pins, connecting links, tilt modules, etc., to upgrade the windbox tilting mechanical systems.
6. Four (4) High pressure overfire air windboxes, with integral air flow control dampers, tilting adjustable air nozzle tips, electric tilt and damper drives, and all associated damper and nozzle linkage and hardware.
7. One (1) Lot overfire air connecting ductwork, complete with required stiffeners, expansion joints, turning vanes, hangers, and supports. Ductwork to be constructed of 1/4" carbon steel, and externally insulated and lagged.
8. One (1) Lot of Rockwell pipe couplings as required to modify existing coal piping support system in order to eliminate coal pipe loading on the windbox.
9. One (1) Lot of steam and water piping to modify existing sootblower and auxiliary piping as required to accommodate the LNCFS II.
10. One (1) Lot of structural steel, rails, grating, platework, and shapes as required to modify existing steel configuration in order to provide access and to install LNCFS II.
11. One (1) Lot of insulation and lagging for the OFA registers and those areas on the furnace waterwalls affected by the retrofit of LNCFS. NOTE: Lagging is to be compatible with existing lagging, i.e. 0.032" ribbed aluminum.
12. Two (2) Annular venturi air flow measuring devices, located in the OFA ductwork for accurate measurement of OFA flow in this Low NOx demonstration project.

Pressure Parts

1. Four (4) waterwall offset tube panels, for the OFA registers, equal to or exceeding existing waterwall tubing materials, with tube ends prepped for welding to the existing wall tubes. These tube panels are to be hydrostatically tested in the shop prior to shipment. (Customer has the option to witness these hydrostatic tests)
2. Sixteen (16) loose bent tubes, approximately 34" long each, for use in forming eight (8) furnace tube openings for observation ports. NOTE: Hydrostatic testing of these loose bent tube pressure parts IS NOT required, per telecon discussion with SCS's Lamar Sumerlin, September 26, 1990.

Instrumentation and Controls

1. Four (4) BECK electric tilt drives to replace the existing pneumatic tilt drives.
2. Four (4) BECK electric tilt drives, one (1) for each of the OFA windboxes.
3. One (1) Control cabinet, NEMA 12, approximate dimensions 72"Hx30"Wx24"D, with the following equipment mounted and wired within:
   a) One (1) MOD 30 air flow controller.
   b) Five (5) MOD 30 overfire air controllers - including two for LNCFS III.
   c) A/R Power supplies, input controllers, terminal blocks.
4. Twelve (12) Overfire air damper drives, Foxborro-Jordan, LA2420.
5. One (1) Differential pressure transmitter, Taylor 400T.
6. One (1) Three valve manifold, HEX.
7. One (1) MOD 30 portable configurator.
8. An ABB-CE Flame Scanner System (Safe Flame I), consisting of:
   a) Sixteen (16) Safe Flame head assemblies
   b) Sixteen (16) Flame scanner guide pipes
   c) Four (4) Safe Flame chassis
   d) Four (4) Remote meters
   e) One (1) Lot triple shielded wiring
   f) One (1) Cooling air system, consisting of:
      Two (2) 100% capacity fans
      One (1) In-line filter
      One (1) Automatic transfer damper
      One (1) Lot spiral welded piping
      One (1) Lot hangers, supports and hardware
9. A Burner Observation System, consisting of:
   a) One (1) Arvin/Diamond Model ST-7 (or comparable) video camera
   b) One (1) High temperature housing
   c) One (1) Wallbox/camera mounting assembly

d) One (1) Cooling air system, w/flex hoses, regulator, strainer, manual shutoff valve, and required piping and fittings.
e) One (1) Lenstube assembly
f) One (1) DM213/C 13" (or comparable) video monitor
g) One (1) Lot cable, connectors, and misc. hardware as required.

III. <u>Outage</u> Ref: Appendix B for Bar Chart Schedule

Pre-outage

ABB-CE moved on site March 4, 1991 to begin pre-outage activities. The pre-outage work took four (4) weeks working eight (8) hours per day, five (5) days per week.

Pre-outage activities consisted of the following:

a) Receive and inventory material
b) Job set-up
c) Erect sections of OFA ductwork that would not interfere with plant operation
d) Install section of scanner cooling air system that would not interfere with plant operation
e) Complete all electrical conduit and wiring that would not interfere with plant operation
f) Stage material in plant for easy access at the time of installation
g) Make final review of installation drawings and finalize construction plans

At the end of the four (4) week period 95% of the activities that were planned for pre-outage were completed. Due to some unforeseen interferences, sections of the OFA ductwork and scanner cooling air system were completed during the outage.

Outage

The unit was removed from service on schedule the evening of March 29, 1991.

The schedule called for the unit to return to service on April 22, 1991. The unit was returned to service at 4:34 a.m. April 22, 1991 on schedule.

During the outage period the work schedule was seven (7) days per week, ten (10) hours per day, two (2) shifts per day. The peak manpower loading was one hundred and thirty-four (134) men with an average loading of one hundred and seven (107).

Outage (cont.)

The critical path work for this outage was the modification to the main windboxes. The windboxes were completely stripped of coal nozzles, auxiliary air nozzle tips, tilt linkage and all bearings and bushings. The windboxes were then repaired and brought back to acceptable tolerances. The installation of the new variable offset adjustable auxiliary air nozzle tips required relocation of the tip bearing in the windbox channels. Two (2) new partition plates were installed in the top and bottom auxiliary air compartments. The windbox mechanical tilting system was replaced. All coal nozzles and tips were replaced. Rockwell couplings were installed in sixteen (16) fuel lines to relieve any fuel pipe loading from the windbox. Four (4) elevations of flame scanners were installed. A full furnace scaffold was installed to expedite the windbox work.

The OFA system was completed during the outage period. This included installing four (4) offset waterwall panels, four (4) OFA windboxes, completing the OFA ductwork, installing two (2) secondary air duct control dampers, installing two (2) Annular venturi air flow measuring devises. To complete the installation of the OFA ductwork a section of the feedwater line and the steam line to the steam coil air heaters had to be relocated. Several smaller auxiliary steam lines and wallblower supply piping had to be modified. Building steel and platforms were modified and relocated to accept the new OFA ductwork and windboxes.

In conjunction with the ABB-CE Technical Services Department the electrical and control portions of this project were installed and commissioned with no major problems.

Post Outage

The post outage period consisted of two (2) weeks working eight (8) hours per day, five (5) days per week. The post outage activities were as follows:

a) Remove materials and equipment from plant
b) Complete modifications to platform steel and handrails
c) Clean and paint work areas
d) Inventory tools and equipment
e) Complete paperwork and move equipment offsite

IV. Major Problems Encountered

Asbestos

In January 1991 Lansing Smith No. 2 was walked down to review the areas of insulation that would be disturbed when installing the LNCFS retrofit. Samples were taken from all known areas. The results of the samples indicated asbestos was not present. In the area that

Asbestos (cont.)

the secondary air dampers were installed asbestos was encountered on one side of the ductwork. The January samples were taken from the other side. Once the asbestos was discovered (4/2/91 at 3:00 p.m.) the building was cleared and procedures started to clean the areas. The building was cleaned and work resumed on (4/4/91 at 5:00 p.m.). The delay caused by asbestos was four (4) working shifts.

Feedwater Line Weld Repair

The main feedwater line required relocation to clear the OFA ductwork. The relocation required ten (10) welds. The non-destructive testing showed one (1) weld to have porosity and a small crack. The location of the damage was in a tight area. Several attempts were made to make repairs from the outside, but the crack would not clear. The line was cut and repairs had to be completed from the inside. The problems encountered with this weld did not impact start-up schedule.

V. Outstanding Items

Furnace Observation System

Problems developed with the camera lense during start-up. Investigation and repairs will be performed during the Phase III outage in October 1991.

Boiler Room Lighting

Some of the boiler room lighting removed to install the OFA ductwork was not reinstalled properly. These items will be corrected during the Phase III outage in October 1991.

Impulse Sensing Lines

Two (2) impulse sensing lines required an anti-vibration brace. These items will be corrected during the Phase III outage in October 1991.

VI. Summary

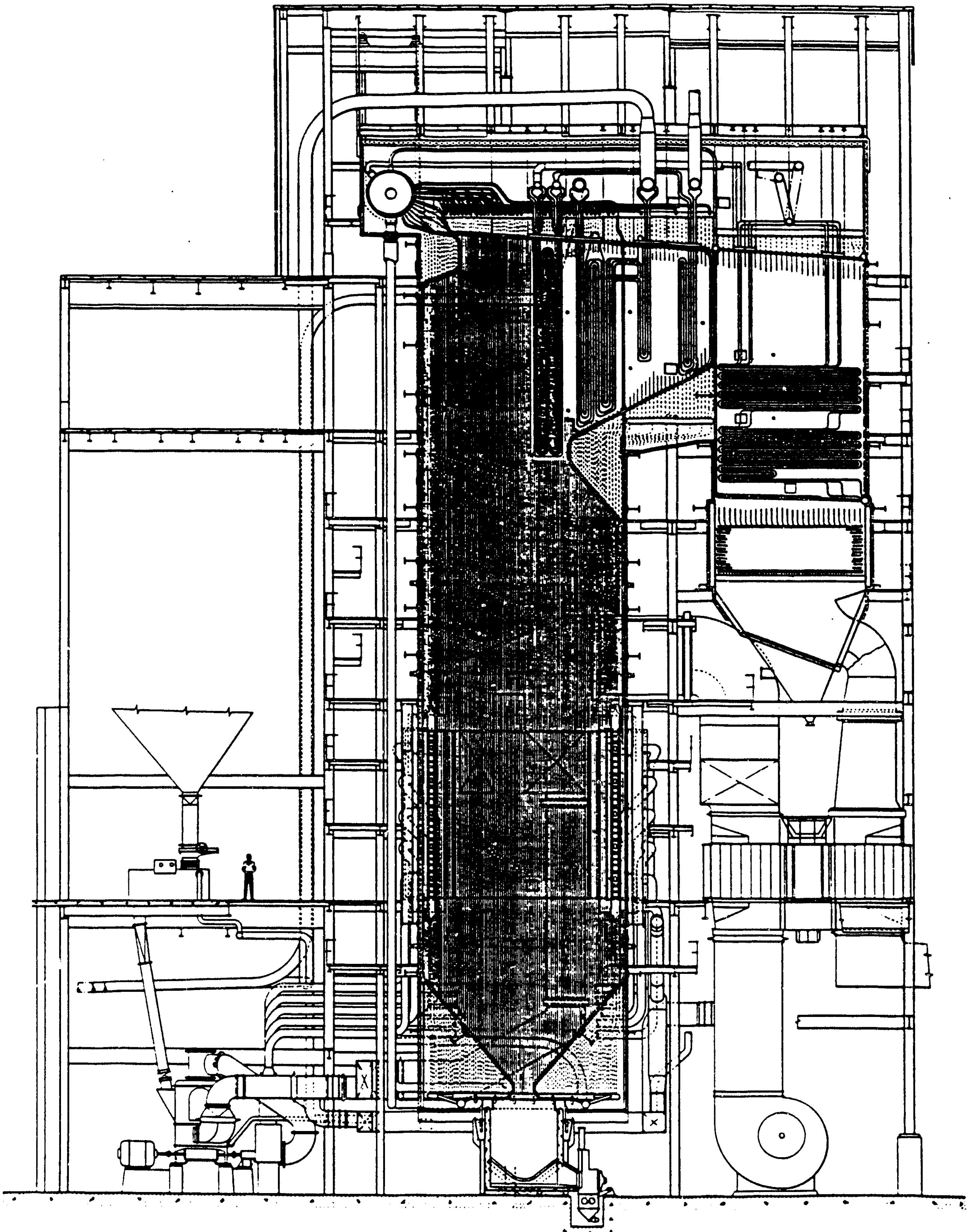
The installation of LNCFS Phase II on Gulf Power Company's Lansing Smith Unit #2 can be considered extremely successful. The outage was completed on schedule and the equipment is performing as designed.

The success of this outage can be attributed to the outstanding cooperation and team work between ABB-CE, Gulf Power Company and Southern Company Services.

VII. Attachments

Appendix A - Scope

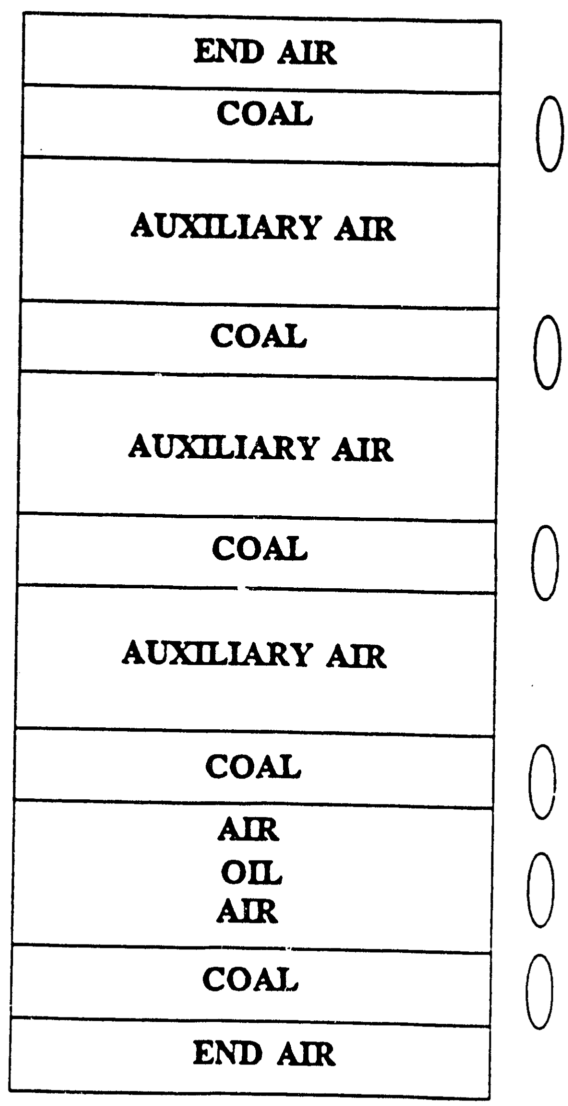
(6A) thru (6H)



Dwg. No. 30-414

(6A)

PHASE I-BASELINE ARRANGEMENT



GULF POWER UNIT 2

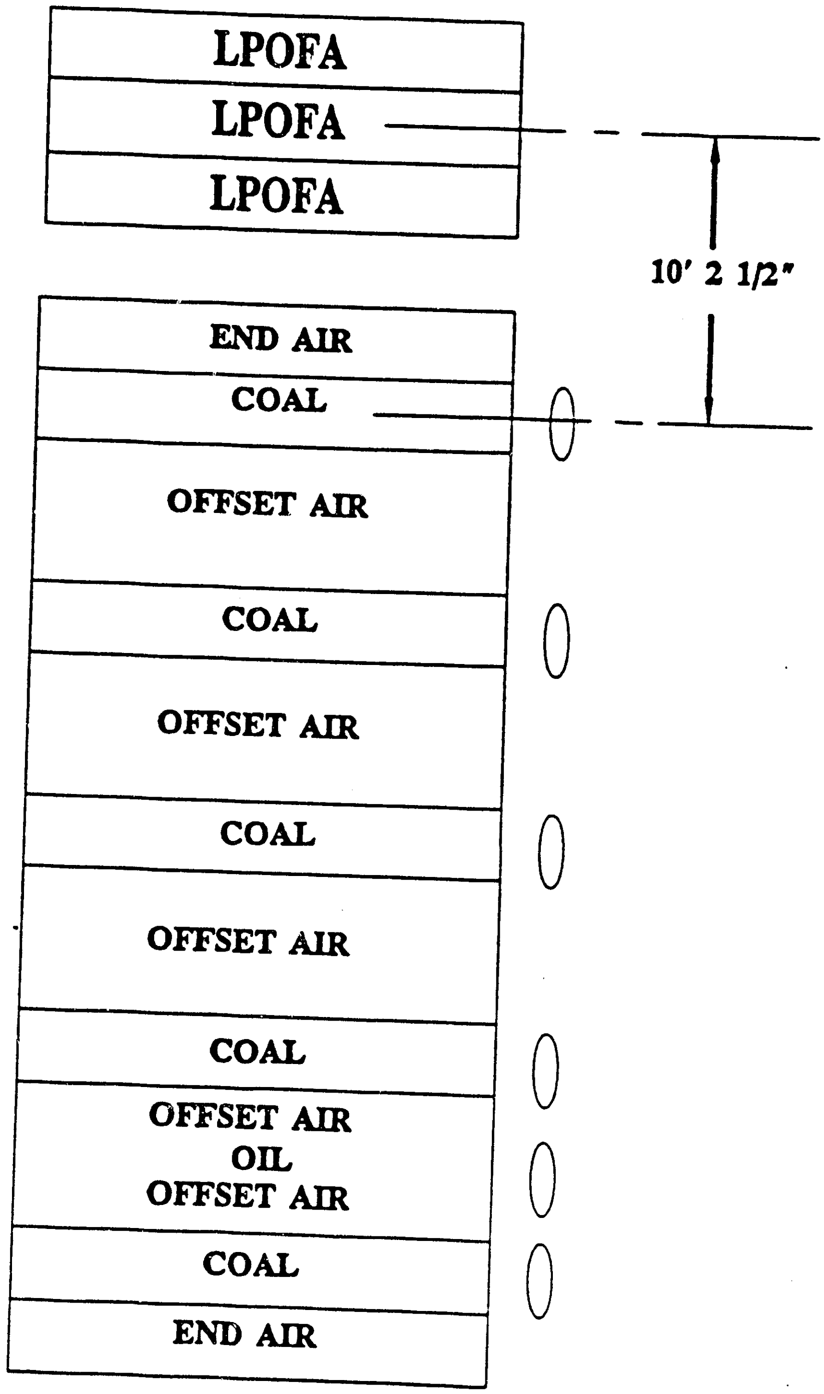
GULF POWER - LANSING SMITH NO. 2
(DOE PROJECT)

PHASE II - LNCFS

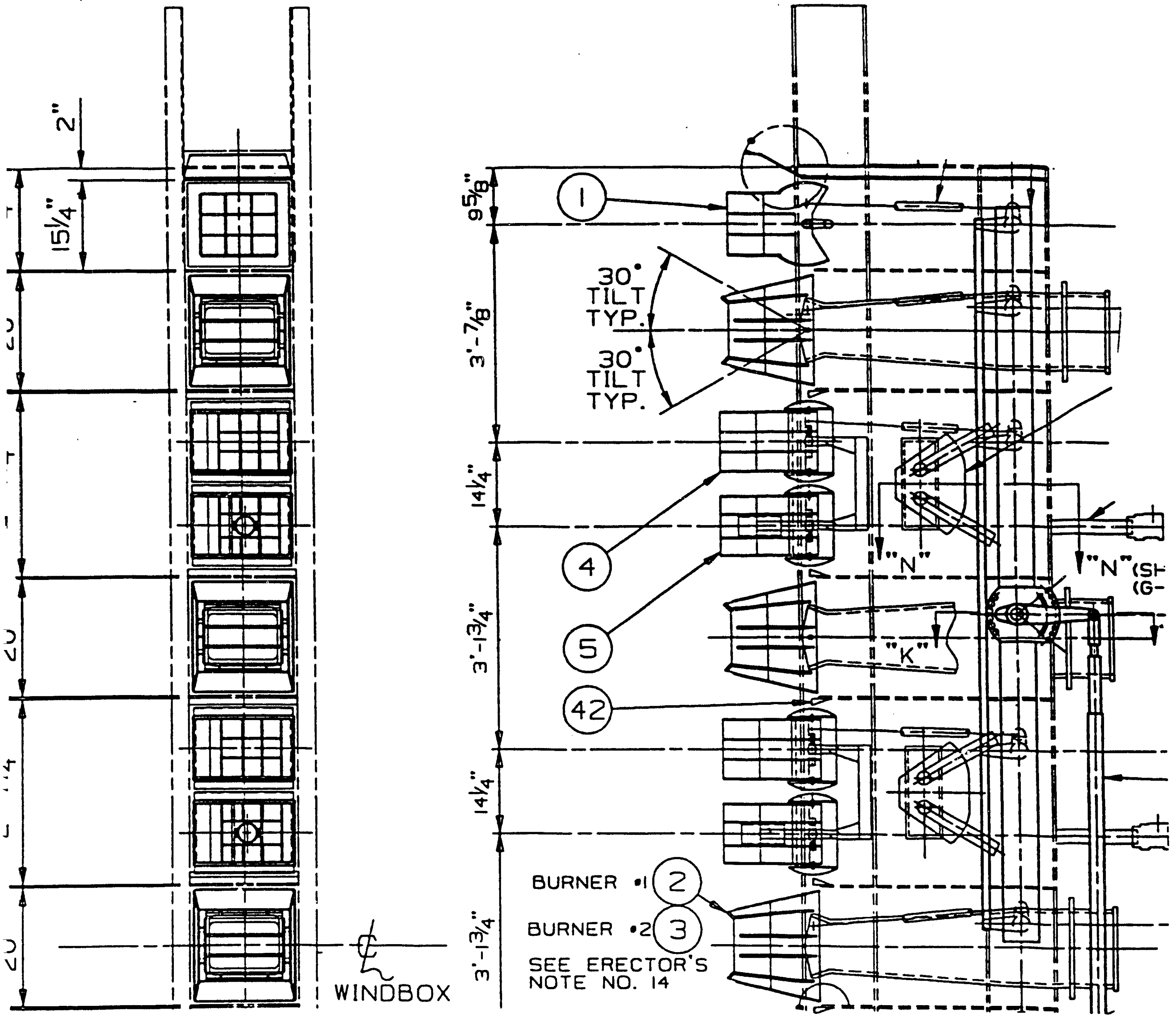
TILT UPGRADE
ELECTRIC TILT DRIVES
OFFSET AUX. AIR NOZZLES
FLAME HOLDER COAL NOZZLE TIPS
COAL NOZZLES
OFA WINDBOXES

OFA DUCTWORK
OFA WATERWALL OFFSET TUBE PANELS
OFA DAMPER CONTROL SYSTEM
FLAME SCANNERS

PHASE II-LNCFS ARRANGEMENT



GULF POWER UNIT 2



LNCFS LEVEL 2

B	C	D	E

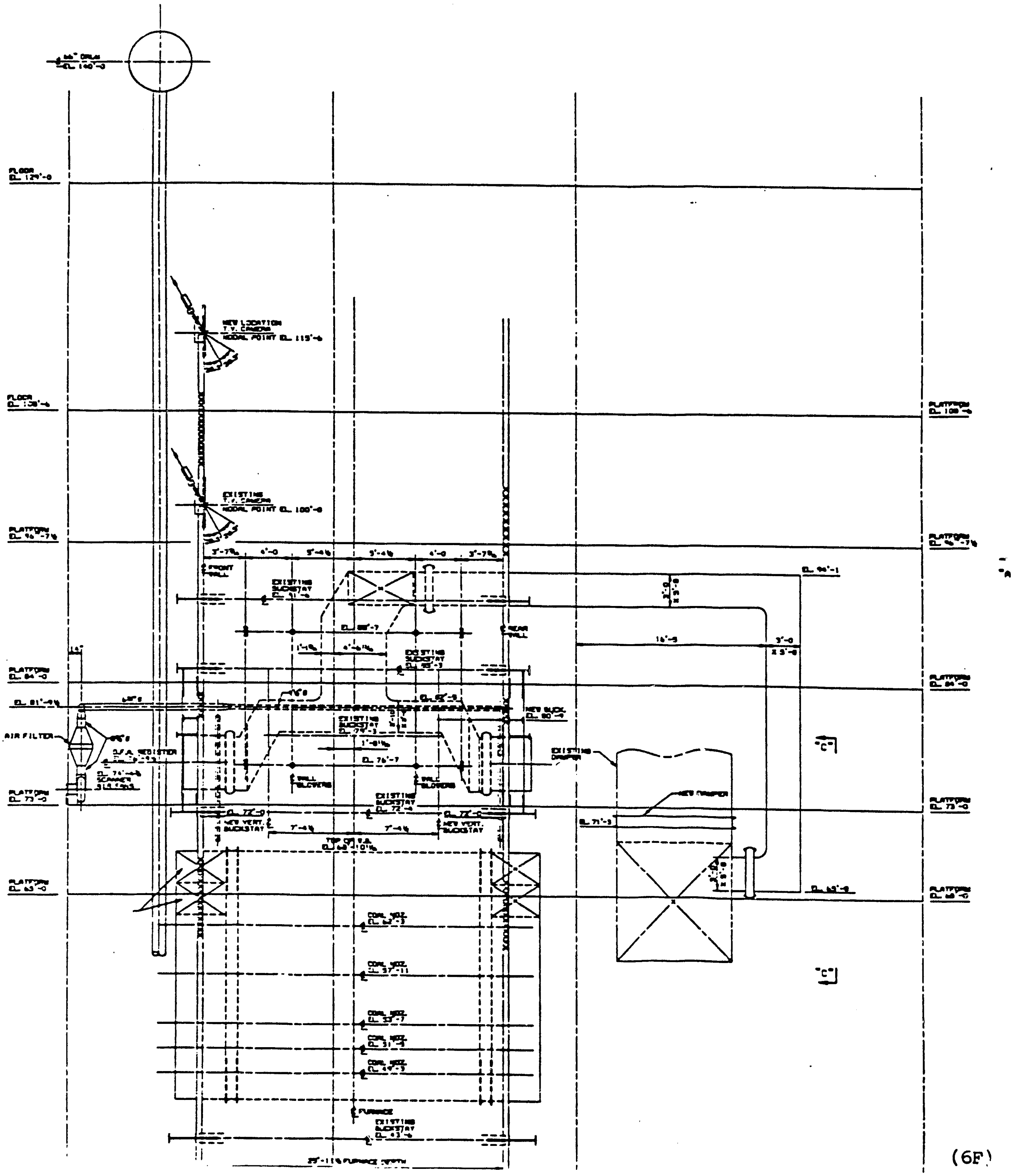
2 11-13-90 FRK

REVISED

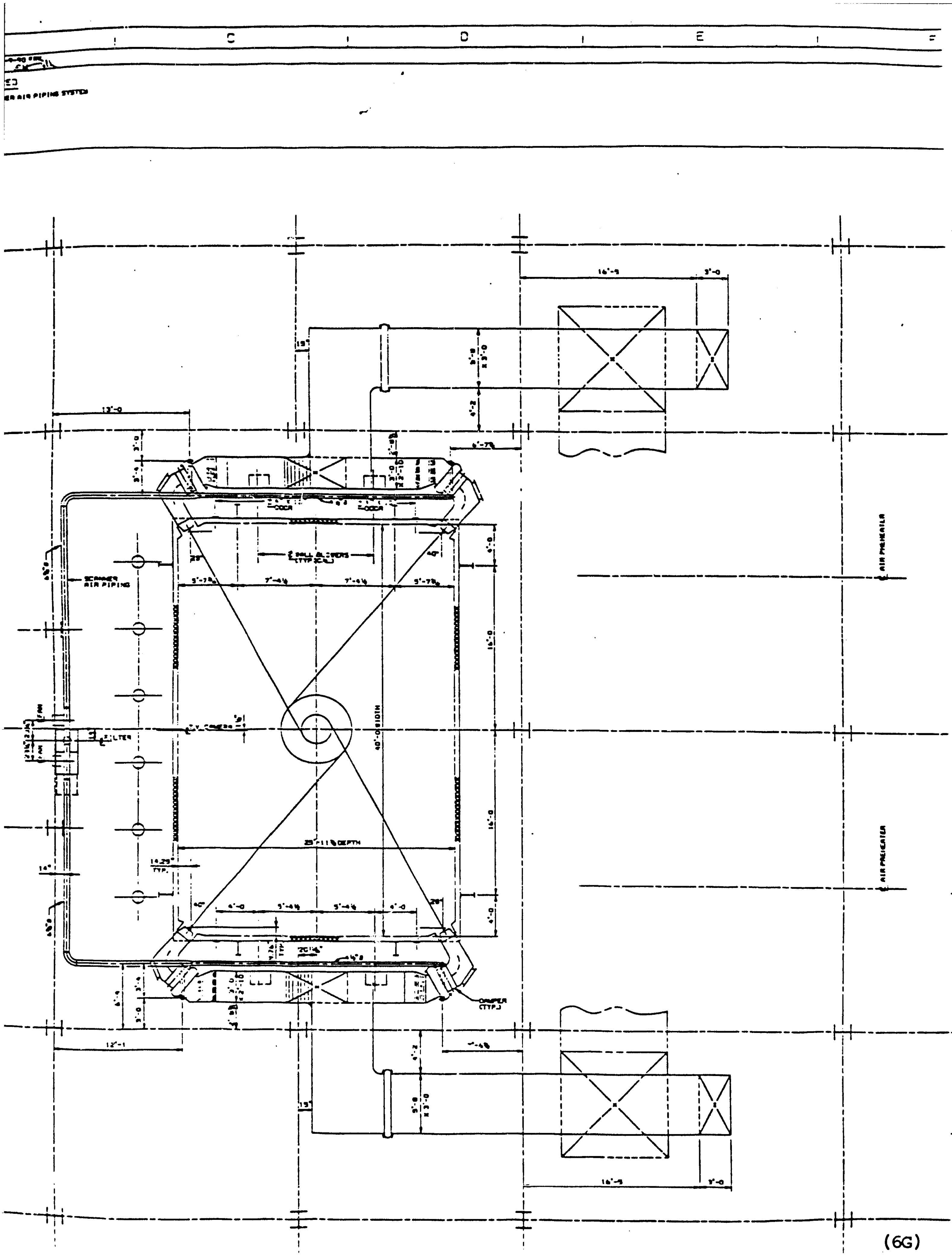
OVERFIRE AIR DUCT AS IT PENETRATES SECONDARY AIR DUCT

ANCED

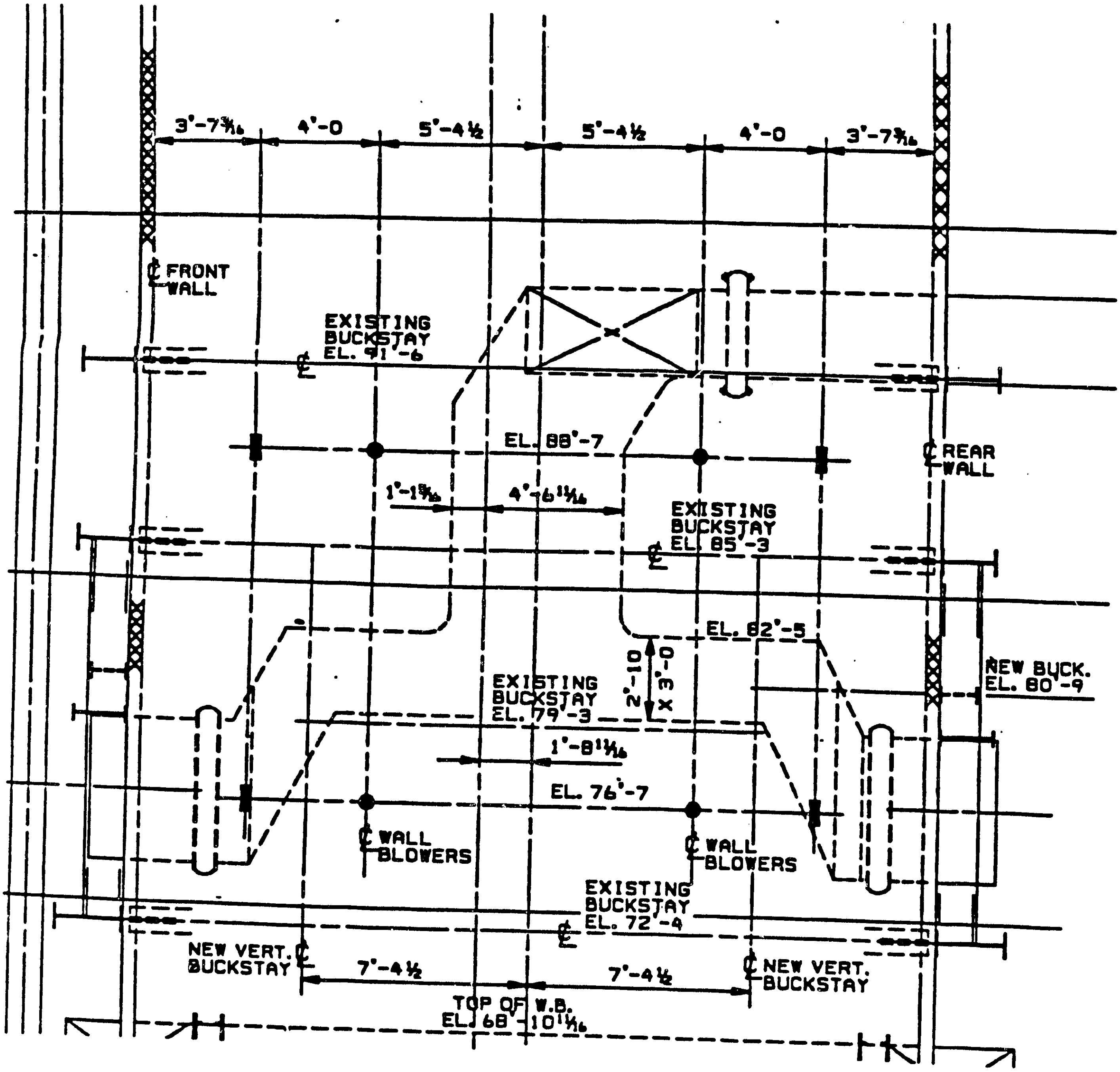
AIR PIPING SYSTEM CAMERA LOCATION



(6F)


C
D
E
SCANNER AIR PIPING
2 WALL BLOWERS (TYP 2CAL)
T.V. CAMERA
FILTER
FAN
DOOR
DAMPER (TYP.)
AIR PREHEATER
40'-0 WIDTH
25'-11¾ DEPTH
13'-0
12'-1
16'-5
3'-0
16'-0
4'-0
14.25" TYP.
14"
40°
28°

(6G)



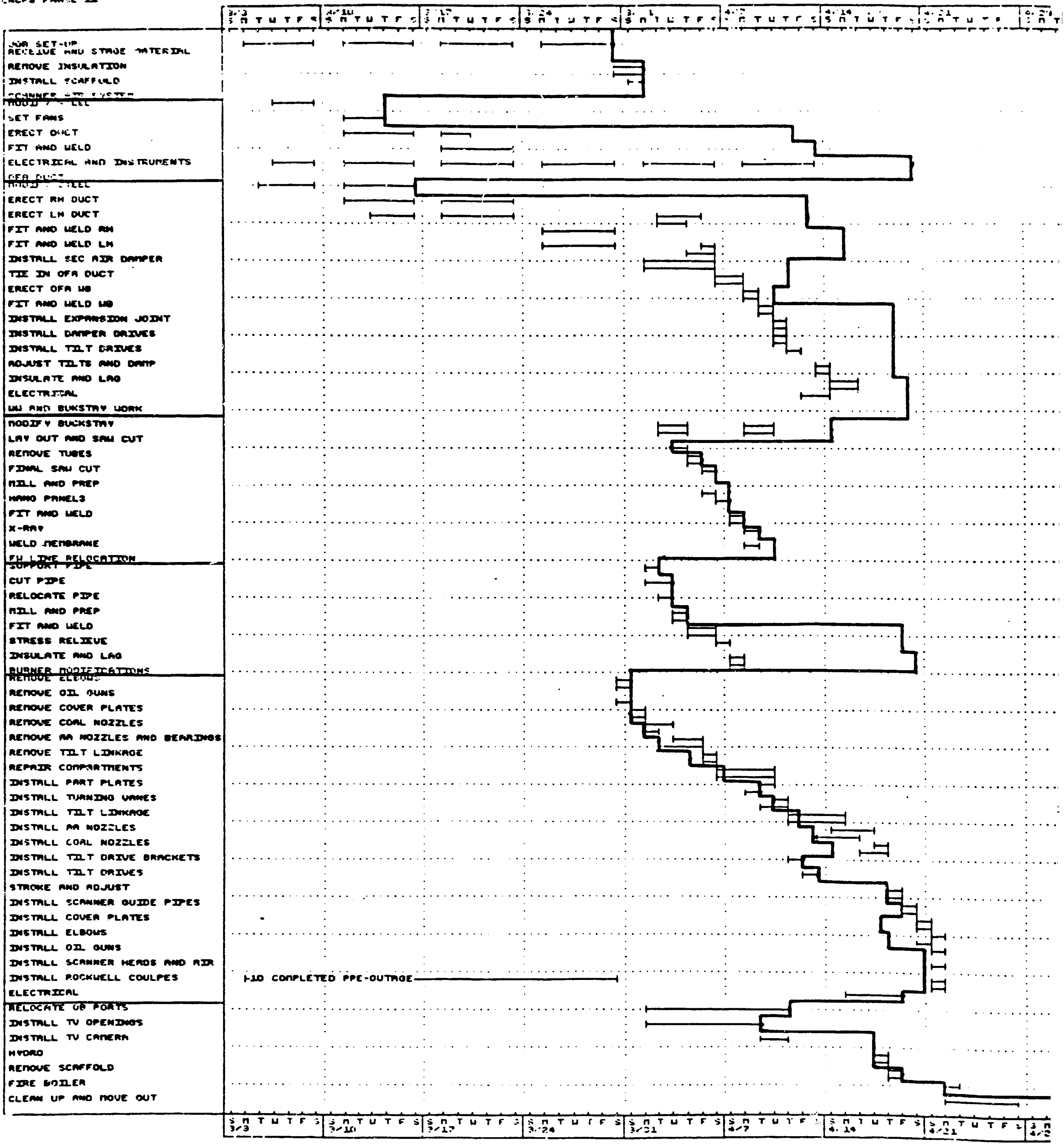
HPOFA SYSTEM - SIDE ELEVATION

VII. Attachments

Appendix B - Bar Chart Schedule and Manpower Loading

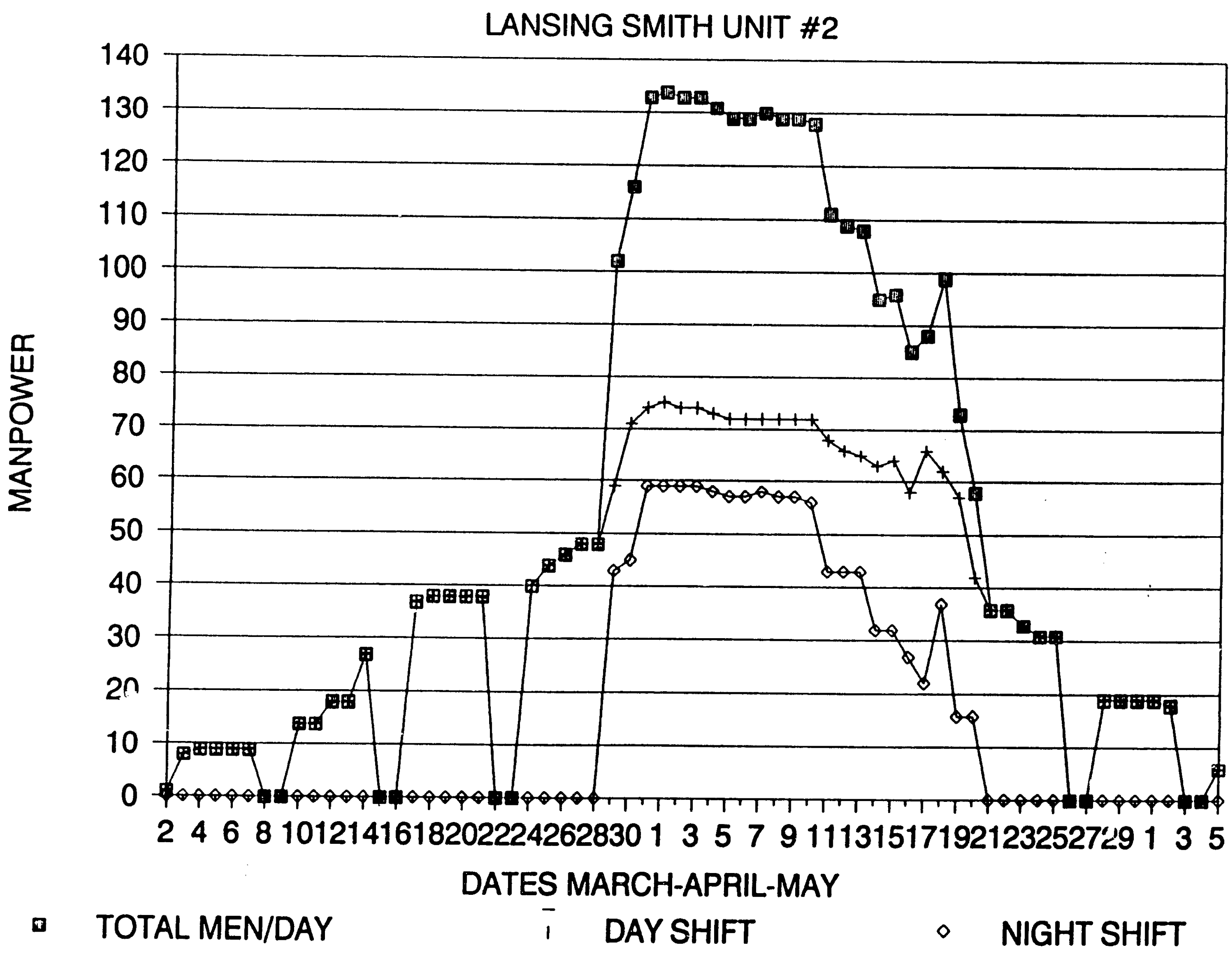
(7A) and (7B)

GULF POWER COMPANY
LANSING SMITH UNIT #2
LNCFS PHASE II



(7A)

GULF POWER COMPANY



END

DATE
FILMED

2 /24/92