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NUCLA Circulating Atmospheric Fluidized Bed Demonstration Project

1989 Annual Report

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1989 Annual Technical Progress Report
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FOREWORD

This is the second in a series of annual technical reports on Colorado-Ute Electric Association's (CUEA) Nucla Circulating Fluidized Bed (CFB) Demonstration Program covering the period from January 1989 through December 1989. The first annual technical report covered the period from unit start-up in February 1987 through 1988. The third annual technical report will cover the period from January 1990 through test program completion in January 1991. A final technical report will summarize pertinent information over the course of the entire test program. This test program is co-sponsored by the U.S. Department of Energy (DOE) under the Cooperative Agreement DE-FC21-89MC25137. This agreement was signed in October, 1988.

During this reporting period, the plant operated with an average availability of 51.9% and a capacity factor of 35.7%. These numbers were affected by several factors including a five week scheduled outage for refractory repairs and modifications, testing and modifications to the primary air fan, equipment failures on the cooling tower circulating pumps and the boiler feed pumps, a 28 day inspection and repair period to correct a secondary superheater tube leak, and delays associated with acceptance testing on high ash (~35 wt.%) and high sulfur (~2.5 wt.%) coals.

Boiler acceptance testing on high ash design "B" coal was completed in November after exhausting this fuel source from the local Nucla coal mine. Acceptance testing with high sulfur coal was not completed in 1989 due to unresolved capacity limitations with the limestone feed equipment. However, modifications to this equipment in December are expected to resolve this issue and testing will be completed in early 1990. In addition, in order to take advantage of a more economical fuel supply, the plant switched fuel sources to the Salt Creek coal mine located approximately 150 miles north of the station. This western sub-bituminous coal is lower and more consistent in ash and sulfur content than the "design" fuel.

Considerable progress was made in 1989 towards completing the objectives and scope of the test program. Both the "cold-mode shakedown" and the "hot-mode" test plans were completed. In addition, a total of 18 steady-state performance tests were conducted. These included tests with the discontinued local Nucla coal as part of alternate fuels testing. As part of the baghouse test plan, comprehensive data were collected at the inlet and outlet of the baghouses. Bag samples and fly ash samples were sent to an off-site location for additional testing. The freeboard gas sampling probes were commissioned and gas samples were collected at two elevations in combustor B for different loads on the local Nucla and Salt Creek coals. Several extended outages in 1989 provided opportunities for the test program to complete inspections of boiler components and to accumulate tube thickness data as part of the materials plan.

This report summarizes activities related to unit operations and to test program activities in 1989. The test program is cosponsored by the DOE, as part of its Clean Coal Technology Program, and the Electric Power Research Institute (EPRI), as part of its demonstration program for fluidized bed technology. The primary objective of DOE Cooperative Agreement DE-FC21-89MC25137 is to conduct a cost shared clean coal technology project to demonstrate the feasibility of circulating fluidized bed combustion technology and to evaluate economic, environmental, and operational benefits of CFB steam generators on a utility scale.

CUEA's original Nucla Station was built in 1959 and consisted of three identical stoker-fired units, each rated at 12.5 MWe. Due to its reduced position on the dispatch order resulting from poor station efficiency and increased maintenance costs, the decision was made in 1984 to upgrade and repower the station with a new 925,000 lb/hr circulating fluidized bed boiler and 74 MWe turbine-generator. This followed a detailed review of existing technologies, including several bubbling and circulating fluidized bed designs.

At this time, there were several small bubbling fluidized-bed combustors (FBC's) operating in the United States, but it wasn't until 1985 that the first two industrial CFB's built by Pyropower came into commercial operation. The boiler contract for Nucla was eventually awarded to Pyropower for their proposed CFB design. Utilizing twin combustion chambers, each chamber represented a 2:1 scale-up in height and plan area from their pilot plant in Karhula, Finland.

Except for the old stoker-fired units, most of the equipment from the old plant, including the turbine-generator sets, was refurbished and reused, bringing the total plant electrical output to 110 MWe. Using finalized capital cost numbers, this upgrade and life extension using CFB technology was accomplished for approximately $1050/kW. The project offered several advantages to CUEA including a station heat rate improvement of approximately 15%, reduced fuel costs due to the inherent fuel flexibility of the CFB design, lower emissions required by New Source Performance Standards, and life extension 30 years beyond the plant's original design.

Construction of the new CFB boiler began in the spring of 1985 and was completed over a two year period. First turbine roll was initiated in May 1987 and first coal fires were achieved in June of that year. Following a start-up period which was prolonged by several problems, including a two month outage from an overheat incident, acceptance tests on the design western bituminous coal were completed in October 1988. Through 1988, the Nucla boiler represented the largest CFB boiler in the world either under construction or in operation.

Detailed planning for a test program was initiated by EPRI in 1985. Preparation for the test program commenced in February 1987 with the arrival of a permanent on-site testing staff. Through the third quarter of 1988, the Cold-Mode Shakedown Plan was implemented. This involved calibrating instruments, commissioning the data acquisition system, developing specialized software, procuring and commissioning equipment for the solids preparation laboratory and other specialized test instrumentation, developing procedures, and training test personnel. This work was largely completed by the conclusion of acceptance testing on the design fuel in October 1988. Also during this period and through the remainder of the test program, data were collected to satisfy the requirements of on-going test plans. These included the collection of plant commercial performance statistics and information related to the operating performance of the solids feed and disposal systems, tubular air heater, baghouses, and CFB materials-related components.

In August 1988, after expressing interest in the Nucla project as part of its Clean Coal Technology Program, the U.S. Department of Energy awarded a cooperative agreement to the Colorado-Ute Electric Association as co-sponsors of the test program. This was after careful review of the overall scope and objectives of the Nucla project to verify the DOE's criteria for demonstrating clean coal technology in new and retrofit/upgrade applications.

The outline for presentation in this report includes a summary of unit operations along with individual sections covering progress in study plan areas during this reporting period. These include the completion of cold-mode shakedown and calibration, plant commercial performance statistics, unit start-up (cold, warm, and hot), solids and gas mixing studies, combustion chamber heat transfer, coal and limestone preparation and handling, ash handling system performance and operating experience, baghouse operation and performance, materials monitoring, and reliability monitoring.

During the next reporting period, plant operations and the boiler vendor will make efforts to complete contractual acceptance testing on high sulfur coal. To achieve this, repairs were made to the limestone feed system near the end of 1989 which should allow these tests to proceed to successful completion early in 1990. The test program will proceed with steady-state unit performance testing on Salt Creek coal. As part of the matrix, tests will be performed at various loads, excess air ratios, primary to secondary air ratios, calcium to sulfur ratios, bed temperatures, and coal/limestone feed point configurations. Progress will also continue on each of the study plan areas that are identified in the Detailed Demonstration Program Test Plan.

This report was prepared by Combustion Systems Incorporated for the Colorado-Ute Electric Association with assistance and input from CUEA. The following individuals from CUEA are responsible for the implementation of the DOE agreement and have reviewed this document:

Raymond E. Keith, Acting Project Manager, Business Contact
Thomas J. Heller, Technical Contact
Stuart A. Bush, Senior Engineer, Project Coordinator

CUEA, Inc. would like to acknowledge the Electric Power Research Institute for providing use of their test hardware and software in completing this report and for their direct involvement and sponsorship of the test program, of which some data are reported herein.

Section 1

SUMMARY

This report summarizes unit operating experience and test program progress for 1989 on Colorado-Ute Electric Association's Nucla CFB Demonstration Program. This project is co-sponsored by the U.S. Department of Energy as part of its Clean Coal Technology Program under Cooperative Agreement DE-FC21-89MC25137, signed in October 1988.

During this period, the objectives of the Nucla Station operating group were to correct problems with refractory durability, resolve primary air fan capacity limitations, complete the high ash and high sulfur coal tests, switch to Salt Creek coal as the operating fuel, and make the unit available for testing without capacity restrictions. Each of these objectives was addressed and accomplished, to varying degrees, except for completion of the high sulfur coal acceptance tests. The properties of Peabody coal from the local Nucla mine, Salt Creek coal, high sulfur and high ash coals are summarized in Table 1-1 below. The range of property values in the second column represent the variability of the local Peabody coal burned during 1988 and 1989.

Table 1-1. Fuel Properties

Property	Peabody Coal	Salt Creek Coal	High Sulfur Peabody Coal	High Ash Peabody Coal
HHV, Btu/lb	7490-11840	10460	-	-
Sulfur, %	0.51-2.75	0.44	2.5	-
Ash, %	9.8-42.8	14.6	-	33
Moisture, %	4.1-14.9	10.0	-	-
Fixed C, %	43.5	43.4	-	-
Volatiles, %	28.4	32.3	-	-

The objectives of the test program were to complete all cold-mode calibration and preparation activities, complete the hot-mode test plan, complete the alternate fuels test matrix on the local Nucla coal, begin performance testing on Salt Creek coal, and continue to make progress in each of the remaining study plan areas. Each of these objectives were accomplished in 1989. Significant progress was made with the baghouse test plan, the materials monitoring plan, unit start-ups and restarts, and other areas. Section headings of this report bear the same titles at the study plans. Information or progress attained for any study plan in 1989 is presented in a corresponding section in this Annual Report.

The study plans outlined in the Detailed Test Plan for the Nucla CFB test program with section headings in this report include: Cold-Mode Shakedown and Calibration, Hot-Mode Testing, Plant Commercial Performance Statistics, Performance Characterization and Optimization with Performance Coal, Start-Up and Restart Characteristics, Solids and Gas Mixing, Heat Transfer, Coal and Limestone Preparation and Handling, Ash Handling System Performance and Operating Experience, Baghouse Operation and Performance, Materials Monitoring, and Reliability Monitoring. Results from performance testing on the local Nucla coal are included in this report under Performance Testing in Section 6.

1.1 OPERATING STATISTICS AND MILESTONES

Section 2 of this report chronologically summarizes the plant operating history for 1989. During this period, the unit operated with an availability of 51.9%, a capacity factor of 35.7%, and an average net on-line heat rate of 12,009 Btu/NkWh. The unit accumulated a total of 4344 operating hours on coal in 1989, bringing the accumulated total to 9778 hours. For comparison, statistics compiled by the North American Reliability Council Generating Availability Data System (NERC/GADS) for coal units in the 100-199 MWe size range from 1984 through 1988 list an average operating availability of 83.9% and capacity factor of 49.7%.

There are several factors contributing to Nucla's availability and capacity factors. At the beginning of 1989, a six week outage was required to modify and correct problems with refractory installation in the combustion chambers, cyclones, and loop seals. This was the first major outage for refractory repairs since initial start-up in May 1987. Three outages lasting five days or more, plus several periods of unit derate, occurred as the result of component failures on the cooling tower circulating pumps and the boiler feed pumps. Both of these are non-CFB related technology areas.

Operational problems during acceptance testing on high ash and high sulfur coals also caused several unit outages and forced derates. These problems stemmed from the removal of large-sized bottom ash during the high ash coal tests, and limestone feeder reliability during the high sulfur coal tests. The intent of including these tests with the acceptance testing package (which included performance testing on the design coal) is to demonstrate the fuel flexibility of the station. Although the plant switched to a high quality, low ash and low sulfur fuel in 1989, CUEA wanted to demonstrate performance on low quality fuels as a long-term benefit of the technology within their generating system.

During 1989, there were three extended outages for modifications to the primary air (PA) fan. Originally, fan selection was based on test block margins of 1.4 times on volume and 1.2 times on static pressure. In particular, this margin was required for excess air testing and primary to secondary air ratio testing at full load. However, during unit operations in 1988, primary air fan capacity was at a maximum with the unit operating at or less than 100% maximum continuous rating (MCR). To correct this deficiency, two separate modifications were made to the inlet duct geometry in 1989. Eventually, improved performance was measured following the replacement of the fan wheel with a more aerodynamic design.

A 29 day outage occurred in October 1989 as the result of a secondary superheater tube leak on the second panel in combustor B. Steam/solids washing from the initial leak resulted in a cascade of additional tube failures of surrounding water-wall and superheater tubes. Agglomerations were also formed in the lower combustion chamber, ash cooler, and windbox on the "B" side. The initial leak was attributed to erosion from the downward flow of internally circulating solids within the combustion chambers during normal unit operation. After a detailed inspection of the secondary superheater tubes in both chambers, erosion shelves were added above the second panel on both combustors.

Additional short-term unit outages occurred from a variety of problems outlined in Section 2. In 1989, the unit experienced a total of 32 outages ranging from 1 hour to 933 hours for the refractory repairs in January and February. Fifteen of these outages lasted more than a 24 hour period. Thirteen of the outages were for 5 days or more. Six outages were for more than 20 days. Seven of the outages were initiated by fan trips on the primary, secondary, and induced draft variable speed drive (VSD) fans. As described in the Annual Technical Progress Report for Start-Up through 1988, these nuisance fan trips continued to be a source of numerous unit outages. The outage log for 1989 is summarized in Section 2 of this report.

Despite the numerous problems reported above, the unit continued to show improved operating reliability as solutions to these problems were implemented. On three separate occasions in 1989, the unit ran for continuous operating periods of 20 days or more. One of these intervals in November and December 1989 was at full-load capacity. Table 1-2 summarizes unit operating milestones for 1989:

Table 1-2. Operational Milestones for 1989

Date	Event
Jan-Feb	- Completed refractory modifications and repairs. Modified PA fan inlet duct geometry.
March	- Completed Pre-Hot-Mode test sequence. - Completed Hot-Mode test series. - Achieved longest continuous operating period of 508 hours on coal.
April-May	- Completed first steady-state performance test as part of the demonstration test program.
June-Aug	- Completed alternate fuels test matrix (8 tests total) on the local Nucla coal. - Depleted the local Nucla mine coal stocks and permanently switched to Salt Creek coal. - Completed second modification to PA fan inlet duct geometry.
Sept-Oct	- Replaced primary air fan wheel with a more efficient aerodynamic design.
November	- Completed high ash coal acceptance testing, exhausting high ash coal supplies.
December	- Completed 25 day run at near 100% MCR.

1.2 SUMMARY OF UNIT OPERATING PROBLEMS

This section contains a list of operational and equipment related problems that forced or extended unit outages or resulted in load curtailments during 1989. Some of the problems encountered are related to completing acceptance testing on high ash and high sulfur coals and may not have been present during operation on design coal.

1.2.1 Primary Air Fan - was modified and tested on three separate occasions during 1989 to increase capacity and improve performance. However, during trial acceptance tests on high ash coal in the fourth quarter of 1988, gross unit output was restricted to less than 110 MWe due to high PA fan transformer amperage.

To improve performance, the vendor added turning vanes and shelving to the inlet box duct work in February and retested the fans in March. Only a very slight improvement in performance was noted and the tests gave indications of air recirculation at the fan inlets. The fan was inspected and retested in April, confirming the problem with inlet recirculation. In June, the PA fan inlet boxes were modified from the in-duct silencer upstream of the fan to the fan housing. The fan was retested in July and again showed only marginal gains in performance. In September, the fan wheel and inlet cones were replaced with a more aerodynamic design. Fan performance tests conducted in October indicated significant improvements in performance, but still short of specified levels. However, improvements in capacity were sufficient enough to proceed with testing as part of the demonstration test program. Further modifications and improvements to specified levels are under review by CUEA and the vendors.

1.2.2 Refractory Durability - On several occasions in 1988, unit operations were affected by spalling and breakage of refractory. Loss of refractory pieces in the combustion chambers can result in blockage of the ash cooler inlets. This prevents removal of bed material from the combustion chambers and forces a unit shutdown for removal. Refractory breakage in the cyclones, downcomers, and loop seals accumulates in the bottom of the loop seals and disrupts the flow of recycled solids from the cyclone back to the combustion chambers. When this occurs, solids build up in the downcomers and periodically surge into the combustion chambers. The sudden increase in combustor operating pressure can force a unit trip by choking off undergrid primary air flows below minimum values.

In January, a hot spot developed on the outside metal casing on the loop seals as the result of refractory breakage around the loop seal archways (discussed further in Section 13). The resulting forced outage was used for the start of a 39-day planned outage for refractory modifications and repairs. After inspecting all components, the following observations and repairs were made (A-E).

A. The conical sections of the cyclones showed significant spalling and breakage around cold joints formed during the original installation. According to the refractory vendor, this may have resulted from excessive shrinkage of the abrasion resistant layer due to the high water content during installation. This resulted from low refractory mix temperatures which necessitated the addition of excess water to improve workability. In addition, the original gunnite process for the abrasion resistant refractory layer proceeded in a downward fashion starting from the top of the cone. This resulted in "rebound" material falling on lower construction joint surfaces and anchor bars and led to poor bonding. The cold joints formed during the original installation were incorrectly set with angles other than 90°, which promotes separation during expansion. To correct the problem, the abrasion resistant layer of refractory was removed in both cyclones, new anchor studs were installed, and a new abrasion resistant layer was gunned in place.

B. The upper cyclones showed significant cracking of the abrasion resistant layer around the "bullnose" of the cyclone inlets caused by circumferential stresses from thermal expansion. Bulkheads (stop bars) were installed at two locations in the upper cyclone area in both cyclones to alleviate circumferential stresses. The bullnose refractory was replaced in the combustor A cyclone and was repaired in the "B" cyclone.

C. According to the vendor, excessive cracking and refractory breakage in the loop seal area (where the hot spot occurred) was caused by excessive water during installation which resulted in shrinkage. Both the abrasion resistant and insulating layers of refractory were removed in the loop seals. The areas were completely rebuilt with a combination of brick, castable, and gunned refractory.

D. Spalled and loose refractory was removed at various locations in the combustion chambers. Refractory breakage and loss has been most significant around the recycle return port on the rear walls of the combustion chambers, and at the water-wall/refractory interface. New refractory was gunned into these areas where loss was substantial.

E. Repairs were made to the insulating layer of refractory in the windboxes downstream of the duct burners. Repairs were also made to damaged areas of abrasion resistant refractory in the cyclone downcomers.

1.2.3 Fan Reliability - During 1989, there were seven outages initiated by fan trips. Some of these fan trips occur during voltage disturbances on the transmission network. Others occurred without apparent reason. A trip of any of the PA, secondary air (SA), induced draft (ID), or high pressure blowers to the loop seals causes a master fuel trip (MFT). Typically, the variable speed drive controls are reset and the fans are restarted. This reliability problem, which is related to fan drives rather than the fans, remains under investigation.

1.2.4 Bubble Cap Retention - In August 1988, over 4000 bubble caps were removed from the air distributor plates in the combustion chambers to replace carbon steel retaining washers with stainless steel. During the second half of 1989, a significant number of bubble caps came loose again. Over 70 were replaced in October and 25 in December. The problem is worse in front of the loop seal return where solids loading is highest. The problem appears to result from damage to the pipe nipple (which the bubble cap attaches to) during installation of the stainless steel washers. At the conclusion of 1989, bubble caps are being replaced on an as-failed basis and the overall problem remains under review.

1.2.5 Ash Cooler Operation - During acceptance testing on high ash coal (~33 wt.%), two problems occurred with the ash coolers that are covered in more detail in Section 11. First, the high ash coal contains a significant quantity of parting material (rock). In addition, hammer wear on the final crushers results in a coarser sized material that has blocked the ash cooler inlets on several occasions during high ash coal acceptance tests. An air lance is used to clear the inlet lines from the combustion chambers to the ash coolers. This lancing has caused damage to the fluidizing pipe located in the first 1.5 feet of inlet line closest to the combustion chamber, and has resulted in additional blockage. Modifications to the design of the fluidizing pipe have prevented this from reoccurring.

In addition, during the high ash tests, the operating temperatures in the ash coolers and ash cooler drains became excessive. In order to protect the baghouse located downstream of the ash coolers on the bottom ash transport system, water sprays were added to the ash coolers to reduce operating and drain temperatures. Fine tuning of the hardware design and controls logic was required before completing high ash coal acceptance tests in November 1989.

1.2.6 Limestone Feeder Performance - The limestone feeders operated well on low sulfur Salt Creek coal with feed rates up to approximately 4000 lb/h per feeder. However, during operation on high sulfur coals, the feeders were unable to maintain steady feed rates at significantly higher levels. Several modifications were made to the transport line, rotary valves, and the vent system as discussed in Section 10. At the conclusion of 1989, it appeared that re-routing vent lines helped to increase limestone feed capacity. Final testing and acceptance at design feed rates up to 12,000 lbs/h per feeder will be completed in 1990.

1.2.7 Pump Problems - During 1989, several problems developed with boiler feed pumps and cooling tower circulating pumps that forced unit outages and load curtailments. The latter problem occurred in February and caused a seven day outage along with a forced derate of 30 to 50 MWe for a five day period. One of two 50% capacity boiler feed pumps failed in August and required unit outages for removal and reinstallation following repairs. The unit was derated to 50% capacity for a 12-day intervening operating period. Failures of both of these pumps are non-CFB related component issues.

1.2.8 Secondary Superheater Tube Failure - On October 13, 1989, the unit tripped on high furnace pressure due to a secondary superheater tube leak. Steam/particle washing from the initial tube leak resulted in a cascade of additional superheater and water-wall tube failures in the immediate vicinity. Subsequent inspections during the ensuing 29-day outage revealed several areas of localized erosion on the superheater panels caused by the downward flow of internally recycled bed material. Repairs were made to the damaged tubes, pad welding was added to those areas affected by erosion, and a protective shelf was added over the second superheater panel to reduce/prevent additional erosion in both combustors.

1.2.9 Combustor Temperature Differential - An operating temperature differential as high as 75-100°F has become apparent between combustion chambers. The differential appears to be more pronounced on lower ash fuels, i.e., for Salt Creek coal as opposed to the higher ash local Nucla coal. Changes in primary to secondary air ratios and bottom ash cooler fluidizing velocities have not reduced this differential. It does not restrict unit availability, capacity factor, or the net plant heat rate. In Section 6, the importance of operating temperature on emissions performance will be discussed. As will be seen, this differential temperature, along with the inability to control it, makes it difficult for plant operations to optimize emissions performance.

1.2.10 Miscellaneous Problems - During 1989, there were several small problems which affected operating statistics, but are not necessarily CFB-related. These include: a leaking flange gasket on superheater safety valve, loop seal surging resulting in an MFT from low primary air flow to underbed grid, instrument air compressor, water-wall tube leak on an outside wall box from differential thermal expansion, a condensor tube leak, high differential pressure on the fly ash transport system baghouse, exciter problems on the 74 MWe turbine-generator, MFT's related to controls tuning, and a leak on the governor valve oil circuit. Operating problems are also discussed in Section 2.

1.3 TEST PROGRAM PROGRESS

During 1989, significant progress was made on test program related activities. All cold-mode calibration activities were completed. Most of this effort was performed in 1988 except for some final calibrations of the air flow monitors. These calibrations were completed in 1989 and are reported in Section 3 of this report.

The hot-mode test plan was also completed during the first quarter of 1989. Results from these tests indicate that a 24 to 48 hour stabilization period is required prior to the start of performance testing following changes in Ca/S ratio and unit load. Results also indicate that six coal and fly ash solids samples, and four limestone and bottom ash samples are required for each steady-state performance test in order to achieve acceptable uncertainty levels in calculated results. A test duration of approximately six to eight hours is required to collect this quantity of solids samples. These conclusions are discussed in more detail in Section 4.

After completing the hot-mode test sequence, the test program conducted an additional 18 steady-state performance tests during 1989. The hot-mode test results were used to establish the quantity of solids samples required, the test duration, and the time to steady-state following changes in load and Ca/S ratio. Eight of these tests comprised the alternate fuels test matrix on the local Nucla coal. Results indicate similar emissions and combustion performance for Salt Creek and the local Nucla coal, as discussed in Section 6 of this report.

Analysis of this limited data base (18 total tests) indicates the following:

- The Ca/S molar ratio required to achieve 70 percent sulfur retention is less sensitive to furnace operating temperatures in the range of 1480°F to 1640°F than for temperatures above 1640°F. With both the Peabody coal (0.7 wt.% sulfur) and the Salt Creek coal (0.5 wt.% sulfur), the Ca/S molar ratio for 70 percent retention is about 1.4 (calculated from the calcium in the limestone only). For 90 percent retention, a Ca/S molar ratio of 2.5 is projected.

- NO_x emissions increase with increasing furnace temperatures, although they are still within compliance for all tests by nearly a factor of two. At a constant flue gas oxygen concentration of 3 vol.% and Ca/S molar ratios between 1.4 and 2.1, the NO_x emissions were 30 ppmv and 155 ppmv at furnace temperatures of 1490°F and 1625°F respectively. NO_x emissions tend to be higher at higher Ca/S molar ratios.

- CO emissions decrease with higher operating temperatures. At a constant 3 percent oxygen in the flue gas, the observed emissions were 155 ppmv and 60 ppmv for furnace temperatures of 1400°F and 1650°F, respectively.

- Both boiler and combustion efficiencies appear to be independent of unit load over the range of 55 MWe to 105 MWe. Over this load range, boiler efficiencies of 87.6 to 89.0 percent and combustion efficiencies of 97.6 to 98.9 percent were observed.

In addition to steady-state performance testing, the test program completed gas traverses in the freeboard region of combustor B. These tests were completed at three different loads on the local Nucla coal, and at 50 and 100 percent MCR on Salt Creek coal for various coal feed configurations. These data are discussed in more detail in Section 8 of this report.

Also during 1989, extensive baghouse testing was completed on the local Nucla coal and Salt Creek coal. Results are presented in detail in Section 12 of this report. Data indicates a collection efficiency of 99.96 percent with an average emission rate of 0.0072 lb/MMBtu. The permit level is 0.03 lb/MMBtu. Calculated drag values ranged from 1.5 to 1.8 in.wg./fpm. These low drag values indicate the shake/deflate cleaning at Nucla allows high filtering air-to-cloth ratios with corresponding low tube sheet pressure drop.

Several extended outages during 1989 allowed boiler inspections to be completed as part of the Materials Plan. Inspections were completed following 5,500 hours, 7620 hours, 8750 hours, and 9625 hours of unit operation on coal. These inspections included boiler tube measurements, photographs, and descriptions of boiler metal and refractory components. This information is summarized in Section 13 of this report.

Several restarts were analyzed during 1989, including one cold start-up, two hot restarts, and one warm restart. The data are summarized in Section 7 and suggest that, under optimum conditions, a cold start-up to half load can be achieved in approximately 12 hours. Warm and hot restart times are dictated by how quickly the turbines are taken off-line and fans are removed from service following a unit trip. The former dictates how well steam conditions are preserved while the latter determines the drop in bed temperature prior to the restart.

In addition to these test results, Section 2 of the report summarizes unit operating history and Section 5 tabulates the monthly plant commercial performance statistics for the same period. Section 14 also discusses progress made in tabulating reliability data and lists some preliminary results.

1.4 FUTURE TESTING

During 1990, the following test activities are planned:

- Resume routine performance testing on Salt Creek coal, primarily at 100% MCR. Testing will include variations in operating temperatures (if possible), primary to secondary air ratio, excess air ratio, and Ca/S molar ratio.
- Complete freeboard gas traversing on Salt Creek coal.
- Complete Dynamic Test Plan.
- Monitor unit start-ups as part of the Start-up, Cold and Hot Restart Test Plan.
- Continue to monitor equipment component performance as part of the remaining study plan areas.

Section 2

PLANT OPERATING HISTORY

2.1 OVERVIEW

During 1989, the Nucla CFB operated with an average unit availability of 51.9% and capacity factor of 35.7%. The total operating time on coal in 1989 was 4344 hours, bringing the total since first coal fires in June 1987 to 9778. Monthly coal operating hours are shown in Figure 2-1.

In addition to meeting CUEA's load demands, operational objectives in 1989 included:

- Resolution of PA fan performance deficiencies
- Improvement of reliability of limestone feed system
- Completion of hot-mode shakedown test matrix
- Completion of alternate fuels test matrix on Peabody coal
- Repeat of acceptance tests on high ash/high sulfur coals
- Steady-state performance testing on Salt Creek coal
- Repair of damaged refractory in combustion chambers, loop seals and cyclones

Section 2.2 presents a detailed description of plant operations during the year and discusses operating problems and unit outages. Section 2.3 presents a summary of the work completed during the refractory repair outage in January and February. Section 2.3.2 describes the work done during the year to improve PA fan performance.

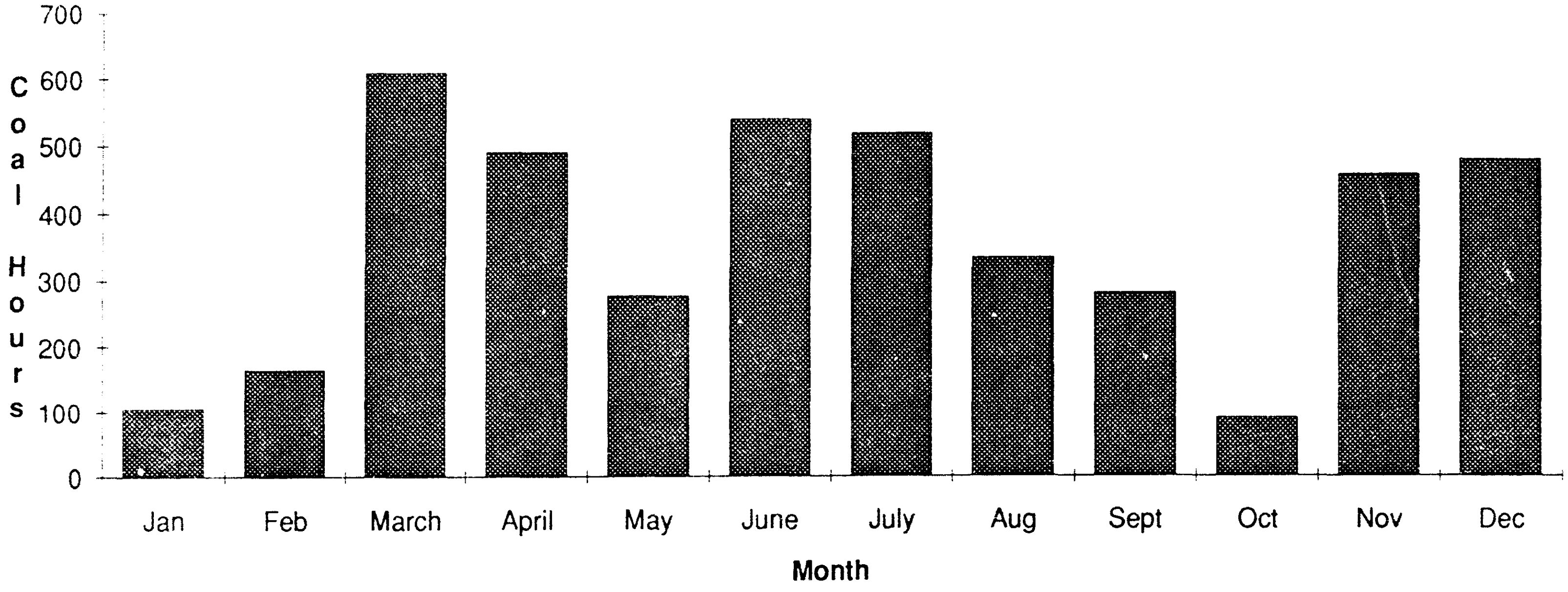
2.2 OPERATING SUMMARY

1989

January

1/1-31 High opacity indicated baghouse leaks. Following repairs, isokinetic traverses were conducted on the air heater outlet as part of the baghouse characterization plan. High PA fan amps at 90-95 MWe were investigated and adjustments were made in the VSD control cabinets. An electronic card was also replaced in the VSD control room to address problems with ID fan trips. The plant was out of SO_2 compliance on 1/4 after limestone feeder 4B tripped; load was reduced. A hot spot was observed on the inboard side of loop seal 4B and the unit was shut down for inspection. A large

Figure 2-1. Nucla CFB Coal Hours
January through December 1989



crack was observed in the refractory in the vicinity of the hot spot and a planned outage for refractory repair and PA fan modifications was begun. During the outage, turning vanes were added to the PA fan inlet and air heater outlet ducting, and new shaker motors were installed on the limestone feeders to improve performance.

February
2/1-28

Refractory repairs and PA fan modifications were completed on 2/11. Unit restart was initiated and included refractory curing. An MFT occurred on 2/13 due to an air to fuel ratio mismatch, which was a result of the Westinghouse control system software update performed during the refractory repair outage. This condition was corrected, but the unit remained off-line for repair of a superheater safety valve flange gasket which began leaking during the previous operating period. The unit was restarted on 2/16 and was back on line after an ID fan trip and MFT. A problem developed with a faulty bearing on circulating water pump 4B on the new cooling tower (one of two pumps). This problem limited the allowable plant load to a maximum 80 MWe gross output through 3/7. Attempts were made to repair a frozen bearing on the circulating water pump while on-line, but leakage of the inlet and outlet butterfly discharge valves prevented this and the unit was shut down. The unit was restarted on 2/22 and problems with repair of cooling tower circulating pump 4B continued. Circulating pump 4A remained in service and load was cycled between 60 and 83 MWe while work continued on the pump impeller shaft. EPRI began calibration of coal and limestone feeders and bottom ash weigh systems in preparation for hot-mode testing. Work also continued on commissioning the continuous fly ash sampler.

March
3/1-24

The test program attempted to begin the pre-hot-mode test matrix on 3/3, but testing was aborted due to a mismatch in combustion chamber temperatures of 100°F and difficulty controlling bed pressures in combustor B. An MFT occurred on 3/3 due to low PA flow to combustor B, which was caused by irregular recycle solids flow. Another MFT due to a PA fan trip occurred on 3/5. After restart, the unit was in operation for pre-hot-mode tests. During the period 3/6-10, CUEA repaired a metal casing crack that developed on the inboard side of loop seal B. On 3/11, switch-over from Peabody to Salt Creek coal was initiated. During 3/12-18, the unit was in operation for hot-mode shakedown tests (see

Section 4). Tests P30 and P31 were conducted on 3/20 and 3/21, respectively. Tests were conducted on the PA, SA and ID fans and a 10% improvement in PA fan performance was observed. This was still insufficient to satisfy performance guarantees, however. Data was collected to assess the effect of soot blowing on back end flue gas temperature following various intervals of dust accumulation.

3/24-31 A controlled shutdown was initiated in preparation for combustion chamber and loop seal inspections to detect any deterioration which had occurred during the 5 week period of operation since previous repairs. All surfaces were in excellent condition. There were no signs of bed agglomeration or growth from the refractory surfaces, even though the Salt Creek coal has a higher sodium content than the previously used Peabody coal. Visual inspection of the refractory/water-wall tube interface area revealed no changes in wear pattern. Refractory in cyclone B was inspected through the upper manway and was found in excellent condition. The bed quality was excellent, with no evidence of accumulations of gravel-like material on the distributor plate which had been observed with the higher ash Peabody coal. A fairly large amount of backsifted material was observed in the windbox. One distributor cap was missing in each combustor. The pipes serving these caps were plugged from the windbox side. The boiler was restarted on 3/29 after the scheduled repair of the boiler feed pump seal. Several trips on duct burner 4B and two vaporizer trips were experienced during startup. High differential pressure (dP) across the fly ash separator baghouse was experienced. While burning high sulfur coal on 3/30, limestone feeders 4A and 4B began tripping. There was recurring pluggage of the "pant leg" above rotary valve 4C. Load was reduced in order to address these problems.

April

4/1-12 Unit burning high sulfur coal and limestone feeder problems being addressed. Sulfur analyzer 4B sampling system problems with plugging in the sample tube orifice were being addressed. 50, 75, and 100% load air flow traverses were completed. High differential pressure across the fly ash transport baghouse, probably due to transport line blockage below the baghouse hoppers, was observed. Electric vibrators were installed to correct the problem. A controlled shutdown was initiated on 4/12 after problems were experienced with bottom ash removal while burning high ash coal.

4/13-30 Agglomeration found in ash classifier 4D had been caused by a water-wall tube leak, which was the result of impingement from the temporary emergency water sprays on the tube walls. Ash intake blockage was also found that was the result of damage to the fluidizing air pipe during rodding out of the ash classifiers. Plant was restarted on 4/18. Fan tests were started at full load to verify earlier tests and to quantify the effect of sealing up PA fan inlet housing cracks. Freeboard gas analysis system (FGAS) traverses were conducted. Alternate fuels tests were being conducted on 4/21 when an ID fan trip terminated the test at 17:00. The unit was restarted by 21:30. Plant was taken off-line on 4/27 after a gasket leak on boiler feed pump 4B and mechanical seal leakage on boiler feed pump 4A.

May
5/1-31 Plant restart was attempted on 5/9, but an ID fan trip delayed restart until 5/10. An FGAS traverse was conducted on 5/12. A boiler MFT due to an SA fan trip occurred on 5/14. Repairs were made during the outage to boiler feed pump 4B and to the fluidizing pipes at the inlets to all four classifying coolers. Unit 4 was back on line on 5/23. FGAS traverses were conducted on 5/26 and Test A07 was conducted on 5/27. An MFT due to an SA fan trip of unknown cause occurred on 5/30.

June
6/1-30 Bottom ash screw cooler 4A bearing repairs were completed. The test program completed test A04 on 6/6, test A05 on 6/7, test A06 on 6/8, and ran freeboard gas traverses on 6/9. The unit was taken off line on 6/9 to remove clinkers and to replace three fluidizing air nozzles in ash classifier 4C. Following a surge in stack opacity, seven bags were replaced in compartment 2S on 6/12. FGAS traverses were done on 6/15. Test A02 was completed on 6/16, test A03 was completed on 6/17, and test A08 was completed on 6/18. On 6/21, isokinetic tests on baghouse 4 inlet and outlet were conducted. FGAS traverses were conducted on 6/21 and 6/22. The unit was brought off line on 6/23 for a scheduled PA fan outage.

July
7/1-7 All units off-line for a scheduled PA fan outage. Work items completed during this outage included modifications to the PA fan inlet boxes, the combustor windbox ash drains, the fly ash and bottom ash silos (to improve access), control logic on the bottom ash emergency sprays, reapplication of the weld overlay on selected water-wall tubes in both combustors, and refractory repairs in combustor A. Boiler inspectors checked the condition of the boiler

convection pass, penthouse, and furnaces. The drum internals were not inspected because several drum head hold-down nuts were seized and could not be removed.

7/8-14 Unit 4 was put on-line at 03:30 on 7/8. Units 3, 2, and 1 were put on-line on 7/9 at 09:50, 15:20, and 21:50, respectively. Load was increased to 107 MWe on 7/12 with the fan manufacturer on site to run PA fan performance tests. Preliminary results of these tests indicated minor improvement in PA fan performance as a result of the inlet box modifications.

7/15-20 All units on-line at 70 MWe. A turbine representative was on-site tuning the turbine controls in order to allow steeper load ramps in the future. Load was increased to 90 MWe at 09:50 to assess the effect of this tuning on load ramping. Control was considered improved during load changes with the limiting factor shifting from the turbine to the boiler. Load was increased to 98 MWe on 7/16 in preparation for performance test P49. This test was completed on 7/17 at 17:00 and limestone feed rates were increased shortly afterwards in preparation for test P50. During test P49, high bed temperatures (1660°F and 1685°F) were noted, and abnormally high limestone feed rates were required to maintain SO_2 emissions within compliance. Test P50 was completed on 7/19 at 15:30 and also required higher than normal limestone feed rates. Test P51, scheduled for 7/21, was cancelled while diagnostic checks were performed to resolve the shift in Ca/S ratio requirements.

7/21-27 Unit load was increased to 104 MWe to help determine if boiler load was adversely affecting the Ca/S ratio. No change was noted. PA underbed to PA overbed air flow ratios were also changed in an attempt to change bed temperature and thereby Ca/S ratio requirements. Again, no effect was noted. The unit was released to dispatch for weekend operation and load was reduced to 60 MWe at 22:35. The unit remained on dispatch throughout 7/22, operating between 60 MWe and 67 MWe. At 02:30 on 7/23, two limestone feeder "boots" blew out on the 4B feeder. These boots are flexible, rubber expansion joints between the limestone weigh bin and rotary valves. Limestone feed to this side was discontinued. Blinded bags in the 4B limestone silo dust collector baghouse were determined to be the cause for the above failures. These bags were replaced and the feeder was put back into service. The feeder tripped out several times when returned to service and was finally left off. A boot also blew out on the combustor A side limestone feeder "D" rotary valve during this time frame and the feeder was taken out of service. Replacement bags were not in stock for the 4A limestone silo dust collector baghouse. At approximately 24:00 on 7/23, unit 3 turbine tripped on generator high differential, C phase. Both side limestone feeders were returned to service, with the exception of D and G blowers, by 17:40 on 7/24. The chain drive on G blower was found off and replaced on the morning of 7/25. The replacement bags for 4A limestone silo dust collector baghouse were received on 7/26 and replaced. Generator checks on unit 3 were completed on 7/27. A faulty relay was determined to be the cause of the trip.

7/28-31 Unit 3 was returned to service at 08:40 on 7/28. Load was increased from 93 to 109 MWe per dispatch request. The unit MFT'd at 14:50 on 7/28 due to loss of the ID fan, which resulted from a system transmission disturbance. 4A boiler feed water pump (BFP) seized during the unit roll down when the recirculation valve did not operate properly. Unit 4 was back on-line at 16:50 with unit 3 on-line at 20:00. Load was restricted to 55 MWe with only one available boiler feed pump. Unit 3 was removed from service at 21:50 on 7/30 and unit 4 was taken off-line at 22:50 to allow removal of 4A BFP for off-site repairs. It was necessary to shut all units down because the 4A boiler feed pump isolation valves were not working properly. The plant started disconnecting 4A BFP on 7/31.

August

8/1-8 All units were off-line for removal of 4A BFP. The pump was removed on 8/1 and shipped to Houston for repairs on 8/2. Blank flanges were installed on 4A BFP suction and discharge lines in preparation for unit start-up. 4A BFP recirculation valve was inspected. Pilot valve operation was rough and badly worn "O" rings were found. The valve internals were cleaned and both a new pilot valve and "O" rings were installed. The unit was released to dispatch at 12:00 on 8/2 with a capacity limitation of 55 MWe and placed on reserve shutdown. Unit start-up was requested by dispatch at 16:10 on 8/4. Start-up was delayed due to a broken interstage check valve on the instrument air compressor. The valve was replaced on 8/5 and unit start-up was initiated. Fires were removed from the boiler at 09:00 on 8/6 during the turbine heat soak due to lack of propane. Propane delivery was eventually received and unit 4 was on-line at 18:20 on 8/7. Unit 2 was on-line at 01:00 on 8/8 and load was increased to the maximum derate load of 55 MWe. EPRI conducted FGAS traverses at the 40' and 80' elevations in combustor B.

8/9-15 The test program conducted test P39 at 55 MWe with limestone feed rates set for emissions compliance. This baseline test was completed at 15:00 and limestone feed rates were increased to obtain 0.1 lb/MMBtu SO_2. Loop seal coal feeder 4D was secured at 08:30 on 8/10 and FGAS traverses at the 40' and 80' elevations were performed starting at 10:00. Test P21 was started at 08:30 on 8/11 and completed at 15:30. Coal feeder 4D was then put back into service. With units 2 and 4 on-line at 55 MWe, all front wall coal feeders (4B, 4C, 4E and 4F) were removed from service. FGAS traverses at the 40' and 80' elevations were performed and completed at 18:30. At 09:00 on 8/15, limestone feeders 4B, 4C, 4F and 4G were secured. The coal/sorbent feed configuration included coal feed to the loop seals only and limestone feed to the loop seals and outside walls. Test S05 was performed without solids sampling to qualitatively assess the effect of this feed configuration on sulfur retention. When the above test was completed at 16:00, the coal feed configuration was reset to normal and the limestone feed configuration remained unchanged for overnight data collection.

8/16-25 At 04:00 on 8/16, the front wall coal feeders were again removed from service in preparation for test P52. This test was cancelled when a faulty load cell caused the 4A limestone feeder flow signal to go bad. The 4B coal crusher rebuild was completed with new hammers and suspension bars. Units 2 and 4 on-line at 55 MWe. Test P52 was started at 08:00 and completed at 15:30 on 8/17. 4A and 4B coal crushers were adjusted one turn open (wider gap) after the test and a second turn on 8/18 to qualitatively test the effect of larger coal size on the combustion process. No change in boiler conditions was noted. The 4A BFP was received on site on 8/19. Unit 2 was taken off-line at 00:30 and unit 4 was removed from service at 00:45. The plant reinstalled the BFP and reconnecting piping on 8/21. Both furnaces and windboxes were inspected on 8/22. 23 bubble caps were found missing in combustor A. The bubble caps were replaced by 15:30 on 8/24. Unit start-up was further delayed due to second stage problems on the instrument air compressor. A portable compressor was received on site and piped up on 8/25. Fires were established in the boiler at

16:53. The boiler MFT'd at 16:50 on high drum level and at 20:03 on low drum level.

8/26-31 Unit 4 on-line at 04:40 on 8/26. It was taken off-line at 05:40 due to lack of propane. Unit 4 was again on-line at 16:30 but an MFT occurred at 17:50 due to loss of propane vaporizer fires. The fires were reestablished and the boiler was operating on 100% coal (no propane assistance) at 19:20. Unit 2 was on-line at 20:50 and total load was increased to 46 MWe. Units 3 and 1 were on-line at 03:00 and 09:30 on 8/27, and load was increased to 98 MWe. On 8/28, all units were removed from service to repair a tube leak. Unit 4 was the last unit to be taken off at 11:30. The leak was discovered on the outside of combustor B where the wall box on the 4F coal feeder is welded to the furnace tube wall. Repairs were completed by 18:30 on 8/30. Fires were established in the boiler at 01:37. Unit 4 tripped during turbine roll at 02:25 due to an exciter voltage cabinet cooling fan failure. The no. 2 throttle valve stuck partially open (approximately 11%) when the turbine tripped. The valve problem was determined to be in the valve body and not the actuator.

September
9/1-13 All units remained off-line to disassemble and repair the no. 2 throttle valve on unit 4 turbine. The unit was cooled down adequately by 9/5 to begin disassembly work, which was completed on 9/8. A turbine manufacturer representative supervised the disassembly process and determined that the upper valve guide bushing clearances were inadequate. The clearances were machined to proper specification and valve reassembly was completed by 17:00 on 9/10. During this outage, two adrift bubble caps near the loop seal entrance to combustor B were capped from the windbox side as a temporary repair. The boiler was lit off at 18:40, but the unit MFT'd at 02:00 on 9/11 due to high drum level. Fires were reestablished and unit 4 was on-line at 13:25 with 100% coal firing at 17:50. Unit 2 was on-line at 12:15 and unit 3 was on-line at 21:40. The boiler MFT'd at 04:40 on 9/12 due to high drum level. This high drum level occurred when the main feed water control valve stuck open with unit load at 55 MWe. Fires were reestablished at 04:50 with 100% coal firing (no propane assistance) at 05:30. Load was increased to 98 MWe. At 03:00 on 9/13, the boiler MFT'd due to an SA fan trip. After several unsuccessful attempts to restart the fan in the normal fashion, the fan was restarted by bypassing the variable speed drive controllers and run at a

fixed RPM. Unit 4 was on-line at 11:50, unit 3 was on-line at 16:00, and unit 2 was on-line at 18:15.

9/14-22 Units 2, 3, and 4 on-line at 80 MWe total load. Unit 1 was placed on-line at 16:10 on 9/14 after a tube leak in the no. 1 condenser was plugged. Total load was increased to 82 MWe in preparation for a performance test on 9/16. This test was cancelled due to problems with the limestone feed system to combustor A. On 9/16, all of the bags in 4A limestone silo bag filter and a broken chain on 4B limestone rotary valve were replaced. At 14:00 on 9/17, the main feed water valve stuck and caused an MFT on low drum level. The valve was repaired and unit 4 was on-line at 14:50. All four units were back in service by 01:20 on 9/18 with load increased to 98 MWe in preparation for baghouse testing. With all units on-line at 98 MWe, baghouse testing began on 9/19 and continued through 9/22. Baghouse testing included the measurement of baghouse inlet and outlet fly ash mass flow concentrations, dust cake weights on selected bags, and fly ash resistivities. Individual baghouse flow monitor (IBFM) data was also collected to determine the baghouse air-to-cloth ratio and to compare the drag of "warp in" versus "warp out" bags. Bed temperatures were high throughout this period of baghouse testing with approximately 1650°F and 1720°F temperatures in combustors A and B, respectively. Efforts to lower these temperatures by changing bottom ash removal rates and bottom ash cooler classifying velocities were unsuccessful.

9/23-30 At 14:00 on 9/23, a test was conducted to assess the effect of soot blowing on the boiler convection pass and air preheater. Shortly after this test was completed, at 22:21, the unit MFT'd due to a "phantom" PA fan trip. The decision was made to begin a scheduled PA fan wheel replacement outage at this time. On 9/24, the boiler manufacturer ran a test to determine the fan down-time required to insure proper boiler cool down. The test program then conducted air flow testing in an attempt to better account for all of the air streams entering the boiler. Started to remove the PA fan wheel on 9/25 and finished on 9/26. The fan wheel was then loaded on a trailer and shipped to Farmington, NM for separation from its shaft and replacement with a new wheel. Furnace A was inspected for loose and/or missing bubble caps on 9/29 and 50 were identified for repair. This includes the 23 bubble caps that were temporarily repaired during a previous outage. Refractory repairs were started in both combustors.

October

10/1-9 All units were off-line for a scheduled outage to replace the primary air fan. Basic design differences in the new fan include a 14" wider wheel with two additional blades (10 instead of 8), a 60 percent larger inlet cone area, and a more functional seal between the cone and the wheel. Before arriving on site, the replacement wheel was fit to the original fan shaft at a service shop in Farmington, N.M. The replacement fan arrived at the plant on 10/4 and installation was completed on 10/7. The fan manufacturer performed operational checks on the fan until unit start-up was initiated on 10/9 with unit 4 on line at 22:14. Other work activities completed during this outage included the replacement of 70 loose or adrift nozzle caps in the combustors, loop seals, and bottom ash coolers, windbox drain modifications, minor refractory repairs, and the addition of a 3" vent above the rotary valves on both 4A and 4B limestone feeders to provide better flow control at high feeder flow rates.

10/10-13 Unit 4 was on-line at 6 MWe and raising load. Unit 2 came on-line at 10:31, unit 3 at 11:54 and unit 1 at 14:53. Load increased to 109 MWe to perform PA fan tests but was later decreased to 105 MWe due to SA fan limitations. The PA fan was tested during the evening on 10/10. Preliminary results indicate that approximately 2/3 of the desired improvement in fan output and efficiency were realized. During the morning of 10/11, load was reduced to 61.5 MWe to conserve coal while the reclaim feeder motor to "C" conveyor was replaced. Load was then increased to 90 MWe, where it was restricted by unreliable limestone feeder operation. High ash coal was introduced into the boiler at approximately 17:30 in preparation for type "B" coal acceptance testing by CUEA. On 10/12, load was held at 87 MWe while the boiler manufacturer made adjustments to the bottom ash cooler (BAC) water sprays and installed air lances into two of the four BAC drains. Modifications were completed by 17:00 hours and load was increased to 105 MWe. On 10/13, final preparations were made for the high ash coal test. At approximately 18:52, the 20" bed temperatures in combustor B started dropping drastically, the 4A baghouse tripped off-line several times on high pressure drop, drum level became unstable, and combustor pressure began climbing. At 19:21, the boiler MFT'd on high furnace pressure and units 1, 2 and 3 tripped off- line. Unit 4 turbine came off-line at 19:33. A tube leak was suspected as the root cause for the trip.

10/14-31 During 10/14 and 10/15, the boiler was cooled down using the ID fan. On 10/16, combustion chamber B was opened and visually inspected. The location of the leak was identified to be in the southwest corner of this combustor in the vicinity of the second superheater panel from the bottom. Water from the tube leak caused agglomeration of the bed material in combustor B, windbox 4B, and bottom ash cooler 4D. On 10/17, the tube leak area was closely inspected from a skyclimber. Localized erosion was noted on the secondary superheater, second platen from the distributor plate floor, in the corners where the superheater tubes bend back around toward the exit header. Steam washing which followed the initial superheater leak caused erosion damage to six adjacent water-wall tubes, three of which developed leaks. On 10/18, the plant started removing cementitious bed material and erecting scaffolding for tube repairs. On 10/24, combustor B bed material removal was completed and work on cleaning the bed nozzle holes was started. A water-wall panel consisting of ten tubes was removed from the center wall of B furnace to expose the superheater panels on 10/24. Several more superheater tubes were found which required replacement due to bed material erosion. The test program conducted inspections, which included ultrasonic tube thickness measurements and pictures. On 10/25, combustor A was inspected and 16 superheater tubes in the northwest corner were found with varying amounts of erosion damage. On 10/28, the plant completed cleaning the bed nozzle holes in combustor B. Superheat and water-wall tube repairs were still in progress on 10/31.

November

11/1-10 All units off-line for boiler tube repairs. Between 11/1 and 11/7, outage work was completed that included extensive visual inspection of combustor A SH II panels and water-wall support tubes, UT measurements at various SH II and water-wall tube locations in both combustors, tube repair or replacement where needed, and the cleaning out of cementitious bed material from combustor A. Several tubes in both combustors found with erosion damage were pad weld repaired. After the above repairs were completed on 11/7, the boiler was successfully hydrostatic tested at approximately 1-1/4 times (1890 psig) the normal operating pressure. On 11/8, a protective shelf was installed on the top of SH II panel P2. This shelf is designed to reduce the flow velocity of ash around SH II panels P1 and P2. Installation was completed at 19:00 on 11/10. The test program then ran a test with only the high pressure (HP) blower in service to zero the loop seal downcomer leg pressure gauges which were being installed. At 19:30, reinjection of bed material from the bottom ash silo was started. At 19:41, the test program conducted a cold air flow test to help resolve continuing air flow measurement discrepancies.

11/11-14 All units off-line. Boiler lit off at 05:36. The unit MFT'd at 06:54 due to a PA fan trip, at 09:06 from low drum level, and at 10:37 and 16:04 from high drum level. Unit 4 was on-line at 18:10 with 100% coal firing (no propane assistance) at 21:53. High ash coal was being used in preparation for boiler acceptance testing. Unit 3 came on-line at 00:50 on 11/12. The test program then conducted hot-air air flow testing with unit load at 50 MWe. After testing was completed, unit 1 and unit 2 were placed back on-line at 07:44 and 12:25, respectively. The unit MFT'd at 18:12 with load at 85 MWe due to a fuel/air ratio imbalance which possibly resulted from an improper coal Btu bias setting. Unit 4 came back on-line at 20:24 with 100% coal firing at 22:54. Units 1, 2 and 3 on-line at 00:34, 00:48 and 01:56, respectively, on 11/13. On 11/14, unit load held at 92 MWe due to high pressure differential across the 4B fly ash separator baghouse. A broken hopper vibrator on the 4B fly ash system was also repaired.

11/15-19 All units on-line at 99.5 MWe. High pressure drop across the #4 baghouse prevented load from being increased. Compartment 4C and 4G non-operational shaker mechanisms were repaired. At 08:00 on 11/15, 4C bottom ash cooler was secured. The unit ran on 4D bottom ash cooler and 4B screw cooler throughout the day without major problems. On 11/16, unit load was increased to 105.7 MWe and a coal sample was checked for ash (20.66%) and sulfur (.7899%). High ID fan inlet pressure prevented load from being increased to 110 MWe. On 11/17, the undergrid air flow to combustor B was increased by 12 klb/h in an attempt to equalize bed temperatures between combustors, which were at 1560°F and 1680°F, respectively. Coal feeders A, C and E were calibrated. On 11/18, coal conveyor C experienced a structural failure at the head end, allowing one side to drop. Units 1 and 2 were taken off-line at 01:17 and 01:28 on 11/18 and load was reduced to 47 MWe to conserve coal while repairs were made. Repairs were completed at 10:25 with Units 2 and 1 on line at 11:33 and 12:41, respectively. Salt Creek coal was introduced to the coal prep system on 11/19 with the load at 105 MWe in preparation for performance testing.

11/20-23	All units were on-line with load at 105 MWe. The test program calibrated the bottom ash weigh hoppers and limestone feeders. The PA underbed air flow to combustor B was increased by 4 klb/hr to 16 klb/hr total. The bottom ash removal system to combustor B was taken out of service to increase bed pressure in combustor B. On 11/21, unit load was reduced to 106 MWe at 07:30 after #4 baghouse tripped on high differential pressure. PA underbed air flow was increased by another 29 klb/hr to 45 klb/hr. Bed temperatures in combustor B dropped by 30°F and freeboard differential increased about 1 in. wc. shortly after this air flow change. With bed pressure in combustor B up to 23-25", bottom ash removal was started in an effort to decrease the bed pressure to 18-20" and observe the effect. The air heater bypass damper, which was approximately 10% open with a broken sheer pin, was repaired. The test program continued limestone feeder calibrations. On 11/22, baghouse differential pressures decreased and load was increased to 109.7 MWe.
11/24-30	All units were on-line with load at 109.7 MWe. On 11/24, the 4C coal rotary valve hung up. Maintenance mechanics removed a piece of metal and the valve was returned to service. On 11/25, the 4A limestone feeder transport line plugged and could not be cleared. On 11/26, a broken hanger arm was replaced on the 4B coal vibrating feeder. On 11/27, with the load at 110 MWe, high differential pressures were again experienced on the baghouses. The solenoids on the compartment outlet dampers were cleaned, which helped to alleviate the problem. PA underbed air flow bias to combustor B was also removed on 11/27. On 11/28, stack opacity started climbing. The baghouses were checked for leaks and bags in compartments 4A, 2Q and 2S were replaced. The test program conducted performance test P55 on 11/29 with combustor A and B temperatures at 1550°F and 1695°F, respectively, and O_2 levels at 3.3%. On 11/30, the test program ran test P56 at 2.3% O_2. Isokinetic sampling at the air heater inlet was also conducted to determine if the ash loading is different between the two combustors, indicating different cyclone efficiencies. The rotometers on loop seal B were checked and found to be running significantly higher than on 4A. At about 16:30 on 11/30, C conveyor belt was found ripped 3" wide and half way around; it remained in use until a replacement could be obtained.

December

12/1-4 All units were on-line at 103 MWe. Scheduled test P57 (4.3% O_2) was postponed because the air flow settings required were not within the current boiler master control range. Instead, the test program conducted a low excess air test to determine the unit's emission characteristics at a very low O_2 setting. The O_2 set point was reduced to 1.0% vol. (wet) for 4 hours with no appreciable increase in the CO levels. Corresponding temperatures in combustors A and B were at 1575°F and 1750°F, respectively. The boiler vendor then changed loop seal 4B rotometer settings to match the loop seal 4A readings. Over the weekend (12/1-12/2), all units were in service at 108 MWe. Limestone feeder adjustments were made and limestone preparation system problems were cleared up. On 12/4, with all units at 108 MWe, an MFT occurred at 10:30 hours due to low turbine electro-hydraulic control (EHC) system pressure while valving a recharged accumulator back into service. Unit 4 was put back on line at 12:00. Units 1, 2 and 3 were on line at 14:52, 16:55 and 17:38, respectively. The boiler manufacturer completed rerouting 4B limestone feeder vents to the coal silo in an attempt to improve limestone feed system performance.

12/5-8 On 12/5, total unit load was 107 MWe. Unit 4 baghouse tripped on high differential pressure at 02:32, 02:43 and 06:20. Load had been reduced to 96 MWe at 02:48 but did not correct the problem. An inspection disclosed that this high dP was the result of full and/or bridged fly ash hoppers, a slow operating compartment outlet damper, and a compartment deflate damper which did not completely close. The boiler manufacturer completed rerouting 4A limestone feeder vents, after which the limestone feed to both combustors was very stable at about 2700 lb/hr. Unit load was increased to 107 MWe after baghouse repairs were completed. On 12/6, high sulfur coal was introduced into the plant in preparation for acceptance testing, which began at 13:00. The coal sulfur content was initially measured at about 1.0%. At 17:30, water was observed leaking from the 4B bottom ash cooler and the cooler was removed from service. The coal acceptance test was still in progress on 12/7. The coal sulfur content during the day, tested on an as-fired basis, increased from 1.2% S with 12.64% ash at 08:00 to 1.73% with 18.6% ash at 15:00. Combustor A underbed pressure was also noted to be increasing throughout the day. At 19:20, load was reduced to 101 MWe when the windbox pressure under combustor A increased to 66 in.wg. Units 1 and 2 were taken off-line at 23:37 and at 23:55, respectively, and load was reduced to 70 MWe on 12/8. The underbed pressure in combustor A remained above 65 in. wg. and the decision was made to shut down. Units 3 and 4 were taken off-line at 04:07 and 04:31, respectively. The fans were shut down to repair the water leaks in 4B bottom ash cooler. After the leaks were repaired, the fans were restarted to continue cool down. Removal of bed material was started for internal inspection purposes.

12/9-14 Over the weekend, all units were off-line as cool down and bed material removal continued. On 12/11, furnace inspections disclosed 25 PA nozzles that were adrift in combustor A. One nozzle in combustor B was also missing. A quantity of refractory was found on the floor of combustor A with three pieces wedged into the 4C bottom ash drain, possibly causing the ash removal difficulties previously encountered. The A and B cyclone vortex finders were inspected on 12/12 and 9 panels were found warped out of shape, inward from the original circular configuration. On 12/13, the plant started replacing the missing nozzles and started weld repair of a vertical crack found in the 4B windbox on the west side, south of the first east-west I-beam. The crack extended through the horizontal weld where the sloped side meets the vertical panel. The water sprays to the 4 bottom ash coolers were also cut off and removed. On 12/14, repairs were completed and the boiler was closed up for bed material reinjection by 16:30.

12/15-31 Fires were lit off at 03:02. An MFT due to high drum water level took the boiler out of service at 03:54. The boiler was relit at 04:19. On start-up, a test was conducted with all vents, drains and warm up lines closed until 300 psig in order to determine the effect on drum level control. At 14:02, high drum level caused an MFT. The boiler was relit at 14:08 and went to 100% coal firing at 17:55 with the load at 47 MWe. Unit 3 was put on-line at 03:28 and the load increased to 72 MWe by 17:18. The 4D coal feeder drag chain hung up on the return guide and the unit 3 baghouse repressure fan was inspected. Bearing failure and shaft damage required new material. The 4B baghouse ash separation gates were causing numerous high differential pressure alarms because of improper sealing. On 12/17, units 2, 3 and 4 were in service at 72 MWe. Unit 1 was put on line at 11:11. There was a delay while waiting for boiler chemistry to reach levels below the maximum water quality limits. At 23:17 while increasing load, unit 4 MFT'd due to an undetermined problem with the exciter firing circuit. After two unsuccessful start-up attempts on 12/18, a Westinghouse representative was called in to help troubleshoot the problem. Between the two exciter firing circuits, enough good cards were found to set up one operational channel on 12/20 and proceed with start-up. One MFT occurred during start-up due to loss of the PA fan, which resulted from a loose VSD cabinet switch. Unit 4 came on-line at 17:30 and was firing 100% coal at 19:03. Unit 1 came on-line at 22:00. On 12/23, the chain drive on 4A coal feeder horizontal conveyor broke and was replaced. Repairs were made to the 4A bottom ash unloader chain drive idler gear and a fly ash drum unloader. 4 bags were replaced in baghouse 4 and 9 bags were replaced in baghouse 2. On 12/29, 4F coal feeder tripped and a scheduled FGAS test was cancelled. The unit MFT'd on low drum level on 12/30. A serious oil leak on the unit 4 governor oil circuit was discovered and the unit was removed from service. Repairs were made and the unit was back on line at 23:30.

2.3 OPERATING PROBLEMS AND OUTAGES

Operational problems contributing to repair outages in 1989 were most frequently caused by difficulties in the following areas:

- Refractory degradation, particularly in the loop seals and cyclone cones. A ten week outage was required in January and February for repairs.
- Feed water pumps: problems with bearings, seals, valves, and casings were frequent.
- Cooling tower circulating water pump 4B: bearing problem corrected during the first quarter.
- ID, SA and PA fan performance
- Ash removal system
- Limestone feed system
- Loose or missing bubble caps
- Tube leaks: The August tube leak was caused by outside wall box differential expansion, the October tube leak was caused by erosion in the combustor.

The unit was off-line a total of 32 times in 1989, and was shut down for 12 extended periods (5 days or more); eight of these were from controlled shutdown sequences. The first of these (Jan-Feb) was for refractory repairs to the combustion chambers, loop seals, cyclones and downcomers. Turning vanes were added to the PA fan inlet and new shaker motors were installed on the limestone feeders. The second (Feb) resulted from a seized circulating water pump on the new cooling tower. The third (April) resulted from difficulties removing bottom ash from the combustion chambers due to bent fluidizing pipes. The fourth (April-May) resulted from water leaks on the mechanical seals of both feed water pumps. The fifth (May) was initiated by an MFT from an SA fan trip, and boiler feed water pump 4B was replaced. The sixth (June-July) was a controlled shutdown for inspections following completion of the alternate fuels test matrix. Modifications were also made to the PA fan inlet ductwork and limestone feed system.

The seventh and eighth extended outages (July-August and August, respectively) were associated with the repair of feed water pump 4A. The ninth (Aug-Sept) resulted from a water-wall tube leak on the outside of the boiler at a coal feeder wall box connection. The unit 4 turbine no. 2 throttle valve was also disassembled and repaired during this outage. The tenth (Sept-Oct) was initiated by a phantom PA fan trip, and the PA fan wheel was replaced during the outage. The eleventh (Oct-Nov) resulted from a boiler tube leak in combustor B. Superheater II platens in both combustors were inspected during the outage, and erosion shelves were installed on top of SH II panel 2. The final extended outage during 1989 resulted from loss of combustion air flow control to combustor A due to excessive bed inventory.

Table 2-1 summarizes these outages throughout the year. The dates, duration, and a brief description of the cause of each outage is given. Each of these problem areas are discussed in more detail in other sections of this report.

2.3.1 Refractory Repair Outage
January 5 - February 13

On January 5, while operating at 90 MWe, a hot spot was discovered on the inboard side of loop seal B and discoloration in paint was observed on the outboard side. A controlled shutdown sequence was then initiated. Bed material was removed from the combustion chambers and the unit was cooled down for inspection of all refractory surface in the combustion chambers, cyclones, and loop seals. Results of the inspection and subsequent repairs are summarized below:

- Conical portion of cyclones: Cracking, spalling and erosion were widespread in the cone sections of the cyclones. Each of the cyclones had three large vertical cracks extending from the bottom of the cone to the horizontal refractory support ring at the base of the inlet spirals. Several of these cracks had been repaired in 1988 using a plastic refractory material which was also found to be cracking and spalling. Breakage and spalling of the refractory may have resulted from excessive shrinkage of

Table 2-1. Outage Summary for 1989

Start Outage	Stop Outage	Duration (Hours)	Cause
5-Jan-89	13-Feb-89	933	CONTROLLED SHUTDOWN DUE TO HOT SPOT AT LOOP SEAL 4B WELDED JOINT. DECISION MADE TO START PPCO OUTAGE TO REPAIR DAMAGED REFRACTORY IN THE LOOP SEALS AND CONES OF THE CYCLONES.
13-Feb-89	16-Feb-89	58	UNIT TRIP ON FUEL/AIR RATIO MISMATCH. THE MFT RESULTED FROM SYSTEM SOFTWARE UPDATE PROBLEM. ALSO FOUND LEAKING FLANGE GASKET ON SH SAFETY VALVE.
16-Feb-89	16-Feb-89	1	UNIT TRIP IMMEDIATELY AFTER SYNCHCRONIZATION ON MFT DUE TO ID FAN UNDERVOLTAGE TRIP.
17-Feb-89	23-Feb-89	141	CONTROLLED SHUTDOWN TO REPAIR SEIZED 4B CIRCULATING WATER PUMP . INLET AND DISCHARGE VALVES LEAKING BY TOO MUCH TO ISOLATE PUMP AND REPAIR ON LINE.
3-Mar-89	3-Mar-89	7	UNIT TRIP ON MFT DUE TO LOW PA FLOW TO COMBUSTOR 4B. THE LOW PA FLOW WAS CAUSED BY A SUDDEN LOOP SEAL SURGE WHICH INCREASED BED PRESSURE TO APPROXIMATELY 60" WC.
24-Mar-89	29-Mar-89	119	SCHEDULED SHUTDOWN TO INSPECT COMBUSTORS AFTER COMPLETING TEST BURN WITH 'SALT CREEK' COAL. REPAIRED 4A BOILER FEED PUMP MECHANICAL SEAL DURING THIS OUTAGE.
12-Apr-89	18-Apr-89	145	CONTROLLED SHUTDOWN DUE TO ASH REMOVAL PROBLEMS IN COMBUSTOR 4A, RESULTING FROM A BENT FLUIDIZING TUBE AT THE ENTRANCE TO EACH BOTTOM ASH COOLER.
21-Apr-89	21-Apr-89	4	UNIT TRIP ON MFT DUE TO LOSS OF THE ID FAN, RESULTING FROM A TRANSMISSION SYSTEM DISTURBANCE.
27-Apr-89	10-May-89	297	CONTROLLED SHUTDOWN DUE TO MECHANICAL SEAL LEAKS ON BOTH 4A AND 4B FEEDWATER PUMPS. 4B FEED PUMP ALSO REQUIRED CASING REPAIRS WHICH WERE COMPLETED OFF SITE.

Table 2-1 (continued)

Start Outage	Stop Outage	Duration (Hours)	Cause
10-May-89	10-May-89	16	UNIT TRIP ON MFT DUE TO LOSS OF THE ID FAN, RESULTING FROM LOOSE ELECTRICAL CONNECTION WHICH CAUSED THE COMMUTATOR TO SHORT OUT.
14-May-89	22-May-89	198	UNIT TRIP ON MFT DUE TO SA FAN TRIP. REPLACED BAD FAN CONTROL CARD. DURING OUTAGE REINSTALLED 4B FEEDWATER PUMP. UNIT ON RESERVE SHUTDOWN AT 20:50 ON 5/19.
22-May-89	23-May-89	11	CONTROLLED SHUTDOWN DUE TO LACK OF PROPANE
23-May-89	23-May-89	3	CONTROLLED SHUTDOWN DUE TO LACK OF PROPANE
30-May-89	30-May-89	1	UNIT TRIP ON MFT DUE TO 'PHANTOM' SA FAN TRIP, REASON UNDER INVESTIGATION.
9-Jun-89	9-Jun-89	4	CONTROLLED SHUTDOWN TO REMOVE CLINKER FROM 4C BOTTOM ASH COOLER. THREE BUBBLE CAPS WERE ALSO FOUND ADRIFT IN THIS COOLER AND REPLACED.
23-Jun-89	9-Jul-89	368	SCHEDULED SHUTDOWN AT THE COMPLETION OF ALTERNATE FUEL TESTING TO COMPLETE PA FAN INLET BOX AND LIMESTONE FEED SYSTEM MODIFICATIONS.
28-Jul-89	28-Jul-89	2	UNIT TRIP ON MFT DUE TO LOSS OF ID FAN RESULTING FROM SYSTEM DISTURBANCE. 4A BFP SIEZED DURING THE UNIT ROLLDOWN WHEN ITS RECIRCULATION VALVE DID NOT PROPERLY OPERATE.
30-Jul-89	7-Aug-89	188	CONTROLLED SHUTDOWN TO ISOLATE 4A BFP FOR REMOVAL AND OFF-SITE REPAIR. UNIT STATUS CHANGED TO RESERVE SHUTDOWN FROM 12:00 HRS ON 8/2 TO 16:10 ON 8/4. THE INSTRUMENT AIR COMPRESSOR CHECK VALVE BETWEEN THE HIGH AND LOW PRESSURE STAGES FAILED AND WAS REPLACED.
20-Aug-89	26-Aug-89	148	CONTROLLED SHUTDOWN TO REINSTALL 4A BFP. OUTAGE EXTENDED TO REPLACE 23 DISTRIBUTOR PLATE "BUBBLE CAPS" IN COMBUSTOR 4A AND TO COMPLETE ADDITIONAL INSTRUMENT AIR COMPRESSOR REPAIRS.

Table 2-1 (continued)

Start Outage	Stop Outage	Duration (Hours)	Cause
26-Aug-89	26-Aug-89	11	CONTROLLED SHUTDOWN DUE TO LACK OF PROPANE
28-Aug-89	11-Sep-89	338	CONTROLLED SHUTDOWN DUE TO WATERWALL TUBE LEAK AT WALL BOX CONNECTION ON OUTSIDE OF BOILER. THE UNIT MFT'D DURING RESTART DUE TO A TRIP ON EXCITER VOLTAGE CABINET FAN FAILURE. THE NO. 2 THROTTLE VALVE REMAINED 11 % OPEN AFTER THE UNIT TRIP. THE VALVE WAS DISASSEMBLED AND THE UPPER STEM GUIDE BUSHING WAS REMACHINED TO THE MANUFACTURER'S SPECIFICATIONS. TWO ADRIFT NOZZLE CAPS NEAR THE LOOP SEAL IN COMBUSTOR 4B WERE ALSO CAPPED FROM THE WINDBOX SIDE AS A TEMPORARY REPAIR.
13-Sep-89	13-Sep-89	9	UNIT TRIP ON MFT DUE TO LOSS OF THE SA FAN ON "PHANTOM" TRIP. AFTER SEVERAL UNSUCCESSFUL ATTEMPTS TO RESART THE FAN IN A NORMAL FASHION, THE FAN WAS RESTARTED ACROSS THE LINE. A CONDENSER TUBE LEAK WAS ISOLATED AND REPAIRED BEFORE UNIT 1 WAS RETURNED TO SERVICE.
17-Sep-89	17-Sep-89	1	UNIT MFT ON LOW DRUM LEVEL DUE TO IMPROPER OPERATION OF THE MAIN FEEDWATER CONTROL VALVE.
23-Sep-89	9-Oct-89	384	UNIT MFT DUE TO LOSS OF THE PA FAN ON "PHANTOM" TRIP. STARTED SCHEDULED OUTAGE FOR PYROPOWER TO REPLACE THE PA FAN WHEEL.
13-Oct-89	11-Nov-89	694	UNIT MFT ON HIGH FURNACE DRAFT PRESSURE DUE TO A BOILER TUBE LEAK IN 4B FURNACE. WATER FROM THE TUBE CAUSED AGGLOMERATION OF THE BED MATERIAL IN 4B COMBUSTOR, 4B WINDBOX, AND 4D BOTTOM ASH COOLER. SUBSEQUENT INSPECTION OF THE SUPERHEATER II PLATENS IN BOTH COMBUSTORS REVEALED MANY AREAS OF LOCALIZED EROSION WHICH WERE REPAIRED.
12-Nov-89	12-Nov-89	2	UNIT MFT ON LOW AIR/FUEL RATIO DUE TO AN IMPROPER BTU BIAS SETTING.

Table 2-1 (continued)

Start Outage	Stop Outage	Duration (Hours)	Cause
4-Dec-89	4-Dec-89	1	UNIT MFT ON LOW ELECTRO-HYDRAULIC CONTROL (EHC) SYSTEM PRESSURE. PROBLEM OCCURRED WHILE I&C TECHNICIAN WAS VALVING AN EHC ACCUMULATOR BACK IN SERVICE AFTER BEING RECHARGED.
8-Dec-89	15-Dec-89	177	CONTROLLED SHUTDOWN DUE TO HIGH BED PRESSURE IN COMBUSTOR 4A DURING TYPE "B" COAL ACCEPTANCE TESTING USING A HIGH SULFUR COAL (1.8% S). SUBSEQUENT INSPECTIONS REVEALED A TOTAL OF TWENTY SEVEN BUBBLE CAPS ADRIFT IN COMBUSTOR 4A, COMBUSTOR 4B, AND LOOP SEAL 4B.
17-Dec-89	18-Dec-89	6	UNIT MFT DUE TO UNIT 4 EXCITER FIRING CIRCUIT CARD FAILURE.
18-Dec-89	20-Dec-89	59	UNIT MFT DUE TO UNIT 4 EXCITER AFTER AN UNSUCCESSFUL ATTEMPT TO RESTART THE UNIT. CUEA OBTAINED ENOUGH GOOD CARDS BETWEEN THE TWO REDUNDENT FIRING CIRCUITS TO RETURN THE UNIT TO SERVICE.
30-Dec-89	30-Dec-89	4	UNIT MFT ON LOW DRUM LEVEL DUE TO A UNIT 4 TURBINE UPSET. THE UPSET WAS THE RESULT OF A TURBINE CONTROL PROBLEM CAUSED BY AN IMPROPERLY CALIBRATED MW TRANSDUCER.
30-Dec-89	30-Dec-89	9	CONTROLLED SHUTDOWN DUE TO LEAK IN UNIT 4 GOVERNOR OIL CIRCUIT.

the abrasion layer due to high water content during installation. Low refractory mix temperatures necessitated the addition of water to improve workability. Second, the original gunnite process for the abrasion resistant refractory layer proceeded in a downward fashion starting from the top of the cyclone, which resulted in "rebound" material falling on lower construction joint surfaces and anchor bars and led to poor bonding. Third, vertical and horizontal construction joints must be prepared with 90° angles to the outside metal surfaces during original installation. Improper control of these interfaces causes the joints to push apart during expansion. Quality control during the original installation may not have been adequate.

The abrasion resistant layer of refractory was removed in the conical portion of both cyclones. New anchor studs were installed and a new abrasion resistant layer was gunned in place.

- Upper cyclones: Cracking of the abrasion resistant layer around the bullnose of the cyclone inlets was caused by circumferential stress from thermal expansion. Bulkheads (stop bars) were added to absorb this stress. They were installed in two locations in the upper cyclone area in both cyclones. The bullnose was replaced in cyclone 4A. Also, the upper cyclone rim that forms the inlet transition was patched or replaced in both cyclones.

- Loop seals: Cracking and breakage was caused primarily by excessive water content during installation. The major source of failure was in the loop seal arch, which led to the hot spot observed prior to shutdown.

Both the abrasion resistant and insulating layers of refractory were removed in the loop seals. A combination of brick, castable (loop seal arches), and gunned refractory was used in the repair.

- Combustion chambers: Spalled or loose refractory was removed at various locations, and new refractory was gunned into those areas where loss was significant, particularly along the combustor A center wall at the refractory/water wall interface.

- Cyclone return legs: The damaged abrasion resistant refractory was removed and new refractory was gunned in place. The rework covered approximately 40 percent of the original surface area on each downcomer.

- Windboxes: The insulating refractory layer located downstream of the startup burners was repaired.

2.3.2 Fan Testing and Repair

The problem of poor fan performance became a prominent issue during high ash testing and resulted in a load limitation of approximately 90 MWe due to high PA transformer amperage. Adjustments made to the controls in the VSD control cabinet for the PA fan on January 4 provided for a load increase to 106 MWe.

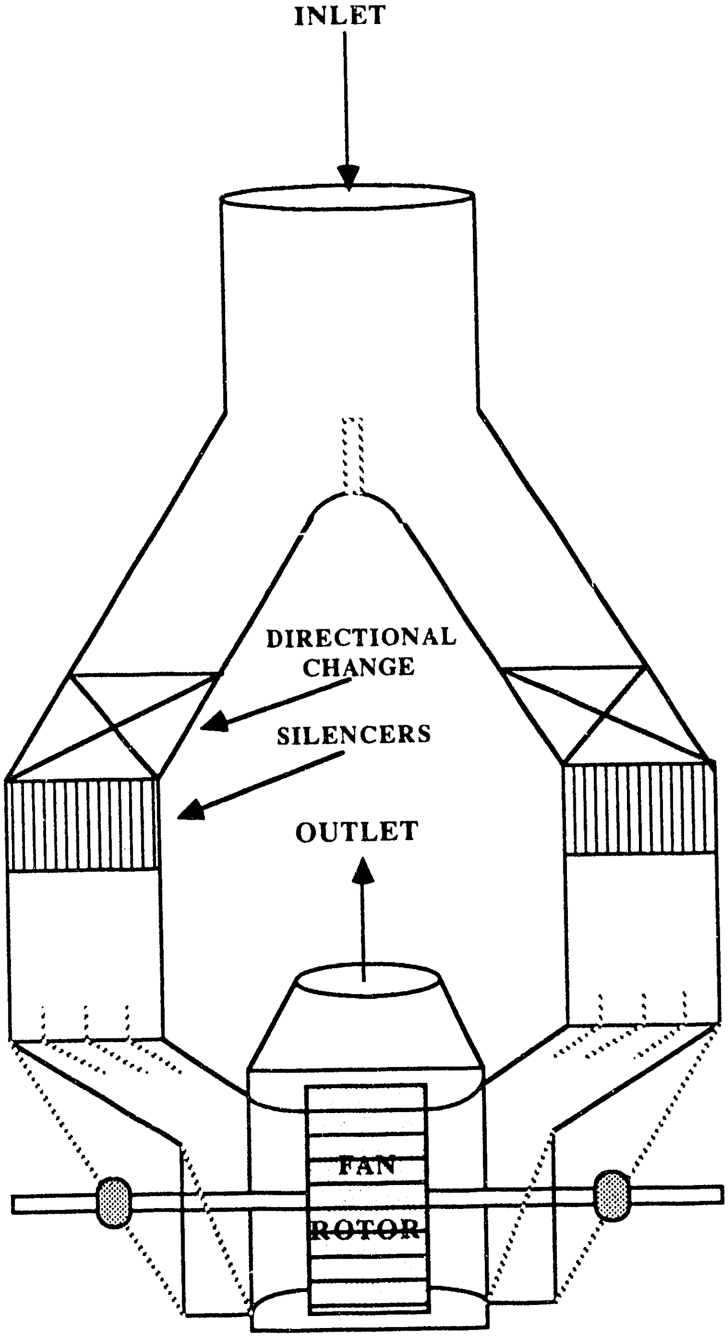
Tests conducted during the fourth quarter of 1988 by the fan vendor revealed that all three fans exceeded guaranteed power consumption and had less than predicted operating efficiencies. The PA fan experienced the largest deviation.

The fan manufacturer, boiler manufacturer, and CUEA met in February to discuss the fan deficiencies and develop a course of corrective action. The fan manufacturer determined that there were major air flow distribution problems in the PA fan inlet boxes and modifications were recommended.

During the February outage, the fan manufacturer added turning vanes and inlet box shelving to the duct work to improve air flow into the fan inlet cones. After retesting in March, results indicated that there was insufficient improvement on PA fan performance. The fan manufacturer decided in May to modify the PA fan inlet boxes from the in-duct silencer to the fan housing. This revision eliminated two air flow directional changes and resulted in a larger inlet box configuration. These changes are shown in Figure 2-2. Installation of the revised inlet boxes was completed on July 6.

The fan manufacturer retested the PA fan on July 12 in accordance with Air Moving Council of America (AMCA) standards. Results indicated only a slight improvement in performance. Subsequently, the fan wheel design was reviewed. An evaluation of original scale model test data, developed many years earlier, indicated that the fan was not appropriate for operation at speeds necessary for the Nucla application, causing the shortfall in capacity and pressure.

On July 26, the fan manufacturer proposed to replace the existing fan wheel with one designed to operate in the speed, pressure and volume ranges necessary for the Nucla application. The new fan has a 14 inch wider wheel with two additional blades, a 60% larger inlet cone area, and a more functional seal between the cone and the wheel. Comparisons of the original design and the new design are shown in Figures 2-3 through 2-5. Installation was completed on October 8 and AMCA fan performance testing was conducted on October 11. Although results showed a significant improvement, performance was still somewhat short of that



Note: Dotted lines show inlet duct modifications.

Figure 2-2. Nucla Primary Air Fan Inlet Duct Modifications.

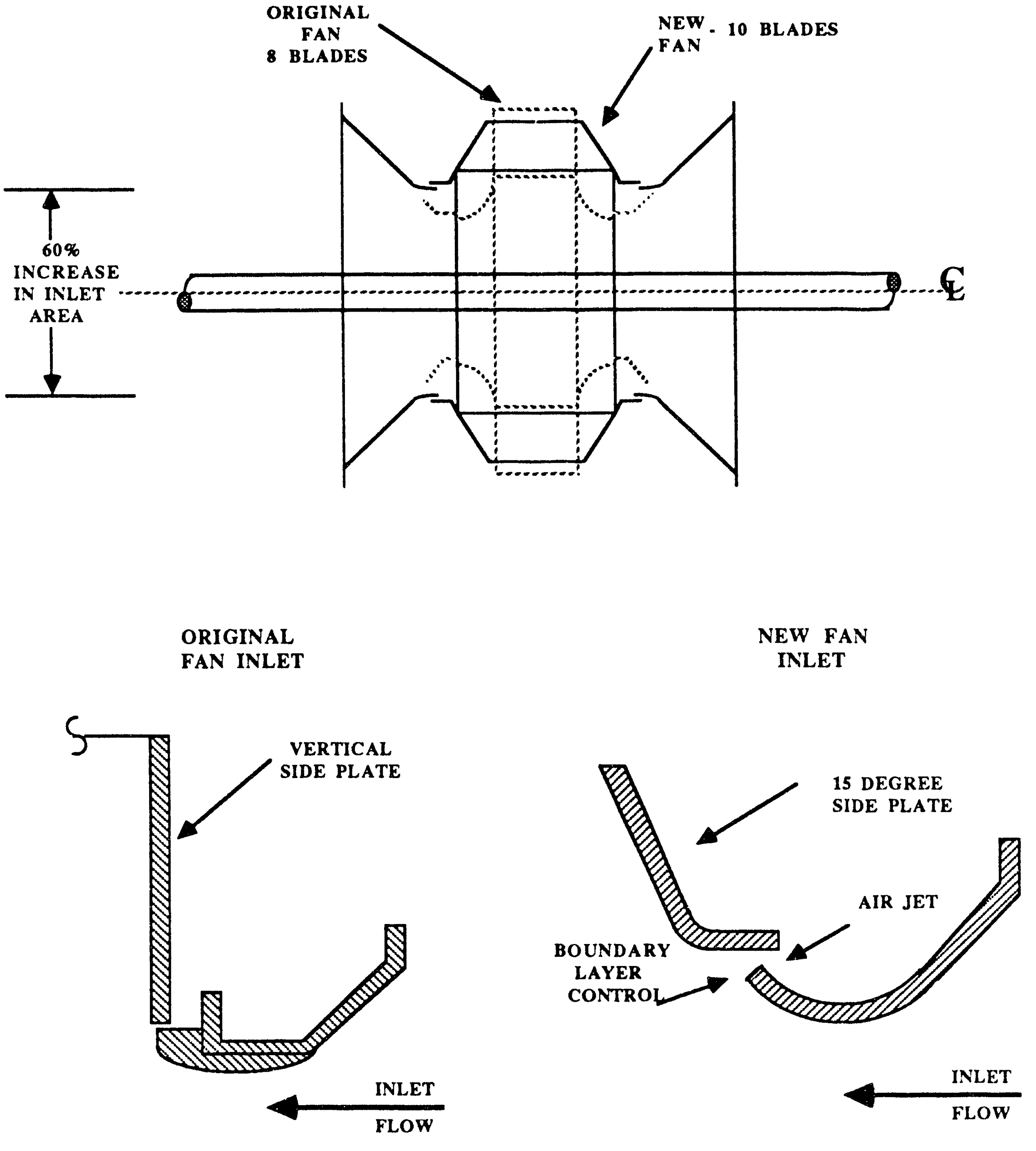


Figure 2-3. Comparison of Original vs. Replacement Primary Air Fan Configurations.

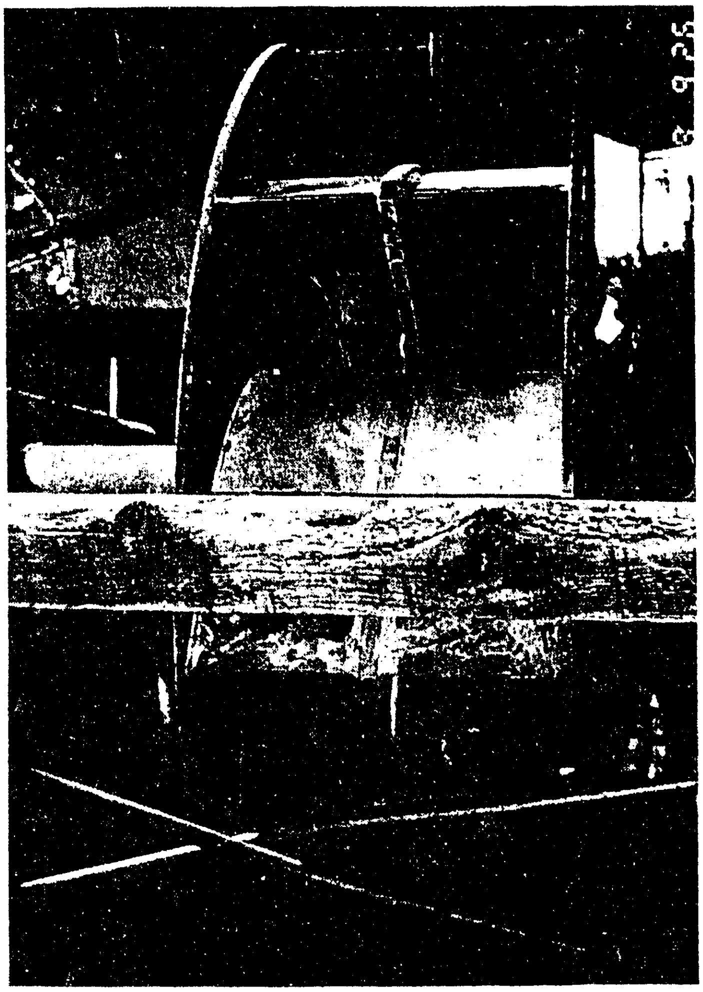


Figure 2-4. Original PA Fan Wheel Design.

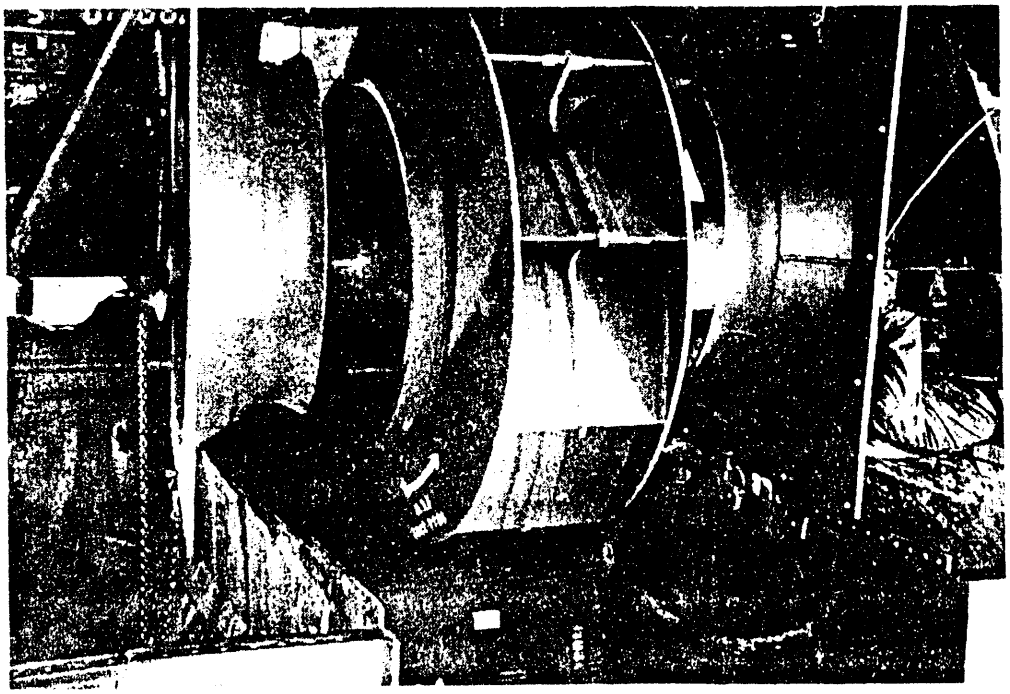


Figure 2-5. Modified PA Fan Wheel Design.

specified, as shown in Table 2-2. Fan performance following this series of modifications remains under review.

Table 2-2
PA Fan Performance Test Results

	Specified	4/20/89	10/10/89
Flow rate, CFM	265,286	236,314	259,821
Static pressure, in.wg	70.2	54.5	63
Horsepower, hp	3238	2870	3197
Static efficiency, %	None	60	83

Section 3

COLD-MODE SHAKEDOWN AND CALIBRATION

3.1 OVERVIEW

The cold-mode shakedown phase of the test program was completed during this reporting period. A revised air flow traversing program showed that the air flow meters are accurate to ±5%. Additional work this reporting period concentrated on modifications to the fly ash metering system and installation of a continuous fly ash sampler. The gas analyzer system was commissioned, with all analyzers working properly. The bottom ash metering system was debugged and is now providing reliable flow rate measurements. The isokinetic sampling crews finished their training program and have been tested in the field.

3.2 FLY ASH FLOW METER MODIFICATIONS AND CALIBRATION

The modifications to the fly ash metering and sampling system, described in the Start-Up through 1988 Annual Technical Progress Report, were completed during the first quarter of 1989. Figure 3-1 shows the modified fly ash flow schematic. The existing rotary feeder valve and knife gate valve above the fly ash flow meter were replaced by a new feeder valve and a continuous full cut sampler. The sampler has an adjustable timer for sampling at 2 to 60 minute intervals. The baghouse ash from the fly ash transport system was rerouted to the fly ash weigh bin. All fly ash now passes through the weigh bin, continuous sampler, and flow meter. The bypass valve around the sampler/flow meter is always kept closed during performance test periods.

The purpose of the new feeder valve is to stabilize the flow rate of fly ash through the flow meter. This was required both to provide a uniform flow rate to the flow meter and to allow the continuous sampler to sample all of the hoppers. Without this valve, meter accuracy may have been affected by the uneven flow as the various hoppers cycled through the fly ash transport system.

The feeder valve has five horizontal blades. The blades are rotated by a pneumatic piston to open the valve on a periodic basis. The valve opening, or degree of rotation, is adjusted by a mechanical stop. The valve opening was set by trial and error to ensure that ash would not accumulate in the fly ash weigh bin.

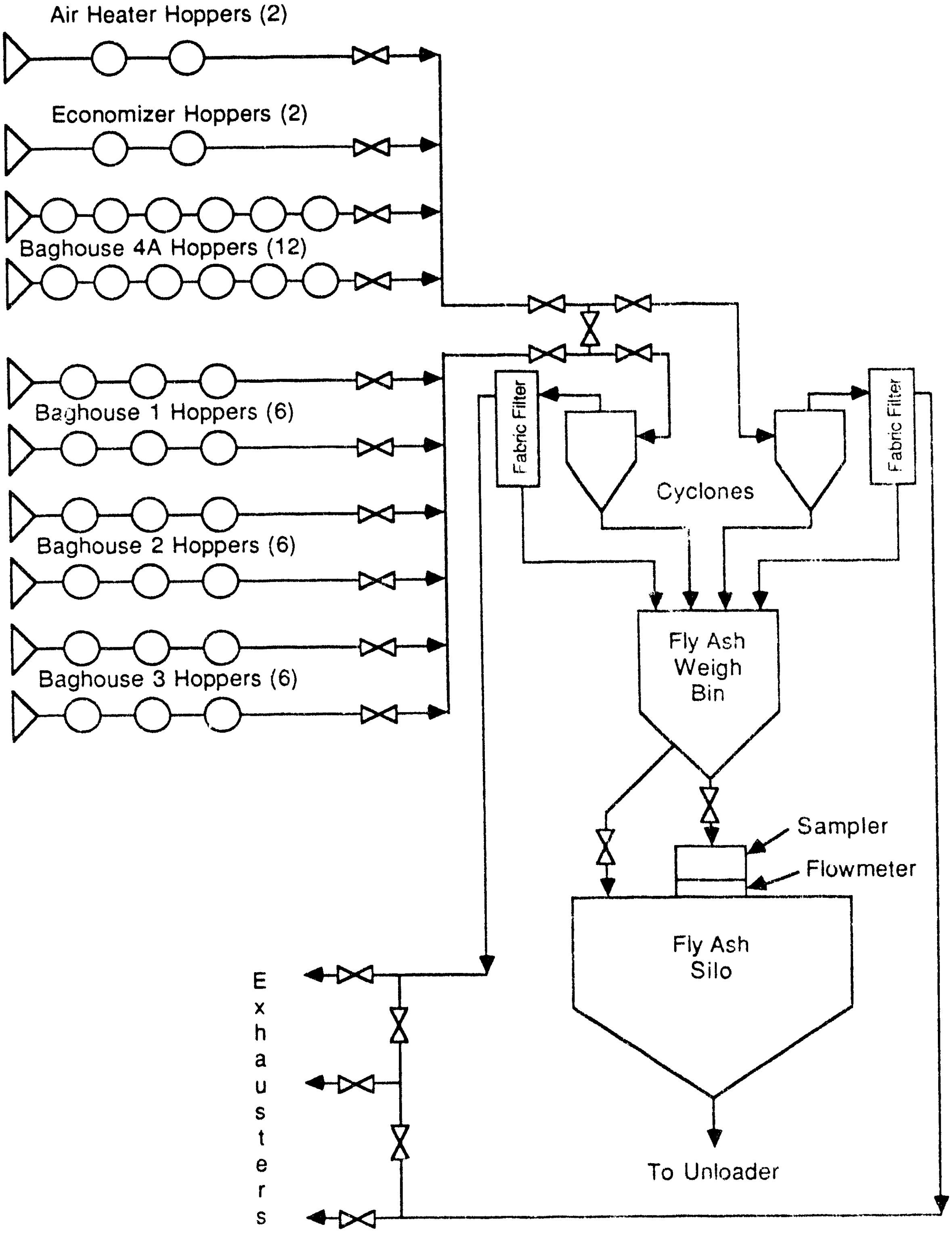


Figure 3-1. Schematic of Revised Fly Ash Collection and Measurement System

The automatic sampler was also placed into operation during the first quarter of 1989. After some initial modifications to prevent binding of the sampler wheels the sampler worked as desired. Continuous samples of fly ash are now routine during testing.

Calibration of the Schenck impact flow meter proved to be difficult. The ash generated during burning of Salt Creek coal was found to be more adhesive than the ash from Peabody coal. As a result the fly ash tended to adhere to the surface of the flow meter causing erroneous readings. A Teflon sheet glued to the surface of the sampler has helped this problem somewhat. However repeatable calibrations are still not being achieved. Because of this problem, the fly ash flow rate will continue to be calculated using the procedure described in Section 3 of the Start-Up through 1988 Annual Technical Progress Report. The calculation method makes it imperative that the fly ash sample, the bed drain sample, and the bed drain flow rate be as representative and accurate as possible. Efforts to improve the accuracy of the bed drain flow rate are described in the next section.

3.3 BOTTOM ASH FLOW RATE CALCULATION

The bottom ash weigh bin is calibrated using the procedure described in Section 3 of the Start-Up through 1988 Annual Technical Progress Report. The procedure was modified slightly to add the weigh chains to the hopper when it contained about 2000 lbs of fly ash rather than when it was empty. The flow rate of bed material is calculated by the performance calculations software. During the reporting period, errors in the calculated bed drain rate were identified. One problem was that occasionally negative bed drain weights would be calculated. Another problem was that occasionally a time increment of zero would be recorded.

To study the problems with the suspect readings, special tests recorded the weight of the bed drain weigh bin at 1 second intervals. Both problems mentioned above were found during these tests. The problems were traced to software bugs that did not correctly account for the weight when a dump cycle was initiated. The zero time increment was due to round off and improper passing of the time between subroutines. Both problems were corrected with a modification to the software. Comparisons of the weight readings with hand calculated values after the software modifications showed excellent agreement between the two methods.

3.4 GAS ANALYSIS EQUIPMENT

During the reporting period problems were encountered with the SO_2 analyzer and the economizer exit gas analysis system

(EGAS) probes. The SO_2 analyzer experienced a severe drift problem and would not stay in calibration. This problem was finally traced to a defective lamp, which was replaced during the first quarter of 1989. Since the replacement of the lamp, the SO_2 analyzer has performed acceptably.

During an inspection of the boiler at the end of 1988, erosion of the EGAS probes was discovered. Figure 3-2 shows the location of the wear. To protect the probes, shields were installed in the areas of highest wear. After 1800 hours of operation on coal, the shields were found to be wearing at an average rate of about 50 mills per year. These shields will be monitored during shutdowns and replaced when appropriate.

3.5 ISOKINETIC SAMPLING

Isokinetic sampling will be used in support of the baghouse monitoring program. Sampling will also be used as a back-up measurement method for the fly ash flow rate. The equipment needed for this procedure was described in Section 3 of the Start-Up through 1988 Annual Technical Progress Report. Training of two isokinetic sampling crews was completed during the last quarter of 1988.

In order to determine the measurement accuracy of the isokinetic crews, two successive isokinetic samples were taken during operations on January 3, 1989 while the boiler was held at a steady load of 68 MWe. The results of these two runs are shown in Table 3-1. This table shows that the particulate mass flow rates were within 2% of each other. All other major results showed good agreement between the two runs.

Table 3-1
ISOKINETIC SAMPLING REPEATABILITY TEST RESULTS
Location: Air Heater Exit

Date	1/3/89	1/3/89
Start Time	12:00	14:30
Flue Gas Moisture %	7.29	7.3
Velocity ft/sec	33.69	34.43
Volumetric Flow DSCFM	147,268	149,874
Particulate Loading gr/DSCF	10.31	10.44
Particulate Mass Flow lb/hr	13,645	13,412
Percent Isokinetic	100.6	100.5

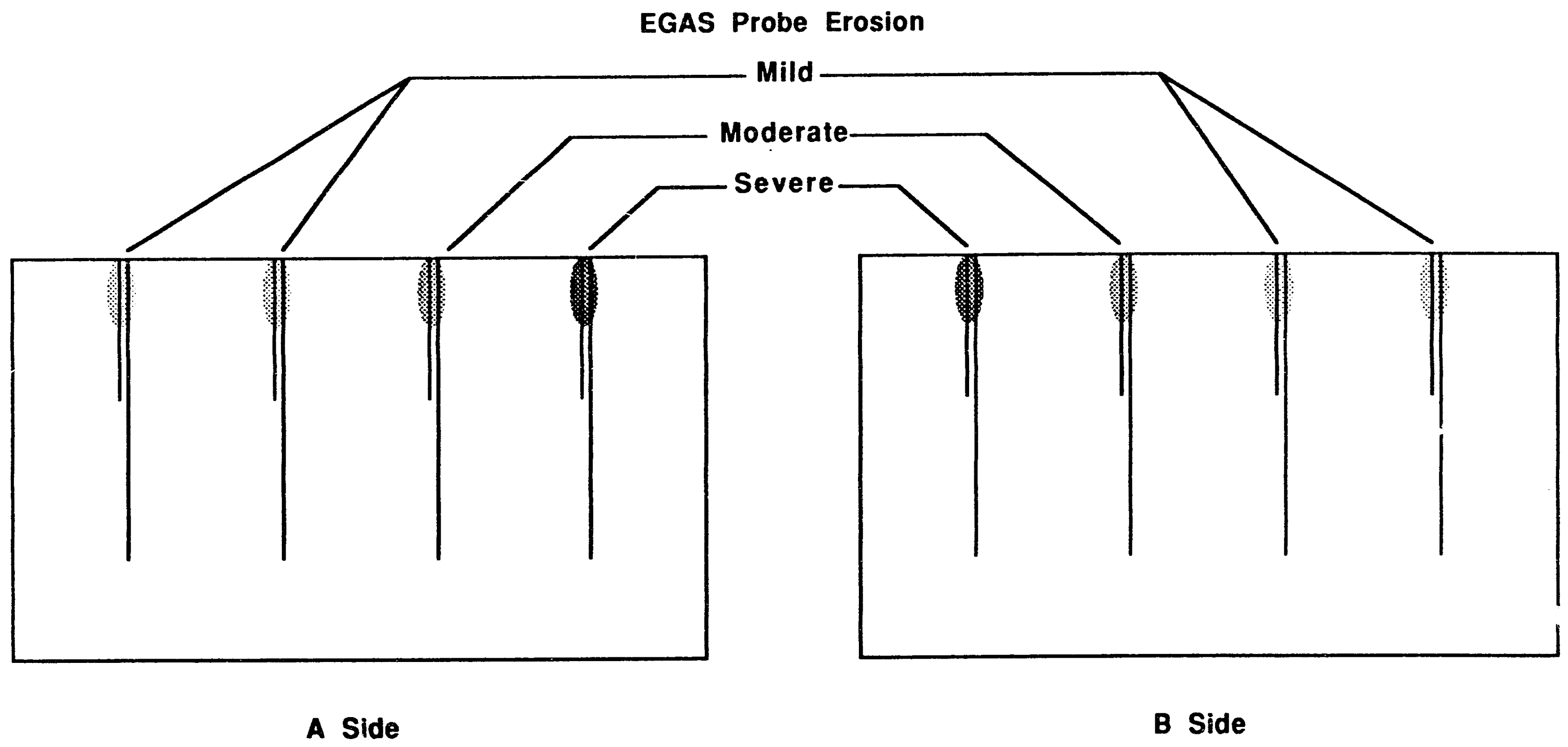


Figure 3-2. Erosion Pattern on the EGAS Probes.

Section 4

HOT-MODE SHAKEDOWN

The purpose of hot-mode testing is to establish the procedures used to conduct the steady-state performance tests presented in Section 6. Specifically, the test plan is designed to establish 1) the required times to reach steady-state conditions following changes in unit load and bed chemistry, 2) the quantity of solids samples and process data required to assure acceptable accuracy in calculated results, and 3) the required duration for each performance test. The hot-mode shakedown tests were conducted from March 6 to 18, 1989.

Prior to these tests, a one week series of operational tests was conducted to establish "design" operating conditions for the boiler during the hot-mode tests. These tests were termed pre-hot-mode tests. In particular, bed temperatures and pressures, ash cooler fluidizing velocities, and primary to secondary air ratios were established for the hot-mode test plan. In addition, the pre-hot-mode tests provided a run-in calibration and training period prior to the start of the hot-mode test plan.

4.1 PRE-HOT-MODE TEST RESULTS

During a one week period prior to hot-mode testing, all solids feed and disposal systems were calibrated, including the six coal feeders, two limestone feeders, two bottom ash weigh bins, and the fly ash weigh bin. The calibrations were performed according to procedures developed during the cold mode shakedown period described in Section 3 of this report and Section 3 of the Start-Up through 1988 Annual Technical Progress Report. Due to difficulties calibrating the fly ash flow meter, a methodology was developed for calculating the flow rate based on a mass balance of inerts in the input coal and limestone streams and the output bottom ash stream. This method was used for the remainder of all performance testing described in Section 6.

In addition, all solids sampling hardware were tested and a partial set of solids samples were withdrawn from the boiler according to the sampling scenario established for the hot-mode test plan. These samples were prepared in the on-site solids preparation laboratory as a final check on all equipment, procedures, and manpower availability.

Conditions during tests performed for pre-hot-mode testing are shown in Table 4-1. Load, steam flow, bed temperatures

Table 4-1. Pre-Hot-Mode Test Matrix

General Conditions			Combustor A, Avg. Temperatures (°F)			Combustor B, Avg. Temperatures (°F)			Solids Flow (klb/hr)			
									Combustor A		Combustor B	
Test	Load (MWe)	Steam Flow (klb/hr)	20 in.	Cyclone In	Cyclone Out	20 in.	Cyclone In	Cyclone Out	Coal	Limestone	Coal	Limestone
PHM1	100.4	762.1	1524.7	1527.5	1499.8	1542.2	1532.9	1513.4	51.4	3.3	N/A	2.9
PHM2	100.7	770.1	1512.9	1532	1499.3	1516.5	1512.2	1489.8	53.5	2.3	53.3	2.4
PHM5	100.7	768.5	1531.7	1540.8	1509.3	1549.9	1536.1	1512	52.7	2.6	52.6	2.7
PHM5A	100.7	773	1559.4	1567.3	1534.9	1563.5	1537.8	1519.2	52.6	2.8	52.5	2.9
PHM6	100.5	771.1	1562.5	1570.1	1535.9	1549.6	1527.2	1509.8	52.7	2.8	52.6	2.9
PHM7	79.5	616.7	1474.2	1434	1430.9	1479	1428.3	1439.2	43.7	2.4	43.6	2.4
PHM7A	80.5	624.7	1506.1	1466.2	1458.4	1514.6	1441.7	1452.2	42.3	2.4	42.2	2.6
PHM8	79.6	621.6	1457.2	1436.7	1423	1456.7	1414.3	1421.6	44.7	3	44.7	2.4
PHM9	79.5	616.2	1444	1424.3	1409.9	1453.6	1413	1410.1	43.1	2.3	43	2.2
PHM14	60.6	503.8	1499.6	1382.6	1402.3	1555	1383.3	1424.9	33.2	2.2	33.1	1.3

at 20 inch depth, cyclone inlet and outlet temperatures and coal and limestone flows are shown. The tests typically lasted four hours.

The first sequence of tests, PHM7, PHM8, and PHM9, was performed on March 6 at approximately 80 MWe output at flue gas O_2 levels of 3.5, 4.5, and 5.5 volume per cent, respectively. These tests were to explore the effect of excess air on the bed temperature. Biases in the secondary air flow settings were used to match O_2 readings between combustion chambers. Using O_2 trim control, O_2 levels were adjusted for these three tests using secondary air only. As expected, increasing excess air produced a drop in combustor temperature.

Tests PHM1 and PHM2 were performed at approximately 100 MWe at flue gas O_2 levels of 3.5 and 4.5 vol %, respectively. Flue gas O_2 was adjusted between tests using secondary air only in automatic control. Operating temperature decreased with increasing excess air. At comparable excess air, the bed operating temperatures were higher at higher load.

Tests PHM5, PHM5A and PHM6 were performed at approximately 100 MWe. In this series, the primary air flow split between the distributor plate and primary overfire air inlet port was varied to explore the effects on combustion temperature. Flue gas O_2 levels were maintained at 4.0 vol. % by trimming with secondary air flow. The observed combustion chamber temperatures were similar to those of test PHM1.

Test PHM5A was run with less air flow through the distributor. Flue gas O_2 levels were trimmed to 3.5 vol. % with secondary air flow. Compared to PHM5, higher combustion chamber temperatures were observed although part of the change is due to the decrease in excess air level.

In test PHM6, the primary air through the distributor plate was increased and overfire air flow was decreased. Flue gas O_2 was 3.5 %. Compared to test PHM5A, this change had little effect on combustor A but had a larger effect on combustor B. The reason for this difference is not fully understood. Section 9 of this report discusses some additional differences that were observed in the operating conditions between combustors A and B.

Test PHM14 was performed at 60 MWe and 5.3 vol. % O_2. While combustor temperatures for this test were higher than those of test PHM9, which had similar excess air levels but was run at a higher load, the temperatures at the inlet of the cyclones for this test were lower than those of test PHM9. Bed pressures were much higher for test PHM14 than for test PHM9.

Overall, pre-hot-mode test results revealed the following:

1. The ability to pre-set combustor operating temperatures was not possible. Temperatures were found to vary with load, excess air, and bed pressures. The latter is measured along each of three walls in the lower combustion chambers approximately one foot above the air distributor plate. The value is an indication of the solids inventory in the bed.

2. At similar loads, excess air levels, and bed pressures, the operating temperatures between combustion chambers could be significantly different. Temperatures could also vary on the same combustion chamber between repeat tests under seemingly identical operating conditions. This suggested that solids distribution in the upper freeboard region of the combustion chambers may be different between the two combustors and between duplicate tests. This distribution of solids is not indicated by the measurement of bed pressure at the one foot level in the combustor. However, the pressure profile is measured at 10 foot intervals along the rear wall of combustor B. Data from these pressure taps suggested differences in profiles under nearly identical operating conditions.

3. Ash cooler fluidizing velocities did little to affect changes in combustor operating temperatures. The original intent of this design was to classify bed material and return the finer size fraction to the combustion process while removing the larger material from the boiler as bottom ash. Although size data did indicate that higher fluidizing velocities in the ash coolers produced a coarser bed drain, this change had little impact on the overall solids distribution in the boiler and hence, on operating temperatures.

4. Changes in primary to secondary air ratio had no immediate impact on combustor operating temperatures. Changes in bed temperatures over 4 to 8 hour periods following these changes were consistent with the normal drift observed during the unit operational period prior to these tests. No definite conclusions could be made regarding the impact of PA/SA ratio on temperature.

5. Increasing excess air at constant load decreased combustor operating temperatures, as expected. This is caused by a reduction in adiabatic flame temperature and by increased water-wall heat transfer rates resulting from higher furnace gas velocities and solids loadings. However, excess air adjustments are limited due to the requirement at half load to maintain a minimum underbed air flow to each combustion chamber to reduce

backsifting into the windbox, and at full load by primary air fan limitations.

Based on results from these tests, unit load and excess air were determined to be the only parameters available to the operators that could affect operating temperatures and hence, test results. To establish repeatability of test results, set points for the following operating variables were established prior to testing:

- Unit load
- Excess air at 3.3 vol. % O_2
- PA/SA ratio as established at a given load by the design flow curves provided by the boiler vendor
- Bed pressures set to 18 in wg. average in each chamber
- Ash cooler velocities set to 6 ft/s
- All coal and limestone feeders in service

Also based on results from these tests, an effort was undertaken to develop a correlation for predicting combustor operating temperatures based on measured controllable and uncontrollable operating parameters. This resulted in the installation of pressure taps on each combustion chamber to measure the differential pressure along the water walls between the lower combustor refractory/water-wall interface and the top of the combustion chamber. This led to a relatively accurate correlation, as discussed in Section 10, for predicting combustor operating temperatures based on this differential pressure measurement and unit load and excess air.

4.2 OBJECTIVES AND PROCEDURES FOR HOT-MODE TESTING

The hot-mode test plan consisted of a series of five special tests designed to:

- Determine the number of solids samples which must be taken during a performance test to achieve a desired degree of analysis accuracy.
- Establish the minimum duration of a steady-state performance test.
- Demonstrate the accuracy of solids preparation procedures according to ASTM standards.

- Determine the times required for the boiler to reach chemical equilibrium after a step change in Ca/S ratio and to reach thermal equilibrium following a step change in load.

4.2.1 Determination of the Number of Solids Samples Required

ASME procedures PTC 19.1-1985 outline a method for determining the number of samples required to achieve a specified accuracy in an output variable, based on the uncertainty of a single input variable. Since feed and waste streams are not uniform throughout a test, the chemical composition of solids streams is expected to vary over the course of a test run. Therefore, it is necessary to collect and analyze several samples to accurately represent the chemical composition of each stream. Because fewer solids samples can be collected relative to the number of readings that can be recorded from on-line instrumentation, the solids data have a much greater effect on performance calculation results uncertainties than data from the data highway.

The uncertainty analysis software subroutine, incorporated into the performance calculations in the second quarter of 1988, calculates the uncertainty in each of the outputs from the performance calculations, given the uncertainty in each of the measurements used as inputs to the performance calculations. The uncertainties depend upon the actual values, standard deviations (precision errors), and bias errors associated with the input variables to the performance calculations. The original algorithm used for calculating uncertainties involved taking partial derivatives of each performance equation. This required that the uncertainty analysis code be changed every time a change was made to the performance calculation code. To avoid this, the test team developed a perturbation method to calculate the uncertainty in test results based on the uncertainty of all input measurements. The contributions to the uncertainty in the result by the uncertainty of the input parameter is found by perturbing each input parameter value by the amount of the input uncertainty and evaluating the result at the new value of the input parameter. Thus, there is no need to change the uncertainty calculations to match revisions in the performance calculations. This method establishes the total uncertainty of all calculated results for a test run based on the contributions of precision and bias errors of all input variables. The uncertainty analysis can also be used to establish output variable sensitivity (sensitivity analysis) to changes in input variables. Sensitivity analysis is helpful in highlighting critical process instrumentation and for establishing required instrument accuracy (i.e., calibration frequency).

To determine the number of samples required, the test team performed the uncertainty analysis on hot-mode test SD1 for various 2-hour increments. Each additional 2-hour increment adds one additional set of coal, limestone, fly ash and bottom ash samples. The variance of other process variables, such as temperature and pressure measurements, also change as the duration of the test run increases. As the number of samples included in a test run increases, the uncertainty in the results is expected to decrease. Target accuracies for calculated test results were established during cold mode shakedown testing. For example, four of these target accuracies for calculated results are:

- Boiler efficiency ± 0.5%
- Calcium balance ± 10%
- Combustion efficiency ± 0.2%
- Sulfur retention ± 5%

It is possible to choose the number of solids samples required to achieve these target uncertainties. This, in turn, establishes the test duration, since manpower limitations at Nucla make it difficult to collect a set of solids samples more frequently than once every 2 hours.

4.2.2 Determination of the Accuracy of Solids Preparation Procedures

The validation process for the solids sampling, preparation, and analysis procedures began during cold-mode shakedown, when an extensive review of the sampling locations and procedures was performed to identify and eliminate any sources of systematic bias. Quantification of the error due to preparation and analysis was completed during the hot-mode test sequence by measuring the variance of the analytical results of four identically prepared samples, each derived from a single initial sample. The variance of the results is called the division and analysis variance (S_{da}^2), and is a measure of the random error introduced by preparing and analyzing samples.

ASTM procedures D2234-76 and D2013-72 provide guidelines for determining the acceptability of the division and analysis variance. The acceptability depends upon two criteria. First, the variance should not change when measured repeatedly. Statistical tests are used to determine if a change in the variance is real - caused by problems with the preparation procedures - or if it is a result of measurement inaccuracies.

To determine the variance of division and analysis, S_{da}^2, a single sample is collected according to normal sampling procedures; the sample is then split into four subsamples. Each of these subsamples is reduced according to standard procedures to a lab sample which is then analyzed. The variance of the four analyses is then calculated and reported as S_{da}^2.

The number of samples called for by the ASTM method D2013-A2 was modified to use 8 samples requiring 32 analyses. This modified plan was used for coal and bottom ash samples, and greatly reduced the cost of the procedure without compromising results.

The second criterion for determining acceptability is that the variance of division and analysis should not be more than 20 percent of the overall variance (S_o^2). The overall variance includes the variability of the material as well as the preparation and analysis variability. The first step in determining S_o^2 involves collecting an incremental sample, which is one acquired through a single operation of the sampling device. This sample is not composited with other increments but is prepared as a separate lab sample. The ASTM plan was modified so that 42 incremental samples were collected for coal and 40 were collected for bottom ash during the 48 hours allotted for the test.

To calculate S_o^2, the analytical results were divided into two groups, and a variance was calculated for each group. The variances of the two groups were averaged and then multiplied by an "F" factor from statistical tables to calculate a "probable maximum" value of S_o^2. This is the number upon which ASTM requirements are based.

4.2.3 Analytical Quality Control

The analytical quality control program is outlined in the Test Program Solids Sampling, Preparation, and Analysis Manual, which was produced by EPRI. The primary means of verifying the preparation and analysis procedure is to process duplicate samples. Duplicate samples are split out from the first regular sample of each solid stream for each test, and are prepared and analyzed separately. Additionally, "blind" samples are sent to the off-site laboratory for analysis. The samples are split out after the preparation procedure is complete, and serve as a quality control check of the off-site laboratory only. The flow sheet for the preparation of samples for analysis is shown in Figures 4-1 through 4-4.

Analysis is conducted on the duplicate and blind pairs for the six most significant measurements (coal HHV, coal H, coal

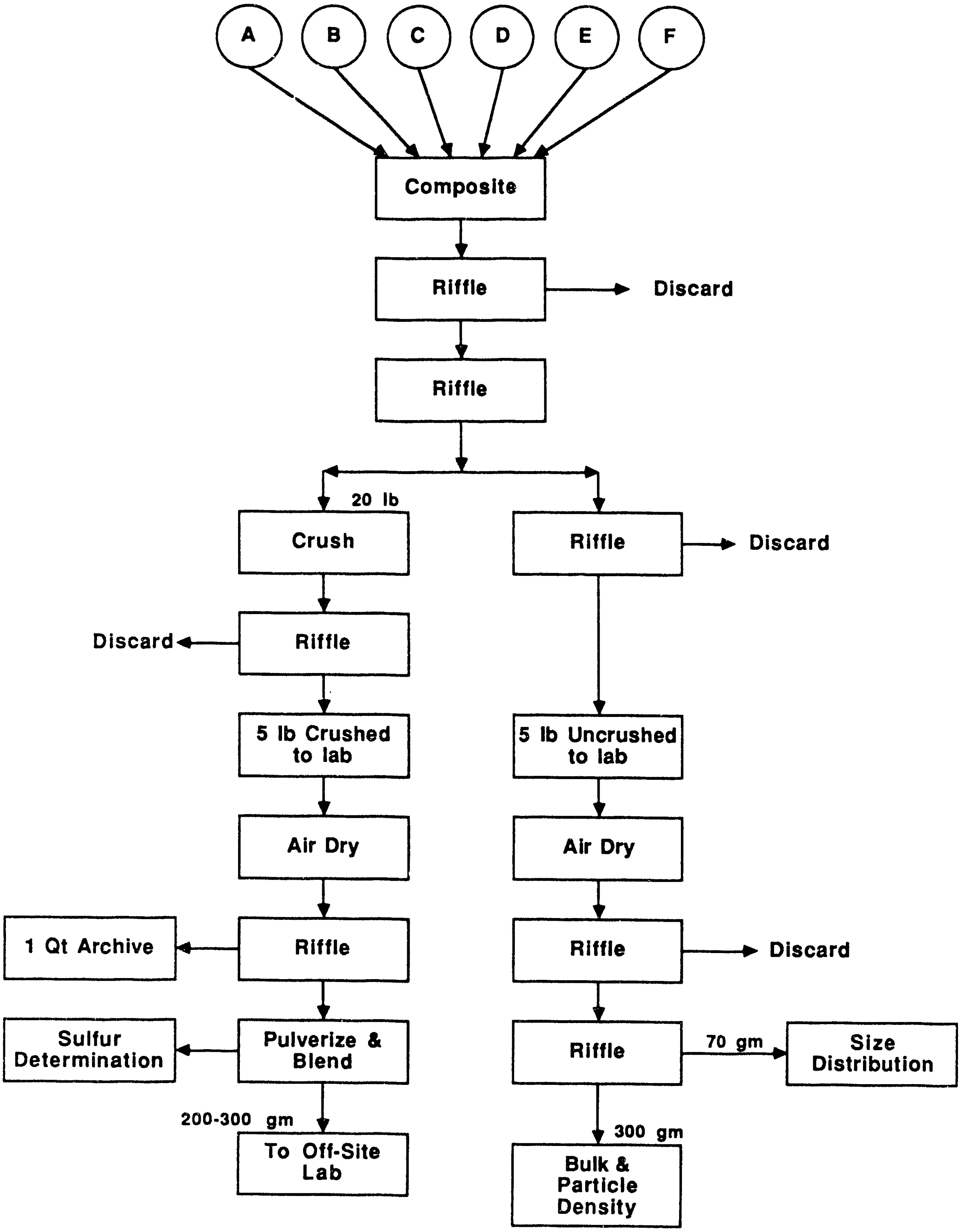


Figure 4-1. Coal Preparation Flow Sheet

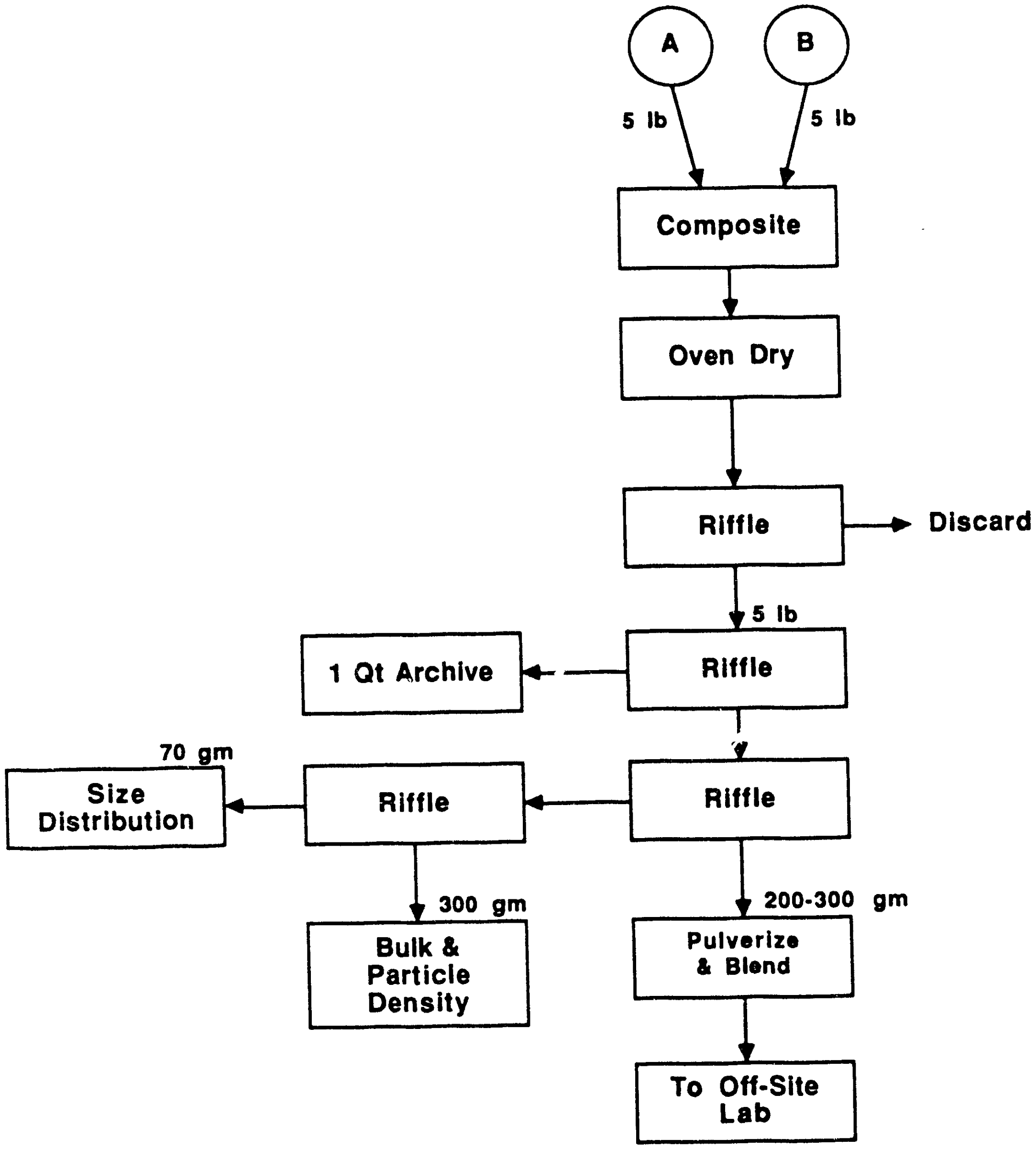


Figure 4-2. Limestone Preparation Flow Sheet

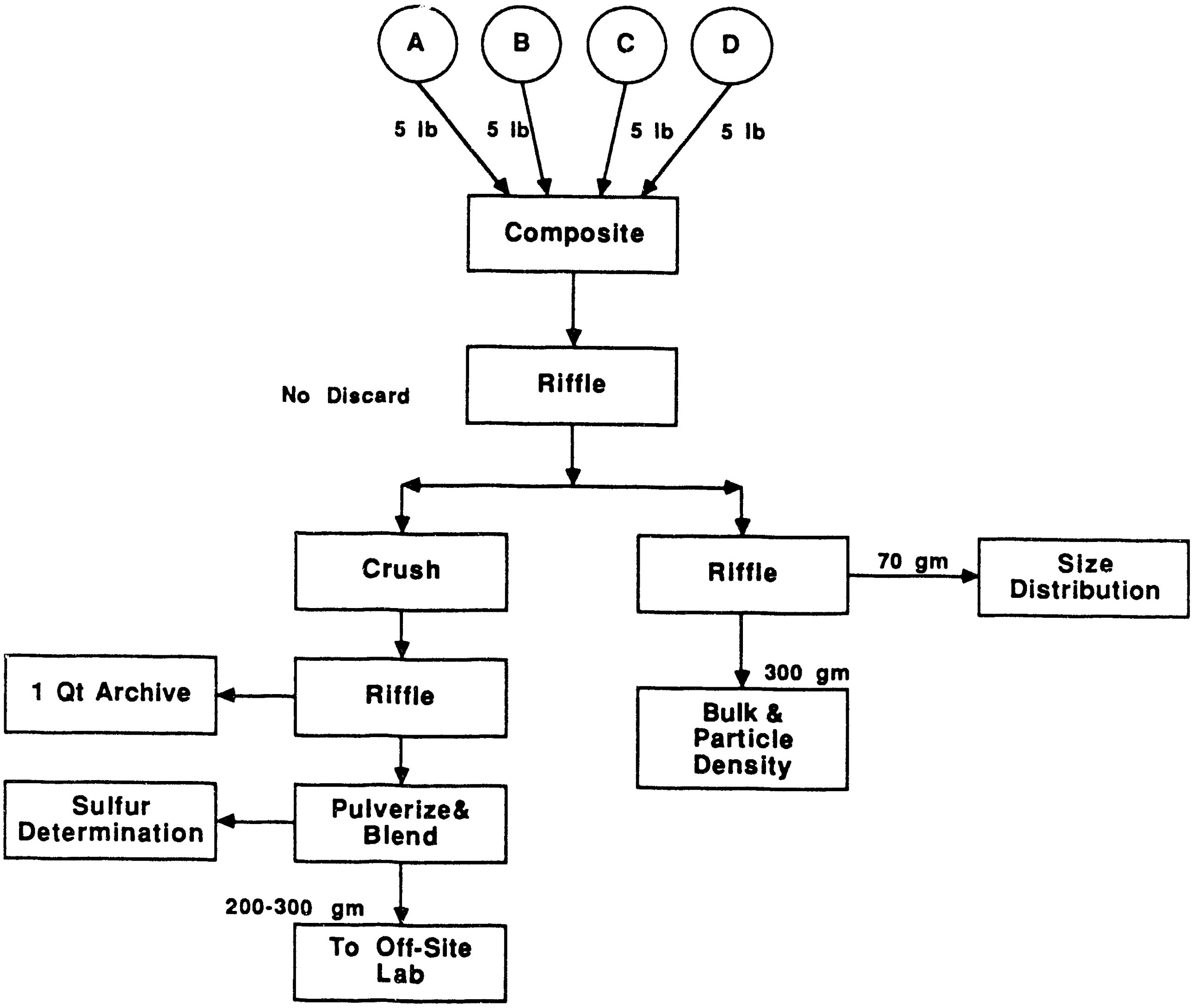


Figure 4-3. Bottom Ash Preparation Flow Sheet

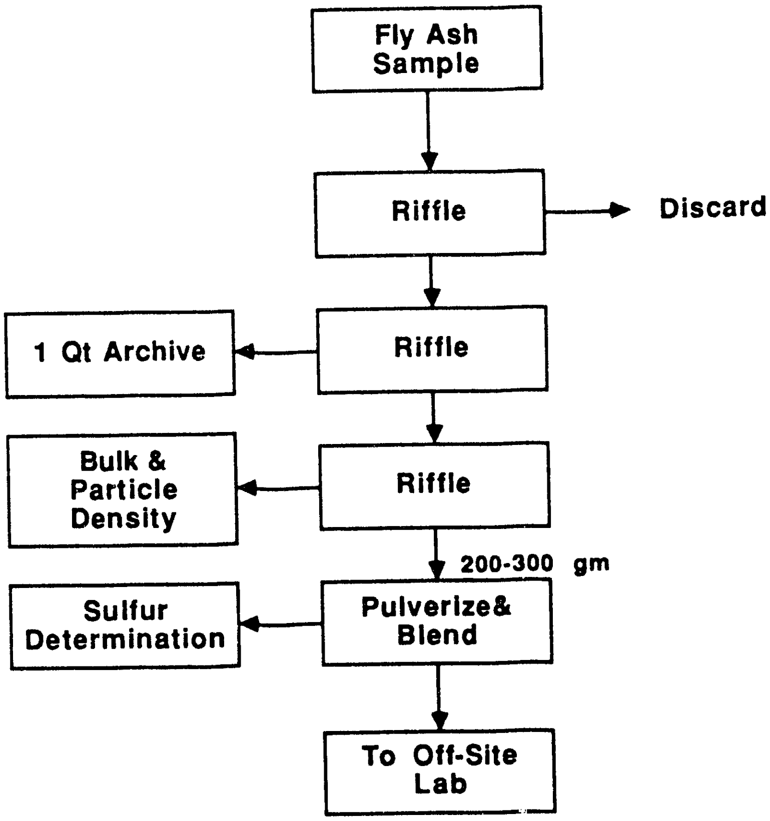


Figure 4-4. Fly Ash Preparation Flow Sheet

C, coal S, coal ash, fly ash C). The coefficient of variation, CV, is used to evaluate the quality of the data. The coefficient of variation is calculated as:

$$CV = 100 \frac{S}{X}$$

where S is the standard deviation of the pair and X is the mean. The CV from the blind pairs represents the variation from the off-site lab. The CV from the duplicates represents the variability of the entire sample preparation and analysis. These numbers are used in conjunction with the uncertainties determined for performance calculation results to evaluate the quality of the solids analytical data.

If the uncertainty in a performance calculation result becomes consistently unacceptable, the term responsible is identified. If this term is from a solids analysis, the blind and duplicate CV trends are evaluated. An increasing CV value for the blind sample indicates an analytical problem, and the off-site lab would be notified. The on-site preparation procedure would be reviewed if the CV value for the duplicate sample increased and the blind sample remained the same. If both CV's remain relatively constant, it may be necessary to increase the number of samples to achieve the required level of uncertainty. The final and best indicator of the solids analysis quality is the calculated uncertainty of the performance results.

4.2.4 Determination of the Time to Steady State

The time requirement to reach steady state operations is defined as the time period over which the plant must operate at constant conditions to ensure chemical and thermal equilibrium with all reacting variables. This information is valuable for test scheduling in that it indicates the time required between tests for the plant to reach equilibrium at the new conditions. For this test plan, major first-order transient times were determined by making changes in the boiler load and the Ca/S ratio. Boiler load for the Ca/S ratio transient test was 100% MCR. The Ca/S ratio transient was introduced by shutting off the limestone feeders. After 12 hours of operation, the limestone feed rate was returned to twice its initial setting. Operation was observed for another 12 hours prior to proceeding to the load change transients.

For the load ramp test, main turbine load was adjusted down in a controlled ramp (not less than 1% per minute and not more than the maximum rate of load reduction which had been previously demonstrated) from an initial value of 100% MCR down to the minimum load at which all turbine/generators remained in service. After 24 hours, load was increased in a controlled ramp back to the initial 100% MCR value.

4.3 TEST MATRIX

The test matrix for the hot-mode-shakedown tests is as shown in Table 4-2.

Table 4-2. Test Matrix for Hot-Mode Shakedown Tests

Test Number	Transient Test Variable	Target Boiler Load	Ca/S	Forecast Test Time (hr)
SD0	Start-up and load Stabilization			48
SD1	Base Case	100%	D	48
SD2	Ca/S	100%	0	12
SD3	Ca/S	100%	2D	12
SD4	Load	50%*	D	24
SD5	Load	100%	D	24

D = Design
* Minimum load with all turbine/generators

Hot-mode tests SD0 through SD5 were performed from 08:00 on March 12 through 10:00 on March 18. The unit switched from Peabody coal to the test coal, Salt Creek, one day prior to the initiation of test SD0. Test SD0 was a 24-hour hold at steady-state conditions prior to the start of solids sampling. Test SD1 was a baseline performance test whose primary objective was to determine the minimum test duration required to achieve an acceptable level of uncertainty in performance calculation results. Tests SD2 and SD3 determined the response time of SO_2 emissions following a complete stoppage of limestone flow into the boiler, and after resumption of limestone feed at twice the previous rate. Tests SD4 and SD5 measured the plant response to a load change.

4.4 HOT-MODE TEST RESULTS

The plant was operated at steady state at close to full load (105 MWe) from 08:00 on March 13, 1989 to 08:00 on March 15, 1989. During this time, instrument readings from the plant control system data highway were recorded by the data acquisition system every 30 seconds and solids samples were collected every 2 to 4 hours.

4.4.1 Determination of the Number of Solids Samples Required

There are four solids streams to consider in uncertainty analyses: coal and limestone enter the boiler, bottom ash and fly ash exit the boiler. Generally, solids analyses from test SD1 indicate that Salt Creek coal has a low composition variability.

The six main types of measurements used as inputs to the performance calculations are:

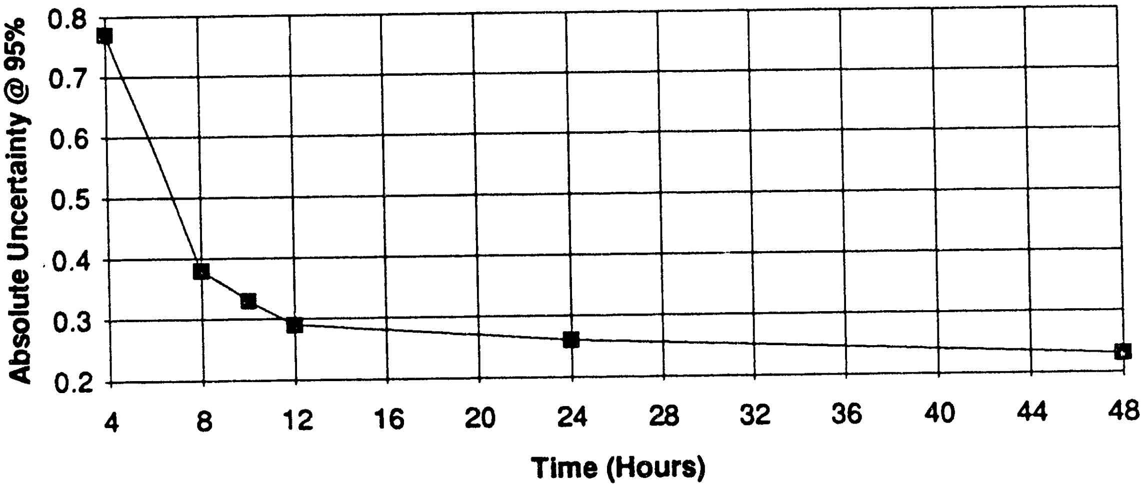
- Pressure (or pressure difference)
- Temperature
- Fluid flow rate
- Solid flow rate
- Gas chemical analysis
- Solid chemical analysis

The uncertainty in a measured variable has two components - a precision component and a bias component. Precision error is a function of the number of readings and the scatter in those readings. A larger number of readings during a steadier process will generally lead to a smaller precision error. Bias error is that component of the uncertainty which is fixed from one reading to the next. Also known as systematic error, it is a function of instrument accuracy, and is estimated using equipment specifications and engineering judgement. See Section 3 and Appendix C of the Start-Up through 1988 Annual Technical Progress Report for more information on measurement uncertainty.

Figure 4-5 shows how the uncertainty in boiler efficiency (loss method) decreased with time. Also shown in the table in Figure 4-5 are the major contributors to uncertainty in the calculation of boiler efficiency by the loss method. In the table, the input variables for a given result are shown in the order of maximum contribution for the results calculated for the 48-hour run period. The numbers shown for the contribution are equivalent to the terms Br^2 (bias limit of the result) and $(tSr)^2$ (Student t factor multiplied by the precision index of the result), as described in Appendix C of the Start-Up through 1988 Annual Technical Progress Report. Contributions shown are those whose values are greater than one percent of the value of the maximum contribution. The total uncertainty (shown near the top of the table) is the square root of the sum of all the contributions.

The plots of the uncertainty of results with time in six other important performance calculation results are shown in Figures 4-6 through 4-11. The major contributors to uncertainty are also shown in the tables in Figures 4-6 through 4-11. The tables and plots are shown for the following performance calculation results:

Figure 4-5. Absolute Uncertainty in Boiler Efficiney (Loss Method) vs. Time



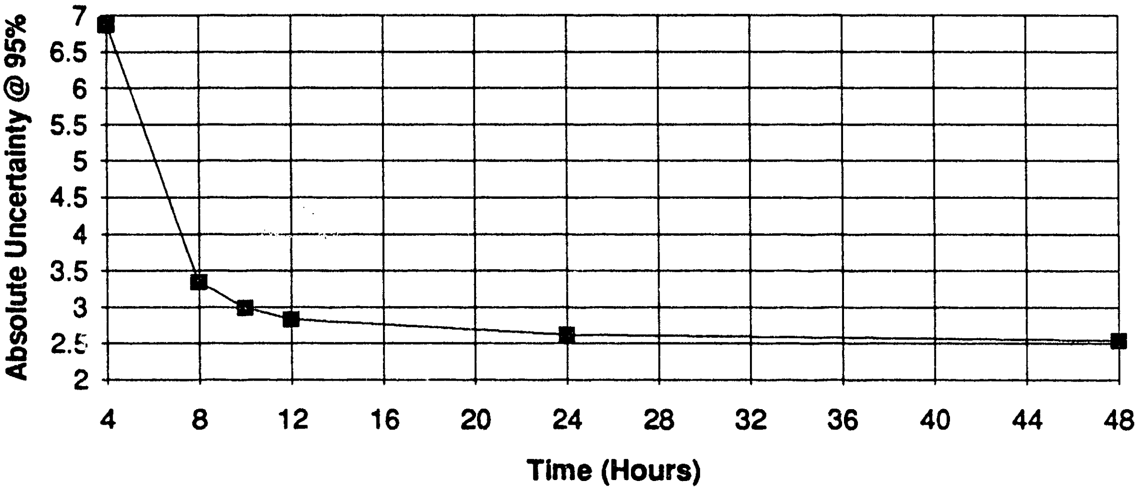
BOILER EFFICIENCY (LOSS METHOD)

Description	4 HR	8 HR	10 HR	12 HR	24 HR	48 HR
MEAN VALUE	88.17	88.04	88.09	88.11	88.27	88.38
TOTAL UNCERTAINTY	0.77	0.38	0.33	0.29	0.26	0.23

UNCERTAINTY CONTRIBUTIONS

Description	Error Type	4 HR	Rank	8 HR	Rank	10 HR	Rank	12 HR	Rank	24 HR	Rank	48 HR	Rank
O2 @ economizer flue gas outlet	Bias	0.012	5	0.0125	3	0.0125	2	0.0124	2	0.0119	2	0.0119	1
HHV of fuel AF basis	P.E.	0.419	1	0.0725	1	0.0415	1	0.0304	1	0.014	1	0.0079	2
Hydrogen in coal AF basis	Bias	0.0063	6	0.00633	5	0.00633	5	0.00631	4	0.00623	3	0.0062	3
Carbon in fly ash	Bias	0.00445	7	0.00449	7	0.00448	7	0.00456	6	0.0045	5	0.0043	4
Hydrogen in fly ash	Bias	-		0.00405	8	0.00407	9	0.00414	7	0.00408	6	0.0039	5
Hydrogen in coal AF basis	P.E.	0.0182	4	0.00566	6	0.00426	8	0.00316	9	0.00466	4	0.0033	6
Carbon in fly ash	P.E.	-		-		0.0111	3	0.00733	3	0.00251	9	0.003	7
HHV of fuel AF basis	Bias	-		0.0032	9	0.0036	10	0.00314	10	0.00305	7	0.003	8
Radiant and convective losses	Bias	-		0.00211	10	0.0021	11	0.0021	11	0.0021	11	0.0021	9
Carbon in coal AF basis	P.E.	0.0406	3	0.00913	4	0.00533	6	0.00365	8	0.00268	8	0.0015	10
Ash in coal AF basis	Bias	-		0.00165	11	0.00156	12	0.00154	12	0.00153	12	0.0014	11
Moisture in coal AF basis	Bias	-		0.00107	12	0.00106	13	0.00106	13	0.00105	13	0.0011	12
Ash in coal AF basis	P.E.	0.0653	2	0.0135	2	0.00724	4	0.00494	5	0.00244	10	0.001	13

Figure 4-6. Absolute Uncertainty in Boiler Efficiney (I/O Method) vs. Time



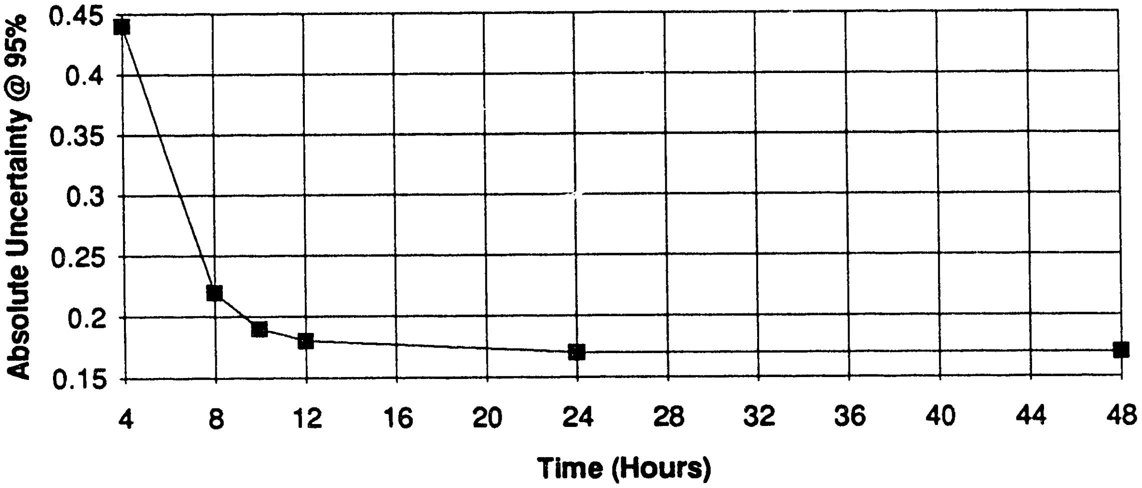
BOILER EFFICIENCY (I/O METHOD)

Description	4 HR	8 HR	10 HR	12 HR	24 HR	48 HR
MEAN VALUE	86.39	86.12	86.01	85.95	86.07	86.14
TOTAL UNCERTAINTY	6.87	3.34	2.99	2.83	2.62	2.54

UNCERTAINTY CONTRIBUTIONS

Description	Error Type	4 HR	Rank	8 HR	Rank	10 HR	Rank	12 HR	Rank	24 HR	Rank	48 HR	Rank
Feedwater flow (Temp Comp)	Bias	4.99	2	4.95	2	4.9	1	4.94	1	4.99	1	4.99	1
HHV of fuel AF basis	P.E.	40.69	1	5.18	1	3.01	2	2.1	2	0.922	2	0.49	2
SH IIB Attemperator flow	Bias			0.191	3	0.19	3	0.19	3	0.191	3	0.192	3
HHV of fuel AF basis	Bias			0.166	4	0.165	4	0.164	4	0.164	4	0.165	4
Coal flow cmb B, rear wall(4D)	Bias			0.0847	5	0.0845	5	0.0846	5	0.085	5	0.0855	5
Coal flow cmb A, fr wall, east (4C)	Bias			0.0843	6	0.0841	6	0.0841	7	0.0844	6	0.0849	6
Coal flow cmb A, rear wall (4A)	Bias			0.0827	8	0.0826	7	0.0826	8	0.0829	7	0.0832	7
Coal flow cmb B, fr wall, east (4E)	Bias			0.0824	9	0.0823	8	0.0823	9	0.0826	8	0.083	8
Coal flow cmb A, fr wall, west (4B)	Bias			0.0812	10	0.081	9	0.081	10	0.0815	9	0.082	9
Coal flow cmb B, fr wall, west (4F)	Bias			0.0808	11	0.0806	10	0.0806	11	0.081	10	0.0814	10
Feedwater temp	Bias			0.0841	7	0.0699	11	0.0844	6	0.0578	11	0.0638	11

Figure 4-7. Absolute Uncertainty In Ca/S Molar Ratio (Sorbent) vs. Time



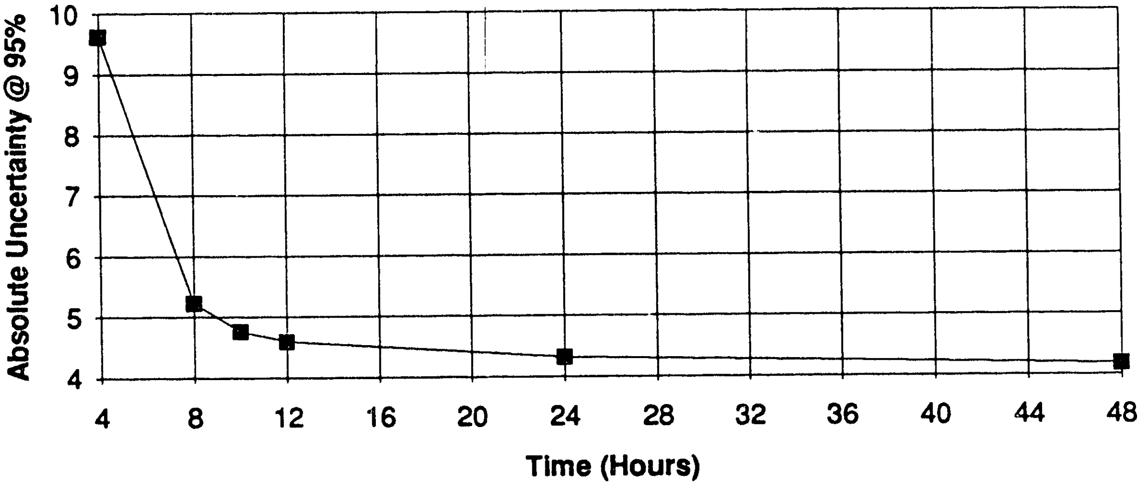
Ca/S MOLAR RATIO (SORBENT ONLY)

Description	4 HR	8 HR	10 HR	12 HR	24 HR	48 HR
MEAN VALUE	1.41	1.38	1.39	1.41	1.41	1.48
TOTAL UNCERTAINTY	0.44	0.22	0.19	0.18	0.17	0.17

UNCERTAINTY CONTRIBUTIONS

Description	Error Type	4 HR	Rank	8 HR	Rank	10 HR	Rank	12 HR	Rank	24 HR	Rank	48 HR	Rank
Sulfur in coal AF basis	Bias	0.0196	2	0.0194	2	0.0197	1	0.0205	1	0.0209	1	0.0213	1
Sulfur in coal AF basis	P.E.	0.169	1	0.0236	1	0.0141	2	0.00962	2	0.00433	2	0.00219	2
Sorbent feed rate CMB 4A	Bias			0.00124	3	0.00127	3	0.0013	3	0.0013	3	0.00144	3
Sorbent feed rate CMB 4B	Bias			0.0018	4	0.00117	4	0.00119	4	0.0012	4	0.00134	4
Calcium in limestone AF basis	P.E.			0.000648	5	0.000586	5	0.000983	5	0.000445	5	0.000234	5

Figure 4-8. Absolute Uncertainty in Sulfur Dioxide Retention vs. Time



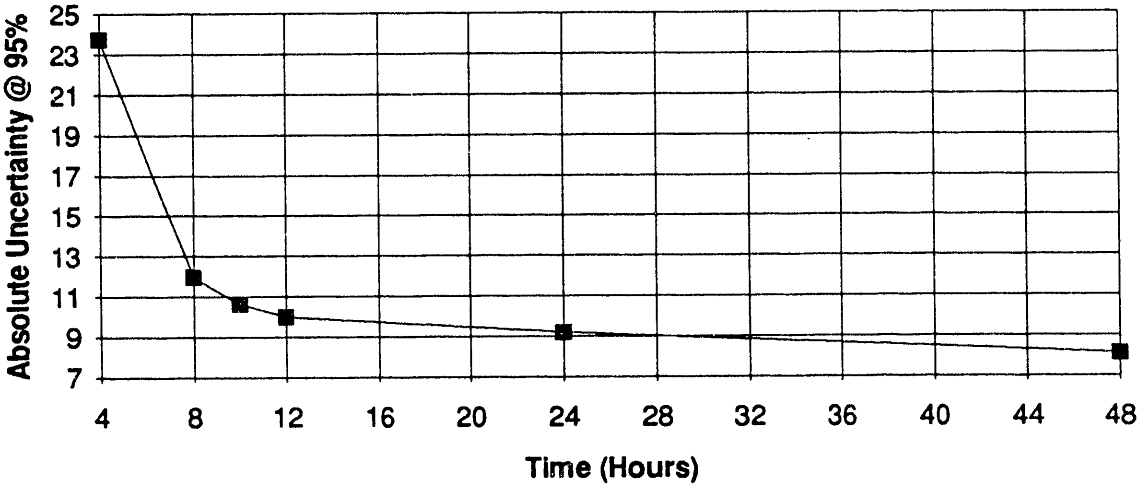
SULFUR DIOXIDE RETENTION PERCENT

Description	4 HR	8 HR	10 HR	12 HR	24 HR	48 HR
MEAN VALUE	70.2	69.28	69.13	68.83	68.66	68.48
TOTAL UNCERTAINTY	9.62	5.23	4.76	4.59	4.31	4.18

UNCERTAINTY CONTRIBUTIONS

Description	Error Type	4 HR	Rank	8 HR	Rank	10 HR	Rank	12 HR	Rank	24 HR	Rank	48 HR	Rank
Sulfur in coal AF basis	Bias	8.69	2	9.49	2	9.65	1	9.98	1	10.3	1	10.4	1
SO2 (LO) @ econ flue gas	Bias	4.92	3	5.13	3	5.15	3	5.22	2	5.35	2	5.39	2
Sulfur in coal AF basis	P.E.	75.1	1	11.6	1	6.9	2	5.02	3	2.18	3	0.989	3
O2 @ econ flue gas	Bias			0.543	5	0.548	4	0.558	4	0.565	4	0.574	4
Carbon in coal AF basis	P.E.	3.19	4	0.553	4	0.329	5	0.219	5	0.152	5		

Figure 4-9. Absolute Uncertainty in Calcium Utilization (Sorbent) vs. Time



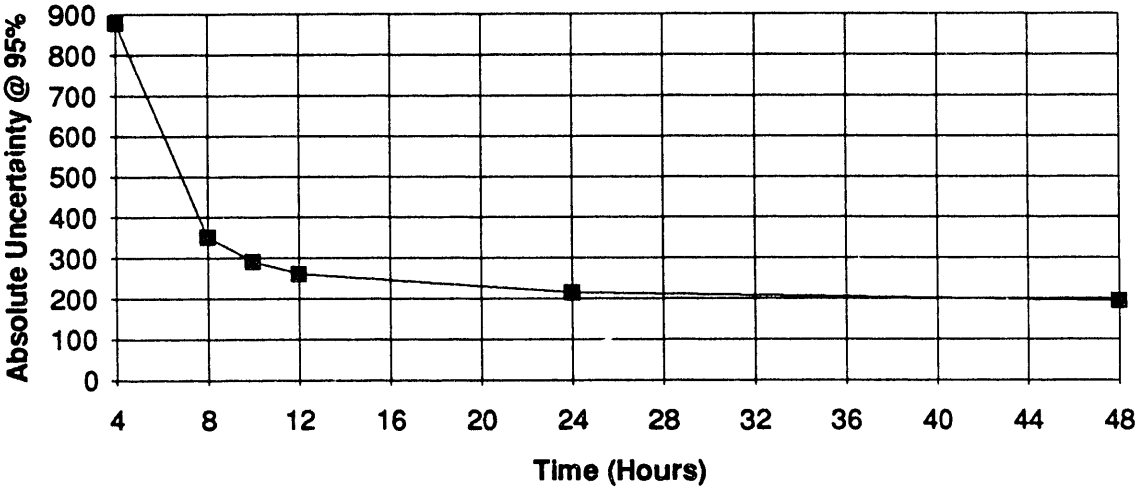
CALCIUM UTILIZATION (SORBENT ONLY)

Description	4 HR	8 HR	10 HR	12 HR	24 HR	48 HR
MEAN VALUE	49.81	50.04	49.71	48.87	48.72	46.12
TOTAL UNCERTAINTY	23.73	11.95	10.62	9.99	9.17	8.09

UNCERTAINTY CONTRIBUTIONS

Description	Error Type	4 HR	Rank	8 HR	Rank	10 HR	Rank	12 HR	Rank	24 HR	Rank	48 HR	Rank
Sulfur in coal AF basis	Bias	61	2	65.1	2	65	1	64.5	1	65.5	1	59	1
Sulfur in coal AF basis	P.E.	492	1	69.6	1	40.2	2	27.7	2	11.7	2	4.72	2
SO2 (LO) @ econ flue gas	Bias			2.68	3	26.6	3	2.63	3	2.69	3	2.44	3
Sorbent feed rate CMB 4A	Bias			1.53	4	1.54	4	1.49	4	1.48	4	1.32	4
Sorbent feed rate CMB 4B	Bias			1.46	5	1.42	5	1.37	5	1.37	5	1.23	5

Figure 4-10. Absolute Uncertainty in Net Plant Heat Rate vs. Time



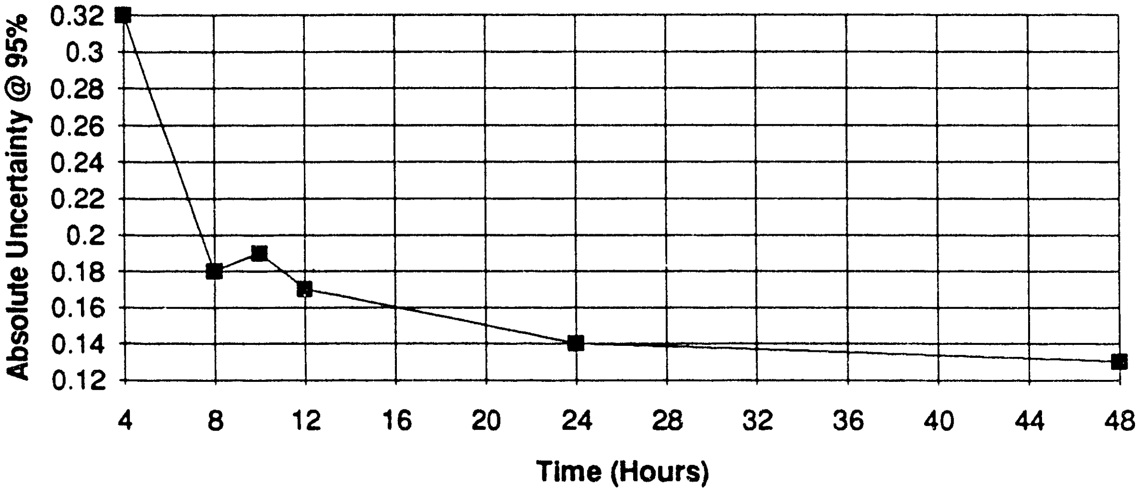
NET PLANT HEAT RATE

Description	4 HR	8 HR	10 HR	12 HR	24 HR	48 HR
MEAN VALUE	11260.5	11301.5	11314.1	11325.2	11297.7	11256.5
TOTAL UNCERTAINTY	878	351	291	260	214	194

UNCERTAINTY CONTRIBUTIONS

Description	Error Type	4 HR	Rank	8 HR	Rank	10 HR	Rank	12 HR	Rank	24 HR	Rank	48 HR	Rank
Total load in MW 1, 2, 3, 4	Bias	17200	2	17400	2	17400	2	17500	2	17300	1	17100	1
HHV of fuel AF basis	P.E.	73900	1	93500	1	54600	1	38000	1	16400	2	8620	2
HHV of fuel AF basis	Bias			2970	3	2970	3	2960	3	2930	3	2910	3
Coal flow cmb B, rear wall(4D)	Bias			1470	4	1470	4	1480	4	1470	4	1470	4
Coal flow cmb A, fr wall, east (4C)	Bias			1460	5	1460	5	1470	5	1460	5	1460	5
Coal flow cmb A, rear wall (4A)	Bias			1430	6	1440	6	1440	6	1440	6	1430	6
Coal flow cmb B, fr wall, east (4E)	Bias			1430	7	1430	7	1440	7	1430	7	1420	7
Coal flow cmb A, fr wall, west (4B)	Bias			1400	8	1410	8	1410	8	1410	8	1410	8
Coal flow cmb B, fr wall, west (4F)	Bias			1400	9	1400	9	1410	9	1400	9	1400	9
Unit auxiliary transformer MW	Bias					578	10	579	10	572	10	566	10

Figure 4-11. Absolute Uncertainty in Combustion Efficiency vs. Time



COMBUSTION EFFICIENCY

Description	4 HR	8 HR	10 HR	12 HR	24 HR	48 HR
MEAN VALUE	98.04	98.04	98.08	98.07	98.09	98.18
TOTAL UNCERTAINTY	0.32	0.18	0.19	0.17	0.14	0.13

UNCERTAINTY CONTRIBUTIONS

Description	Error Type	4 HR	Rank	8 HR	Rank	10 HR	Rank	12 HR	Rank	24 HR	Rank	48 HR	Rank
Carbon in fly ash	Bias	0.00504	3	0.0051	2	0.0051	3	0.00519	3	0.00508	1	0.00484	1
Hydrogen in fly ash	Bias	0.00411	4	0.00416	3	0.00418	4	0.00426	4	0.00417	2	0.004	2
Carbon in fly ash	P.E.	0.00171	8	0.000767	7	0.036	1	0.00872	1	0.0029	3	0.00365	3
Ash in coal AF basis	Bias	0.00179	7	0.00178	5	0.00168	5	0.00167	5	0.00164	5	0.00153	4
Ash in coal AF basis	P.E.	0.0706	1	0.0156	1	0.00844	2	0.00558	2	0.00268	4	0.00141	5
Bed drain rate CMB 4B	Bias			0.000552	9	0.000494	7	0.000411	7	0.00041	6	0.000449	6
Carbon in bed drain	Bias			0.000249	11	0.000237	10	0.000218	11	0.000212	9	0.000242	7
Bed drain rate CMB 4A	Bias			0.000251	10	0.000236	11	0.00023	10	0.000219	8	0.00023	8
HHV of fuel AF basis	P.E	0.0118	2	0.00215	4	0.00119	6	0.000863	6	0.000387	7	0.000205	9
Hydrogen in bed drain	Bias			0.000205	12	0.00018	12	0.00018	12	0.000175	10	0.000202	10
CO2 in fly ash	Bias			0.000167	13	0.000175	13	0.000175	13	0.000172	12	0.000169	11
Hydrogen in flyash	P.E.	0.0034	5	0.000879	6	0.000463	8	0.000296	8	0.000152	13	0.0001	12
Carbon in bed drain	P.E.	0.00252	6	0.000576	8	0.000368	9	0.00028	9	0.000173	11	0.0000945	13
HHV of fuel AF basis	Bias									0.0000826	14	0.0000745	14

- Boiler efficiency (I/O method)
- Ca/S molar ratio
- SO_2 retention (%)
- Ca utilization
- Net heat rate
- Combustion efficiency

In Figures 4-5 through 4-11, a bias error is the largest contributor to the uncertainty for the period. The only precision errors that appear are those associated with solids analysis. In general, a larger number of samples will lead to a smaller precision error. This leads to the conclusion that results uncertainties are reduced by increasing the number of solids samples. Also, the uncertainty obtained by taking 16 solids samples over a 48-hour steady-state period can be replicated by taking 16 solids samples over a shorter period of time. However, factors such as manpower, sample processing equipment requirements, and residence time of material in the boiler impose practical limitations on the feasible increases in sampling frequency and corresponding decreases in test duration.

For four out of the seven major calculated results, (Ca/S ratio, SO_2 retention, calcium utilization, and boiler efficiency (I/O method)) the contribution of the largest precision error was reduced to below that of the largest bias error after 10 hours (six solids samples) for test SD1. So for those variables, the point of diminishing returns has been reached with regard to minimizing uncertainty from increasing the number of samples. For combustion efficiency and net heat rate, this point is reached after 24 hours of sampling (10 samples). For boiler efficiency by loss method, it takes 48 hours (16 samples). However, since the uncertainties associated with these results are acceptably low after only 10 hours of sampling, it is not necessary to increase the number of solids samples taken to achieve a further reduction in uncertainty.

In Figures 4-5 through 4-11, it can be seen that a point of diminishing returns for uncertainty minimization is reached when a bias error becomes the top ranking contributor to the uncertainty in a given result. To further reduce the uncertainty, reduction in this top ranking bias error will be required.

4.4.2 Accuracy of Solids Preparation Procedures

Three tests are available for determining the acceptability of the variance of division and analysis, S_{da}^2: excessive variation and division and analysis variance limit (from ASTM method D2013-A2), and high uncertainties in performance analysis results (from ASME PTC 19.1).

The values obtained during repeated determinations of S_{da}^2 may not vary excessively. Whether the amount of variation is excessive is based on the statistical "F" test, which limits the amount of the ratio of each individual measurement of S_{da}^2 to the average of all the measurements within the group. Another check is provided by comparing the average value of each group to the overall average again using the statistical "F" factors.

Table 4-3 shows the results of the variance ratio tests for coal and bottom ash for each of the eight samples, which were divided into two groups of 4 samples each.

The ratio of each individual S_{da}^2 to the average of the group of four must not exceed 3.49 (from "F" factor tables); none of the ratios exceed this limit. The ratio of each group average to the overall average must not exceed 2.18; none of the ratios exceed this limit, either. If any of the ratio tests fail the "F" factor criteria, ASTM methodology would have required that the techniques of preparation and analysis be improved.

The division/analysis variance limit test requires that the division and analysis variance be no more than 20% of the overall variance. The probable maximum value of S_o^2, which is used for comparison of S_o^2 and S_{da}^2, is also shown in Table 4-3. From the table, the division and analysis variance exceeds 20% of the overall variance in all instances. Since the value for S_{da}^2 represents a precision error for solids sampling and analysis, the 20% criteria set by ASTM code becomes more difficult to achieve as the coal properties become more uniform. Improving the precision error may require more sample increments, larger sample lot sizes, and/or sample crushing at earlier stages of preparation. However, this was not considered necessary, as the overall calculated uncertainties on the performance results were within the required range.

Table 4-3. Results of Variance Analysis

	Coal Variance			Bottom Ash Variance	
Item	Total Moisture	Dry Ash	As-fired HHV	Carbon	Calcium
S_{da}^2 (Group 1)	0.045	0.175	3446	0.038	0.457
	0.076	0.034	2464	0.015	0.133
	0.343	0.016	7525	0.097	0.458
	0.061	0.021	2699	0.008	0.069
(Group 2)	0.047	0.232	5660	0.029	0.066
	0.004	0.052	5783	0.019	0.121
	0.014	0.01	11805	0.014	0.164
	0.272	0.068	911	0.008	0.028
Avg S_{da}^2 (Group 1)	0.131	0.062	4033	0.04	0.279
Avg S_{da}^2 (Group 2)	0.084	0.09	6040	0.017	0.095
S_{da}^2 Avg Overall	0.108	0.076	5037	0.029	0.187
Variance Ratios, Maximum limit from "F" factor tables = 3.49					
Group 1	0.34	2.84	0.85	0.96	1.64
	0.58	0.55	0.61	0.39	0.47
	2.61	0.27	1.87	2.45	1.64
	0.46	0.35	0.67	0.2	0.25
Group 2	0.56	2.57	0.94	1.67	0.7
	0.05	0.57	0.96	1.07	1.28
	0.17	0.11	1.95	0.79	1.73
	3.22	0.75	0.15	0.46	0.29
Group Variance ratios, Maximum = 2.18					
	1.22	0.81	0.8	1.39	1.49
	0.78	1.19	1.2	0.61	0.51
Overall Variance, S_o^2					
Group 1	0.1	0.164	8783	0.058	0.502
Group 2	0.131	0.107	6581	0.08	0.693
Probable Maximum:					
	0.175	0.205	11600	0.104	0.902
Comparisons:					
S_{da}^2	0.108	0.076	5037	0.029	0.187
S_o^2	0.175	0.205	11600	0.104	0.902
S_{da}^2/S_o^2	0.62	0.37	0.43	0.27	0.21

4.4.3 Determination of the Time to Steady State

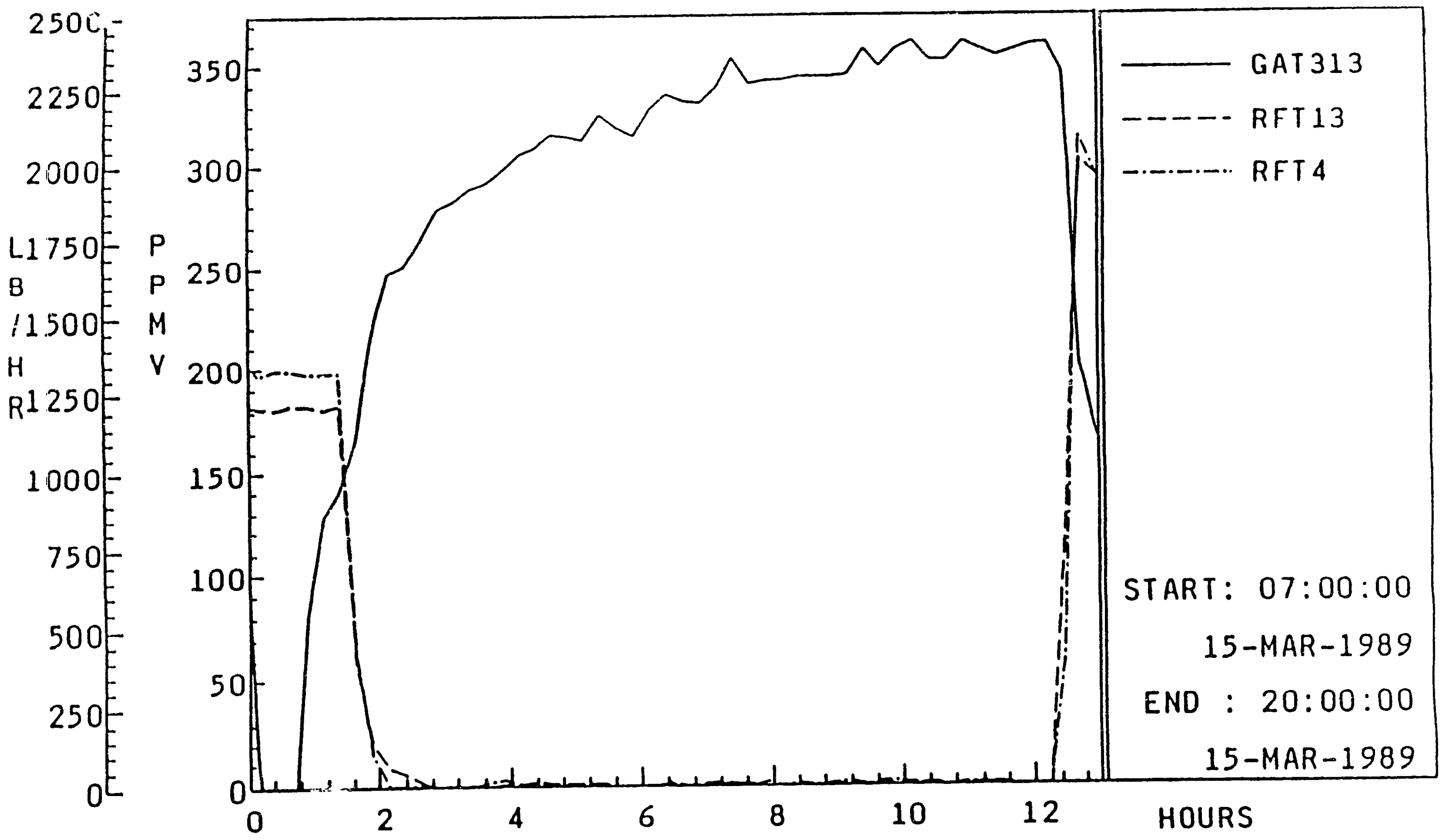
Transient tests SD2 was conducted to determine the response time of SO_2 emissions following a complete stoppage of limestone flow into the boiler. Test SD3 was conducted to determine the response time after resumption of limestone feed at twice the rate used in test SD1. Results are shown in Figures 4-12 through 4-14. Figure 4-12 shows the twelve hour period following the stoppage of limestone for test SD2, Figure 4-13 shows the twelve hour period following the resumption of limestone feed for test SD3. Figure 4-14 shows both tests SD2 and SD3 on a single graph. These curves show the characteristic first order response curve that was expected for this type of process change. The data for test SD2 was best fit with a first order time constant of about 1.7 hours, while the data from test SD3 was fit with a first order time constant of 2.17 hours.

Tests SD4 and SD5 measured the plant response to a fairly rapid load change. Of primary concern is the rate of change in refractory temperatures. These represent the longest lag time to thermal equilibrium of any variable. A representative cyclone refractory temperature is displayed for the load decrease and increase, respectively, in Figures 4-15 through 4-17. Figure 4-15 shows the refractory temperature response curve for Test SD4. Figure 4-16 shows the refractory temperature response curve for test SD5. Figure 4-17 shows both tests periods on a single graph. The time constant for the load increase was found to be 7.37 hours, while the time constant for the load decrease was 7.46 hours. The slight difference in time constants is probably due to the effect of higher heat transfer coefficients at higher loads.

4.5 CONCLUSIONS

Ultimately, the overall uncertainty in the final performance results dictates requirements for precision error for all input parameters. The uncertainty analysis program used on the test results ties the uncertainties of all input parameters to the uncertainties in the results.

After test SD1, uncertainty analysis was used by the test team to establish the number of solids samples required to minimize the uncertainties of important results. This was determined to be six samples each of coal, fly ash, limestone, and bottom ash. The test duration required to physically collect these samples is 10 hours. Better estimates of bias error also became available and were included in the uncertainty analysis. Solids sampling requirements were updated with the bias errors.



GAT313-SO2(LO) ECON FLUE GAS OUTLET RFT13-SORBENT FEED RATE CMB 4B
RFT4-SORBENT FEED RATE CMB 4A

Figure 4-12. Sorbent Feed Rate and SO_2 Output

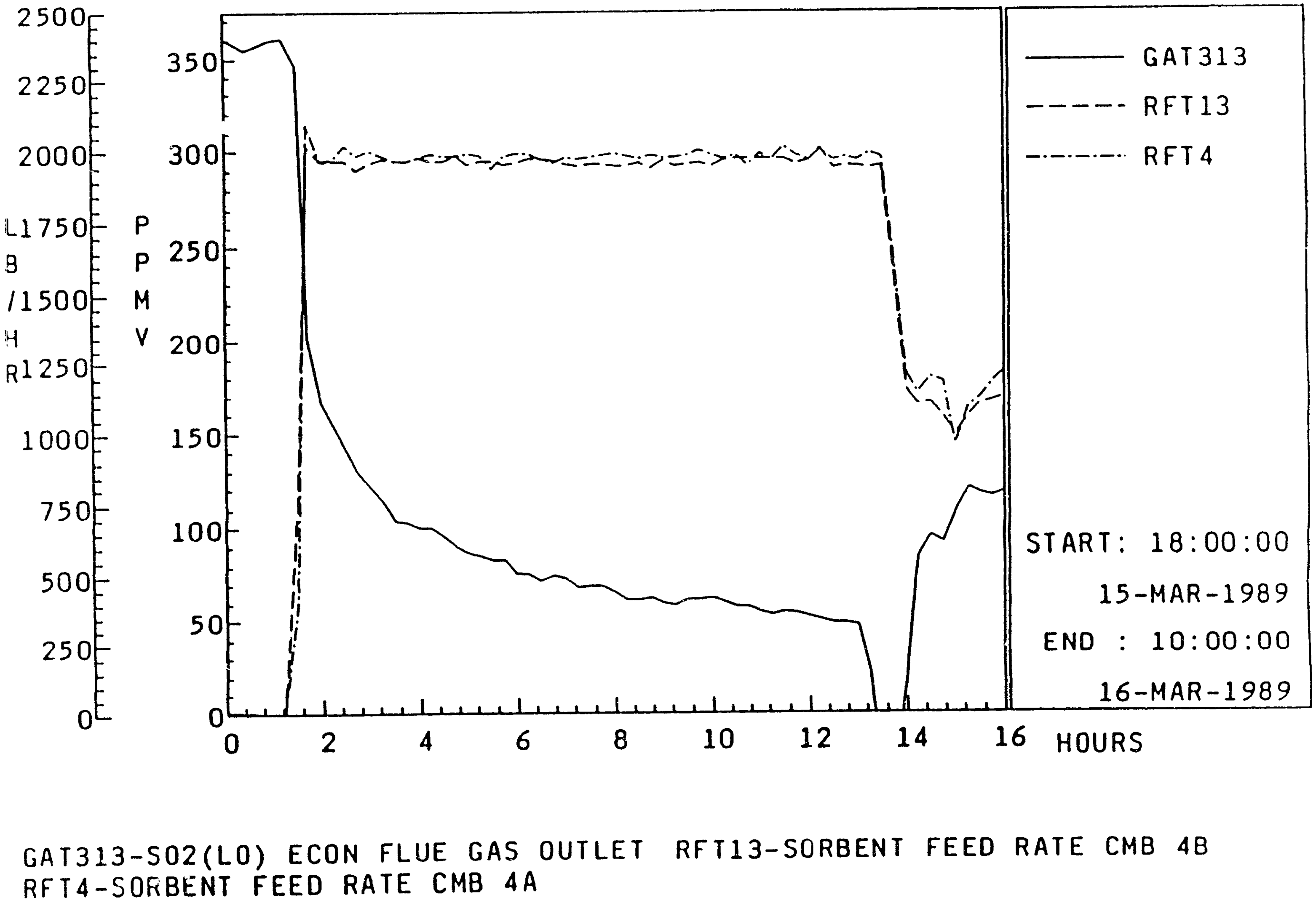
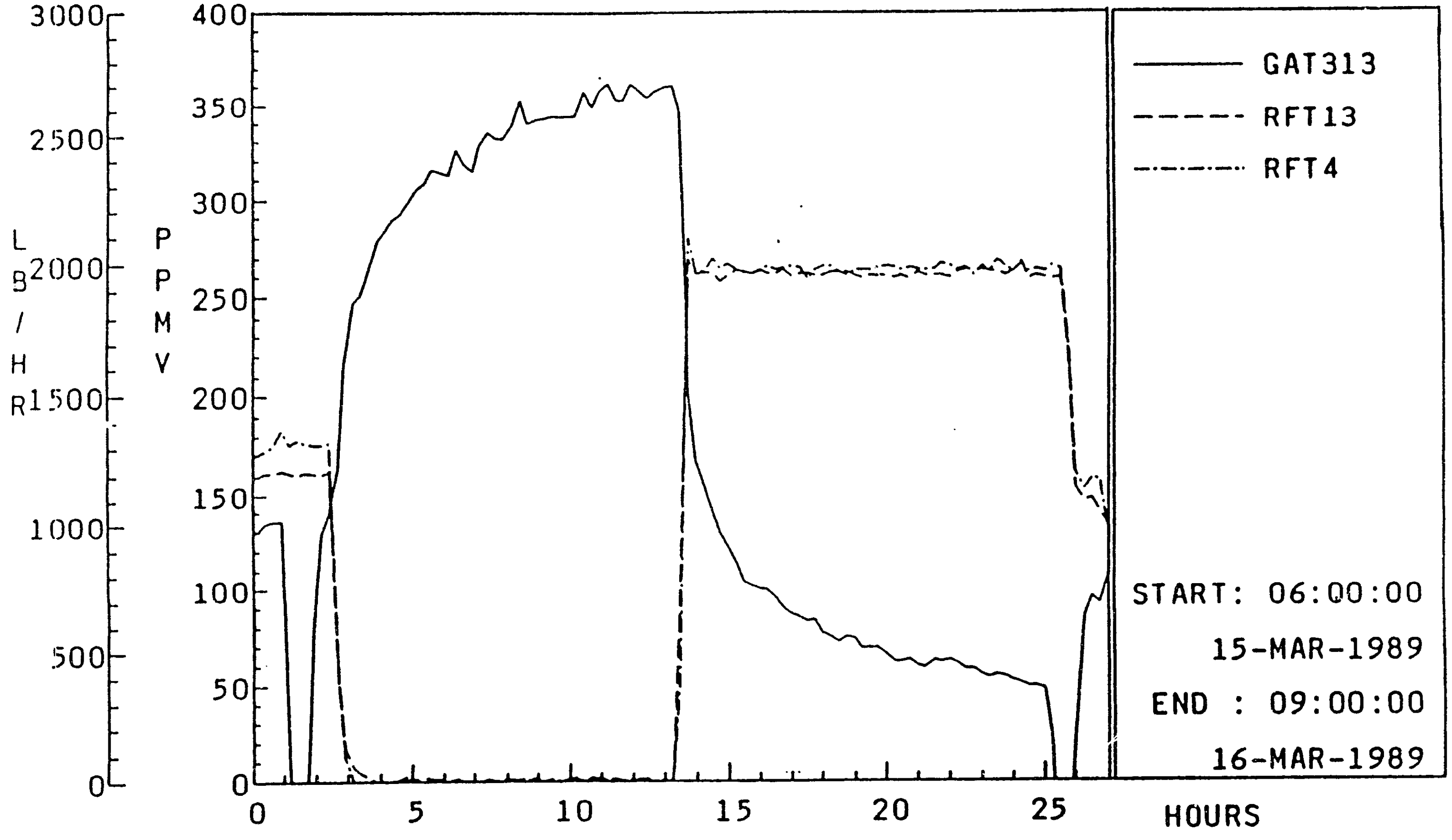


Figure 4-13. Sorbent Feed Rate and SO_2 Output



GAT313-S02(LO) ECON FLUE GAS OUTLET RFT13-SORBENT FEED RATE CMB 4B
RFT4-SORBENT FEED RATE CMB 4A

Figure 4-14. Sorbent Feed Rate and SO_2 Output

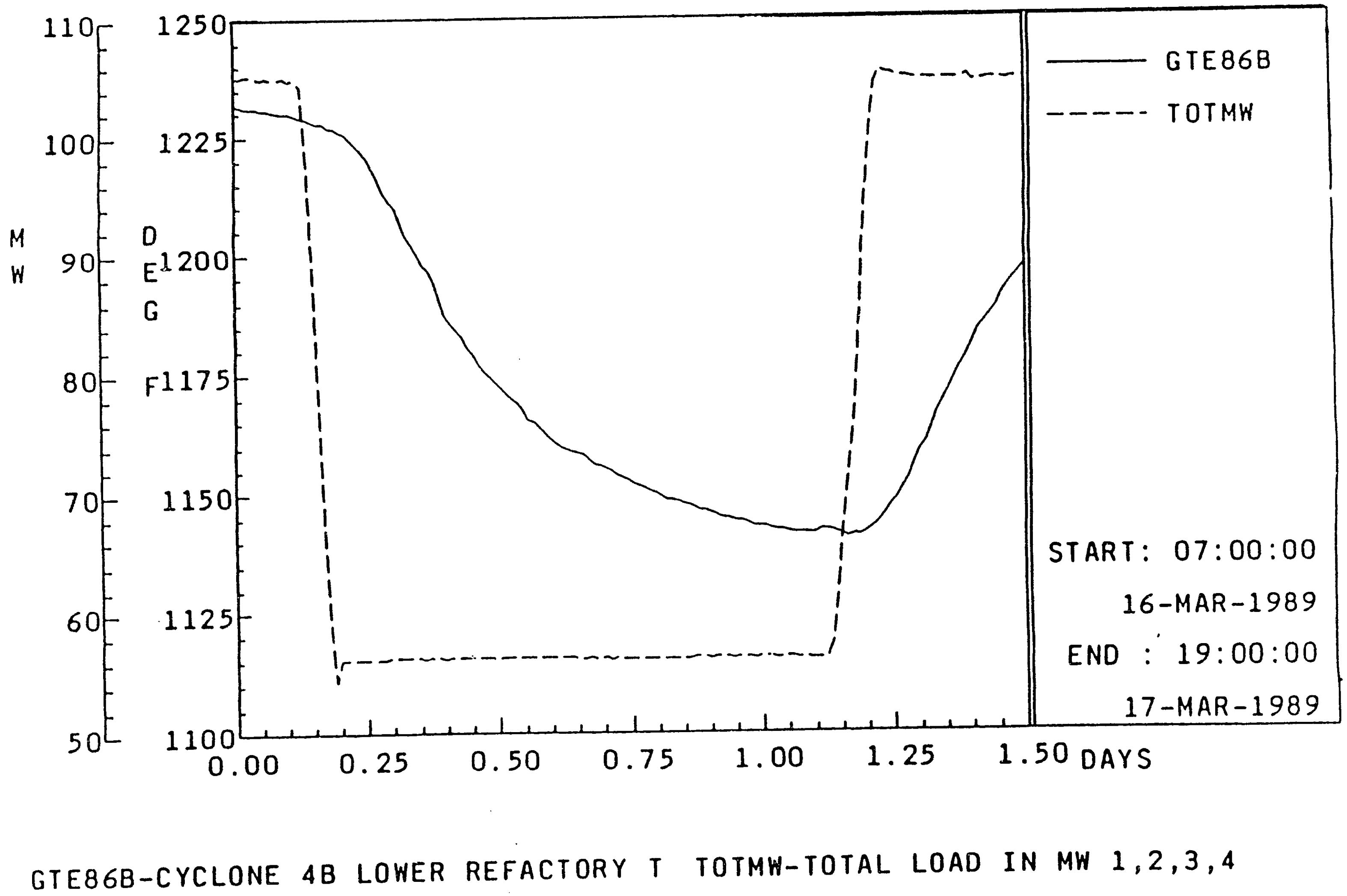


Figure 4-15. Cyclone B Refractory Temperature

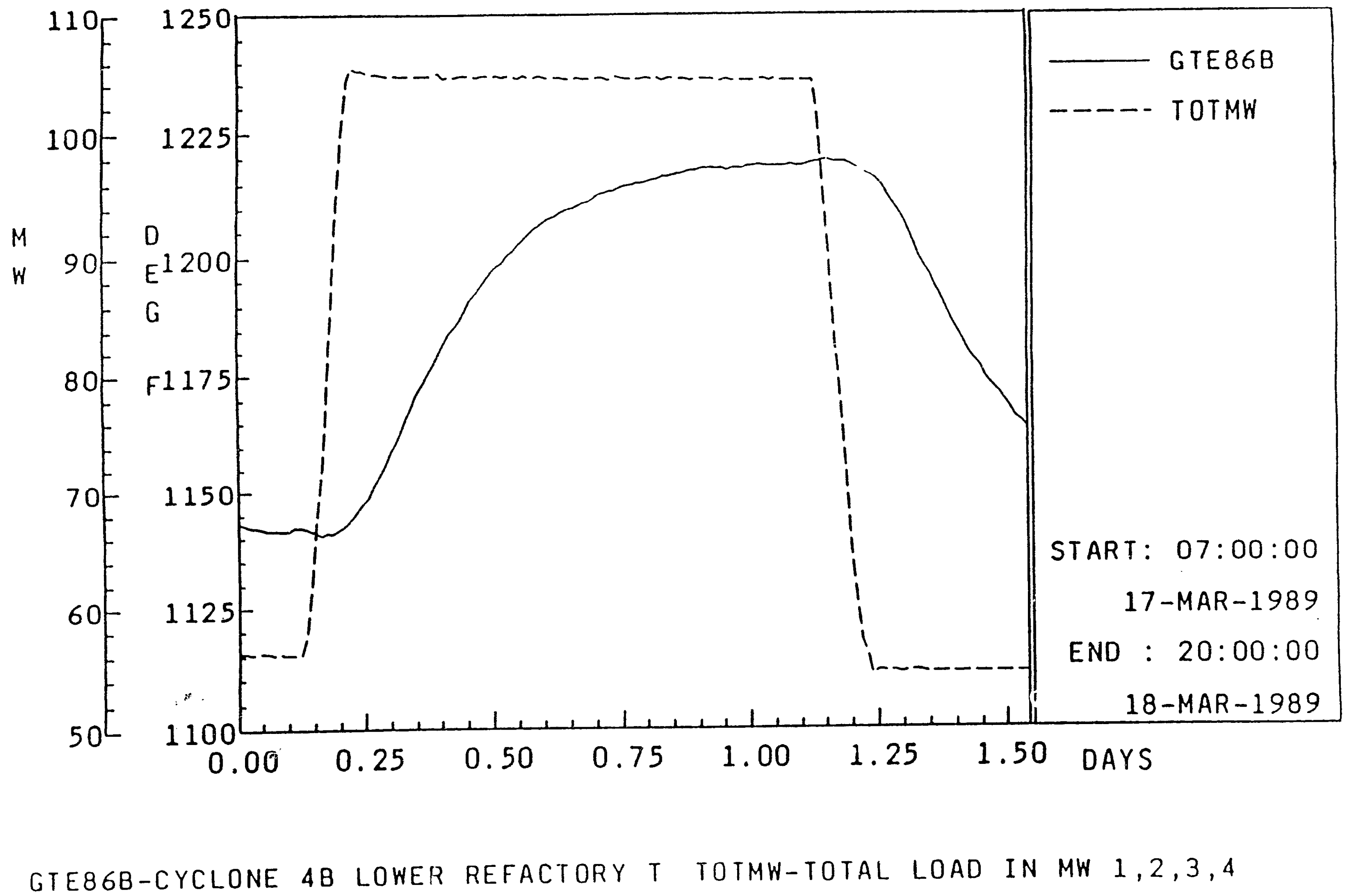
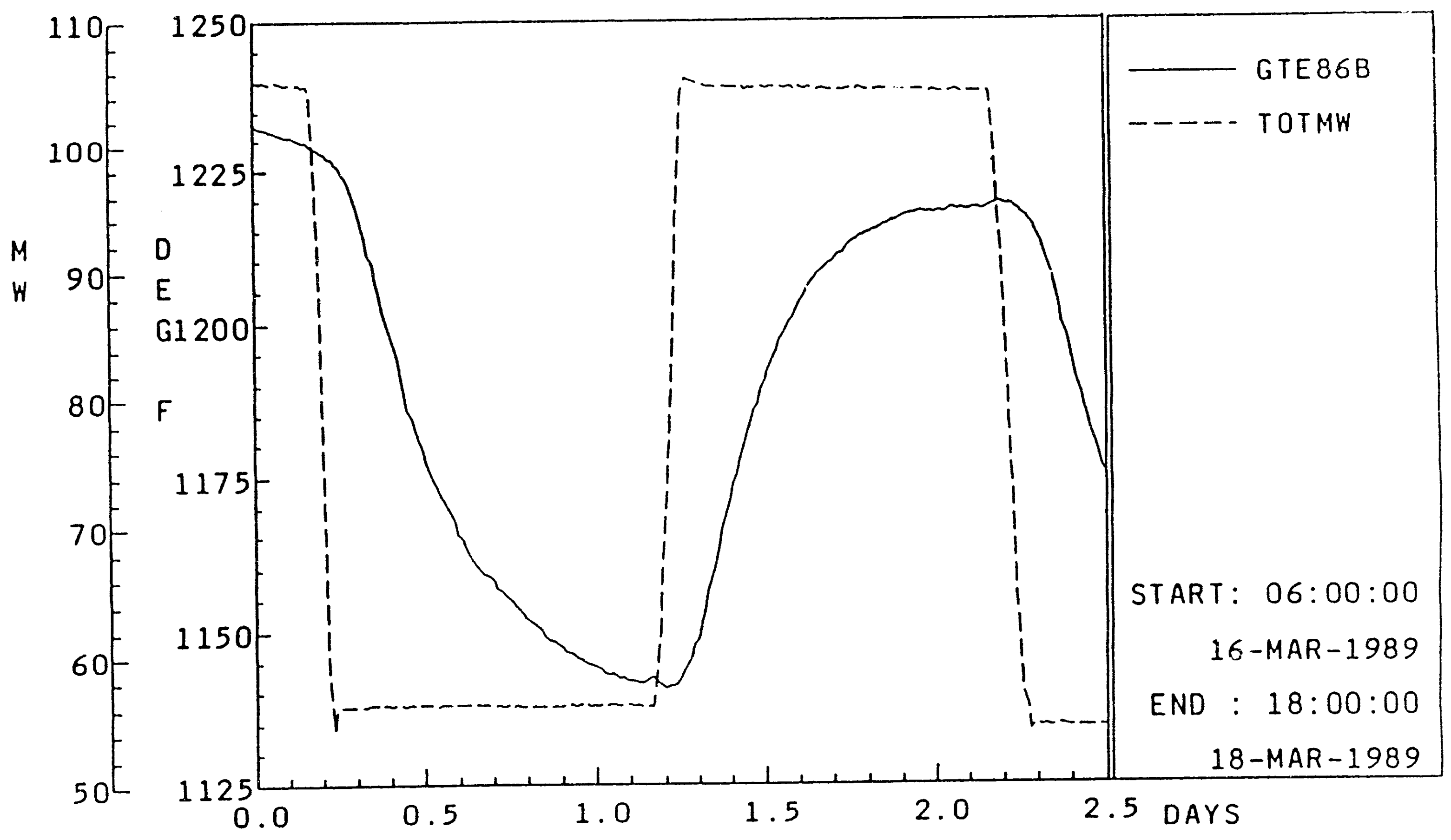


Figure 4-16. Cyclone B Refractory Temperature



GTE86B-CYCLONE 4B LOWER REFACTORY T TOTMW-TOTAL LOAD IN MW 1,2,3,4

Figure 4-17. Cyclone B Refractory Temperature

In addition, the test team chose to target minimum uncertainty rather than targeting a specific uncertainty. Furthermore, calcium balance was replaced by calcium to sulfur ratio as a key performance result. Minimum uncertainty is defined as that obtained when a reduction in measurement precision errors has a negligible impact on the total results uncertainties.

4.5.1 Revised Bias Estimates

As performance test results were evaluated, a better understanding developed of what measurements contributed the most to results uncertainty. Four of the most important are identified here:

1. Solids sample chemical data
2. Coal feed rates
3. Limestone feed rates
4. Gas analyzer data

The bias error values used originally for solids chemical data were overestimated for most of the chemical species. Discussion with the off-site laboratory resulted in the revised values currently in use. These will be discussed in more detail in the 1990 Annual Technical Progress Report.

The bias determined from 10 coal feed calibrations agreed well with the original bias estimate. A 1% span error and a 0.3 Klb/hr zero error are used.

The bias determined from calibration data for limestone feed rates was much larger than the original estimate, as shown in Table 4-4:

Table 4-4. Limestone Feeder Bias Estimates

	Original		Revised	
Combustor	A	B	A	B
Span error, %	5	5	20	12
Zero error, lb/hr	50	50	50	50

The bias estimates for NO_x, CO, and SO_2 gas analyzers remained at the originally estimated 10 ppmv. The O_2 estimated bias was reduced to 0.15% from 0.40%, and the CO_2 bias was increased from 0.40% to 1.1%. A temperature-related drift is responsible for the higher CO_2 bias.

The revisions made to the bias estimates did not have a substantial impact on the performance results uncertainties. Increases in some bias estimates were offset by decreases in others. The effect on each of the four key results uncertainties after changes in the bias estimates after test SD1 is shown in Table 4-5

Table 4-5. Effect of Revised Bias Estimates on Results Uncertainties

Calculated result	Original Test Plan Unc, %	Revised Uncertainty, %
Boiler efficiency	± 0.5	± 0.3
Combustion efficiency	± 0.2	± 0.2
Ca/S	± 10	± 14
Sulfur retention	± 5	± 5

In conjunction with the revised bias estimates, the solids sampling requirements were reassessed. The solids sampling requirements for dual and split combustor tests was determined as follows:

4.5.2 Split Combustor Tests

Temperature differences between the combustors has forced the test team to analyze the test data as "split combustor tests". The emissions performance of each combustor is evaluated separately by sampling the flue gas on both sides of the air heater inlet. The EGAS probes are sampled for one half of the test using the combustor A sample points only. For the remainder of the test the combustor B sample ports are sampled.

Fly ash samples are taken at a point that is common to both combustors. Since a difference in fly ash carbon is expected between the combustors, combustion and boiler efficiency results for a single combustor are not valid. Ca/S ratio and sulfur retention are the remaining key results uncertainties and will determine the number of solids samples required.

With only Ca/S ratio and sulfur retention uncertainty to contend with, sulfur in the coal becomes the most significant precision error. By varying the number of coal samples included in completed test uncertainty analyses, it was determined that four samples will yield minimum results uncertainty for most of the split combustor tests completed to date. Only two each of limestone, fly ash, and bottom ash samples are required.

4.5.3 Combined Combustor Tests

For combined combustor tests, the boiler and combustion efficiencies can be evaluated. To minimize the uncertainty in these results, coal ash and fly ash carbon precision errors must be kept low. Analyses have shown that five coal and six fly ash samples consistently minimized uncertainty in these results for performance tests completed to date. Again, only two limestone and two bottom ash samples are required per test. The five coal samples required for minimum boiler and combustion efficiency uncertainties exceed the four samples necessary to minimize Ca/S ratio uncertainty and sulfur retention uncertainty.

Expected uncertainties for the four key results with the present bias estimates and with five coal samples, six fly ash samples, two limestone samples, and two bottom ash samples are:

Performance Result	Uncertainty, %
Boiler efficiency	± 0.3
Combustion efficiency	± 0.1
Ca/S	± 5
Sulfur retention	± 3

4.5.4 Time to Chemical or Thermal Equilibrium

Due to scheduling and coal supply constraints, tests SD2, SD3, SD4, and SD5 were not run for a sufficient time to reach full equilibrium. Initially, this time was deemed sufficient as it was assumed that extrapolations could be made from collected data yielding equilibrium values and times to steady state. However, this was not the case and analyses showed that the time required for the plant to reach equilibrium after a step change in limestone flow rate is longer than 12 hours. To ensure equilibrium conditions, at least one day of operation at the new Ca/S setting should be scheduled before testing after a step change in limestone feed rate.

Analysis of the transient effects of step changes in load also lead to the conclusion that at least one day of unit operation is required for process stabilization between steady-state performance tests at different loads.

For both types of transient responses, a longer period of time than 24 hours is recommended before the start of testing following significant changes in load and/or Ca/S ratio.

Section 5

PLANT COMMERCIAL PERFORMANCE STATISTICS

5.1 OVERVIEW

This section presents plant commercial performance statistics from January 1989 through December 1989. Table 5-1 contains monthly operating and equivalent availabilities, capacity factors and heat rates. These are also plotted on Figures 5-1 through 5-4. Tables 5-2 through 5-13 present monthly commercial performance statistics for the entire year. Section 5.2 contains the definitions of terms used in the presentation of plant commercial performance statistics.

Table 5-1. Nucla CFB Plant Commercial Performance Statistics

Month (1989)	Operating Availability (%)	Equivalent Availability (%)	Capacity Factor (%)	Net Heat Rate (Btu/Nkwh)
Jan	14.3	14.3	9.3	11883
Feb	26.0	19.2	13.0	13424
March	83.0	75.4	60.2	11710
April	69.1	36.5	46.2	12069
May	48.5	30.7	17.0	13131
June	75.5	41.2	53.3	11800
July	70.1	64.9	50.4	11911
August	52.5	29.2	23.8	12429
Sept	40.0	36.0	30.4	12064
Oct	12.5	12.5	10.0	11876
Nov	63.9	60.3	57.9	11854
Dec	65.5	64.8	56.2	11934

During 1989, the unit was in service for 4422 hours at an average load of 77.8 MWe and was on standby for 121 hours. The operating availability for the year was 51.9% and the capacity factor was 35.7%. The average net on-line (coal and gas) heat rate was 12009.0 Btu/Nkwh.

During the first quarter of the year, operating and equivalent availabilities were 41.6% and 36.9%, respectively. The capacity factor for the quarter was 28%. The plant experienced three master fuel trips during 899 hours of operation, and was taken off-line by controlled shutdown three times. In January and February, the plant was on a scheduled outage for 680 hours for refractory repair. As such, there were only 106 in-service hours in January and 175

Figure 5-1. Nucla CFB Operating Availability
January through December 1989

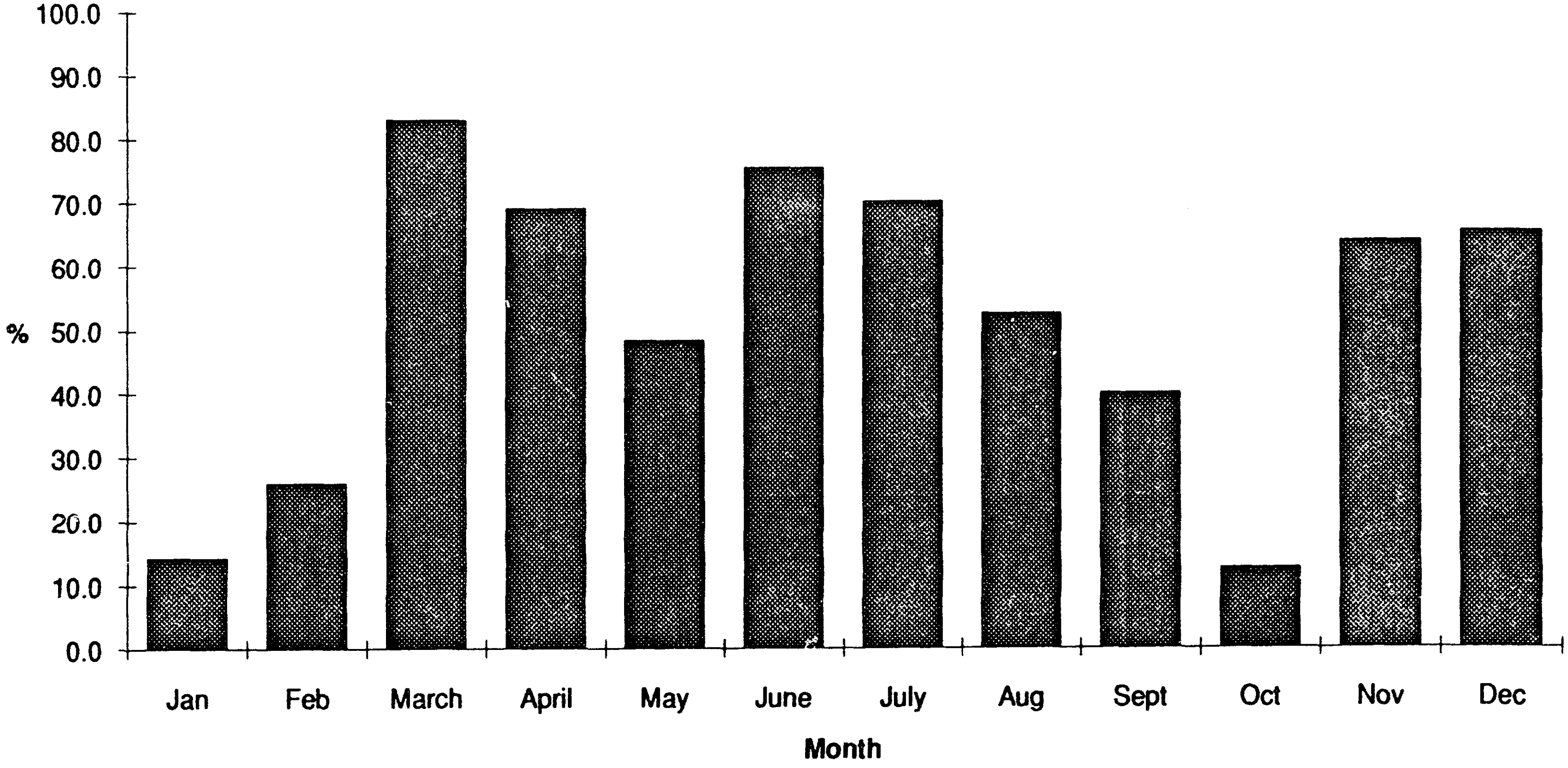


Figure 5-2. Nucla CFB Equivalent Availability
January through December 1989

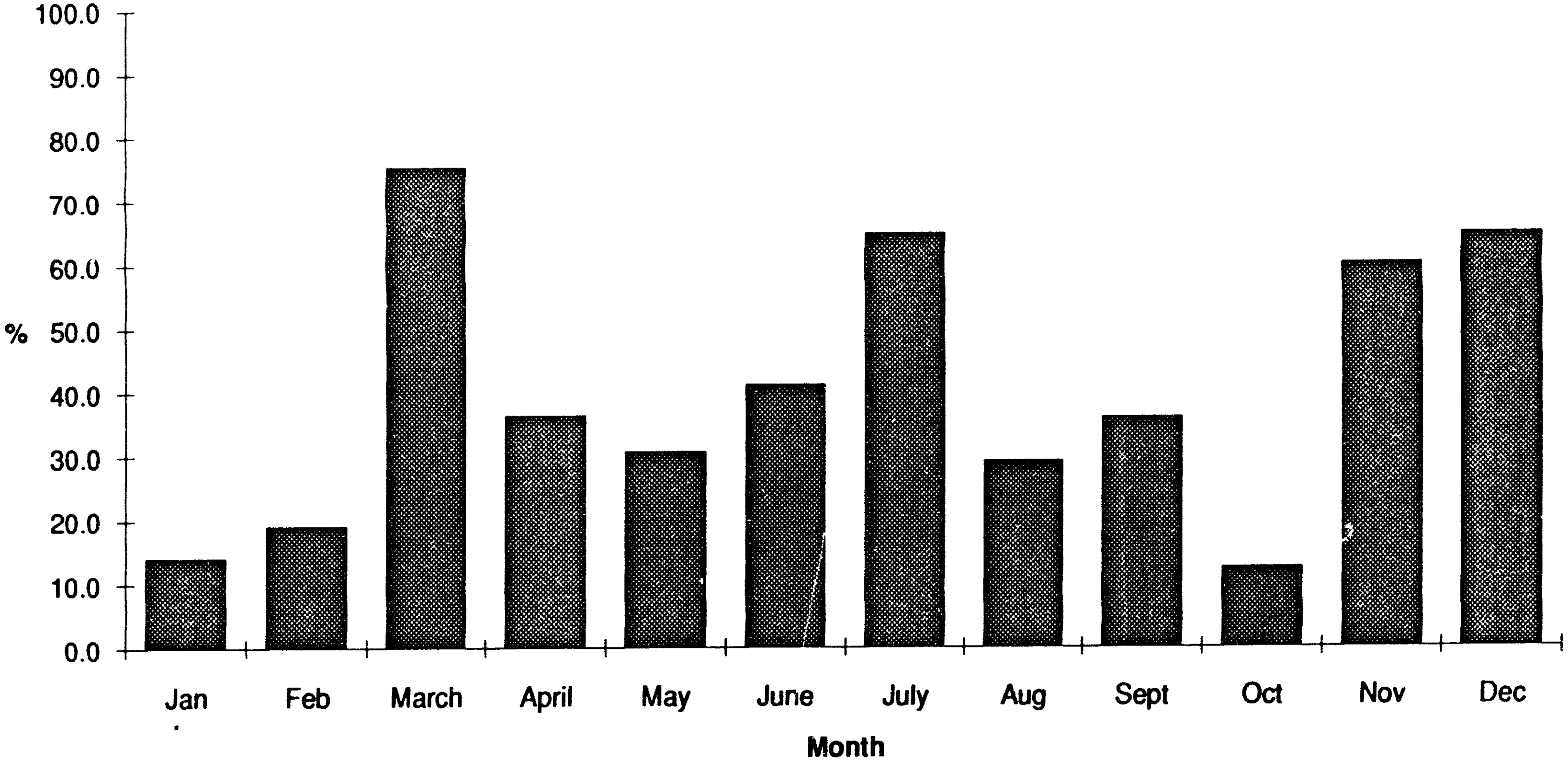


Figure 5-3. Nucla CFB Capacity Factor
January through December 1989

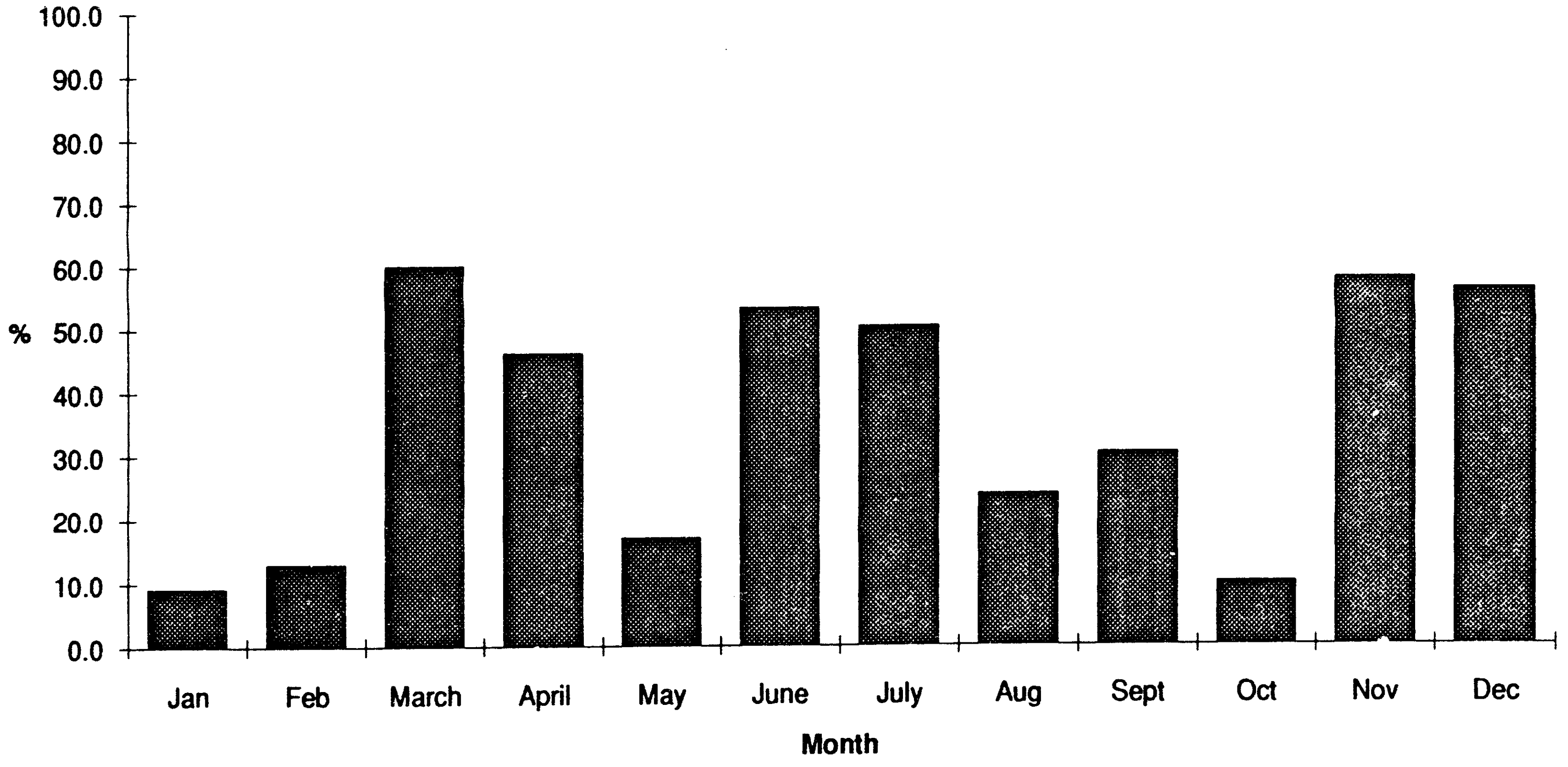


Figure 5-4. Nucla CFB Net Plant Heat Rate
January through December 1989

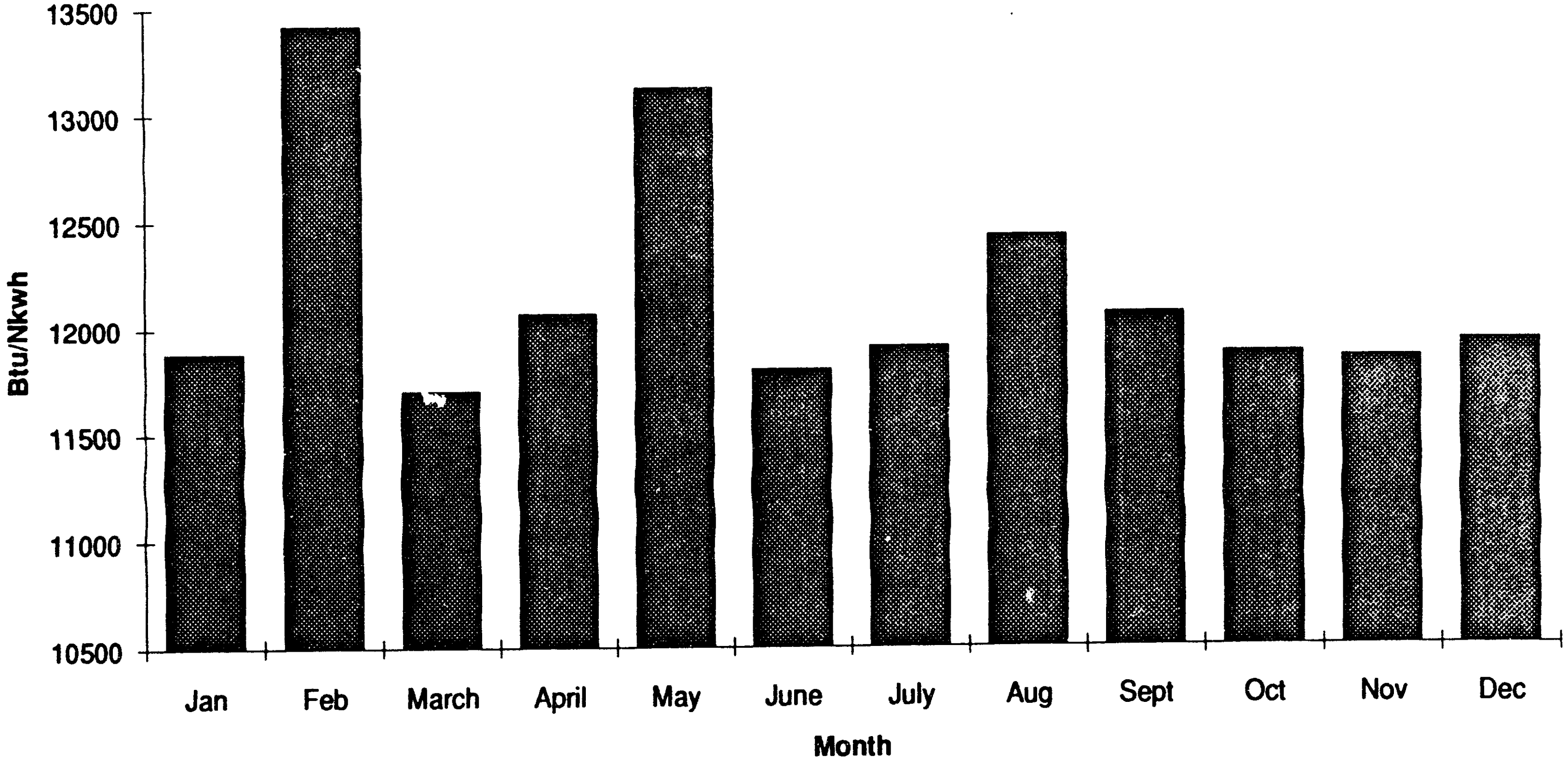


Table 5-2
PLANT COMMERICAL PERFORMANCE STATISTICS
January 1989

1. Plant Outputs and Consumptions

• Gross generation:	7580	mWhrs
• Net generation:		
- Period	6013	mWhrs
- On line	6736	mWhrs
• Aux power use:		
- Period	1567	mWhrs
- On line	844	mWhrs
• Aux power use (in %):		
- Period	20.7	%
- On line	11.1	%

2. Operating Hours

• Period hours:	744	hrs
• In Service:	106	hrs
• Coal hours:	106	hrs
• On standby:	0	hrs
• Scheduled outage:	608	hrs
• Unscheduled outage:	30	hrs
• Number of Unit Starts:	0	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	700	6.7	105
2	689	6.6	105
3	665	6.3	106
4	5527	51.9	106
Unit Total	7580	71.2	106

4. Operating Availability:	14.3	%
5. Equivalent Availability:	14.3	%
6. Capacity Factor:	9.3	%

7. Average Heat Rate for Period:

• On line (coal and gas):	11883.1	btu/nkwh
• On line (coal):	11886.9	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	228	mWhrs
• Primary air fan:	202	mWhrs
• Secondary air fan:	33	mWhrs
• Induced draft fan:	106	mWhrs
• High pressure blowers:	17	mWhrs
• Bottom ash cooler fan:	16	mWhrs

9. Material Consumptions

• Total coal flow:	4140	tons
• Total limestone flow:	444	tons
• Total start-up burner gas (propane) flow:	23	kscf
• Avg higher heating value of propane gas:	2550	btu/scf

10. Average Coal Analysis

• Higher heating value:	9659	btu/lb
• Sulfur:	1.7	%
• Ash:	16.5	%
• Moisture:	11.0	%

Table 5-3
PLANT COMMERICAL PERFORMANCE STATISTICS
February 1989

1. Plant Outputs and Consumptions

• Gross generation:	9580	mWhrs
• Net generation:		
- Period	7663	mWhrs
- On line	8380	mWhrs
• Aux power use:		
- Period	1917	mWhrs
- On line	1199	mWhrs
• Aux power use (in %):		
- Period	20.0	mWhrs
- On line	12.5	mWhrs

2. Operating Hours

• Period hours:	672	hrs
• In Service:	175	hrs
• Coal hours:	167	hrs
• On standby:	0	hrs
• Scheduled outage:	296	hrs
• Unscheduled outage:	201	hrs
• Number of Unit Starts:	4	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	667	6.3	105
2	835	7.7	108
3	1387	9.3	150
4	6690	38.3	175
Unit Total	9580	54.8	175

4. Operating Availability:	26.0	%
5. Equivalent Availability:	19.2	%
6. Capacity Factor:	13.0	%

7. Average Heat Rate for Period:

• On line (coal and gas):	13424.7	btu/nkwh
• On line (coal):	12660.0	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	419	mWhrs
• Primary air fan:	364	mWhrs
• Secondary air fan:	48	mWhrs
• Induced draft fan:	148	mWhrs
• High pressure blowers:	26	mWhrs
• Bottom ash cooler fan:	36	mWhrs

9. Material Consumptions

• Total coal flow:	5294	tons
• Total limestone flow:	487	tons
• Total start-up burner gas (propane) flow:	3922	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis

• Higher heating value:	10178	btu/lb
• Sulfur:	1.0	%
• Ash:	18.0	%
• Moisture:	8.6	%

Table 5-4
PLANT COMMERICAL PERFORMANCE STATISTICS
March 1989

1. Plant Outputs and Consumptions

• Gross generation:	49278	mWhrs
• Net generation:		
- Period	43741	mWhrs
- On line	44070	mWhrs
• Aux power use:		
- Period	5537	mWhrs
- On line	5208	mWhrs
• Aux power use (in %):		
- Period	11.2	%
- On line	10.6	%

2. Operating Hours

• Period hours:	744	hrs
• In Service:	618	hrs
• Coal hours:	611	hrs
• On standby:	0	hrs
• Scheduled outage:	119	hrs
• Unscheduled outage:	7	hrs
• Number of Unit Starts:	2	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	5524	9.5	582
2	4897	8.7	561
3	5248	9.0	581
4	33609	54.4	618
Unit Total	49278	79.8	618

4. Operating Availability:	83.0	%
5. Equivalent Availability:	75.4	%
6. Capacity Factor:	60.2	%

7. Average Heat Rate for Period:

• On line (coal and gas):	11710.1	btu/nkwh
• On line (coal):	11645.9	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	1378	mWhrs
• Primary air fan:	1275	mWhrs
• Secondary air fan:	272	mWhrs
• Induced draft fan:	729	mWhrs
• High pressure blowers:	57	mWhrs
• Bottom ash cooler fan:	84	mWhrs

9. Material Consumptions

• Total coal flow:	25230	tons
• Total limestone flow:	1209	tons
• Total start-up burner gas (propane) flow:	2299	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis:

• Higher heating value:	10163	btu/lb
• Sulfur:	0.7	%
• Ash:	18.8	%
• Moisture:	8.6	%

Table 5-5
PLANT COMMERICAL PERFORMANCE STATISTICS
April 1989

1. Plant Outputs and Consumptions

• Gross generation:	36558	mWhrs
• Net generation:		
- Period	32206	mWhrs
- On line	32547	mWhrs
• Aux power use:		
- Period	11032	mWhrs
- On line	9821	mWhrs
• Aux power use (in %):		
- Period	11.9	%
- On line	10.6	%

2. Operating Hours

• Period hours:	720	hrs
• In Service:	498	hrs
• Coal hours:	488	hrs
• On standby:	0	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	222	hrs
• Number of Unit Starts:	2	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	3259	7.4	442
2	3220	7.5	427
3	3543	7.5	471
4	26536	53.3	498
Unit Total	36558	73.5	498

4. Operating Availability: 69.1 %

5. Equivalent Availability: 37.7 %

6. Capacity Factor: 46.2 %

7. Average Heat Rate for Period:

• On line (coal and gas):	12068.7	btu/nkwh
• On line (coal):	12058.0	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	1104	mWhrs
• Primary air fan:	896	mWhrs
• Secondary air fan:	100	mWhrs
• Induced draft fan:	476	mWhrs
• High pressure blowers:	35	mWhrs
• Bottom ash cooler fan:	74	mWhrs

9. Material Consumptions

• Total coal flow:	19347	tons
• Total limestone flow:	1327	tons
• Total start-up burner gas (propane) flow:	1797	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis

• Higher heating value:	10081	btu/lb
• Sulfur:	1.0	%
• Ash:	20.0	%
• Moisture:	6.7	%

Table 5-6
PLANT COMMERICAL PERFORMANCE STATISTICS
May 1989

1. Plant Outputs and Consumptions

• Gross generation:	13894	mWhrs
• Net generation:		
- Period	11663	mWhrs
- On line	12293	mWhrs
• Aux power use:		
- Period	2231	mWhrs
- On line	1601	mWhrs
• Aux power use (in %):		
- Period	16.1	%
- On line	11.5	%

2. Operating Hours

• Period hours:	744	hrs
• In Service:	292	hrs
• Coal hours:	276	hrs
• On standby:	69	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	383	hrs
• Number of Unit Starts:	6	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	0	ERR	0
2	0	ERR	0
3	1800	7.0	257
4	12094	41.4	292
Unit Total	13894	47.6	292

4. Operating Availability:	48.5	%
5. Equivalent Availability:	30.7	%
6. Capacity Factor:	17.0	%

7. Average Heat Rate for Period:

• On line (coal and gas):	13130.7	btu/nkwh
• On line (coal):	12680.7	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	403	mWhrs
• Primary air fan:	461	mWhrs
• Secondary air fan:	35	mWhrs
• Induced draft fan:	191	mWhrs
• High pressure blowers:	36	mWhrs
• Bottom ash cooler fan:	49	mWhrs

9. Material Consumptions

• Total coal flow:	7822	tons
• Total limestone flow:	337	tons
• Total start-up burner gas (propane) flow:	4742	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis:

• Higher heating value:	9890	btu/lb
• Sulfur:	0.9	%
• Ash:	23.7	%
• Moisture:	5.3	%

Table 5-7
PLANT COMMERICAL PERFORMANCE STATISTICS
June 1989

1. Plant Outputs and Consumptions

• Gross generation:	42175	mWhrs
• Net generation:		
- Period	37613	mWhrs
- On line	37965	mWhrs
• Aux power use:		
- Period	4562	mWhrs
- On line	4210	mWhrs
• Aux power use (in %):		
- Period	10.8	%
- On line	10.0	%

2. Operating Hours

• Period hours:	720	hrs
• In Service:	544	hrs
• Coal hours:	541	hrs
• On standby:	0	hrs
• Scheduled outage:	173	hrs
• Unscheduled outage:	4	hrs
• Number of Unit Starts:	1	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	2454	9.8	250
2	3559	10.5	338
3	5077	9.9	511
4	31085	57.2	544
Unit Total	42175	77.6	544

4. Operating Availability:	75.5	%
5. Equivalent Availability:	41.2	%
6. Capacity Factor:	53.3	%

7. Average Heat Rate for Period:

• On line (coal and gas):	11800.3	btu/nkwh
• On line (coal):	11780.7	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	1035	mWhrs
• Primary air fan:	1077	mWhrs
• Secondary air fan:	131	mWhrs
• Induced draft fan:	611	mWhrs
• High pressure blowers:	59	mWhrs
• Bottom ash cooler fan:	84	mWhrs

9. Material Consumptions

• Total coal flow:	21677	tons
• Total limestone flow:	987	tons
• Total start-up burner gas (propane) flow:	394	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis

• Higher heating value:	10313	btu/lb
• Sulfur:	0.7	%
• Ash:	19.4	%
• Moisture:	7.1	%

Table 5-8
PLANT COMMERICAL PERFORMANCE STATISTICS
July 1989

1. Plant Outputs and Consumptions

• Gross generation:	41285	mWhrs
• Net generation:		
- Period	36688	mWhrs
- On line	36982	mWhrs
• Aux power use:		
- Period	4597	mWhrs
- On line	4303	mWhrs
• Aux power use (in %):		
- Period	11.1	%
- On line	10.4	%

2. Operating Hours

• Period hours:	744	hrs
• In Service:	521	hrs
• Coal hours:	519	hrs
• On standby:	0	hrs
• Scheduled outage:	195	hrs
• Unscheduled outage:	27	hrs
• Number of Unit Starts:	2	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	4035	9.0	449
2	4280	9.4	455
3	3855	9.5	406
4	29116	55.9	521
Unit Total	41285	79.2	521

4. Operating Availability:	70.1	%
5. Equivalent Availability:	64.9	%
6. Capacity Factor:	50.4	%

7. Average Heat Rate for Period:

• On line (coal and gas):	11911.1	btu/nkwh
• On line (coal):	11877.5	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	1105	mWhrs
• Primary air fan:	975	mWhrs
• Secondary air fan:	138	mWhrs
• Induced draft fan:	585	mWhrs
• High pressure blowers:	59	mWhrs
• Bottom ash cooler fan:	73	mWhrs

9. Material Consumptions:

• Total coal flow:	20414	tons
• Total limestone flow:	1342	tons
• Total start-up burner gas (propane) flow:	1304	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis:

• Higher heating value:	10757	btu/lb
• Sulfur:	0.5	%
• Ash:	14.2	%
• Moisture:	9.1	%

Table 5-9
PLANT COMMERICAL PERFORMANCE STATISTICS
August 1989

1. <u>Plant Outputs and Consumptions</u>

• Gross generation:	19509	mWhrs
• Net generation:		
- Period	16600	mWhrs
- On line	17467	mWhrs
• Aux power use:		
- Period	2909	mWhrs
- On line	2042	mWhrs
• Aux power use (in %):		
- Period	14.9	%
- On line	10.5	%

2. <u>Operating Hours</u>

• Period hours:	744	hrs
• In Service:	338	hrs
• Coal hours:	333	hrs
• On standby:	52	hrs
• Scheduled outage:	59	hrs
• Unscheduled outage:	294	hrs
• Number of Unit Starts:	3	hrs

3. <u>Individual Unit Outputs</u>

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	267	10.4	26
2	3198	9.8	326
3	327	10.2	32
4	15718	46.4	338
Unit Total	19509	57.6	338

4. <u>Operating Availability</u>:	52.5	%
5. <u>Equivalent Availability</u>:	29.2	%
6. <u>Capacity Factor</u>:	23.8	%

7. <u>Average Heat Rate for Period:</u>

• On line (coal and gas):	12429.1	btu/nkwh
• On line (coal):	12325.0	btu/nkwh

8. <u>Major Equipment Usages</u>

• Boiler feed pumps:	482	mWhrs
• Primary air fan:	770	mWhrs
• Secondary air fan:	56	mWhrs
• Induced draft fan:	326	mWhrs
• High pressure blowers:	55	mWhrs
• Bottom ash cooler fan:	49	mWhrs

9. <u>Material Consumptions</u>

• Total coal flow:	9860	tons
• Total limestone flow:	587	tons
• Total start-up burner gas (propane) flow:	3501	kscf
• Avg higher heating value of propane gas:	2615	btu/scf

10. <u>Average Coal Analysis</u>

• Higher heating value:	10907	btu/lb
• Sulfur:	0.6	%
• Ash:	13.0	%
• Moisture:	9.9	%

Table 5-10
PLANT COMMERICAL PERFORMANCE STATISTICS
September, 1989

1. Plant Outputs and Consumptions
   - Gross generation: 24095 mWhrs
   - Net generation:
     - Period 21108 mWhrs
     - On line 21607 mWhrs
   - Aux power use:
     - Period 2988 mWhrs
     - On line 2488 mWhrs
   - Aux power use (in %):
     - Period 12.4 %
     - On line 10.3 %

2. Operating Hours
   - Period hours: 720 hrs
   - In Service: 288 hrs
   - Coal hours: 281 hrs
   - On standby: 0 hrs
   - Scheduled outage: 170 hrs
   - Unscheduled outage: 262 hrs
   - Number of Unit Starts: 3 hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	2092	9.4	222
2	2526	9.9	256
3	2738	10.5	260
4	16738	58.1	288
Unit Total	24095	83.6	288

4. Operating Availability: 40.0 %

5. Equivalent Availability: 36.0 %

6. Capacity Factor: 30.4 %

7. Average Heat Rate for Period:
   - On line (coal and gas): 12064.2 btu/nkwh
   - On line (coal): 11936.7 btu/nkwh

8. Major Equipment Usages
   - Boiler feed pumps: 643 mWhrs
   - Primary air fan: 651 mWhrs
   - Secondary air fan: 68 mWhrs
   - Induced draft fan: 377 mWhrs
   - High pressure blowers: 35 mWhrs
   - Bottom ash cooler fan: 36 mWhrs

9. Material Consumptions
   - Total coal flow: 12069 tons
   - Total limestone flow: 871 tons
   - Total start-up burner gas (propane) flow: 2123 kscf
   - Avg higher heating value of propane gas: 2516 btu/scf

10. Average Coal Analysis:
    - Higher heating value: 10674 btu/lb
    - Sulfur: 0.6 %
    - Ash: 15.5 %
    - Moisture: 8.8 %

Table 5-11
PLANT COMMERICAL PERFORMANCE STATISTICS
October 1989

1. Plant Outputs and Consumptions

• Gross generation:	8184	mWhrs
• Net generation:		
- Period	6705	mWhrs
- On line	7326	mWhrs
• Aux power use:		
- Period	1479	mWhrs
- On line	858	mWhrs
• Aux power use (in %):		
- Period	18.1	%
- On line	10.5	%

2. Operating Hours

• Period hours:	745	hrs
• In Service:	93	hrs
• Coal hours:	91	hrs
• On standby:	0	hrs
• Scheduled outage:	214	hrs
• Unscheduled outage:	437	hrs
• Number of Unit Starts:	1	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	767	10.0	76
2	853	10.5	81
3	784	9.9	79
4	5779	61.8	93
Unit Total	8184	87.6	93

4. Operating Availability:	12.5	%
5. Equivalent Availability:	12.5	%
6. Capacity Factor:	10.0	%

7. Average Heat Rate for Period:

• On line (coal and gas):	11875.7	btu/nkwh
• On line (coal):	11752.9	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	210
• Primary air fan:	237
• Secondary air fan:	27
• Induced draft fan:	160
• High pressure blowers:	11
• Bottom ash cooler fan:	12

9. Material Consumptions:

• Total coal flow:	4812	tons
• Total limestone flow:	274	tons
• Total start-up burner gas (propane) flow:	1038	kscf
• Avg higher heating value of propane gas:	2516	btu/lb

10. Average Coal Analysis:

• Higher heating value:	8933	btu/lb
• Surfur:	0.6	%
• Ash:	28.0	%
• Moisture:	7.6	%

Table 5-12
PLANT COMMERICAL PERFORMANCE STATISTICS
November 1989

1. Plant Outputs and Consumptions

• Gross generation:	45854	mWhrs
• Net generation:		
- Period	40999	mWhrs
- On line	41317	mWhrs
• Aux power use:		
- Period	4856	mWhrs
- On line	4538	mWhrs
• Aux power use (in %):		
- Period	10.6	%
- On line	9.9	%

2. Operating Hours

• Period hours:	720	hrs
• In Service:	460	hrs
• Coal hours:	452	hrs
• On standby:	0	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	260	hrs
• Number of Unit Starts:	2	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	4443	10.1	442
2	4783	10.9	437
3	5057	11.3	448
4	31570	68.7	460
Unit Total	45854	99.7	460

4. Operating Availability:	63.9	%
5. Equivalent Availability:	60.3	%
6. Capacity Factor:	57.9	%

7. Average Heat Rate for Period:

• On line (coal and gas):	11853.9	btu/nkwh
• On line (coal):	11811.1	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	1083	mWhrs
• Primary air fan:	976	mWhrs
• Secondary air fan:	178	mWhrs
• Induced draft fan:	867	mWhrs
• High pressure blowers:	43	mWhrs
• Bottom ash cooler fan:	60	mWhrs

9. Material Consumptions

• Total coal flow:	24532	tons
• Total limestone flow:	1420	tons
• Total start-up burner gas (propane) flow:	1443	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis

• Higher heating value:	10051	btu/lb
• Sulfur:	0.6	%
• Ash:	20.4	%
• Moisture:	7.8	%

Table 5-13
PLANT COMMERICAL PERFORMANCE STATISTICS
December 1989

1. Plant Outputs and Consumptions

• Gross generation:	46023	mWhrs
• Net generation:		
- Period	40847	mWhrs
- On line	41417	mWhrs
• Aux power use:		
- Period	5176	mWhrs
- On line	4606	mWhrs
• Aux power use (in %):		
- Period	11.2	%
- On line	10.0	%

2. Operating Hours

• Period hours:	744	hrs
• In Service:	488	hrs
• Coal hours:	479	hrs
• On standby:	0	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	256	hrs
• Number of Unit Starts:	6	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	4812	11.4	422
2	4828	11.3	426
3	5022	11.1	451
4	31360	64.3	488
Unit Total	46023	94.4	488

4. Operating Availability:	65.5	%
5. Equivalent Availability:	64.8	%
6. Capacity Factor:	56.2	%

7. Average Heat Rate for Period:

• On line (coal and gas):	11933.8	btu/nkwh
• On line (coal):	11826.9	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	1128	mWhrs
• Primary air fan:	1170	mWhrs
• Secondary air fan:	120	mWhrs
• Induced draft fan:	816	mWhrs
• High pressure blowers:	51	mWhrs
• Bottom ash cooler fan:	77	mWhrs

9. Material Consumptions

• Total coal flow:	23972	tons
• Total limestone flow:	1600	tons
• Total start-up burner gas (propane) flow:	3499	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis

• Higher heating value:	10223	btu/lb
• Sulfur:	0.6	%
• Ash:	18.1	%
• Moisture:	9.1	%

in February. Therefore, operating and equivalent availabilities and capacity factors were low (Tables 5-2 and 5-3). March's operating statistics (Table 5-4) were much more favorable, setting monthly operating records for in-service (618) and coal hours (611), capacity factor (60.2%), and average load (79.8 MWe). The plant was forced out of service for only 7 hours during the month.

During the second quarter of the year, operating and equivalent availabilities were 64.2% and 36.5%, respectively. The capacity factor for the quarter was 38.6%. The plant experienced four master fuel trips during 1334 hours of operation, and was taken off-line via controlled shutdown six times. There were 498 in-service hours in April at an average load of 73.5 MWe (Table 5-5). Two start-ups were required; the first after an ID fan trip and the second after a controlled shutdown for repair of bottom ash cooler inlet fluidizing nozzles. In May, the unit was in service for 292 hours with an average load of 47.6 MWe; availability and capacity factors were correspondingly low (Table 5-6). In June, there were 544 in-service hours at an average load of 77.6 MWe (Table 5-7). One startup was required. The plant was removed from service on June 23 at the completion of alternate fuel testing on Peabody coal for a scheduled outage to complete PA fan and limestone feed system modifications.

During the third quarter of the year, operating and equivalent availabilities were 54.3% and 43.3%, respectively. The capacity factor was 34.9%, and there were eight unit starts. The unit was in-service for 521 hours in July with an average load of 79.2 MWe (Table 5-8). Two start-ups were required during the month; the first after a scheduled PA fan modification outage and the second after an ID fan trip. During August, there were 338 in-service hours with an average load of 57.6 MWe. Prolonged operation at low load due to a BFP 4A repair caused correspondingly low commercial performance statistics (Table 5-9). Three plant start-ups were required during the month; the first two involved BFP 4A and the third was after a controlled shutdown due to lack of propane. September's in-service hours (288) were at an average load of 83.6 MWe (Table 5-10). Three plant start-ups were required; the first was after a controlled shutdown to repair a water-wall tube leak and the second was after an SA fan trip. The third was after a drum level trip due to a feed water control valve problem.

During the final quarter of 1989, operating and equivalent availabilities averaged 47.1% and 45.7%, respectively. The capacity factor averaged 41.2%. The unit was in service for only 93 hours in October at an average load of 87.6 MWe. The limited number of operating hours contributed to low commercial performance statistics (Table 5-11). The unit was out of service at the beginning of the month to complete replacement of the PA fan wheel and a secondary superheater tube leak forced a unit outage that lasted through the end of the month. During November, the unit was in service for 460 hours at an average load of 99.7 MWe. Two unit start-ups were required; the first was after a boiler tube repair outage and the second was after an MFT due to air to fuel ratio imbalance. The unit was also derated three times during the month. During December, the unit was in service for 488 hours at an average load of 94.4 MWe. Six start-ups were required; the first was after an MFT on low EHC system pressure, the second was after a controlled shutdown on high bed pressure. The third and fourth start-ups were due to unit 4 exciter problems; the fifth was after a drum level trip due to a turbine control problem; the sixth was after a controlled shutdown to repair a unit 4 governor oil leak. The unit was derated three times during the month due to high baghouse pressure drop, boiler chemistry problems, and a cooling tower problem. On 12/4, the unit established a new record for continuous operation of 518 hours.

5.2 DEFINITIONS FOR PLANT COMMERCIAL PERFORMANCE STATISTICS

The following definitions are used by CUEA in generating plant commercial performance statistics that are presented and discussed in Section 5.1. These definitions are adopted from those used by the North American Electric Reliability Council in their report "Data Reporting Instructions for the Generating Availability Data System", October, 1990.

The definition for equivalent availability does not include seasonally adjusted derate hours which is included with planned and unplanned derate hours in the NERC/GADS definition.

Availability Factor:	(Available Hours/Period Hours)*100%
Available:	State in which a unit is capable of providing service, whether or not it is actually in service, regardless of the capacity level that can be provided.
Available Hours (AH):	Sum of all Service Hours and Reserve Shutdown Hours; Period Hours less Planned Outage Hours, Forced Outage Hours, and Maintenance Outage Hours.
Average Period Heat Rate (On Line, Net):	[Coal HHV * Coal Consumed] + [(Gas HHV * Gas Consumed (On-Line)) / Net Generation]
Capacity Factor:	(Gross Generation / Gross Maximum Capacity) * 100%

Note: In Section 5 tables and figures, Capacity Factors are calculated using the capacity factor equation prior to July, 1990 and using the net capacity factor equation from July, 1990 to present.

Equivalent Availability :	[(Available Hours - (Planned Derate + Unplanned Derate))/Period Hours]*100%

Note: In Section 5 tables and figures, Equivalent Availabilities are calculated using the gross equivalent availability equation prior to July, 1990 and using the equivalent availability equation from July, 1990 to present.

Forced Derating/Curtailment:	An unplanned component failure or other condition that requires the load on the unit be reduced immediately or before the next weekend.
Forced Outage:	An unplanned component failure or other condition that requires the unit be removed from service immediately or before the next weekend.
Gross Actual Generation:	Actual number of electrical megawatt hours generated by the unit during the period being considered.
Gross Capacity Factor:	(Gross Actual Generation / (Period Hours * Gross Maximum Capacity)) * 100%
Gross Equivalent Availability:	(Gross Maximum Capacity * Available Hours - MWh loss due to Derating) / (Gross Maximum Capacity * Period Hours)

Note: In Section 5 tables and figures, Equivalent Availabilities are calculated using the gross equivalent availability equation prior to July, 1990 and using the equivalent availability equation from July, 1990 to present.

Gross Maximum Capacity:	Maximum capacity a unit can sustain over a specified period of time when not restricted by seasonal, or other deratings.
Maintenance Derating:	The removal of a component for scheduled repairs that can be deferred beyond the end of the next weekend, but requires a reduction of capacity before the next planned outage.
Maintenance Outage:	The removal of a unit from service to perform work on specific components that can be deferred beyond the end of the next weekend, but requires the unit be removed from service before the next planned outage. Typically, a maintenance outage may occur anytime during the year, have flexible start dates, and may or may not have a predetermined duration.

Net Actual Generation (MWh):	Actual number of electrical megawatt hours generated by the unit during the period being considered less any generation (MWh) utilized for that unit's station service or auxiliaries.
Net Capacity Factor:	[Net Actual Generation/(Period Hours * Net Maximum Capacity)]*100%

Note: In Section 5 tables and figures, Capacity Factors are calculated using the capacity factor equation prior to July, 1990 and using the net capacity factor equation from July, 1990 to present.

Net Maximum Capacity:	Gross maximum capacity less the unit capacity utilized for that unit's station service or auxiliaries.
Number of Unit Starts:	The number of times Unit 4 was electrically connected to the system during the reporting period.
Period Hours:	Number of hours a unit was in the active state.
Planned Derating:	The removal of a component for repairs that is scheduled well in advance and has a predetermined duration.
Planned Outage:	The removal of a unit from service to perform work on specific components that is scheduled well in advance and has a predetermined duration (e.g., annual overhaul, inspections, testing).
Reserve Shutdown:	A state in which a unit is available but not in service for economic reasons.
Scheduled Derating Extension:	The extension of a maintenance or planned derating.
Scheduled Deratings/ Curtailments:	Scheduled deratings are a combination of maintenance and planned deratings.
Scheduled Outage Extension:	The extension of a maintenance or planned outage.

Scheduled Outages:	Scheduled outages are a combination of maintenance and planned outages.
Service Hours:	Total number of hours a unit was electrically connected to the system.
Unavailable:	State in which a unit is not capable of operation because of the failure of a component, external restriction, testing, work being performed, or some adverse condition.
Unavailable Hours:	Sum of all Forced Outage Hours, Maintenance Outage Hours, and Planned Outage Hours.
Unplanned Derated:	Sum of all hours experienced during Forced Deratings, Maintenance Deratings and Scheduled Derating Extensions of any Maintenance Deratings.
Unplanned Outage:	Sum of all hours experienced during Forced Outages, Maintenance Outages, and Scheduled Outage Extensions of any Maintenance Outages.

Section 6

PERFORMANCE TEST RESULTS

During the reporting period a total of 18 performance tests were conducted. In March three tests were conducted using Salt Creek coal. These tests were SD1, P30, and P31. Test SD1 was the first of the hot-mode shakedown tests and was conducted for 24 hours. However, only the first 12 hours of the test was averaged for the performance test. Tests P30 and P31 were both conducted for 12 hours. From April to June the unit was switched back to the Peabody coal and eight alternate fuel tests, numbers A01 through A08 were conducted. From July through the end of the year, tests were conducted using Salt Creek coal. Table 6-1 lists some of the important performance data obtained from the 18 tests. Detailed summary sheets for all 18 tests can be found in the separate volume of performance test summaries.

When the unit was switched back to Salt Creek coal, there was difficulty in maintaining the same temperature in both combustors. A study of this problem can be found in Section 9 of this report. Tests P49 and P50 were conducted at 98 MWe rather than at full load because the temperature differential became worse at higher loads. After attempts to equalize the temperature in the two combustors failed, the decision was made to conduct the tests as "dual combustor" tests.

For the dual combustor tests, four sets of coal, limestone, and bed material samples were withdrawn from both combustors. The gas sampler at the air heater inlet was isolated so that gas readings could be obtained from either the A side of the combustor or the B side. Although the flue gas pass through the convection pass is common to both combustors, the assumption is made that there is little mixing between the two sides. The emissions data may be biased towards the direction of the other combustor due to the mixing problem. For example, in test P55 the NO_x on A side read 138 ppmv while the NO_x on the B side read 199 ppmv. Thus there is probably a bias towards higher readings on combustor A since gas with a higher NO_x value could have mixed with it from the B side. Conversely, the gas reading for combustor B is probably biased downward.

During the split combustor tests, the test conditions were maintained at steady state for six hours. The A side of the air heater inlet was sampled for three hours, and the B side was then sampled for the next three hours. Since fly ash is

Table 6-1. SUMMARY OF PERFORMANCE TEST RESULTS

DATA SET ID NUMBER	TEST DATE	COAL TYPE	LOAD (MWe)	BED TEMPERATURE (DEG F)	COAL FEED CONFIGURATION	LIMESTONE FEEDERS OUT OF SERVICE	EXCESS AIR (%)	SECONDARY TO PRIMARY AIR RATIO	CALCIUM TO SULFUR RATIO	SULFUR RETENTION (%)	NOX EMISSIONS (PPMV DRY @3% O2)	CO EMISSIONS (PPMV DRY @3% O2)	COMBUSTION EFFICIENCY (%)	BOILER EFFICIENCY (%)
SD1	3/13/89	SALT CREEK	105	1558	BALANCED	NONE	23	0.7	1.4	69	62	104	98.1	87.7
P30	3/20/89	SALT CREEK	55	1491	BALANCED	-	36	0.7	2.1	78	30	113	98.7	87.8
P31	3/21/89	SALT CREEK	82	1552	BALANCED	-	22	0.8	2.0	83	58	83	98.6	88.0
A01	4/21/89	PEABODY	105	1611	BALANCED	-	21	0.7	1.8	73	146	83	97.6	87.6
A07	5/26/89	PEABODY	55	1495	BALANCED	NONE	39	0.7	1.5	78	52	111	97.6	87.4
A04	6/6/89	PEABODY	82	1607	BALANCED	NONE	25	0.6	1.7	75	141	78	98.3	88.2
A05	6/7/89	PEABODY	82	1597	BALANCED	NONE	25	0.7	3.9	98	189	72	97.9	87.6
A06	6/8/89	PEABODY	83	1599	BALANCED	NONE	24	0.7	0.6	37	103	80	97.9	87.9
A02	6/16/89	PEABODY	104	1627	BALANCED	NONE	19	0.7	3.7	98	208	72	98.0	87.9
A03	6/17/89	PEABODY	104	1614	BALANCED	NONE	20	0.6	0.7	45	138	67	97.8	88.3
A08	6/19/89	PEABODY	104	1625	BALANCED	NONE	19	0.7	1.8	73	154	61	97.7	87.7
P49	7/17/89	SALT CREEK	98	1643	BALANCED	NONE	20	0.6	0.9	14	118	61	98.6	88.6
P50	7/19/89	SALT CREEK	98	1636	BALANCED	NONE	20	0.6	3.5	78	156	65	98.7	88.2
P39	8/9/89	SALT CREEK	55	1537	BALANCED	NONE	39	0.8	2.6	80	61	98	98.8	87.1
P21	8/11/89	SALT CREEK	55	1518	BALANCED	NONE	42	0.8	3.1	89	58	101	98.7	86.8
P52	8/17/89	SALT CREEK	55	1516	LOOPSEAL	1 FW & 1 SW	42	0.8	2.8	81	46	88	98.9	87.1
P55	11/29/89	SALT CREEK	108	1598	50-50	NONE	20	0.7	4.8	76	170	77	98.2	87.7
P55A	11/29/89	SALT CREEK	108	1535	50-50	NONE	20	0.7	4.7	92	138	87		
P55B	11/29/89	SALT CREEK	108	1659	50-50	NONE	20	0.8	4.8	61	199	68		
P56	11/30/89	SALT CREEK	108	1619	50-50	NONE	13	0.7	5.1	74	157	72	97.9	87.6
P56A	11/30/89	SALT CREEK	108	1546	50-50	NONE	13	0.7	5.1	90	135	80		
P56B	11/30/89	SALT CREEK	108	1688	50-50	NONE	13	0.7	5.2	57	182	63		

common to both combustors, boiler efficiency and combustion efficiency could only be calculated for the total boiler system. However, the split combustor tests gave emissions data at two sets of combustion conditions. The split combustor tests conducted so far are P55 and P56. The data for the separate combustors are designated P55A and P56A for combustor A, and P55B and P56B for combustor B. The summary sheets for the split combustor tests include a full set of eight sheets for the total test, and four additional sheets for the A test and four sheets for the B test. Summary sheets for all tests are contained in a separate volume of performance summaries.

Two special tests were conducted this period, designated S06 and S07. Test S06 was conducted to study, qualitatively, the effect of coal size on unit performance. The purpose of test S07 was to determine the operability of the CFB at a very low oxygen concentration. This test was conducted at 1% O_2 at the air heater inlet. No samples were taken during this test, so the performance was not measured. This test was intended to obtain qualitative data for a short test period to see if a full performance test could be run. Details of this test are given in Section 6.3

6.1 EMISSIONS

Emissions data for the 18 performance tests conducted this reporting period are listed in Tables 6-2 and 6-3. Table 6-2 contains the data from the FGAS probes located at the air heater inlet. These probes were designed to support the test program. For comparison, Table 6-3 contains data that was taken from the plant continuous emissions monitoring system located at the stack during the performance tests. The emissions of SO_2, NO_x, and CO will be discussed in separate sections below.

6.1.1 SO_2 Emissions

Table 6-4 lists the SO_2 air heater data for the 18 performance tests, along with other data pertinent to the sulfur capture reaction. Figure 6-1 shows a plot of the percent sulfur retention versus Ca/S molar ratio. The Ca/S molar ratio is based on the calcium in the limestone and the sulfur in the coal only. With the exception of four data points the remainder of the points could be fit to an expression of the form:

$$R = 100\ (1 - \exp(-K\ Ca/S)) \qquad (1)$$

Where: R = the percent sulfur retention
Ca/S = the calcium to sulfur molar ratio
K = a constant = 0.822

Table 6-2. FLUE GAS ANALYSIS SUMMARY

Air heater inlet

Date	Time	Test no.	Coal Type	Load GMWe	Mean bed Temp. A Deg F	Mean bed Temp. B Deg F	SA/PA Ratio	O2 A Side Wet % Vol	O2 B Side Wet % Vol	O2 Dry % Vol	CO2 Dry % Vol	CO PPMV Dry		NOx			SO2			Ca/S (Sorbent) Ratio
												Act.	3% O2	PPMV Dry Act.	3% O2	Lb/ MM Btu	PPMV Dry Act.	3% O2	Lb/ MM Btu	
3/13/89	8:00-20:00	SD1	S.C.	105	1567	1556	0.9	3.5	3.5	3.9	15.1	99	104	59	62	0.08	136	144	0.27	1.4
3/20/89	8:00-21:00	P30	S.C.	55	1469	1516	0.9	5.2	5.4	5.7	13.7	119	139	26	30	0.04	77	91	0.17	2.1
3/21/89	8:00-21:00	P31	S.C.	82	1534	1578	0.8	3.5	3.5	3.8	15.3	92	96	56	58	0.08	78	82	0.15	2.0
4/21/89	8:00-16:30	A01	P.B.	105	1574	1638	0.9	3.3	3.3	3.7	15.3	80	83	141	146	0.20	192	199	0.37	1.8
5/26/89	8:00-17:30	A07	P.B.	55	1492	1497	0.9	5.1	5.1	5.9	12.9	93	111	44	52	0.07	150	179	0.35	1.5
6/6/89	7:30-14:30	A04	P.B.	82	1601	1614	0.8	3.5	3.5	4.2	14.8	73	78	132	141	0.19	162	174	0.33	1.7
6/7/89	8:00-14:30	A05	P.B.	82	1582	1611	0.8	3.5	3.4	4.3	15.0	67	72	175	189	0.25	9	10	0.02	3.9
6/8/89	8:30-15:30	A06	P.B.	83	1586	1611	0.8	3.5	3.5	4.2	15.0	75	80	96	103	0.14	381	408	0.76	0.6
6/16/89	10:00-17:00	A02	P.B.	104	1609	1645	0.9	3.3	3.3	3.5	15.8	70	72	202	208	0.27	13	13	0.02	3.7
6/17/89	10:00-17:00	AO3	P.B.	104	1602	1625	0.8	3.3	3.4	3.5	15.8	65	67	132	136	0.18	388	398	0.73	0.7
6/19/89	10:00-17:00	A08	P.B.	104	1629	1621	0.8	3.2	3.3	3.4	15.9	59	61	150	154	0.20	188	193	0.35	1.8
7/17/89	10:00-17:00	P49	S.C	98	1633	1650	0.8	3.3	3.4	3.5	15.6	59	61	114	118	0.16	424	436	0.81	0.9
7/19/89	9:15-13:15	P50	S.C.	98	1617	1659	0.8	3.3	3.3	3.5	15.6	63	65	152	156	0.21	111	114	0.21	3.5
8/9/89	8:15-15:00	P39	S.C.	55	1533	1542	1.0	5.6	5.5	6.0	12.6	82	98	51	61	0.09	94	113	0.22	2.6
8/11/89	8:30-15:30	P21	S.C.	55	1526	1513	1.0	5.5	5.5	6.3	12.6	83	101	47	58	0.08	50	61	0.12	3.1
8/17/89	8:00-14:00	P52	S.C.	55	1526	1520	1.0	5.5	5.5	6.3	12.4	72	88	38	46	0.07	85	104	0.20	2.8
11/29/89	9:20-11:45	P55A	S.C.	108	1532	NA	1.0	3.3	3.3	3.5	14.9	85	87	134	138	0.19	37	38	0.07	4.8
11/29/89	12:30-15:10	P55B	S.C.	108	NA	1659	1.0	3.3	3.3	3.5	14.8	66	68	193	199	0.28	165	170	0.33	4.8
11/30/89	9:15-12:15	P56A	S.C.	108	1552	NA	0.9	2.3	2.3	2.5	15.9	82	80	139	135	0.19	42	41	0.08	5.2
11/30/89	12:35-15:35	P56B	S.C.	108	NA	1686	0.9	2.3	2.3	2.5	15.7	65	63	188	182	0.26	189	184	0.36	5.0

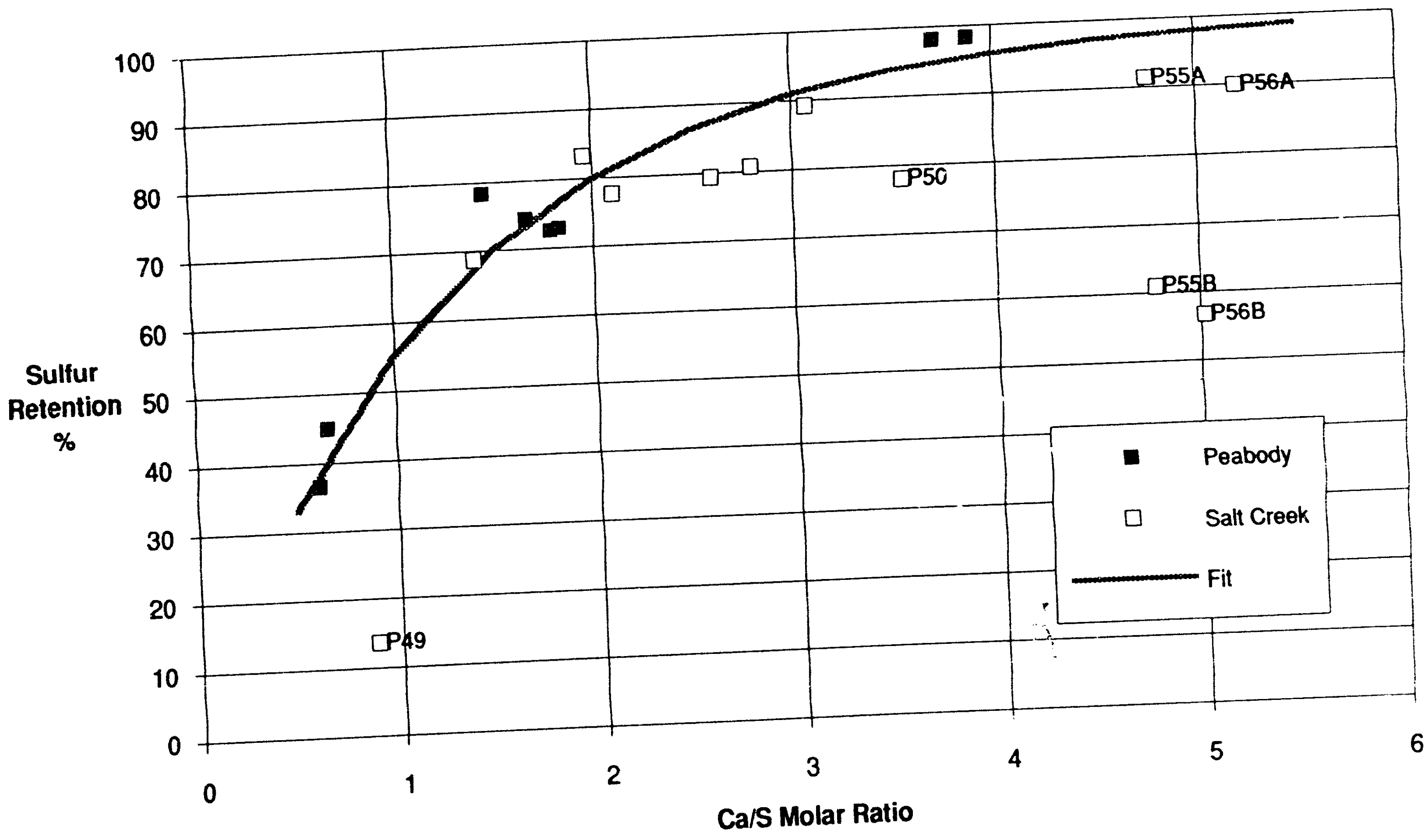
Table 6-3. PLANT STACK EMISSION SUMMARY

Date	Time	Test No.	Type of coal	Load GMWe	NOX Lb/ MM Btu	SO2 PPMV	SO2 LB/ MM Btu	SO2 A Side PPMV	SO2 B Side PPMV	Opacity %
3/13/89	8:00-20:00	SD1	S.C.	105.3	0.08	117	0.25	101	14	4
3/20/89	08:00-21:00	P30	S.C.	55.2	0.04	63	0.15	65	126	3
3/21/89	08:00-21:00	P31	S.C.	82.3	0.08	65	0.15	51	97	4
4/21/89	8:00-16:30	A01	P.B.	105.2	0.20	174	0.39	170	67	0
5/26/89	8:00-17:30	A07	P.B.	54.9	0.07	141	0.35	137	107	3
6/6/89	7:30-14:30	A04	P.B.	82.4	0.18	151	0.30	135	125	6
6/7/89	8:00-14:30	A05	P.B	82.4	0.26	9	0.02	4	10	9
6/8/89	8:30-15:30	A06	P.B.	82.6	0.14	355	0.84	322	313	10
6/15/89	10:00-17:00	A02	P.B.	103.6	0.28	3	0.00	4	9	7
6/17/89	10:00-17:00	AO3	P.B	103.8	0.18	367	0.79	302	299	7
6/19/89	10:00-17:00	A08	P.B	103.95	0.20	175	0.36	167	122	8
7/17/89	10:00-17:00	P49	S.C	98.2	0.17	395	0.83	389	321	8
7/19/89	9:15-13:15	P50	S.C.	98.2	0.22	98	0.21	99	82	8
8/9/89	8:15-15:00	P39	S.C.	55.4	0.08	78	0.19	68	74	7
8/11/89	8:30-15:30	P21	S.C.	55.4	0.08	37	0.09	36	33	7
8/17/89	8:00-14:00	P52	S.C.	55.4	0.07	70	0.19	67	64	7
11/29/89	9:20-11:45	P55A	S.C	107.7	0.24	84	0.18	22	116	9
11/29/89	12:30-15:10	P55B	S.C	107.8	0.23	85	0.18	21	116	9
11/30/89	9:15-12:15	P56A	S.C	108.2	0.21	101	0.21	27	142	9
11/30/89	12:35-15:35	P56B	S.C.	108.3	0.21	99	0.20	26	136	9

Table 6-4. AIR HEATER FLUE GAS ANALYSIS: SO2 EMISSION

Date	Time	Test no.	Type of Coal	Load in MW	Mean bed Temp. A in °F	Mean bed Temp. B in °F	PPMV Act.	SO2 PPMV @ 3% O2	SO2 LB/ MM BTU	Ratio Ca/S Sorbent Only	Ratio Ca/S Sorbent & Coal	SO2 Retention %	Ca Utilization (%) Sorbent Only	Ca Utilization (%) Sorbent & Coal
4/2189	8:00-16:30	A01	P.B.	105.2	1574	1638	192	199	0.37	1.8	2.0	73	41	36
5/26/89	8:00-17:30	A07	P.B.	54.9	1492	1497	150	179	0.35	1.5	2.3	78	54	34
6/6/89	7:30-14:30	A04	P.B.	82.4	1601	1614	162	174	0.33	1.7	2.5	75	45	30
6/7/89	8:00-14:30	A05	P.B.	82.4	1582	1611	9	10	0.02	3.9	4.7	98	25	21
6/8/89	8:30-15:30	A06	P.B.	82.6	1586	1611	381	408	0.76	0.6	1.3	37	60	29
6/16/89	10:00-17:00	A02	P.B.	103.6	1609	1645	13	13	0.02	3.7	4.0	98	26	24
6/17/89	10:00-17:00	AO3	P.B.	103.8	1602	1625	388	398	0.73	0.7	1.2	45	69	38
6/19/89	10:00-17:00	A08	P.B.	103.95	1629	1621	188	193	0.35	1.8	2.1	73	40	35
3/13/89	8:00-20:00	SD1	S.C.	105.3	1567	1556	136	144	0.27	1.4	2.1	69	49	34
3/20/89	08:00-21:00	P30	S.C.	55.2	1469	1516	77	91	0.17	2.1	2.9	78	37	27
3/21/89	08:00-21:00	P31	S.C.	82.3	1534	1578	78	82	0.15	2.0	2.5	83	42	34
7/17/89	10:00-17:00	P49	S.C.	98.2	1633	1650	424	436	0.81	0.9	1.3	14	15	10
7/19/89	9:15-13:15	P50	S.C.	98.2	1617	1659	111	114	0.21	3.5	3.9	78	22	20
8/17/89	8:00-14:00	P52	S.C.	55.4	1526	1520	85	104	0.20	2.8	3.2	81	29	25
8/11/89	8:30-15:30	P21	S.C.	55.4	1526	1513	50	61	0.12	3.1	3.5	89	29	26
8/9/89	8:15-15:00	P39	S.C.	55.4	1533	1542	94	113	0.22	2.6	3.0	80	31	27
11/29/89	9:20-11:45	P55A	S.C.	107.7	1532	NA	37	38	0.07	4.8	5.2	92	19	18
11/29/89	12:30-15:10	P55B	S.C.	107.8	NA	1659	165	170	0.33	4.8	5.2	61	13	12
11/30/89	9:15-12:15	P56A	S.C.	108.2	1552	NA	42	41	0.19	5.2	5.8	90	17	16
11/30/89	12:35-15:35	P56B	S.C.	108.3	NA	1688	189	184	0.36	5.0	5.6	57	11	10

Figure 6-1. Effect of Ca/S Molar Ratio on Sulfur Retention



The four test points that do not fit on the curve are designated by their test number. Of these, Tests P50 and P49 had combustor B temperatures over 1650°F Note that the B tests for P55 and P56 fell well below the curve, while the A tests fell near the curve. In these two tests combustor B was operating over 1650°F while combustor A was operating at temperatures below 1555°F. While it may be premature to draw any firm conclusions with this limited amount of data, it appears that the sulfur capture efficiency falls off dramatically when the combustor temperature exceeds 1650°F. Future tests should help to identify the temperature effect on sulfur capture better, as more data is obtained at different temperatures.

6.1.2 NO_x Emissions

The NO_x emissions data at the air heater inlet was given in Table 6-2. All of the tests produced NO_x emissions that were well below the emissions limit at Nucla of 0.5 lb/MMbtu, with the highest value being only 0.28 lb/MMbtu. Figure 6-2 shows a plot of NO_x emissions corrected to 3% O_2 versus the average bed temperature. The line marked "Fit" in this figure is simply a least squares fit of the data, and is intended only to show the general trend of the data. The data clearly show a trend for increasing NO_x with increasing bed temperatures. However the Peabody coal tests, conducted between 1590°F and 1630°F show considerable scatter.

To further study this scatter, the NO_x data was plotted versus the Ca/S molar feed ratio in Figure 6-3. To eliminate the temperature effect seen in Figure 6-2, the data in this figure were limited to a narrow temperature band. The Peabody data was taken in the range of 1590°F to 1630°F. The Salt Creek data was limited to the temperature range of 1520°F to 1560°F. From Figure 6-3 it appears that there is a trend for increasing NO_x with increasing limestone feed.

Figure 6-4 shows a plot of NO_x emissions versus calcium utilization for the temperature ranges shown in Figure 6-3. This figure shows that NO_x emissions decrease as the calcium utilization increases. However, there appears to be a level of utilization (approximately 30%) above which the NO_x stops decreasing.

6.1.3 CO Emissions

The CO emissions data taken at the air heater inlet for the 18 performance tests were given in Table 6-2. Figure 6-5 shows a plot of CO emissions versus average bed temperature for these tests. The data show a clear trend of decreasing

Figure 6-2. Effect of Bed Temperature on NOx Emissions

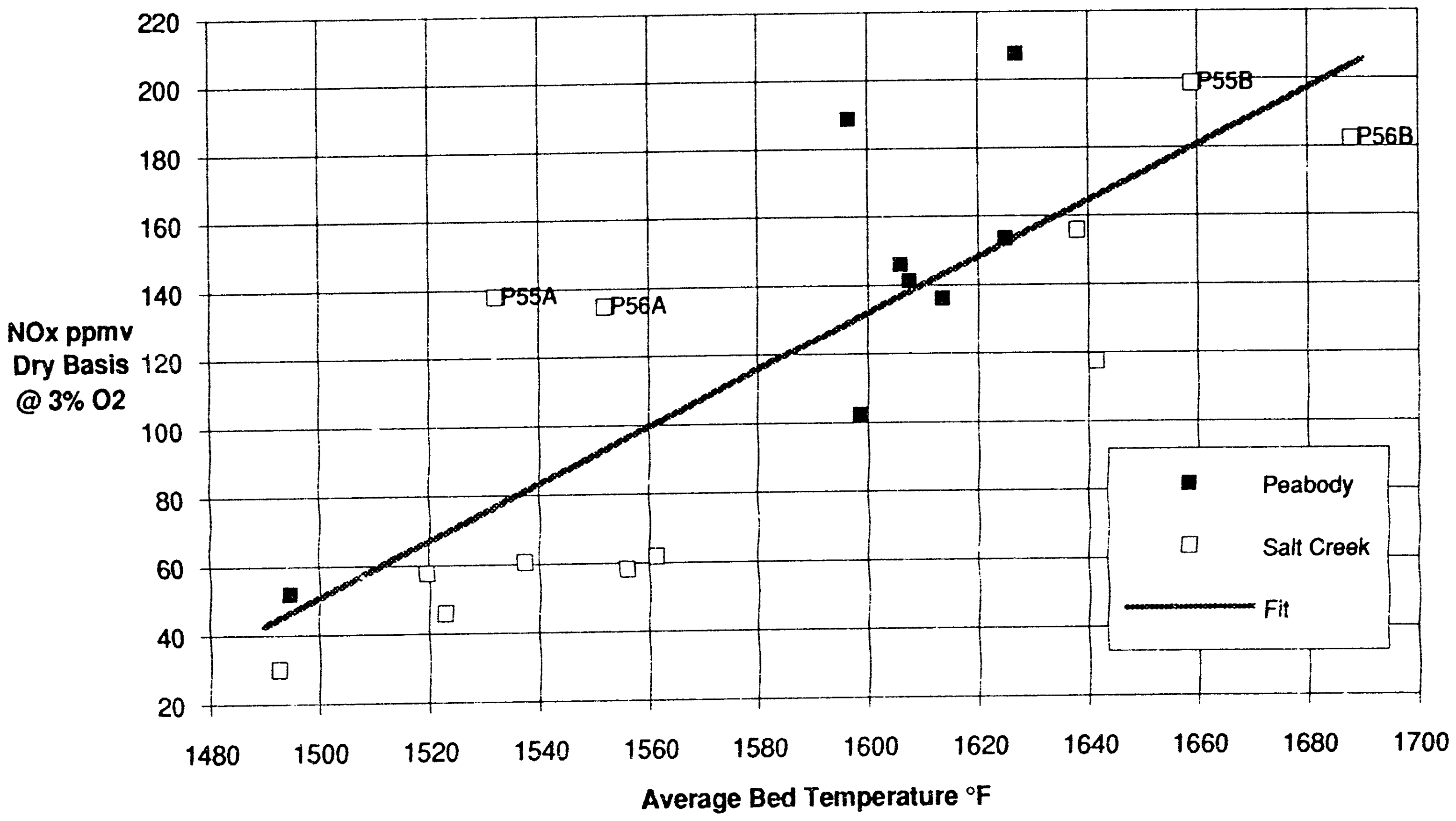


Figure 6-3. Effect of Ca/S Molar Ratio on NOx Emissions

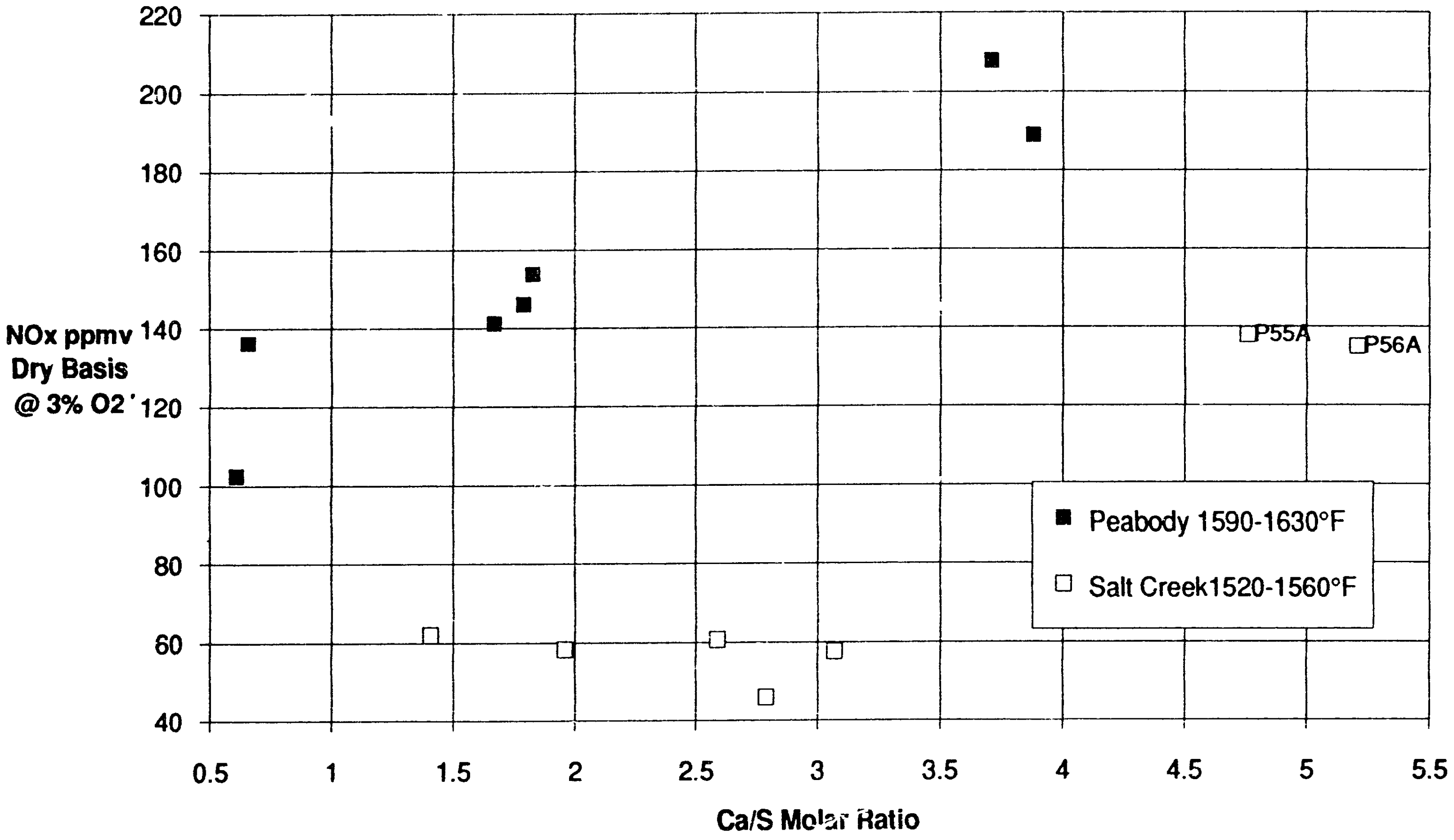


Figure 6-4. Effect of Calcium Utilization on NOx Emissions

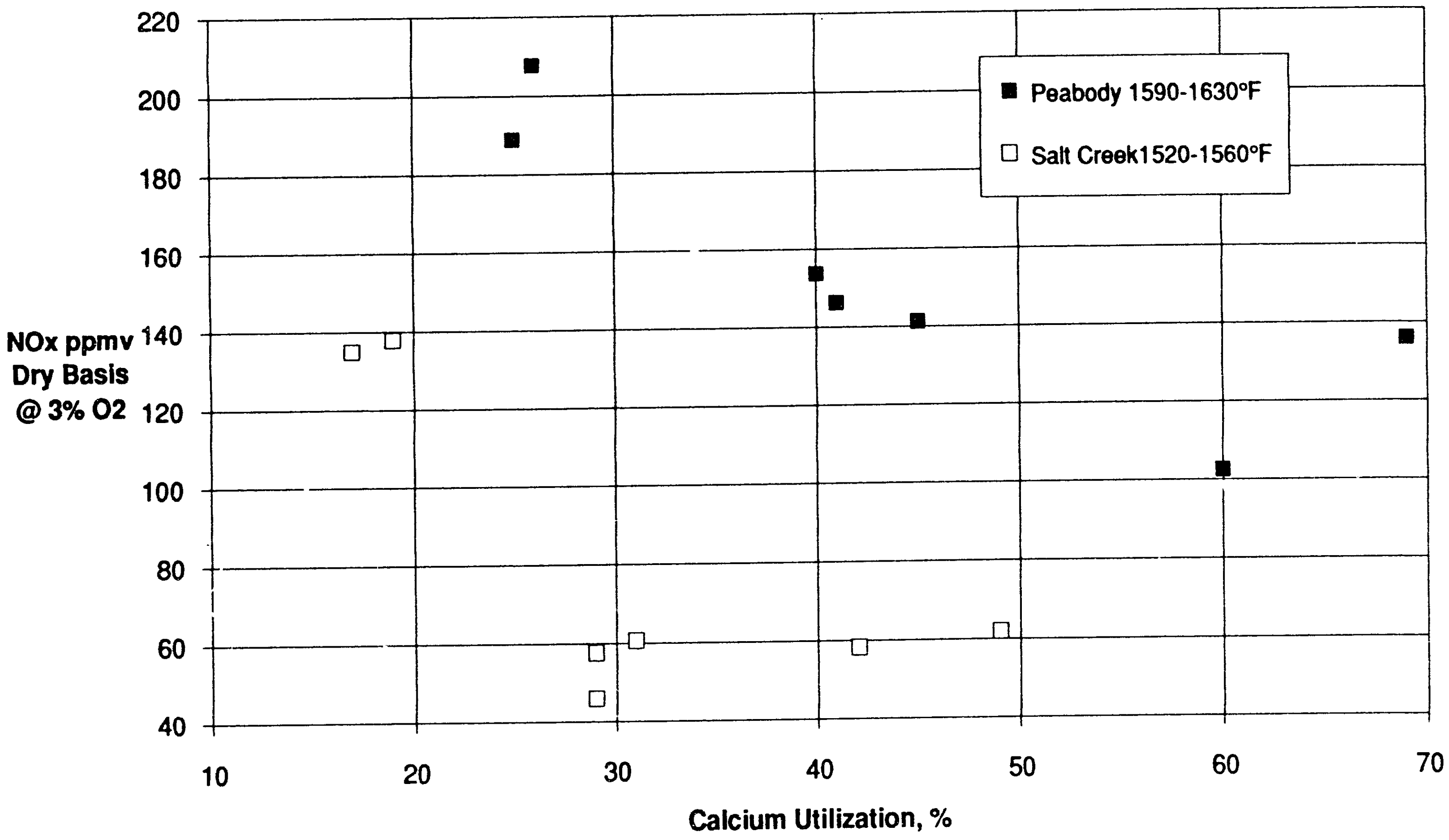
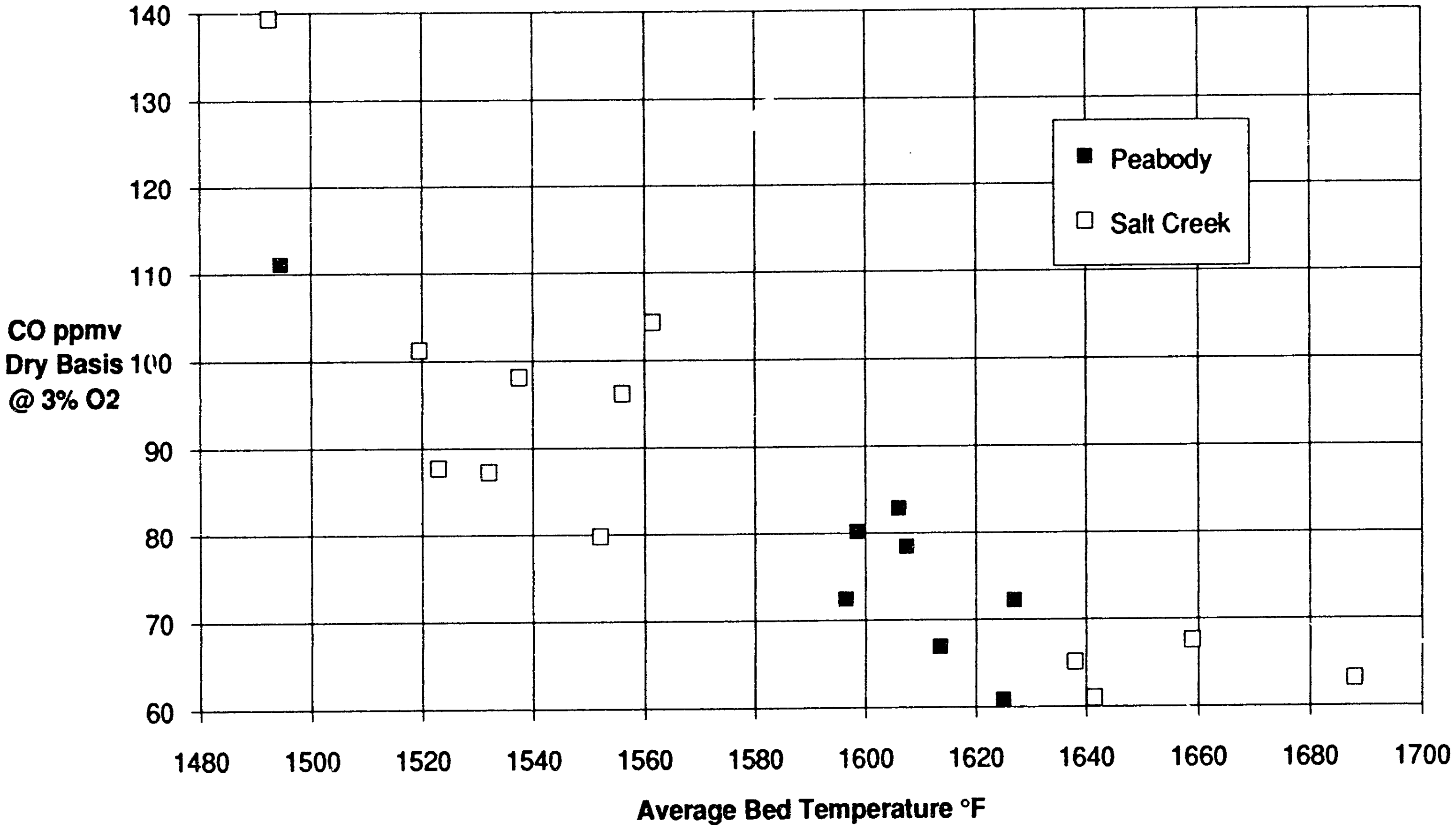


Figure 6-5. Effect of Bed Temperature
On CO Emissions



CO with increasing bed temperature. Although, at the highest bed temperatures the CO appears to level out at between 60 and 70 ppmv.

6.2 COMBUSTION AND BOILER EFFICIENCY

Table 6-5 contains data on the combustion efficiency and boiler efficiency for all 18 performance tests conducted this reporting period. For tests P55 and P56 only the full test results are shown, as the combustion efficiency and boiler efficiency could not be measured for the split tests.

Figure 6-6 shows a plot of combustion efficiency versus load. From this figure, excluding test A07, it appears that the combustion efficiency falls off slightly as the load is increased. However, there is still quite a bit of scatter at the different loads. Figure 6-7 shows a plot of the combustion efficiency versus the volatile content of the coal. This graph indicates that increased volatile content will increase the combustion efficiency. This is not too surprising, since volatiles are easier to burn than fixed carbon. Future tests should help to clarify the mechanisms important to combustion efficiency.

Figure 6-8 shows a plot of the boiler efficiency versus load for the 18 performance tests. This data appears to indicate a maximum efficiency near 98 - 100 MWe generation. To see if this effect is real, the data was plotted up versus excess air. Figure 6-9 shows a plot of the boiler efficiency versus excess air as a function of load. This figure shows that the full load tests had a slightly lower boiler efficiency than the 98 MWe tests even though they were conducted at about the same excess air. As more data is obtained, the relationships between boiler efficiency and load should become clearer.

6.3 SPECIAL TESTS

A special test, number S06, was conducted on August 29, 1989 to determine the qualitative effects of coal particle size on sulfur capture performance. This test was conducted because it was believed that the decrease in sulfur capture efficiency during tests P49 and P50 was due to a shift in the coal size distribution from 20% retained on the 1/4 inch screen for tests SD1, P30, and P31, to about 7% retained on the 1/4 inch screen for tests P49 and P50. After the alternate fuel tests, the hammers in the coal crusher were replaced. This resulted in the observed size distribution shift. Attempts to change the size distribution of the coal by making adjustments to the coal crusher, however, were unsuccessful, and the performance of the unit did not change appreciably.

Table 6-5. COMBUSTION EFFICIENCY AND RELATED PARAMETERS FOR ALL TESTS

TEST	COMBUSTION EFFICIENCY %	BOILER EFFICIENCY %	UNIT LOAD MW	EXCESS AIR %	AVG BED TEMP DEG F	AVG WINDBOX PRESSURE IN WG	FLYASH/ BOTTOM ASH RATIO	FLYASH CARBON %	BOTTOM ASH CARBON %	FLUE GAS CO PPMV
SD1	98.1	87.7	105	23	1558	44	4.9	7.5	1.0	99
P30	98.7	87.8	55	36	1491	32	3.1	6.1	1.0	96
P31	98.6	88.0	82	22	1552	37	4.5	6.5	0.8	79
A01	97.6	87.6	105	21	1611	45	4.6	10.6	2.5	80
A07	97.6	87.4	55	39	1495	33	1.7	8.3	2.2	93
A04	98.3	88.2	82	25	1607	42	3.7	5.7	1.4	73
A05	97.9	87.6	82	25	1597	42	4.6	5.9	1.5	67
A06	97.9	87.9	83	24	1599	42	3.2	7.6	1.1	75
A02	98.0	87.9	104	19	1627	45	9.8	6.9	1.3	70
A03	97.8	88.3	104	20	1614	45	3.1	8.6	1.8	65
A08	97.7	87.7	104	19	1625	44	5.0	8.8	1.7	59
P49	98.6	88.6	98	20	1643	44	36.0	6.0	0.4	59
P50	98.7	88.2	98	20	1636	45	15.6	5.6	0.7	63
P39	98.8	87.1	55	39	1537	39	2.4	5.2	1.4	82
P21	98.7	86.8	55	42	1518	38	3.6	5.1	2.1	83
P52	98.9	87.1	55	42	1516	37	2.7	5.2	2.1	72
P55	98.2	87.7	108	20	1598	48	4.9	6.6	1.2	75
P56	97.9	87.6	108	13	1619	50	6.2	7.3	1.4	74

Figure 6-6. Combustion Efficiency
Versus Load

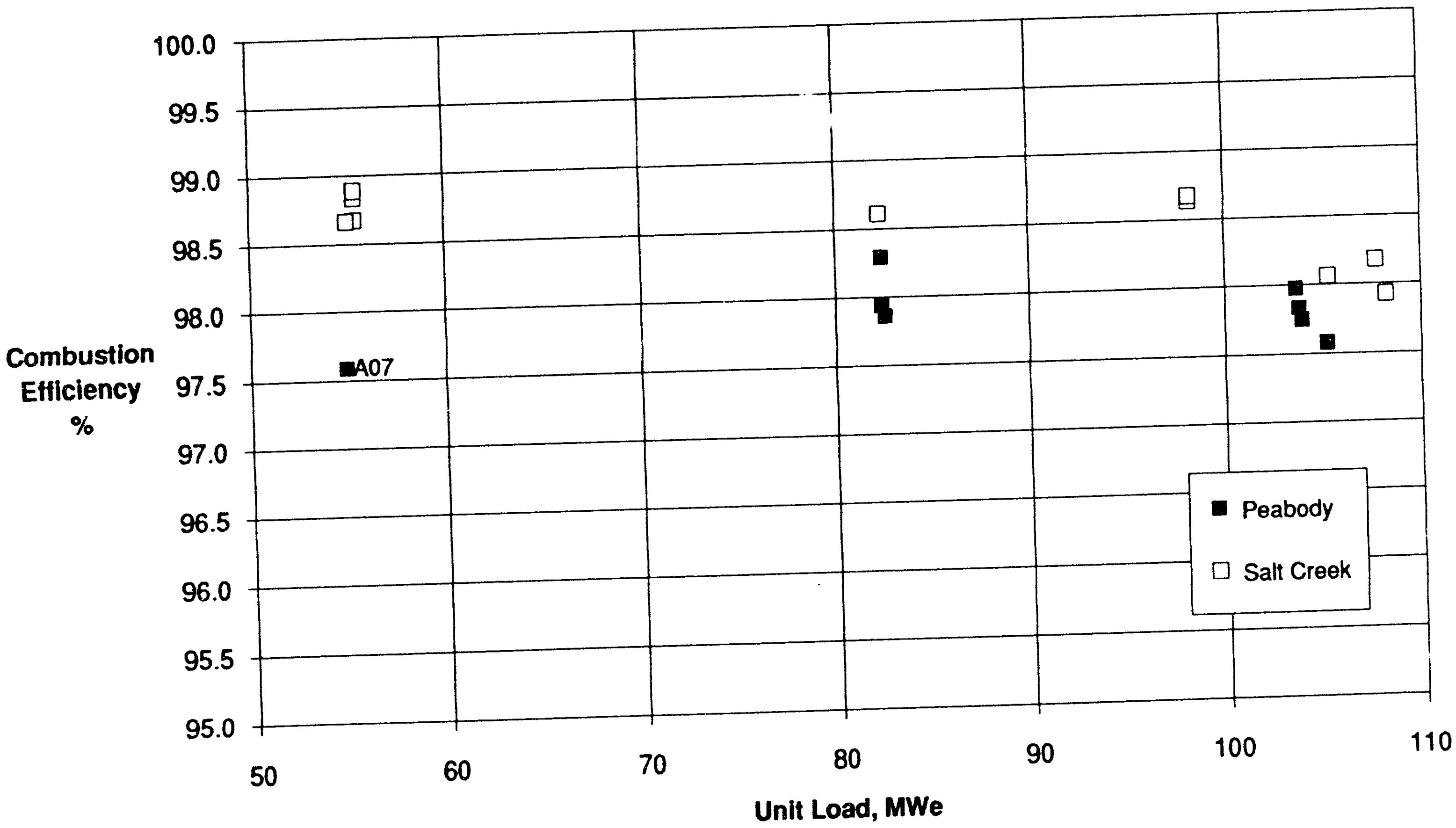


Figure 6-7. Combustion Efficiency
Versus Coal Volatiles

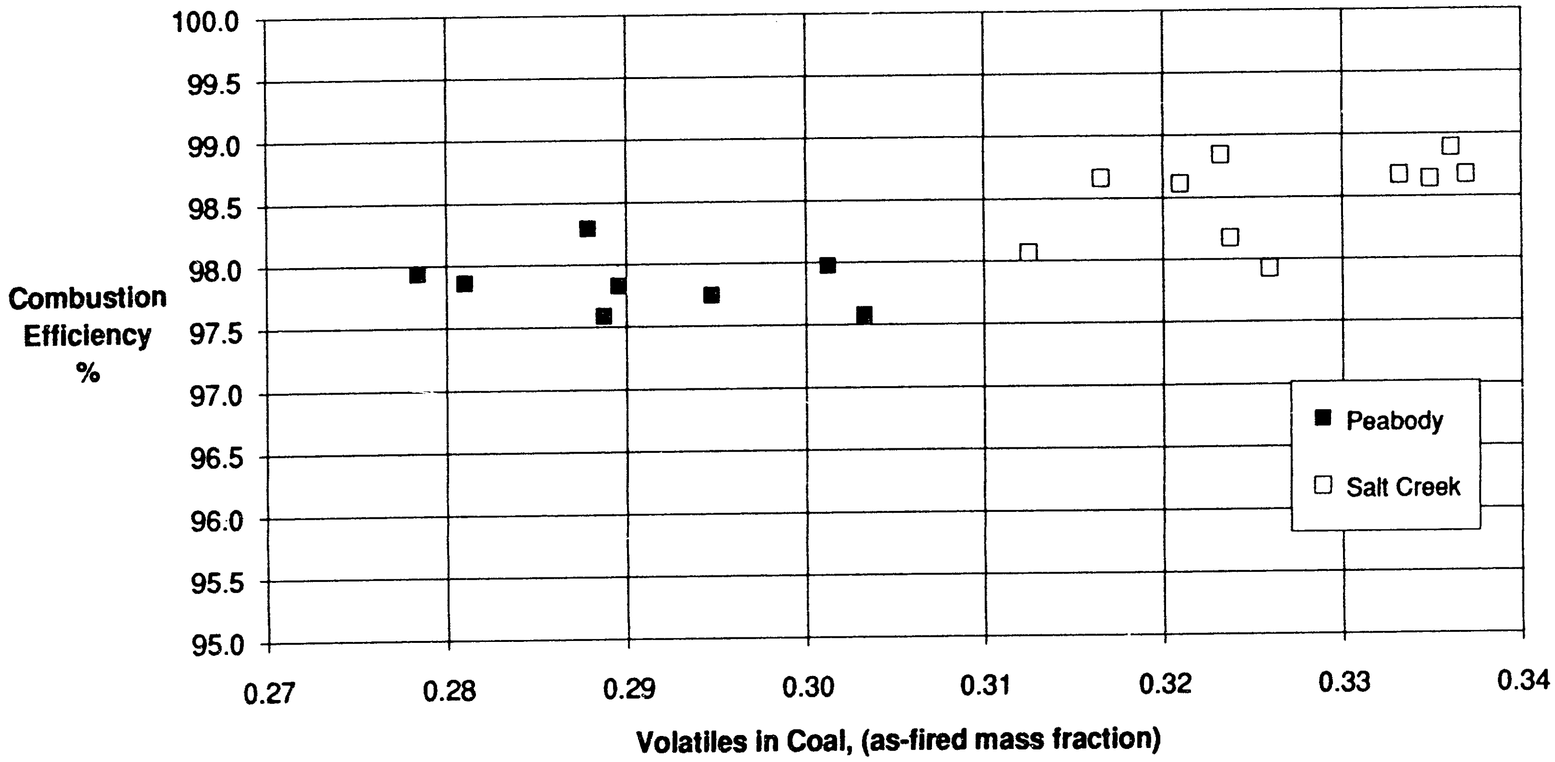


Figure 6-8. Boiler Efficiency Versus Load

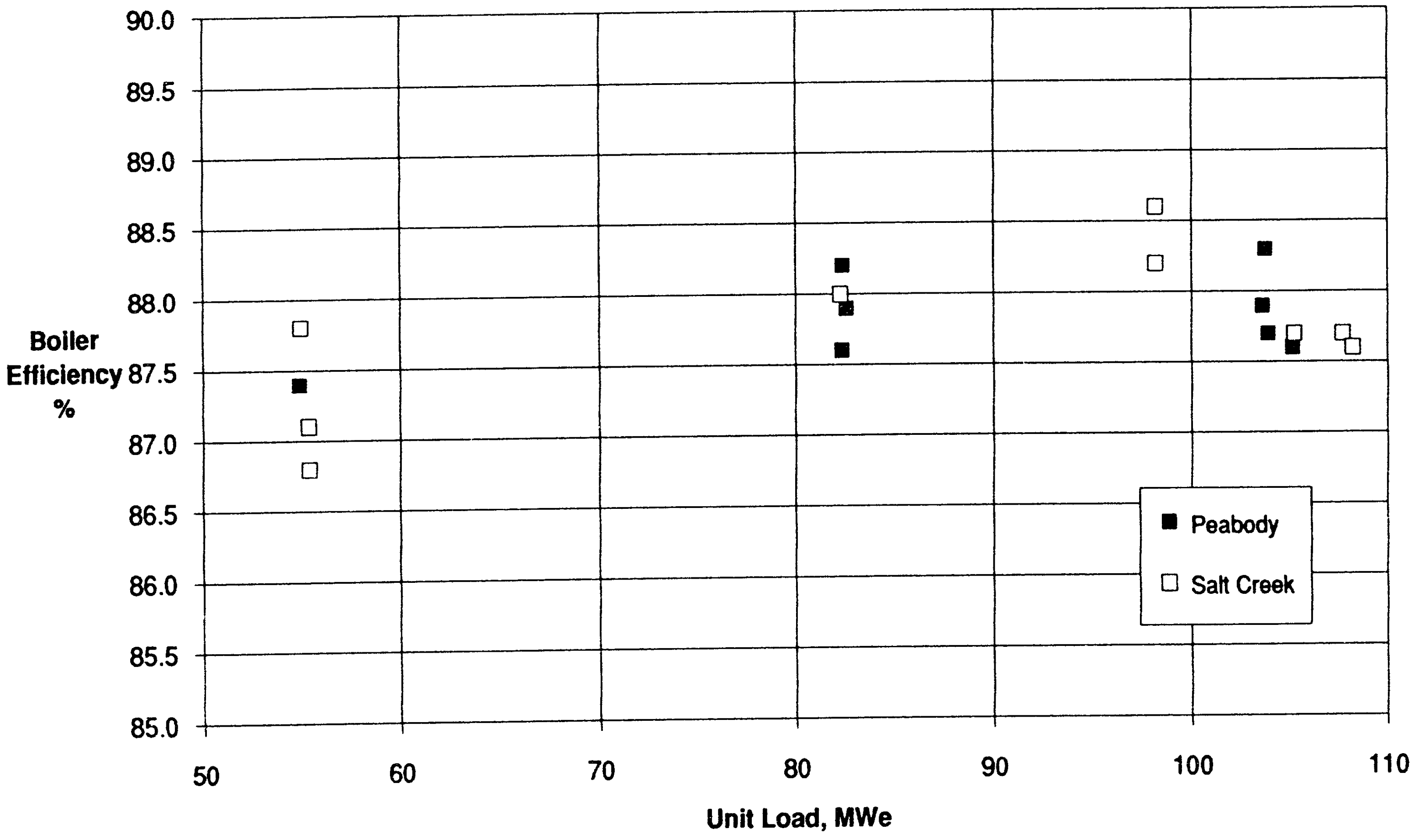
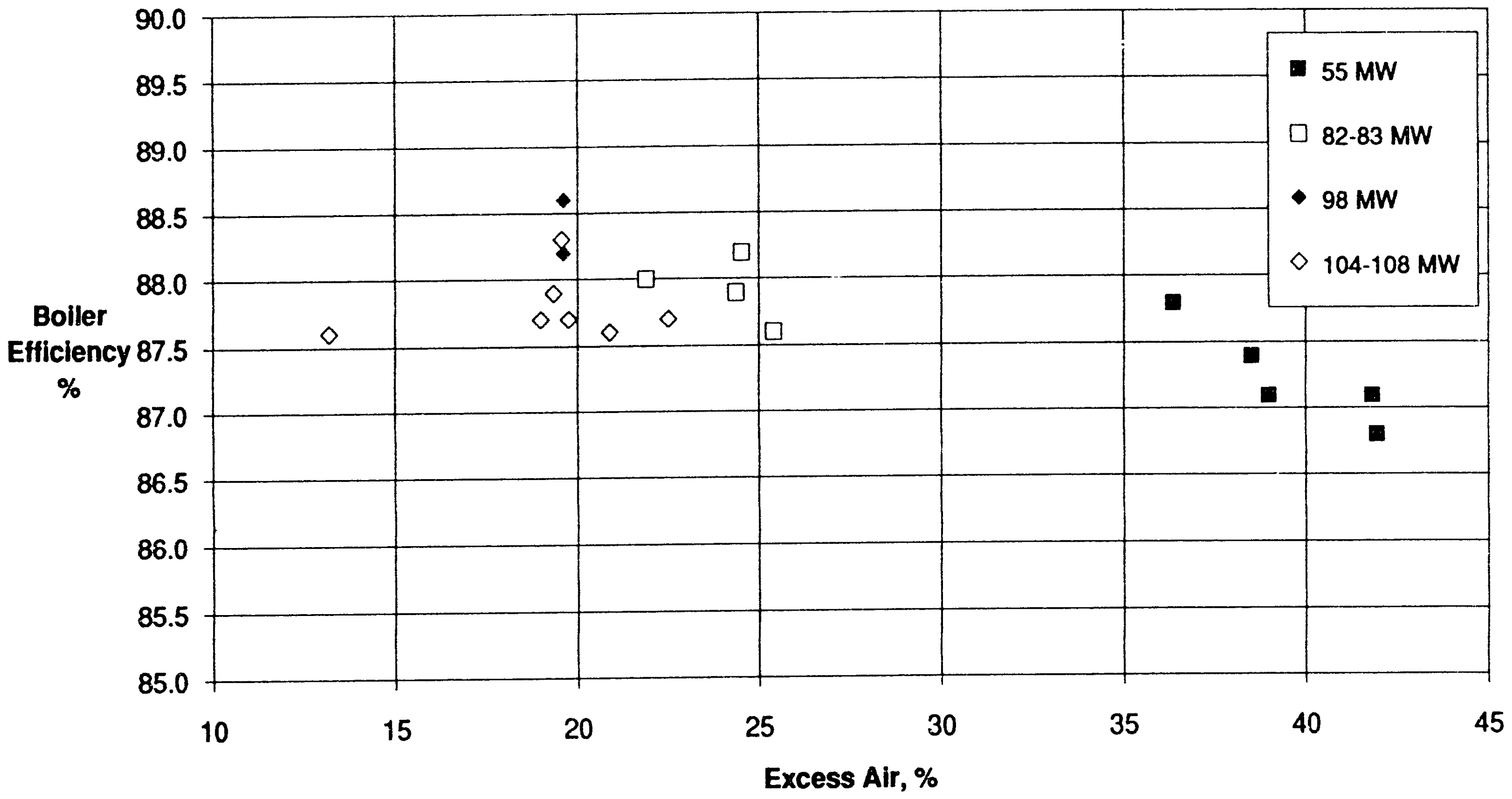


Figure 6-9. Effect of Load and Excess Air on Boiler Efficiency



On December 1, 1989, a qualitative test, number S07, was conducted to determine if stable combustor operation could be achieved at 1 % O_2 by volume. The advantages of this operation would be lower auxiliary power consumption and reduced flue gas sensible heat loss. Potential disadvantages would be reduced combustion efficiency and sulfur retention.

The operation of the unit was stable for a two hour period during the test. Prior to achieving 1 % O_2 (vol % wet), load was increased to 108 MWe gross output. The O_2 set point was 3.3% before the test and was ramped down to 1.0 % over a two hour period. Flue gas oxygen was maintained at 1% for two hours before the O_2 set point was rapidly increased up to the original value of 3.3 %. Sorbent feed rates were increased as O_2 was decreased in an attempt to maintain SO_2 emissions in compliance. Solid samples were not taken during this test, and therefore, performance calculations could not be run. Single fly ash and bed ash samples were taken to check the carbon content.

The following observations were made regarding this test:

1. No real changes in the stability of the throttle pressure, steam temperature, or attemperator flow rates were observed.

2. The unit auxiliary transformer power dropped from about 10.7 MWe to about 9.6 MWe. The major contributor to this drop was the ID fan power consumption.

3. The fly ash carbon content was about 8%; prior to testing it was about 6%. The bed ash carbon content increased dramatically from 1.5% before the test to 6.8% during the test.

4. CO levels remained constant during the test, indicating good mixing in the upper combustor.

5. During the test, limestone feed and SO_2 levels increased. This indicates that the sulfur retention suffered by the low excess air. After the test, increasing the O_2 to 3.3 % resulted in SO_2 emissions of only about 10 ppmv. This indicated that there was a considerable amount of unreacted limestone inventory in the bed.

6. Bed pressures and windbox pressures did not increase by a substantial amount, indicating no significant change in fluidizing conditions.

Because the unit was capable of operating stably at 1% O_2, a future performance test will be conducted under similar test conditions to quantify the performance of the unit.

Section 7

START-UP, COLD AND HOT RESTART

During 1989, the on-site test team analyzed data from two hot restarts, one warm restart, and one cold restart. Data from these tests are presented below. During a cold start-up or a hot restart, drum metal and refractory temperature ramp rates limit the firing rate and hence, affect the time required to raise unit load. Another constraint during a hot or warm restart is matching turbine metal and final steam temperatures to prevent undue turbine stress. On the Nucla CFB, the drum metal temperature ramp rate is 100°F/h. The refractory temperature warm-up criteria is 90-100°F/h until a temperature of 600°F is reached. Thereafter, the temperature can be increased at 130°F/h until 1100°F is reached. There are no ramp rate restrictions above this absolute temperature.

7.1 TESTS COMPLETED IN 1989

Table 7-1 summarizes data from the four tests analyzed during 1989. Although there were other start-ups and restarts during the reporting period, these have been selected as representative. A cold start-up is defined here as one which occurs after an outage of sufficient duration for all metal and refractory components to return to near ambient temperature. The minimum outage time required to achieve this is approximately 60 hours, with fans in service during the period to assist in the cool down. A hot restart is defined here as that which occurs after an outage of 4 hours or less. A warm restart is that which occurs after an outage of approximately 8 to 12 hours, thereby representing cycling service on a unit with off-peak shutdown and high-peak restart.

7.2 HOT RESTART TEST DATA

The first of the two hot restarts analyzed during this reporting period occurred on April 21, 1989. An MFT occurred with the unit operating at 105 MWe gross output as the result of an induced draft fan trip. Fans remained out of service for approximately 2.5 hours following the trip. The second hot restart occurred on December 4, 1989 following a MFT created by a turbine control problem. A hot restart was initiated immediately and fans were out of service for a period between 30 and 40 minutes, as opposed to 2.5 hours for the previous hot restart.

Table 7-1. Summary of Start-Up and Restart Tests for 1989.

Test Type	Hot	Hot	Warm	Cold
Date	4/21/89	12/4/89	9/13/89	3/28/89
Outage Duration	4	1	8.8	120
Time w/o Under-bed Air Flow	2.5	0.6	~7	na
Duration of Gas Firing	7	3.6	4.5	21
Gas Required to Restart, Mscf	.27	0.29	0.415	1.468
Avg. Gas Firing Ramp Rate, Kscf/h	40.4	80.2	74.1	66.5
Max. Drum dT/dt	n/a	+62,-85	+68,-184	+80
Max. Refractory dT/dt	n/a	+15,-52	+34,-58	+25
	Times (hours)			
Trip to Fan Restart	2.5	0.6	~7	na
Fan Restart to Gas Fires	0.4	0.5	~0.4	1
Gas Fires to Generator	2	0	~1.6	13
Synch. to Coal Flow	2	1.2	~2.5	2
Coal Flow to 45 MWe	2	2.6	~2	2

na - not applicable
n/a - not available

Figures 7-1, 7-5, and 7-6 show the final steam conditions and gross unit output for the two hot restarts. For the hot restart in April 1989, the final steam pressure and temperature fell to approximately 650 psig and 650°F before gas fires were restored. For the restart in December 1989, the final steam pressure and temperature fell to approximately 775 psig and 750°F. The magnitude of the decrease in conditions depends on the duration of the outage, and how quickly the turbine is taken off-line following the termination of fuel flow.

Descriptions of the numbering sequence on Figure 7-1 are as follows:

1. Unit trip. All coal feeders and fans are stopped.

2. ID, PA, and SA fans are restarted (Note that the restart was delayed on 4/21/89 due to several unsuccessful attempts at restarting the ID fan.

3. Gas fires are initiated to raise bed temperatures required for coal fires.

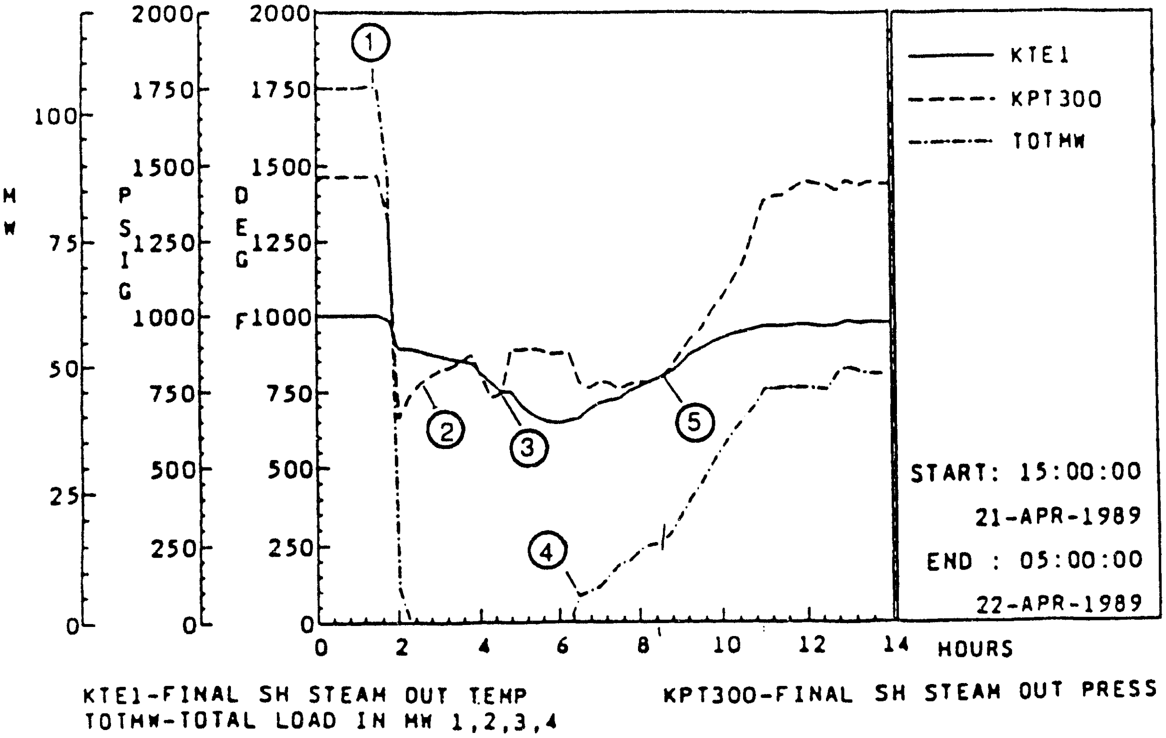


Figure 7-1. Hot Restart - 4/21/89. Final Steam Conditions and Gross Unit Output

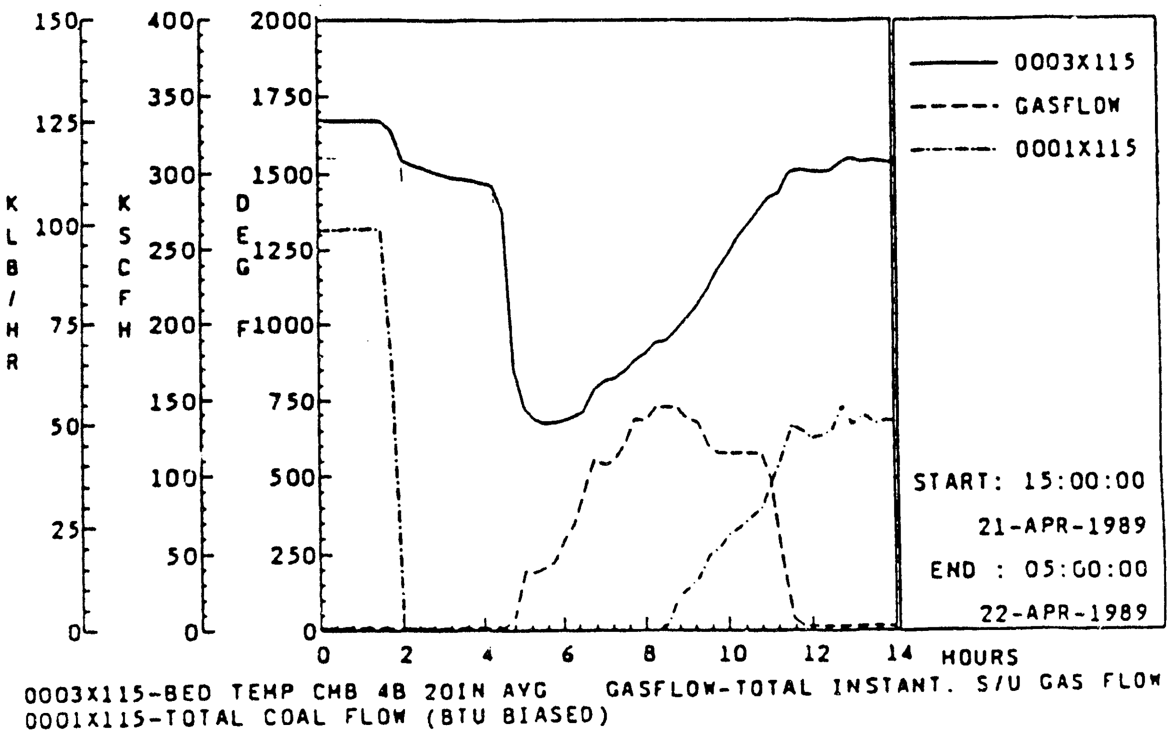


Figure 7-2. Hot Restart - 4/21/89. Fuel Flows and Bed Temperatures

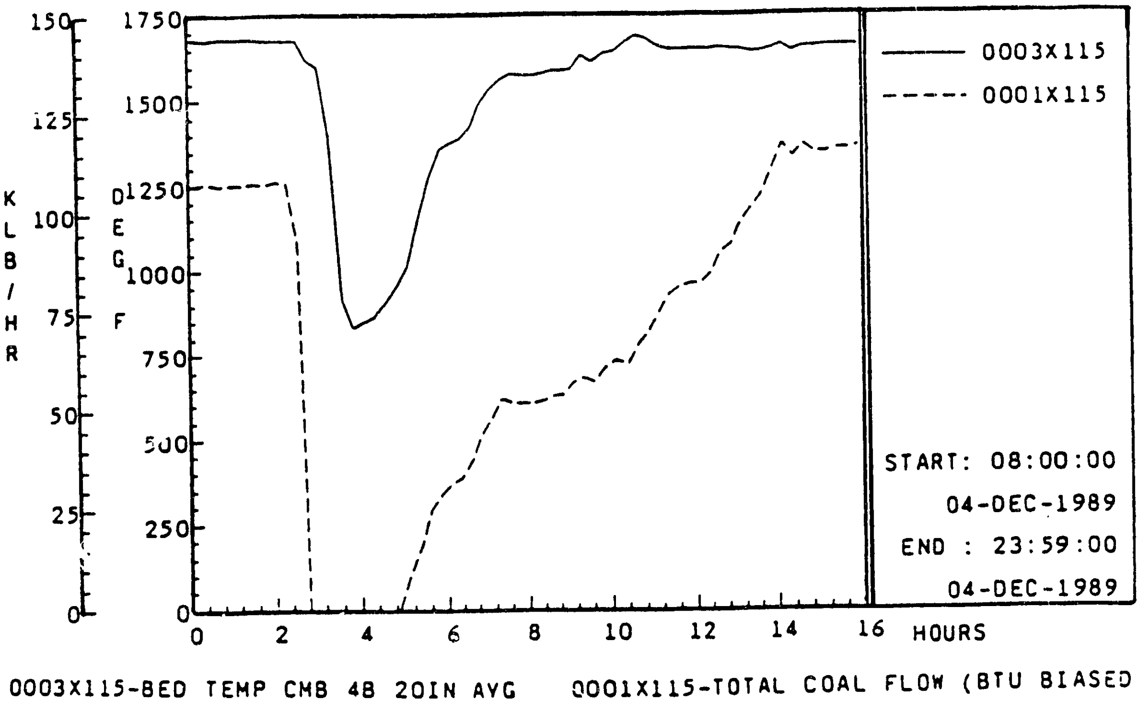


Figure 7-3. Hot Restart - 12/4/89. Total Coal Flow and Bed Temperatures

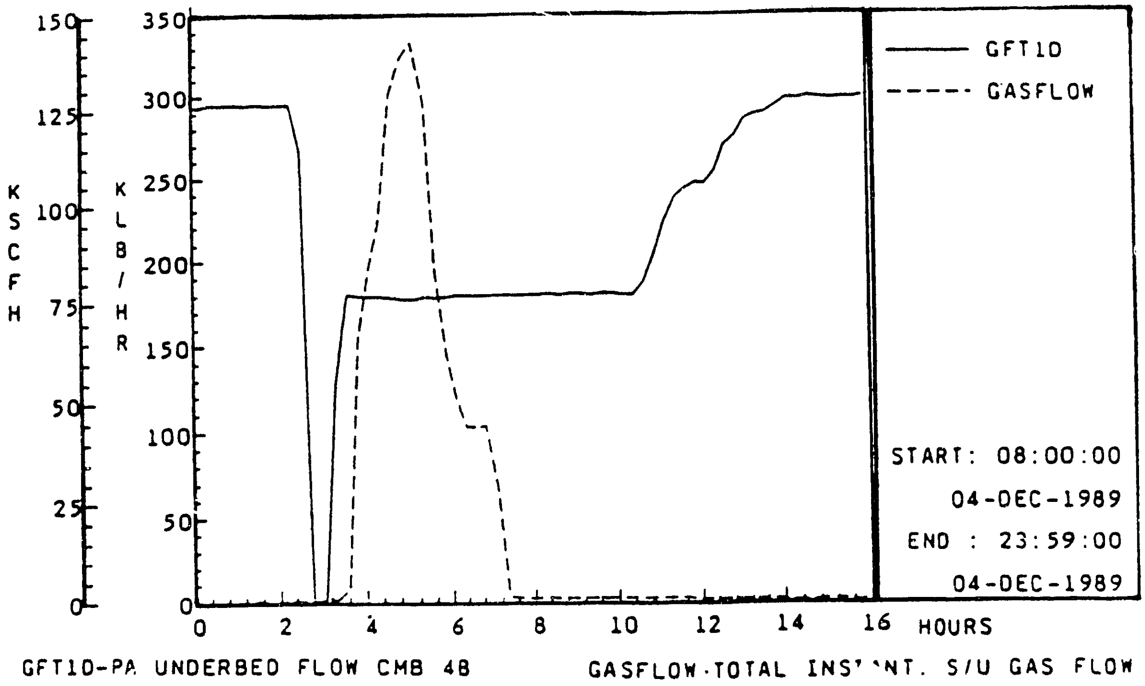


Figure 7-4. Hot Restart - 12/4/89. Underbed Air Flow to Combustor "B" and Total Gas Flow Rate

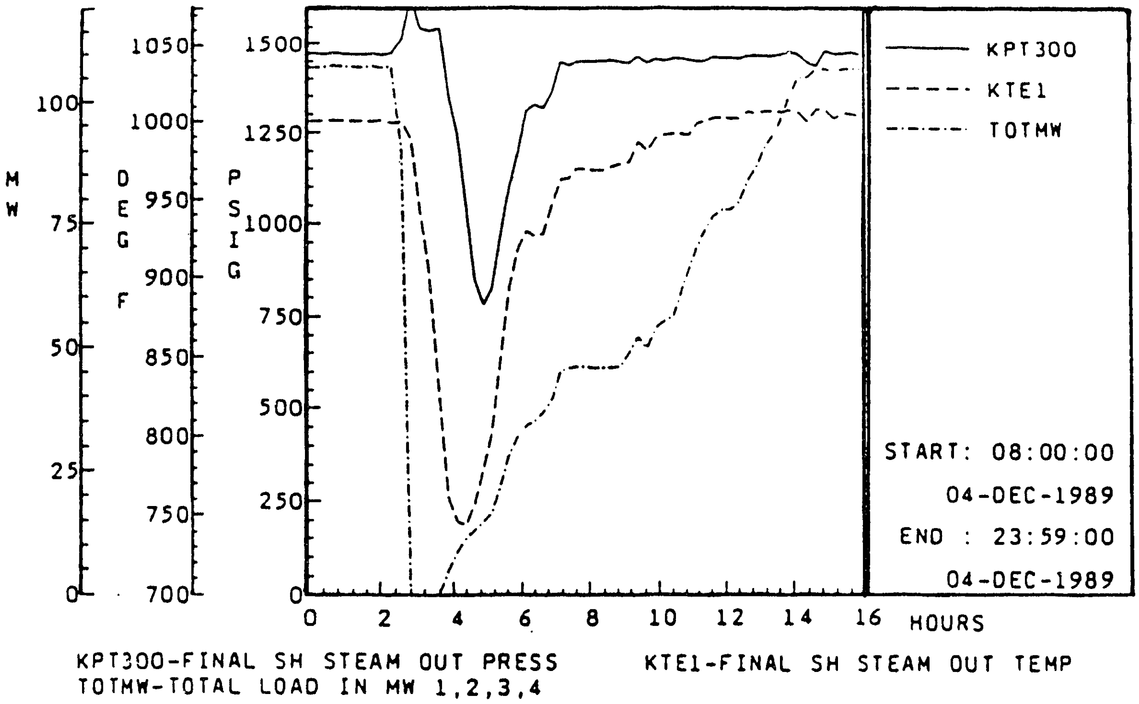


Figure 7-5. Hot Restart - 12/4/89. Final Steam Conditions and Gross Unit Output

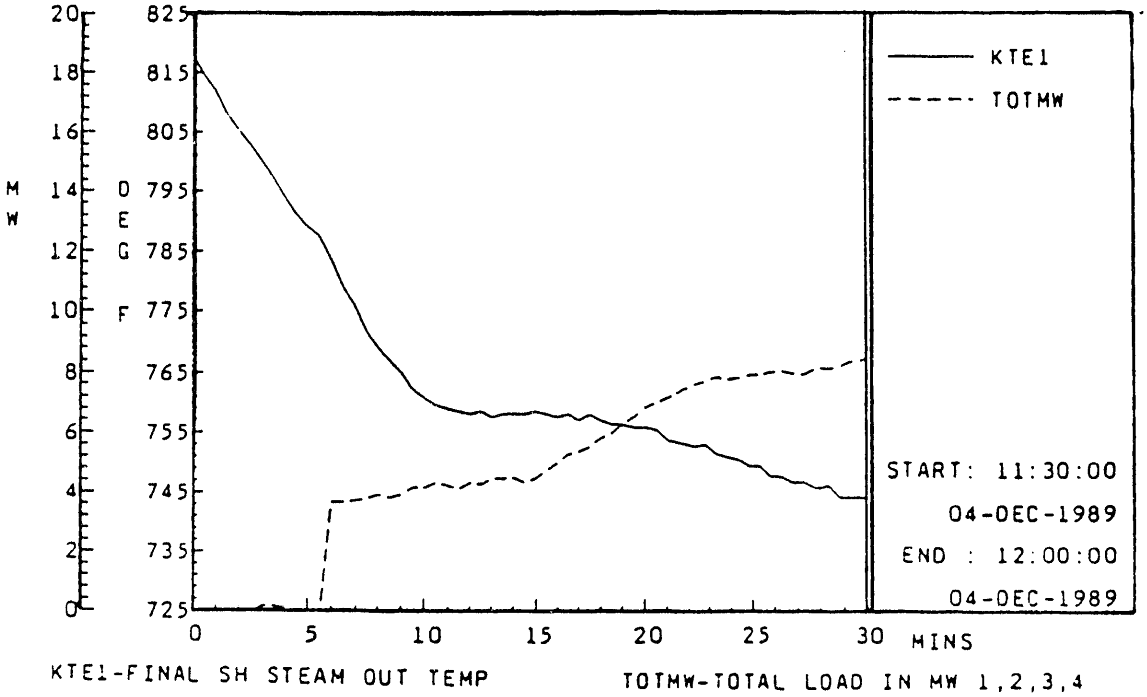


Figure 7-6. Hot Restart - 12/4/89. Final Steam Pressure and Gross Unit Output

4. The 74 MWe unit 4 turbine is rolled to 3600 rpm and is synchronized.

5. Coal flow is initiated once bed temperatures are greater than 950°F. Load is slowly raised to approximately 45 MWe gross output on the #4 turbine-generator where it is held to stabilize and prepare for bringing each of the three 12.5 MWe turbines into service. Gas fires are withdrawn from the combustion chambers once bed temperatures are greater than 1400°F.

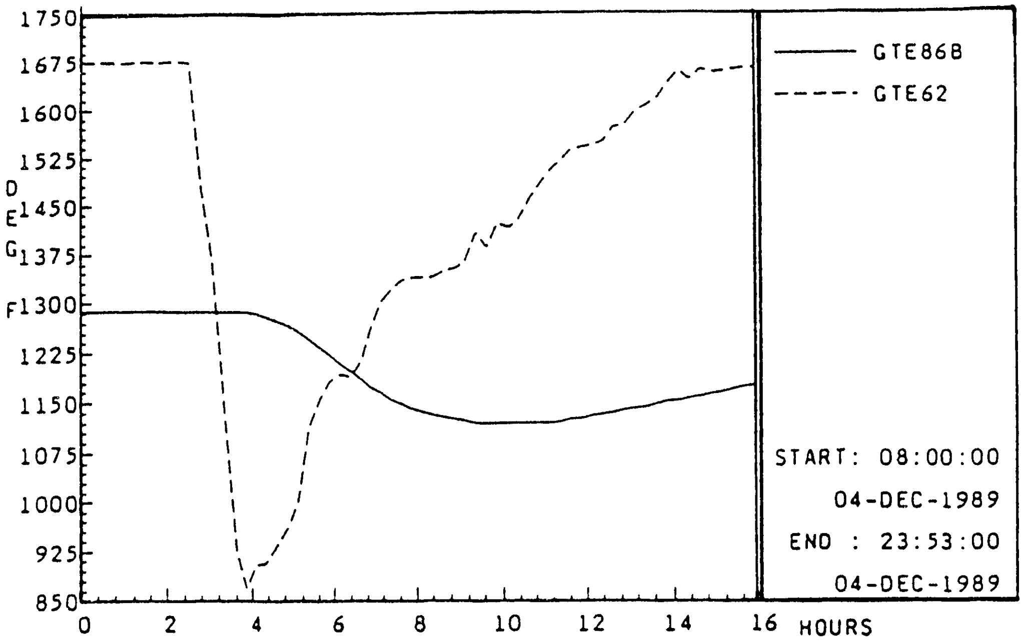
Figures 7-2, 7-3, and 7-4 show the coal and gas flow rates and bed temperatures for the two hot restarts. In Figure 7-2, bed temperatures initially drop from approximately 1625°F to 1550°F as fans wind down following the trip. Bed temperatures drop only 75°F over the next 2.5 hours with all fans out of service, or approximately 30°F/h. Since bed temperatures in Figure 7-2 are still greater than 1400°F at 19:00, the unit is ready for a hot restart without gas assistance. However, once fans are restarted and the unit is purged, bed temperatures drop from 1475°F to 700°F in 30 to 40 minutes. Gas firing is now required to raise bed temperatures back up to 950°F prior to the introduction of coal feed. Figure 7-3 for the hot restart on 12/4/89 shows a similar drop in bed temperature during restart of the fans and the completion of the purge cycle.

One possible method of preserving bed temperatures following a unit trip is to bypass flow away from the underbed grid during restart and run-up of the fans, and then complete the purge cycle of the boiler through the overbed air ports. This would preserve the temperature of the slumped bed above 950°F, required for the initiation of air, coal and propane flow immediately following the completion of the purge cycle. However, the National Fire Prevention Association currently requires a 5 minute purge through the bed to eliminate volatile accumulation in the windbox and slumped bed.

Figures 7-7 through 7-10 show the cyclone refractory temperature of the combustor B cyclone and the drum metal temperature during the hot restart on 12/4/89. The maximum rate of change in drum metal temperature for this hot restart is 85°F/h, which is below the 100°F/h limitation. As mentioned in Section 7, above 1100°F, the rate of change of refractory temperature is no longer a limitation. However, by comparing Figures 7-8 and 7-10, it is apparent that the rate of change in refractory temperature is much slower than the drum metal temperature.

7.3 WARM RESTART TEST DATA

A warm restart was initiated on 9/13/89 following a secondary air fan trip. Due to difficulties restarting this fan, a period of almost 10 hours elapsed with the unit off-line.



GTE86B-CYCLONE 4B LOWER REFACTORY T GTE62-CYCLONE 4B GAS INLET TEMP

Figure 7-7. Hot Restart - 12/4/89. Cyclone Inlet Gas Temperature and Refractory Temperature

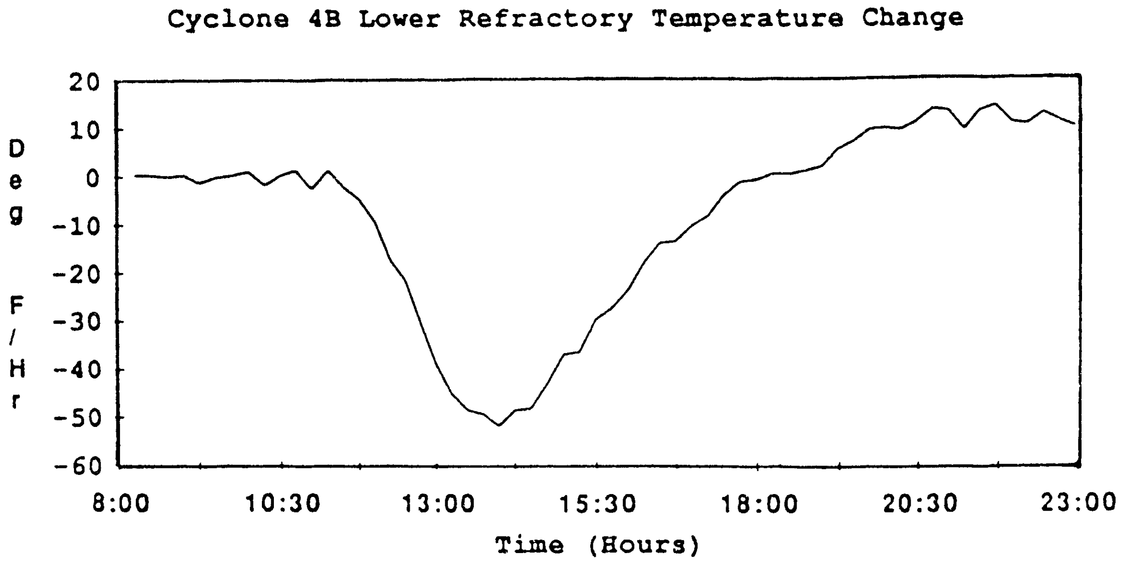


Figure 7-8. Hot Restart - 12/4/89. Cyclone Refractory Rate of Temperature Change.

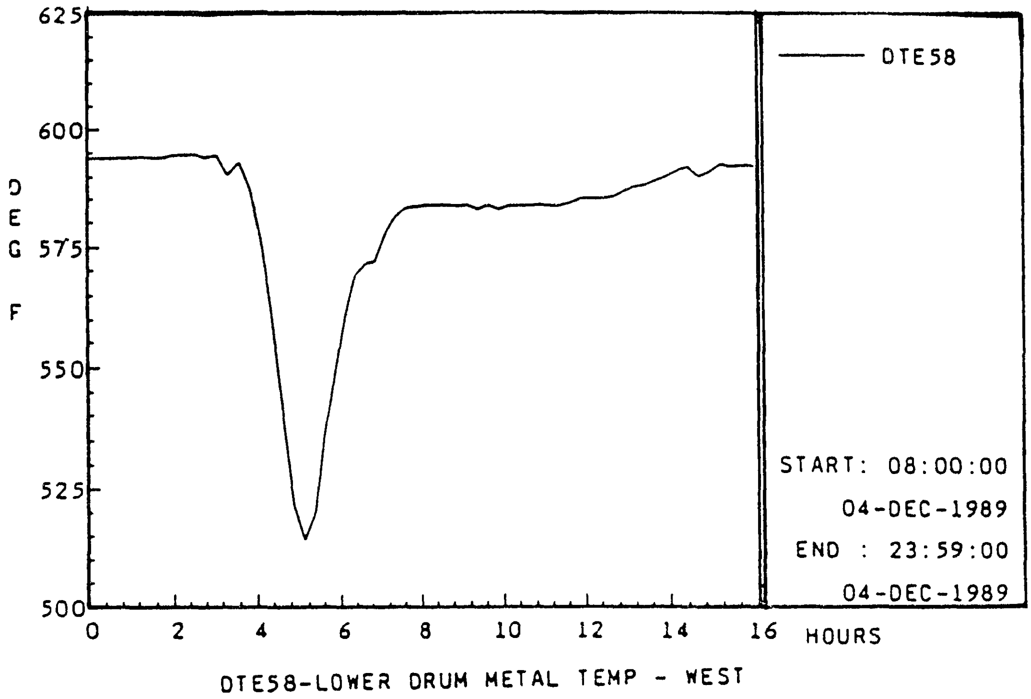


Figure 7-9. Hot Restart - 12/4/89. Drum Metal Temperature

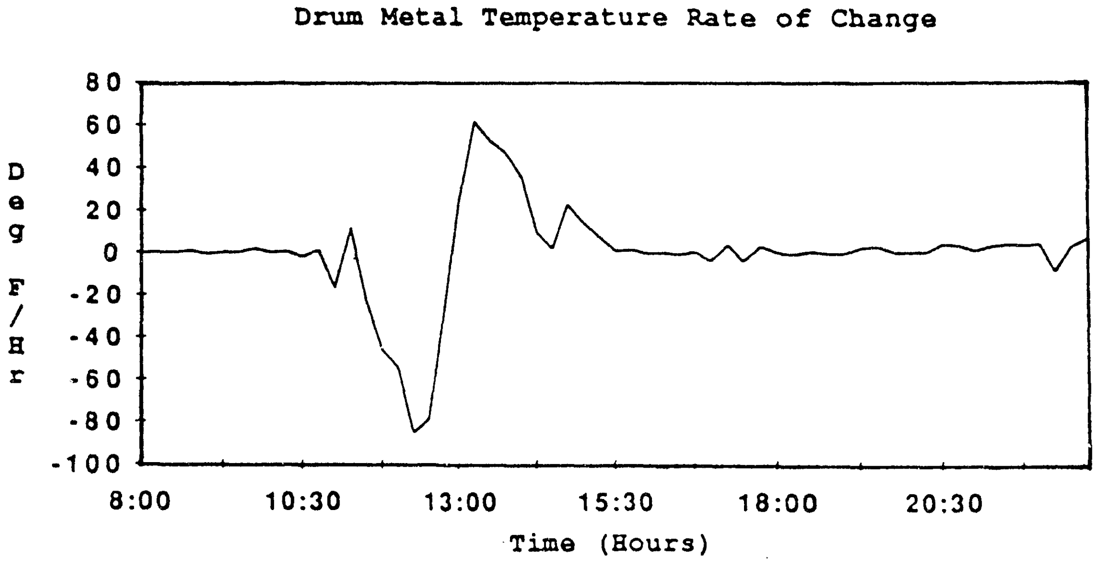


Figure 7-10. Hot Restart - 12/4/890. Rate of Change of Drum Metal Temperature

Data from this restart are summarized in Figure 7-11 through 7-17. Following the trip, steam conditions dropped to 250 psig and 525°F prior to the start of fans and the initiation of gas fires. Bed temperatures, shown in Figure 7-12, drop from 1550°F to 1400°F over a six hour interval following the MFT with fans off, but then fall to 650°F in the 20 to 30 minute interval required to restart and run-up all the fans and purge the boiler.

Coal flow is initiated once bed temperatures increase above 950°F. Gas fires are withdrawn from the boiler once bed temperatures are greater than 1400°F. Although not shown, gaseous emissions of NO_x and SO_2 are typically in compliance during unit trips followed by hot and warm restarts. However, CO emissions remain in excess of 2000 ppmv until bed temperatures increase above 1250°F, which is approximately the minimum ignition temperature for carbon monoxide.

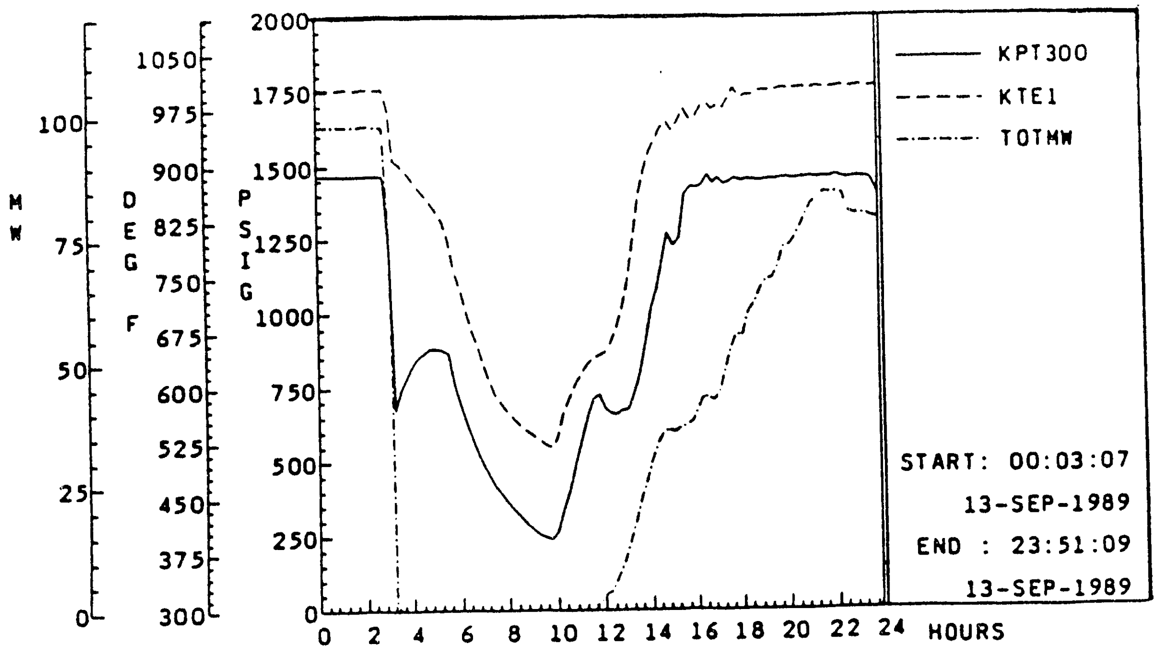
Figures 7-14 through 7-17 show refractory and drum metal temperatures and rates of temperature change for the warm restart. As was the case for the hot restart in Section 7.2, refractory temperature rates of change are not a consideration once the temperature has increased above 1100°F. The curves indicate that a maximum rate of change in temperature of 60°F/h occurs during the restart of coal feed. Drum metal temperatures are within the 100°F/h constraint throughout most of the start-up except for a brief interval immediately following the unit trip. During this interval, steam temperature drops rapidly with the decrease in steam pressure. These data are under review by the plant.

7.4 COLD START-UP DATA

Data from a cold unit start-up on 3/28/91 are presented in Figures 7-18 through 7-20. Data represent a routine start-up following a 120 hour unit outage during which refractory and metal components had returned to near ambient conditions. Analysis of routine start-up data will assist in the optimization of start-up times and procedures, which is one of the goals of this test plan. The numbered sequence on Figures 7-18 and 7-19 is summarized below:

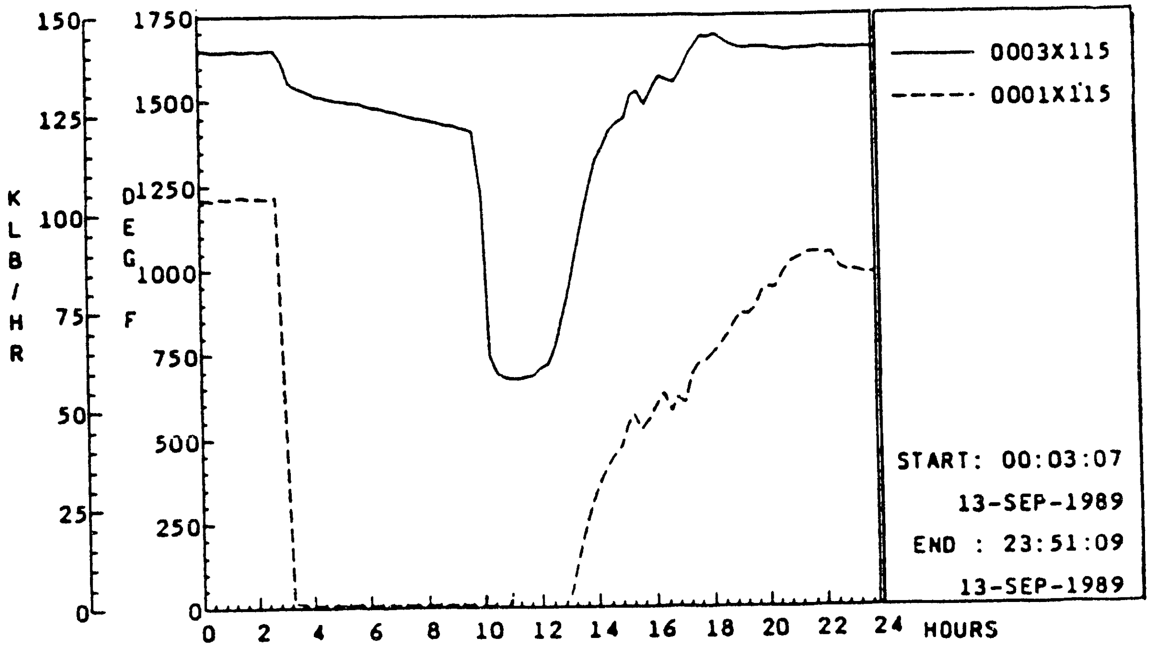
1. Duct burners are started and run for 2 hours to warm the lower portion of the combustor, including the windbox. All vents and drains (except the main steam leads) are closed once a steam pressure of 25 psig is reached.

2. One in-bed start-up burner is started in each combustion chamber and drum pressure is slowly raised. The drum metal and refractory temperature rate limit is 100°F/h.



KPT300-FINAL SH STEAM OUT PRESS KTE1-FINAL SH STEAM OUT TEMP
TOTMW-TOTAL LOAD IN MW 1,2,3,4

Figure 7-11. Warm Restart - 9/13/89. Final Steam Conditions and Gross Unit Output



0003X115-BED TEMP CMB 4B 20IN AVG 0001X115-TOTAL COAL FLOW (BTU BIASED

Figure 7-12. Warm Restart - 9/13/89. Bed Temperature and Total Coal Flow

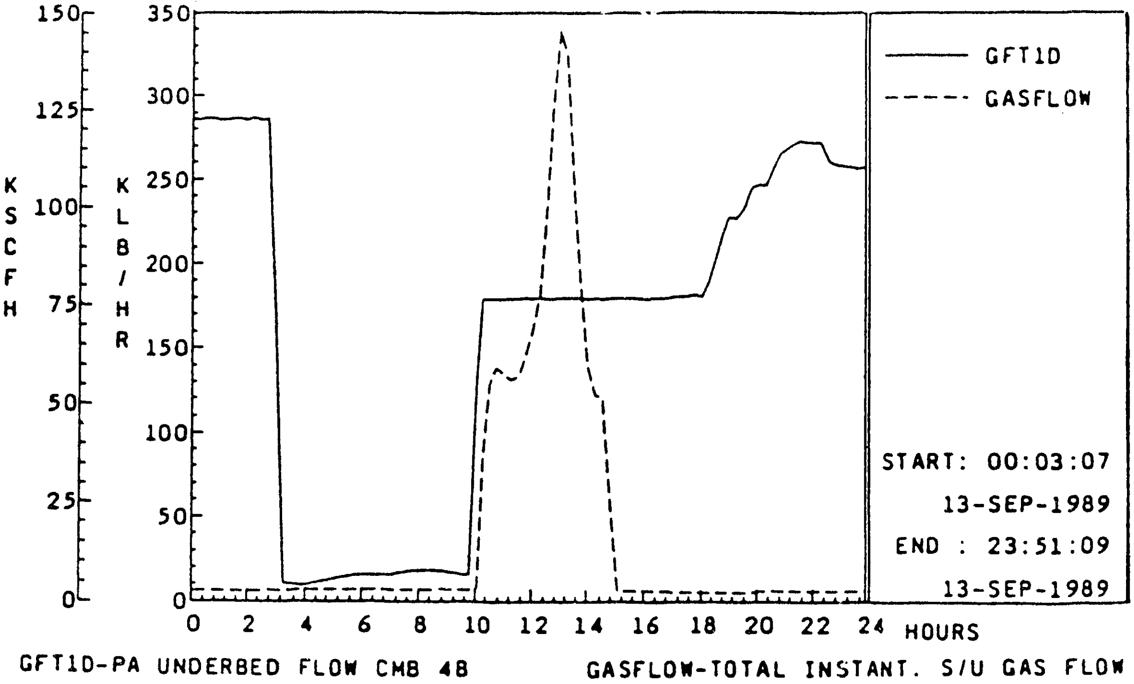


Figure 7-13. Warm Restart 9/13/89. Underbed Air Flow and Start-Up Gas Flow Rate

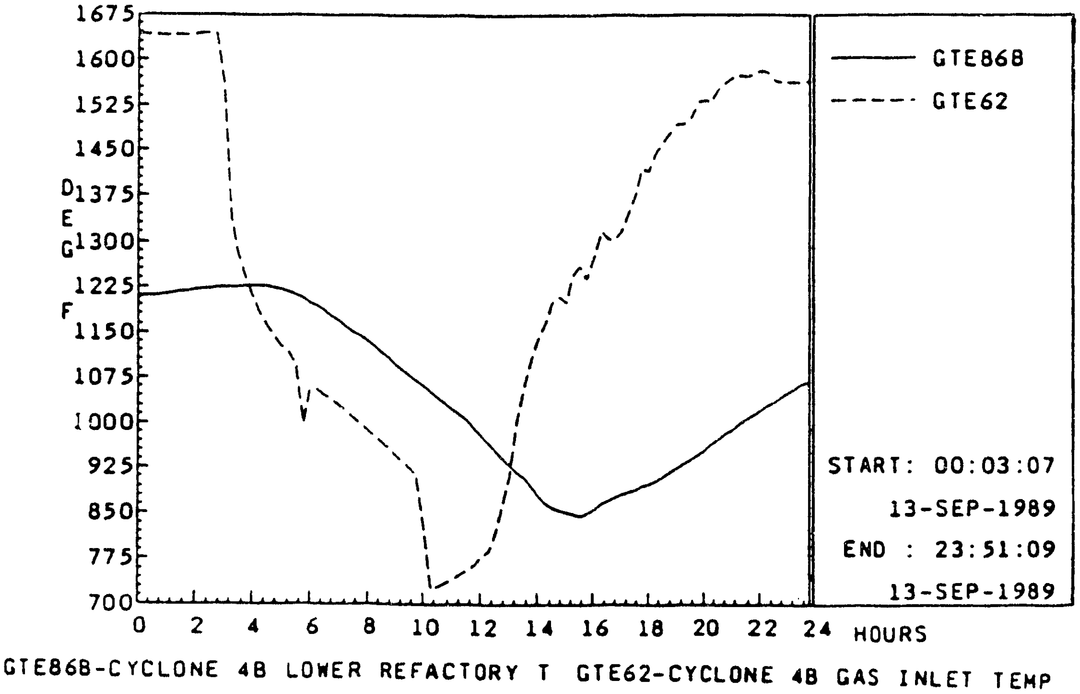


Figure 7-14. Warm Restart - 9/12/89. Cyclone Gas Inlet Temperatures and Refractory Temperature

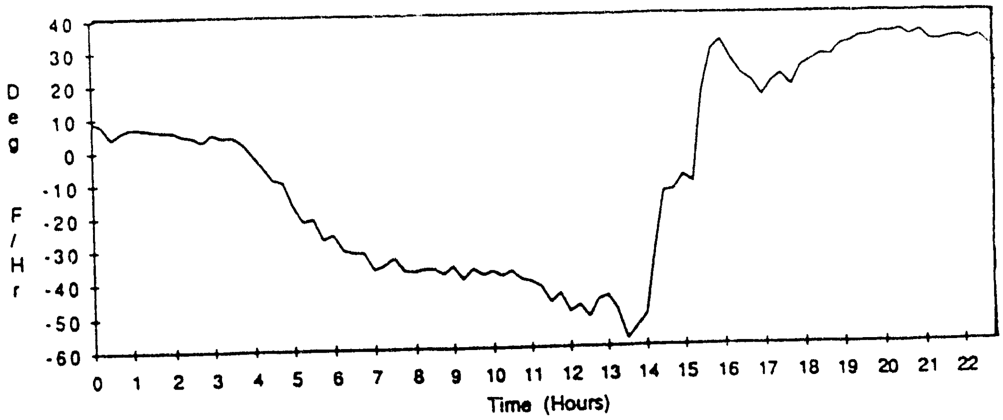


Figure 7-15. Warm Restart - 9/13/89. Rate of Change of Refractory Temperature vs. Time (dT/dt)

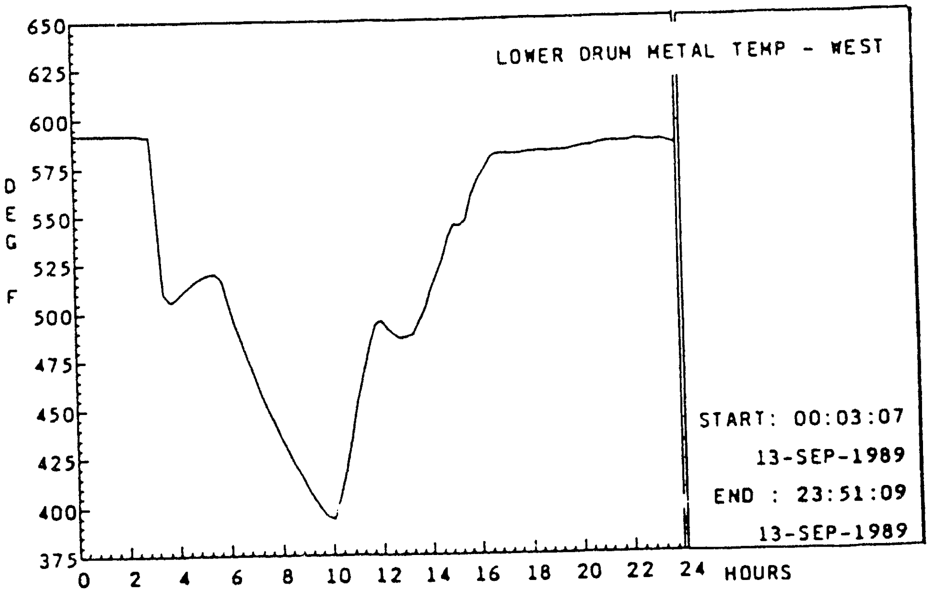


Figure 7-16. Warm Restart - 9/13/89. Drum Metal Temperature

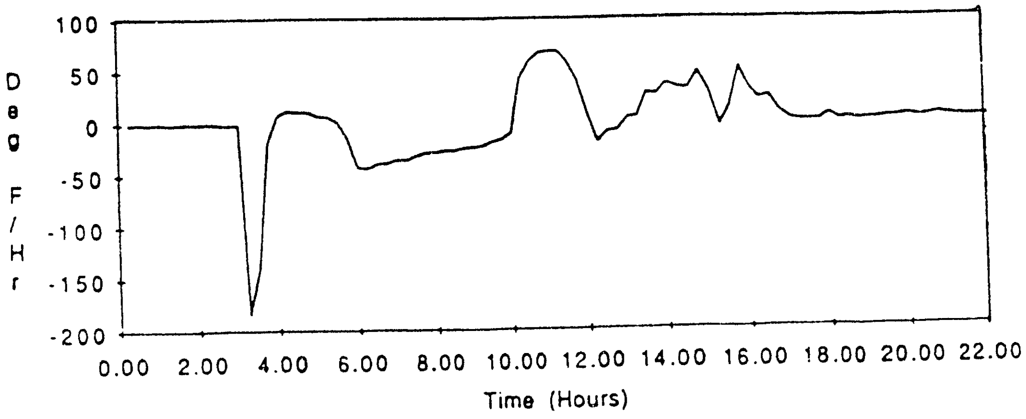
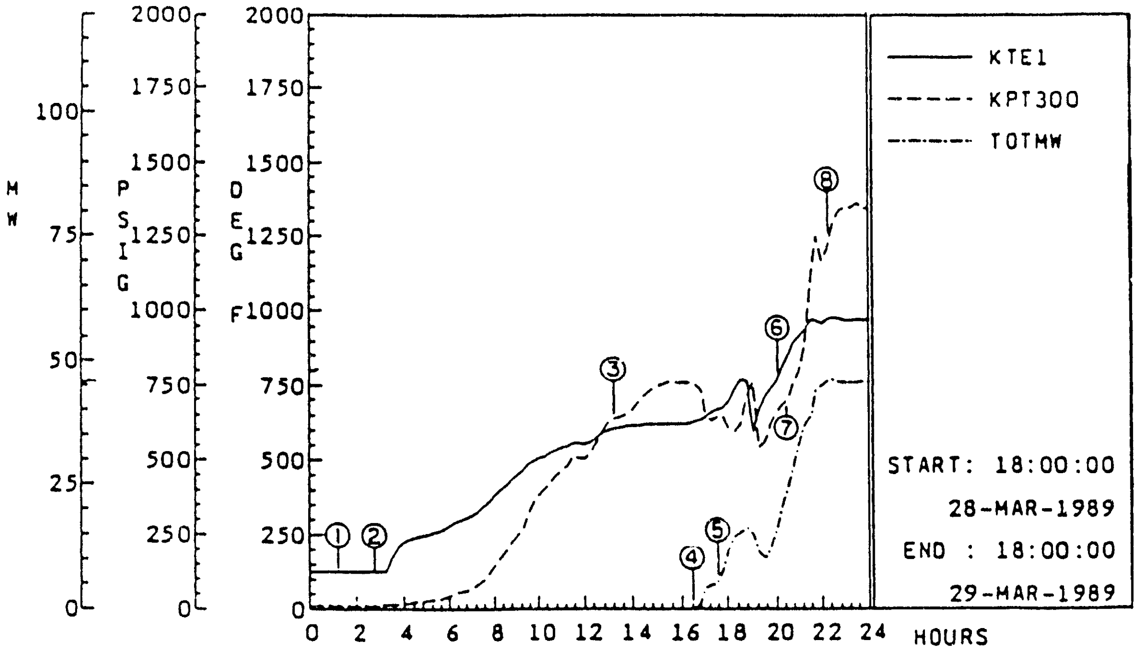
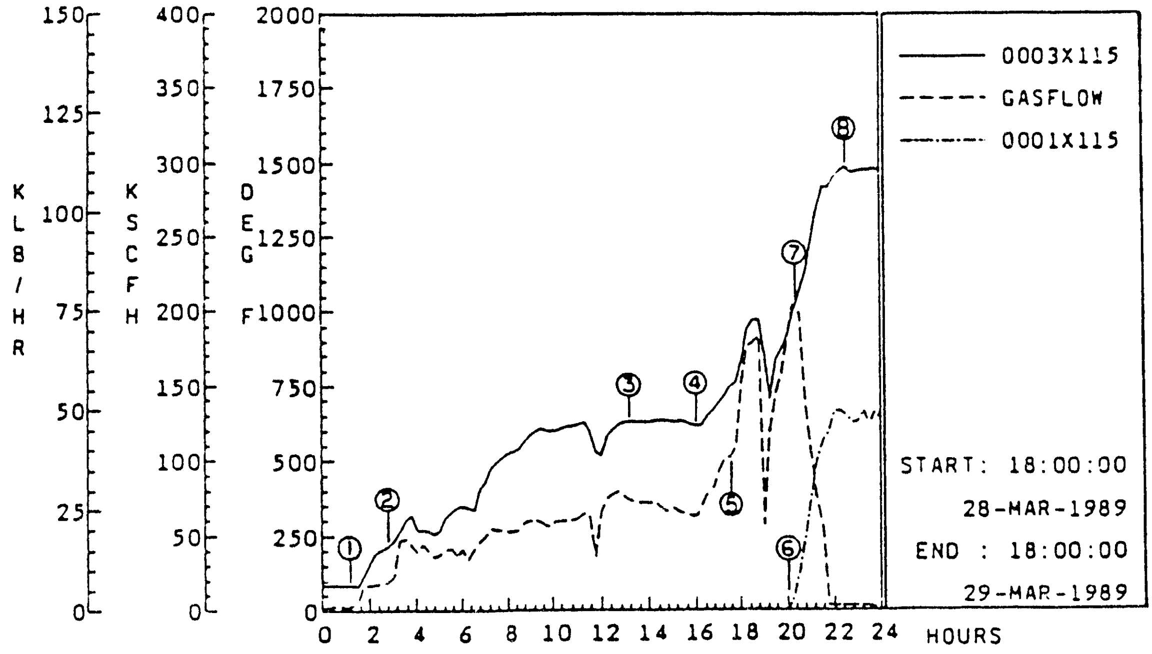


Figure 7-17. Warm Restart - 9/13/89. Rate of Change of Drum Metal Temperature vs. Time (dT/dt)



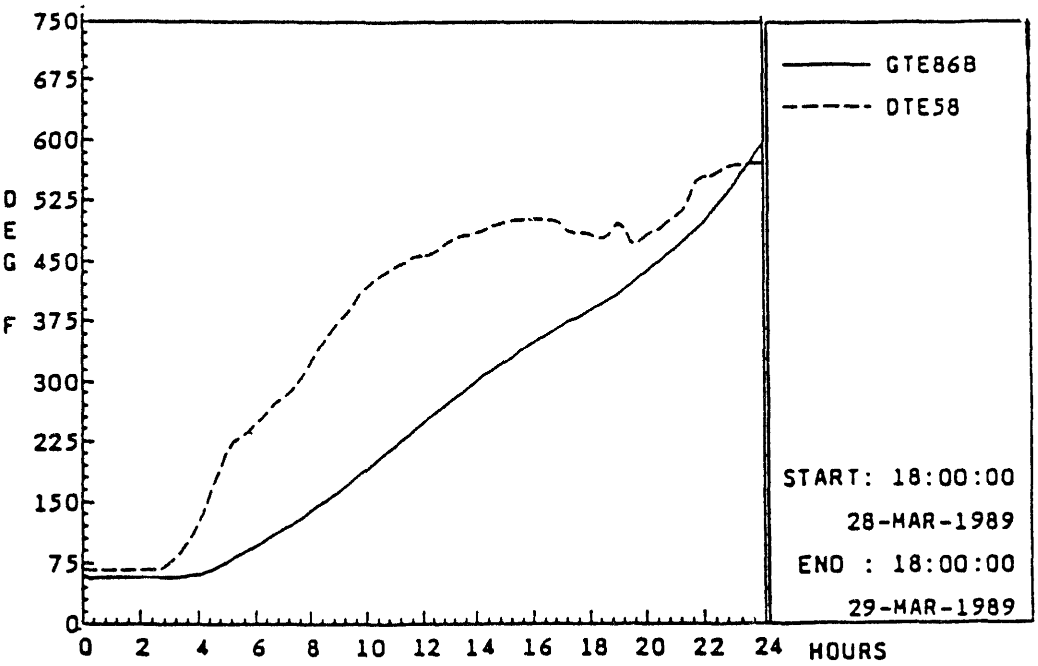
KTE1-FINAL SH STEAM OUT TEMP KPT300-FINAL SH STEAM OUT PRESS
TOTMW-TOTAL LOAD IN MW 1,2,3,4

Figure 7-18. Cold Start-Up - 3/28/89. Final Steam Conditions and Gross Unit Output



0003X115-BED TEMP CMB 4B 20IN AVG GASFLOW-TOTAL INSTANT. S/U GAS FLOW
0001X115-TOTAL COAL FLOW (BTU BIASED)

Figure 7-19. Cold Start-Up - 3/28/89. Bed Temperatures and Coal and Start-Up Gas Flows



GTE86B-CYCLONE 4B LOWER REFACTORY T DTE58-LOWER DRUM METAL TEMP - WEST

Figure 7-20. Cold Start-Up - 3/28/89. Refractory and Drum Metal Temperatures

3. Drum pressure reaches approximately 600 psig for 100°F of superheat. The turbine is rolled and the three hour heat soak is initiated.

4. The turbine heat soak is completed and turbine speed is raised to 3600 rpm. The generator is then synchronized and run at a minimum load of 5 MWe for one hour.

5. The start-up burner firing rate is increased and load is raised to 20-25 MWe.

6. Once bed temperatures have reached 950°F, coal feed is initiated and load is raised.

7. Once bed temperatures have increased above 1400°F, gas fires are secured and coal flow is increased.

8. Unit load is stabilized at 45 MWe in preparation for bringing each of the 12.5 MWe turbines sequentially into service.

Figure 7-20 shows the temperature curve for cyclone refractory and drum metal. Note that the rate of change is much steeper for drum metal temperature compared to cyclone refractory temperatures. From the data presented in Table 7-1, the maximum rate of change for drum metal and refractory temperatures is 80°F/h and 25°F/h respectively. Both of these are within the manufacturer's recommended margins for these materials.

For this cold start-up, 14 hours elapsed between initial gas fires and synchronization of the #4 turbine-generator. Two hours were used to raise 25 psig steam pressure in a very slow, controlled manner. Nine hours were used to raise 100°F of superheat temperature prior to turbine roll. Under optimum conditions, it should be possible to complete this in 5 hours. Four hours were used for a turbine soak, although it is possible to complete this in three hours. The remainder of the start-up, from synchronization of the #4 turbine to load stabilization at 45 MWe, is fairly routine.

Under optimum conditions, the time from step 1 to step 3 could be completed in 5 to 6 hours. Achieving this at Nucla has been difficult due to drum level stability problems. A considerable number of MFT's have been experienced to date during the start-up interval from first gas fires to turbine roll as the result of drum level control problems. Drum level control is a problem during initial start-up until a sufficient pressure (300 psig) is reached on the drum. This is a result of swell (increase in void fraction), common on all water-tube constructed boilers. The problem is exacerbated at Nucla during low load operation due to the absence of an accurate steam flow signal used in 3-element drum level control below 30% MCR. In 3-element control, any change in steam flow is used to anticipate a change in feed water flow before a change in drum level is recorded. Drum stability improves significantly once the turbine is rolled and steam flow is established.

Section 8

SOLIDS AND GAS MIXING

8.1 OBJECTIVES AND APPROACH

During the reporting period, the freeboard gas analysis system was used to conduct flue gas traverses at two elevations in combustor B at Nucla. Tests were conducted at three loads with Peabody coal and at half load with Salt Creek coal. In addition, traverses were also conducted with different coal feed and limestone feed configurations at half load with Salt Creek coal to study the impact of the feeder configurations on the gas profiles.

8.2 DESCRIPTION OF EQUIPMENT

A description of the FGAS traversing probe is given in Section 3.2.1 of the Start-Up through 1988 Annual Technical Progress Report. Two retractable probes were used to extract gas samples. One was located at elevation 44'6" and the other was located at 86'6". For convenience these two traverse points are referred to as the 40 ft and 80 ft traverse points. The 40 ft elevation is approximately 25 ft above the air distributor plate and the 80 ft elevation is approximately 65 ft above the air distributor.

Gas samples are collected at 1 ft intervals throughout the 10 ft range of the probes. Figure 8-1 shows a plan view of the Nucla combustor B and shows the relative locations of the coal feeders, limestone feeders, loop seal, secondary air ports, and the traverse points. The loop seal enters the combustor approximately 2 ft above the air distributor. One coal and one limestone feeder feed directly into the loop seal. The limestone feeders on the front wall and the outside wall are located about 5 ft above the air distributor. The coal feeders on the front wall are approximately 8.5 ft above the air distributor as are the front and rear wall secondary air nozzles and the start-up burners. The secondary air nozzles along the outside and center walls are located about 10 ft above the air distributor. On the outside wall two ash cooler air return lines are located approximately where the secondary air nozzles would normally be located.

Ten points are sampled as the probe is moved into the furnace. Each point is sampled for 6 minutes. The gas concentrations are recorded on the VAX computer every 4 seconds throughout the duration of the traverse. Data collected during the periodic line purges are deleted from

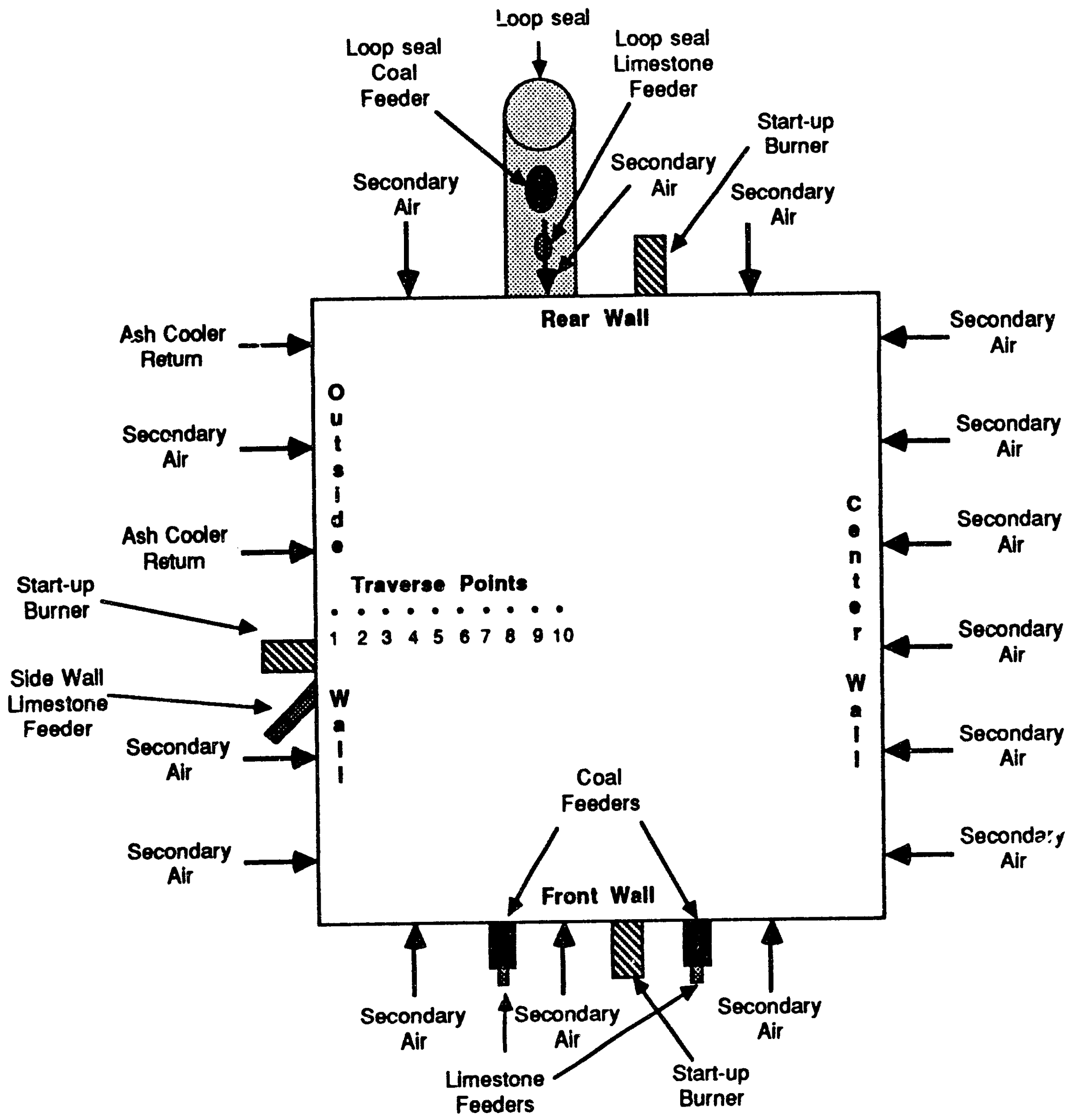


Figure 8-1. Plan view of Nucla B combustor showing location of fuel, limestone, loop seal and secondary air feeders.

the traverse results. Once a traverse is complete, the data are reviewed carefully, and the purge periods are identified and eliminated. The remaining data are broken down into the 6-minute periods representing the ten traverse points, averaged, and then plotted against depth into the boiler. These graphs illustrate the gas concentration profiles along a single axis at two elevations within the combustor.

There are two limitations to the gas traverse data that must be considered when analyzing the results. First, the data are taken along a single axis at each elevation. The traversing points are located directly above each other. However, the traverse location only represents the gas concentrations within a narrow band at each elevation. There is no information provided across the entire cross section of the boiler. Second, aspirating air is required at the probe port on the combustor wall to prevent combustion gasses from escaping the boiler. This air may contaminate the gas sample taken at the 1-foot depth. However, there is no indication that this contamination has occurred.

8.3 GAS TRAVERSE RESULTS

Eight gas traverse tests were conducted during the reporting period, representing six sets of traverses. Table 8-1 contains a list of the tests and the dates completed. The results of the gas traverses taken during the reporting period are given in Tables 8-2 through 8-7. Table 8-2 contains the data obtained during traverses taken on May 25, 1989 when firing Peabody coal at a load of 55 MWe. Table 8-3 contains the traverses taken on June 9 and June 22 for Peabody coal at 82.5 MWe load. Table 8-4 contains the traverses taken on June 20 and June 21 when firing Peabody coal at 105 MWe. Table 8-5 contains the traverse data taken on August 8 for Salt Creek coal at a load of 55 MWe, with balanced fuel feed. Table 8-6 shows the traverse data taken on August 10 firing Salt Creek coal at 55 MWe with fuel feed to the front walls only. Table 8-7 shows the traverse data taken August 14 firing Salt Creek coal at 55 MWe with fuel feed to the loop seal coal feeder only.

8.3.1 Effect of Load

The first five traverses listed in Table 8-1 were performed using Peabody coal. These tests were conducted at three loads with balanced feed to all three coal and limestone feeders to study the effect of load on gas mixing. Figures 8-2 through 8-5 show the effect of load for Peabody coal on O_2, CO, NO_x, and SO_2 traverses, respectively. Also shown on each figure is the concentration that was obtained at the air heater inlet. In order to allow comparisons of different graphs, all graphs for a gaseous component are drawn with the same Y-axis.

Table 8-1. Test Conditions For Gas Traverse Tests

Reference Test Number*	Traverse Test Date	Coal Type	Traverse Location	Load (MWe)	B-Bed Temperature °F	B-Bed Ca/S Ratio	Sulfur Retention B-Bed %	Coal Feed Configuration	Limestone Feeders Out Of Service	Gas Composition at Air Heater Inlet			
										O2 Dry Vol %	CO Dry PPMV	NOx Dry PPMV	SO2 Dry PPMV
A07	5/25/89	Peabody	40 & 80ft	55	1535	1.5	78	Balanced	None	5.9	93	44	150
A04	6/9/89	Peabody	40 ft	82.5	1650	1.7	75	Balanced	None	4.2	73	132	162
A04	6/22/89	Peabody	80 ft	82.5	1650	1.7	75	Balanced	None	4.2	73	132	162
A08	6/20/89	Peabody	40 ft	105	1650	1.8	73	Balanced	None	3.4	59	150	188
A08	6/21/89	Peabody	80 ft	105	1650	1.8	73	Balanced	None	3.4	59	150	188
P39	8/8/89	Salt Creek	40 & 80 ft	55	1569	2.6	80	Balanced	None	6.0	82	51	94
None	8/10/89	Salt Creek	40 & 80 ft	55	N/A	N/A	N/A	Front only	None	N/A	N/A	N/A	N/A
P52	8/14/89	Salt Creek	40 & 80 ft	55	1525	2.8	81	Loopseal only	None	6.3	72	38	85

* Reference test number refers to a performance test of similar conditions and are not necessarily the same test.

Table 8-2. Gas Profiles for Peabody Coal
55 MW - Balanced Feed

Distance From Wall	O_2 at 40 ft El.	O_2 at 80 ft El.	CO at 40 ft El.	CO at 80 ft El.	NO_x at 40 ft El.	NO_x at 80 ft El.	SO_2 at 40 ft El.	SO_2 at 80 ft El.
1	9.98	9.60	439	193	45	34	56	96
2	9.04	6.36	481	222	60	42	72	142
3	9.52	6.10	425	218	84	46	75	140
4	9.79	6.10	440	223	88	46	81	128
5	9.91	6.15	450	213	92	49	89	142
6	10.23	6.32	439	206	101	52	97	139
7	9.95	6.90	455	193	103	51	110	118
8	9.96	7.03	449	184	107	58	114	114
9	9.61	6.96	433	176	107	63	113	104
10	9.15	7.17	422	185	112	55	116	121

Table 8-3. Gas Profiles for Peabody Coal
82.5 MW - Balanced Feed

Distance From Wall	O_2 at 40 ft El.	O_2 at 80 ft El.	CO at 40 ft El.	CO at 80 ft El.	NO_x at 40 ft El.	NO_x at 80 ft El.	SO_2 at 40 ft El.	SO_2 at 80 ft El.
1	8.27	4.00	2,379	676	102	97	616	24
2	7.59	2.99	2,081	1,010	141	109	628	200
3	8.50	3.60	1,338	444	146	128	572	426
4	7.64	3.72	726	418	160	138	356	452
5	5.96	4.22	448	299	174	155	283	324
6	4.95	4.60	384	253	181	161	230	224
7	4.91	5.31	327	210	190	175	328	132
8	5.58	6.44	350	259	193	164	146	101
9	7.43	6.38	401	243	203	167	232	112
10	7.62	6.24	385	254	199	169	237	106

Table 8-4. Gas Profiles for Peabody Coal
105 MW - Balanced Feed

Distance From Wall	O_2 at 40 ft El.	O_2 at 80 ft El.	CO at 40 ft El.	CO at 80 ft El.	NO_x at 40 ft El.	NO_x at 80 ft El.	SO_2 at 40 ft El.	SO_2 at 80 ft El.
1	7.99	4.72	700	298	126	84	428	291
2	7.50	3.76	712	329	170	102	697	270
3	7.95	3.65	605	297	181	114	736	259
4	6.95	4.02	666	209	199	138	651	176
5	5.35	4.19	696	207	216	157	673	126
6	4.58	4.06	625	180	234	174	432	85
7	3.88	4.24	394	175	246	181	300	76
8	4.30	4.48	328	168	265	206	160	53
9	4.87	4.27	356	170	272	205	148	45
10	5.96	4.73	394	173	280	218	154	35

Table 8-5. Gas Profiles for Salt Creek Coal
55 MW - Balanced Feed

Distance From Wall	O2 at 40 ft El.	O2 at 80 ft El.	CO at 40 ft El.	CO at 80 ft El.	NOx at 40 ft El.	NOx at 80 ft El.	SO2 at 40 ft El.	SO2 at 80 ft El.
1	9.06	10.48	279	299	100	71	27	10
2	8.04	8.55	266	277	133	117	30	15
3	7.45	7.78	272	286	150	145	37	23
4	7.28	7.52	288	317	162	155	40	27
5	7.09	7.34	282	280	169	164	49	31
6	6.94	7.29	301	300	173	170	58	40
7	7.42	7.29	308	301	171	170	60	49
8	7.69	7.50	320	332	178	178	68	64
9	7.66	7.77	331	340	187	184	76	67
10	7.20	7.53	327	331	185	184	74	64

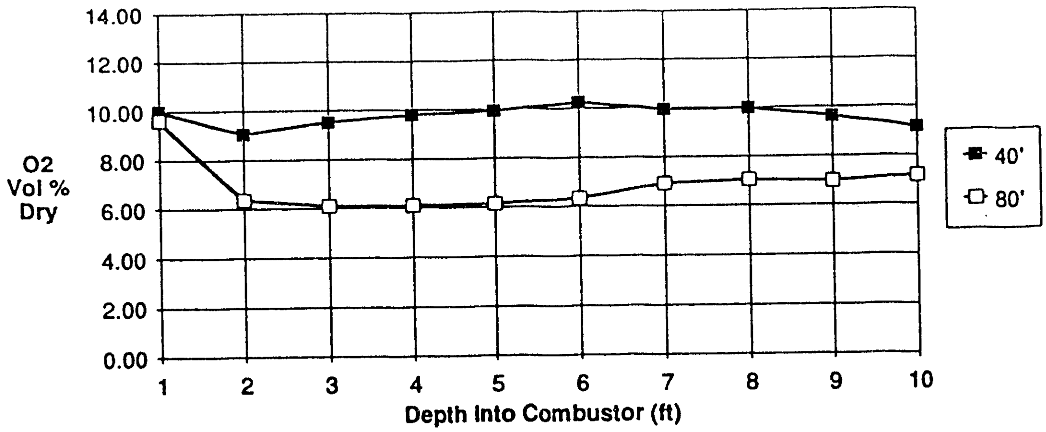
Table 8-6. Gas Profiles for Salt Creek Coal
55 MW - Front Wall Feed

Distance From Wall	O2 at 40 ft El.	O2 at 80 ft El.	CO at 40 ft El.	CO at 80 ft El.	NOx at 40 ft El.	NOx at 80 ft El.	SO2 at 40 ft El.	SO2 at 80 ft El.
1	8.30	8.47	943	740	109	71	41	18
2	9.21	7.71	621	1,165	127	74	32	68
3	9.72	9.18	612	778	146	92	26	67
4	10.27	9.46	399	596	148	96	17	57
5	11.51	9.91	315	438	157	96	12	40
6	11.76	10.56	371	290	152	104	13	35
7	13.52	11.21	314	194	148	108	8	24
8	13.74	11.47	313	191	144	108	8	19
9	13.58	11.17	339	177	139	104	8	20
10	13.25	10.46	309	170	143	100	7	24

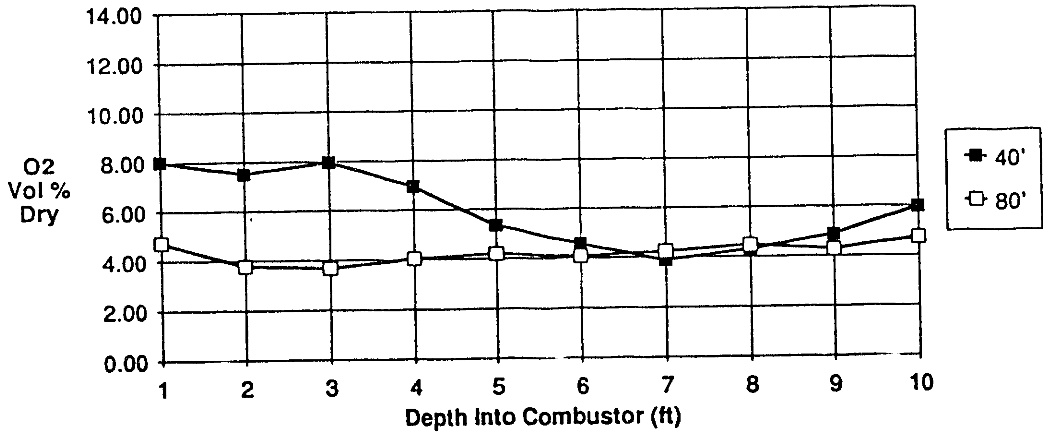
Table 8-7. Gas Profiles for Salt Creek Coal
55 MW - Loop Seal Feed

Distance From Wall	O2 at 40 ft El.	O2 at 80 ft El.	CO at 40 ft El.	CO at 80 ft El.	NOx at 40 ft El.	NOx at 80 ft El.	SO2 at 40 ft El.	SO2 at 80 ft El.
1	10.81	14.41	918	126	59	15	78	63
2	6.62	9.61	1,554	175	79	30	149	110
3	4.70	4.89	1,911	207	83	34	226	163
4	3.84	4.63	2,295	189	91	37	259	178
5	2.82	4.63	2,450	189	99	39	326	181
6	2.75	4.44	2,652	195	107	35	360	191
7	2.23	4.42	3,207	188	120	36	408	194
8	1.92	4.69	3,407	189	127	43	448	179
9	2.20	4.50	3,075	192	133	40	435	175
10	2.29	4.52	2,410	190	131	42	412	171

O2 Profile @ 55 MW
Peabody Coal - Balanced Feed
Air Heater Inlet O2 = 5.9 vol %



O2 Profile @ 105 MW
Peabody Coal - Balanced Feed
Air Heater Inlet O2 = 3.4 vol %



O2 Profile @ 82.5 MW
Peabody Coal - Balanced Feed.
Air Heater Inlet O2 = 4.2 vol %

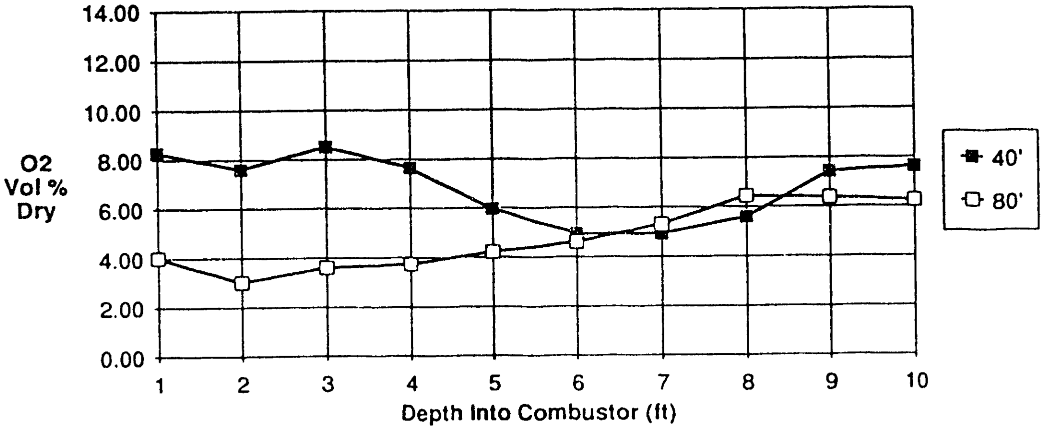
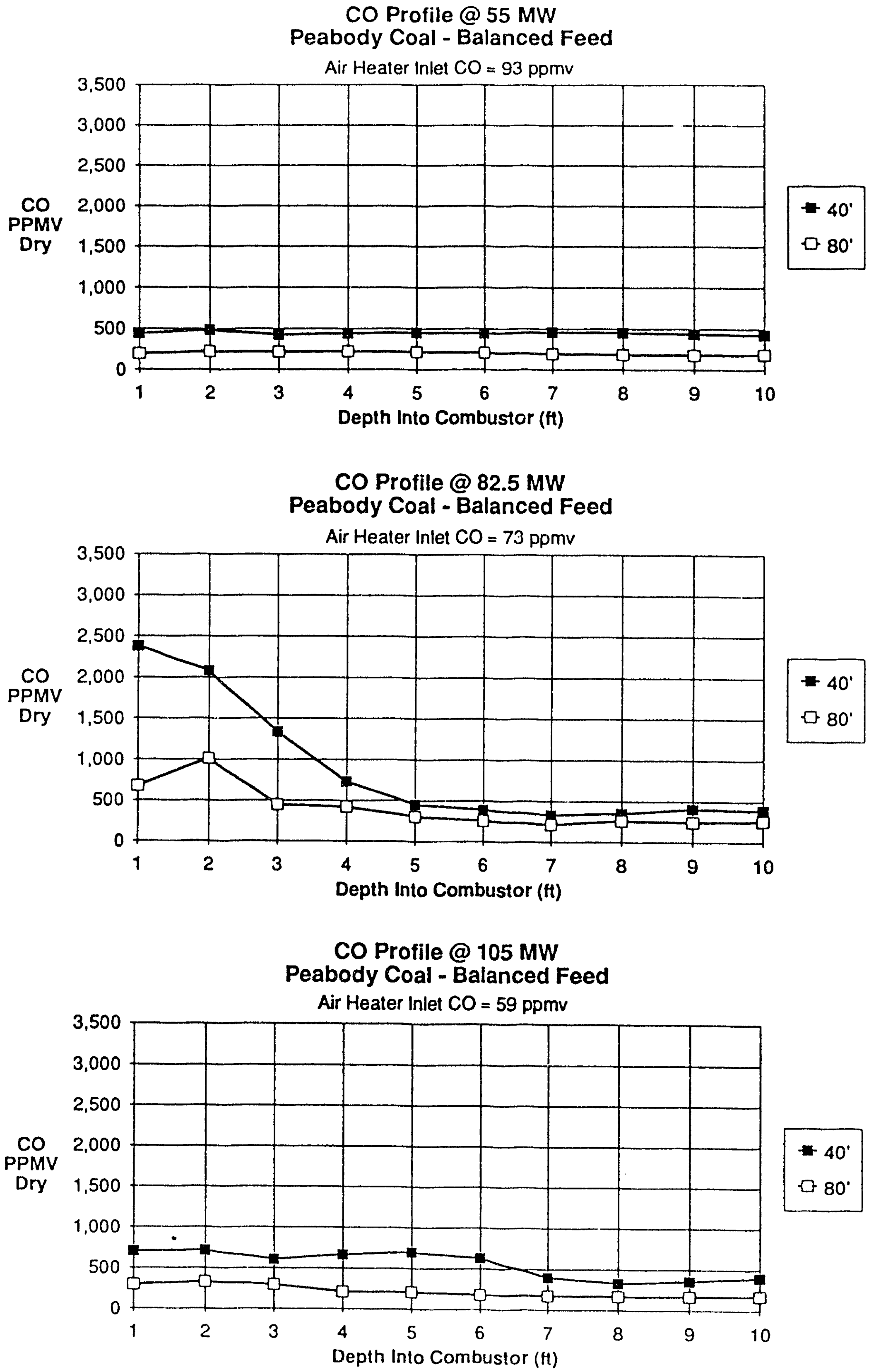


Figure 8-2. O_2 traverses for Peabody coal at three loads.


CO Profile @ 55 MW
Peabody Coal - Balanced Feed
Air Heater Inlet CO = 93 ppmv

CO Profile @ 82.5 MW
Peabody Coal - Balanced Feed
Air Heater Inlet CO = 73 ppmv

CO Profile @ 105 MW
Peabody Coal - Balanced Feed
Air Heater Inlet CO = 59 ppmv

Figure 8-3. CO traverses for Peabody coal at three loads.

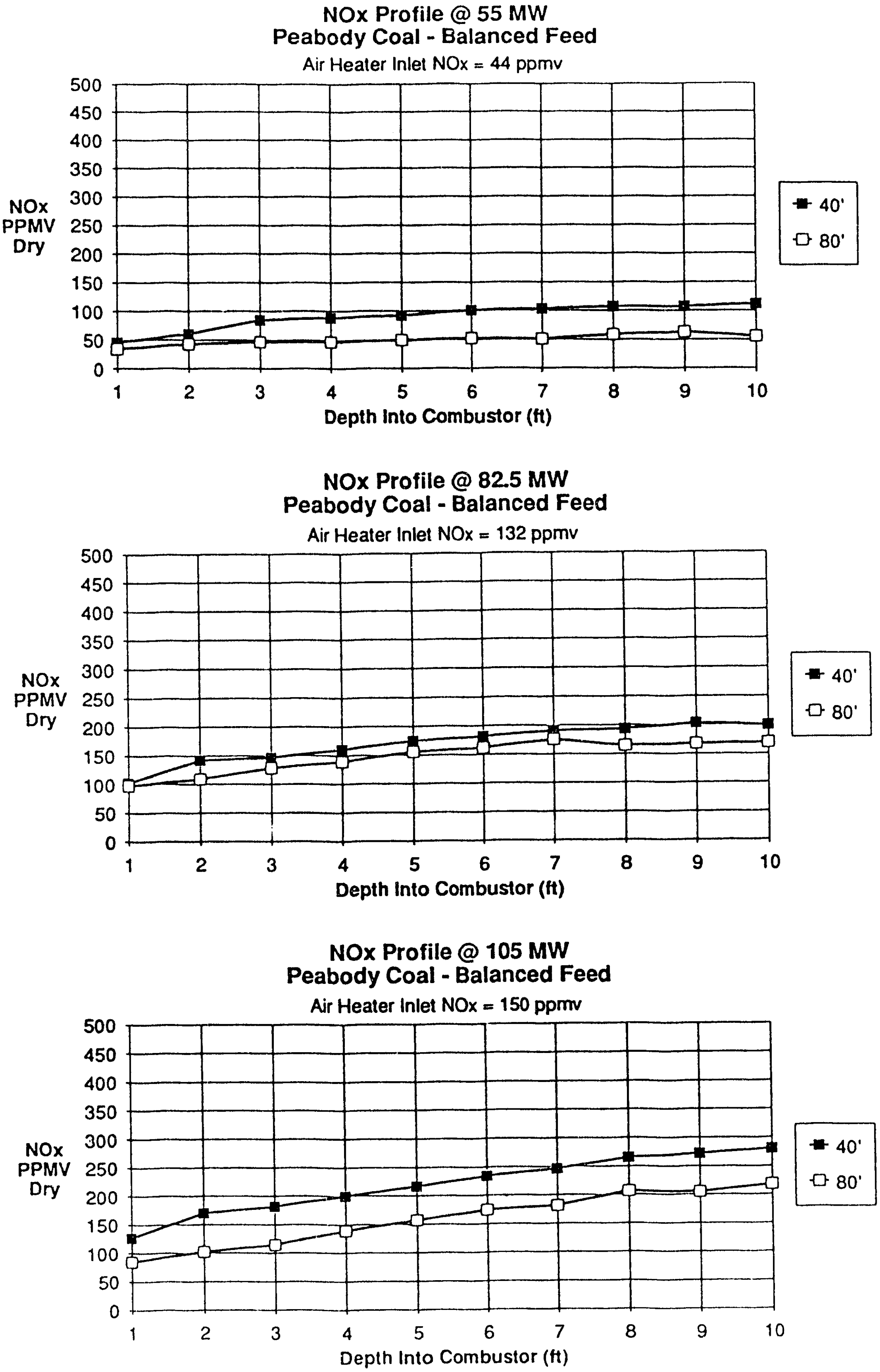
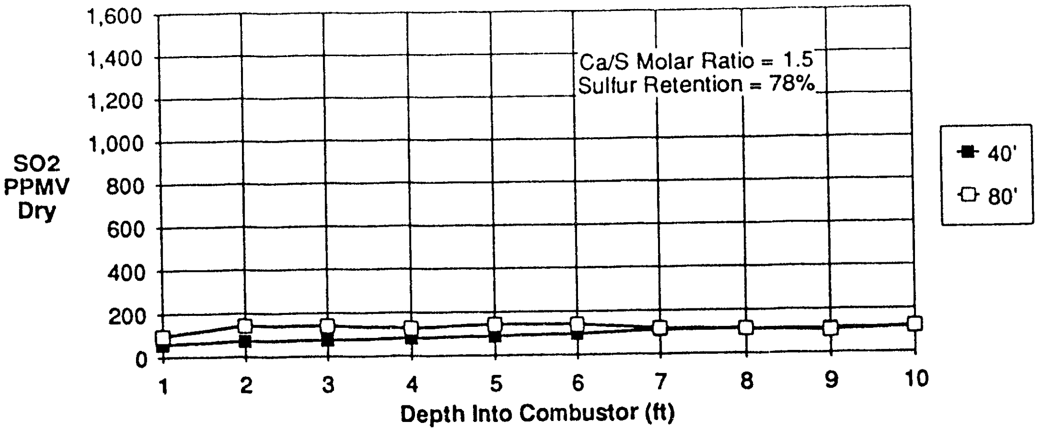
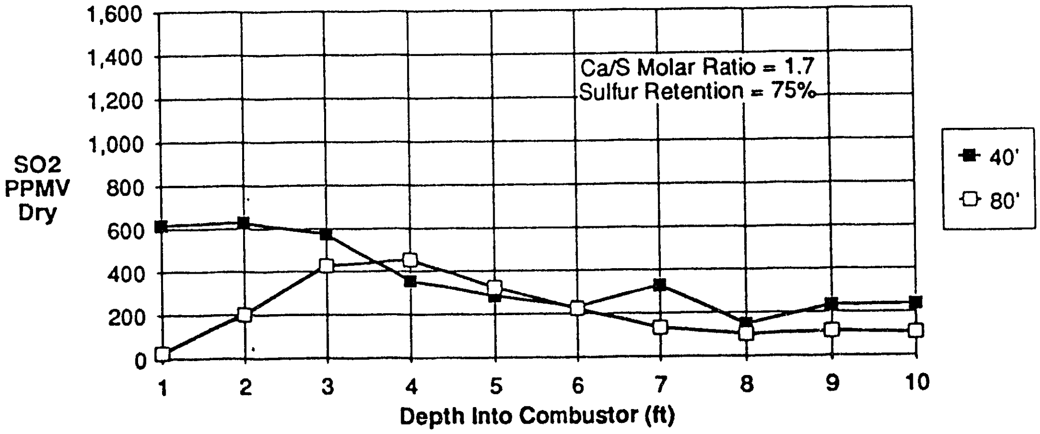


Figure 8-4. NO_x traverses for Peabody coal at three loads.

SO2 Profile @ 55 MW
Peabody Coal - Balanced Feed
Air Heater Inlet SO2 = 150 ppmv



SO2 Profile @ 82.5 MW
Peabody Coal - Balanced Feed
Air Heater Inlet SO2 = 162 ppmv



SO2 Profile @ 105 MW
Peabody Coal - Balanced Feed
Air Heater Inlet SO2 = 188 ppmv

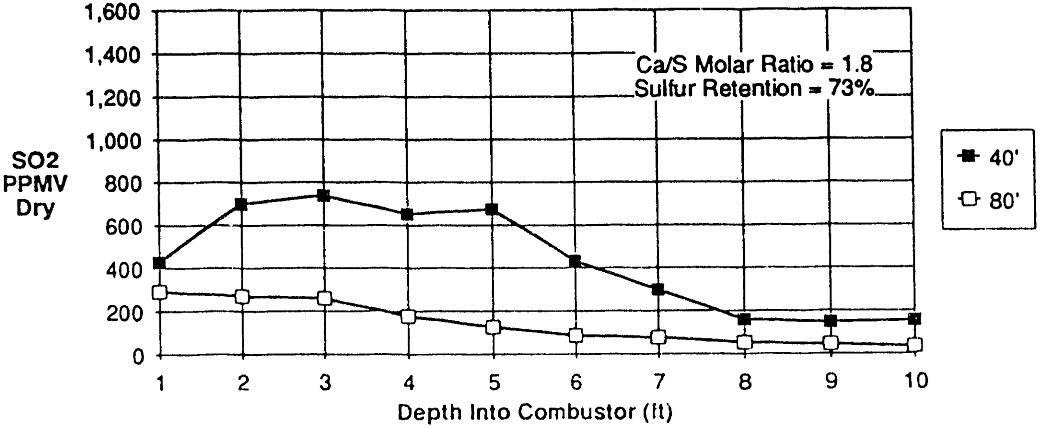


Figure 8-5. SO_2 traverses for Peabody coal at three loads.

The O_2 profiles shown in Figure 8-2 are relatively flat. The 55 MWe traverses indicate that there is a considerable amount of combustion occurring between the 40 and 80 ft traverse points, as evidenced by the decrease in O_2 between these readings. The 82 and 105 MWe traverses seem to indicate that there is little if any combustion occurring between the two traverse planes near the center of the boiler, as evidenced by the fact that the oxygen is not changing. At the walls there is still oxygen being consumed.

The CO profiles, shown in Figure 8-3, show little difference for the 55 and 105 MWe traverses. However the 82.5 MWe traverse shows rather large concentrations of CO near the walls at the 40 ft location. At the 80 ft traverse, the CO levels have been reduced considerably. Note that the air heater inlet values show a trend of increasing CO with decreasing load. This trend is most likely due to the lower furnace temperatures at the lower loads.

The NO_x profiles, shown in Figure 8-4, show a general trend of increasing values towards the center of the furnace. There is clear evidence of decreasing NO_x with height in the combustor. Note also that there is little difference between the 80 ft values and the air heater inlet value.

The SO_2 profiles, shown in Figure 8-5, are relatively flat at 55 MWe with little change between the traverse planes and the air heater inlet. At 82.5 and 105 MWe the trend is for increased SO_2 near the wall. These traverses indicate that, for 82.5 and 105 MWe, SO_2 is being released high up in the combustor and near the wall. This observation is corroborated by the O_2 profiles that indicate combustion occurring between the two traverse planes. Also note that the Ca/S ratio increased with increasing load. This may have been due to the higher bed temperatures, or it may have been due to the release of SO_2 higher in the combustor. Note also that there is evidence of some sulfur capture occurring between the 80 ft elevation and the air heater inlet.

8.3.2 Effect of Coal Type

Figures 8-6 through 8-9 show a comparison of traverses for Peabody and Salt Creek coals at half load for O_2, CO, NO_x, and SO_2, respectively. Also shown on the traverses are the values obtained at the air heater inlet during the traverses. These plots are shown to allow comparison of the gas traverses for the two fuels. The Peabody profiles are the same ones shown in Figures 8-2 through 8-5.

Table 8-8 shows the composition and size distribution for the coals used during these tests. The Salt Creek coal appears to have about 8% more fines (<600 microns). Furthermore, the

Table 8-8. Fuel Analyses for Traverse Tests

Test No Coal Gross Load MW	A07 Peabody 55	A08 Peabody 105	P39 Salt Creek 55
HHV (Btu/lb)	10,520	10,936	10,691
Proximate Analysis			
Total Moisture (%)	5.20	5.88	9.82
Voaltiles (%)	28.87	29.47	32.62
Fixed Carbon (%)	43.71	48.12	43.17
Ash (%)	22.22	16.53	14.38
Ultimate Analysis			
Carbon	59.28	63.77	61.41
Hydrogen	3.46	3.45	3.47
Oxygen	8.13	8.84	9.24
Nitrogen	0.93	0.81	1.13
Sulfur	0.79	0.72	0.54
Ash	22.22	16.53	14.38
Size Distribution % less Than			
19,000	100.00	100.00	100.00
12,500	92.40	93.15	100.00
6,300	79.15	82.25	93.05
4,750	71.75	75.65	86.85
3,350	62.85	64.60	77.65
2,360	54.30	53.90	68.10
1,700	45.50	43.35	57.65
1,180	36.95	34.55	47.60
850	29.95	27.55	38.90
600	24.60	22.55	31.80
300	15.30	14.10	18.95
150	8.00	8.05	10.35
106	3.30	4.85	4.21

ratio of oxygen to fixed carbon is slightly higher for Salt Creek coal. The ratio of oxygen to fixed carbon (O_2/FC) has been found to be indicative of the reactivity of the char. Based on the O_2/FC ratios, Salt Creek coal is about 14% more reactive than Peabody coal. Salt Creek coal also has slightly higher volatiles and nitrogen contents than Peabody coal.

The O_2 profiles are shown in Figure 8-6. For the 55 MWe traverses, the shape of the two profiles are similar. However, the Salt Creek coal shows little evidence of combustion between the 40 and 80 ft traverse planes. This would indicate that Salt Creek coal burns lower in the furnace. This could be due to the higher reactivity and higher volatile content of Salt Creek coal.

CO profiles are shown in Figure 8-7. These traverses are quite similar, and show no noticeable trends. The Peabody coal shows a trend of CO reduction between the 40 and 80 ft elevations. Salt Creek coal shows no similar trends, as the readings at 40 ft are almost equal to the 80 ft readings. In both cases, the CO readings at the 40 ft elevation are lower than the 80 ft elevation readings, indicating that CO is being burned above the 80 ft elevation. This probably occurs in the cyclone where turbulence mixes the oxygen with the CO.

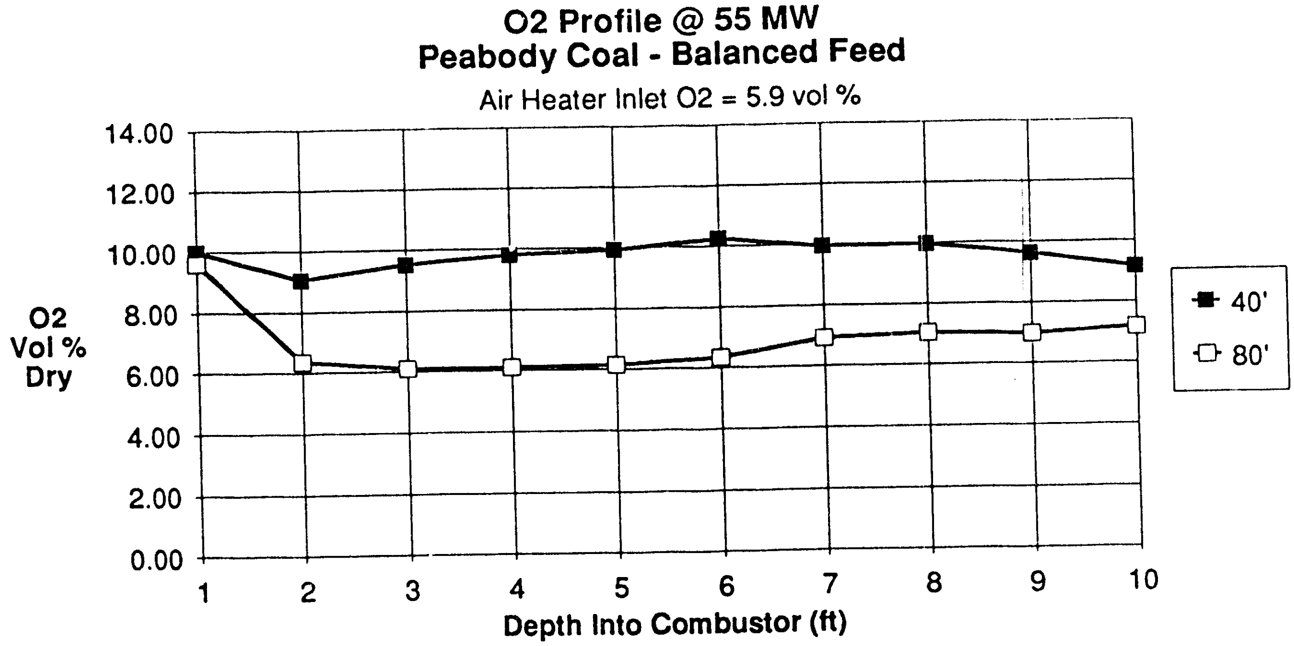
Figure 8-8 shows a comparison of the NO_x traverses for Peabody and Salt Creek coals. The NO_x readings for Salt Creek coal are consistently higher than the Peabody coal readings. This probably reflects the higher fuel nitrogen in the Salt Creek coal. In all cases the NO_x levels increase towards the center of the furnace. Furthermore, there is considerable disappearance of NO_x between the 80 ft elevation and the air heater.

Figure 8-9 shows the SO_2 profiles for both coals. The traverse profiles are quite similar, being relatively flat and near the value measured at the air heater.

8.3.3 Effect of Fuel Feed Location

Another series of tests were performed to study the effect of fuel feed location on the gas traverses. These tests were conducted at 55 MWe with Salt Creek coal. Three fuel feed configurations were examined during the reporting period. The three configurations are:

- balanced coal, with 33% coal feed to all three feeders.
- front wall feed, with 50% of the coal feed to each of the front wall feeders.
- loop seal feed, with 100% coal feed to the loop seal coal feeder.



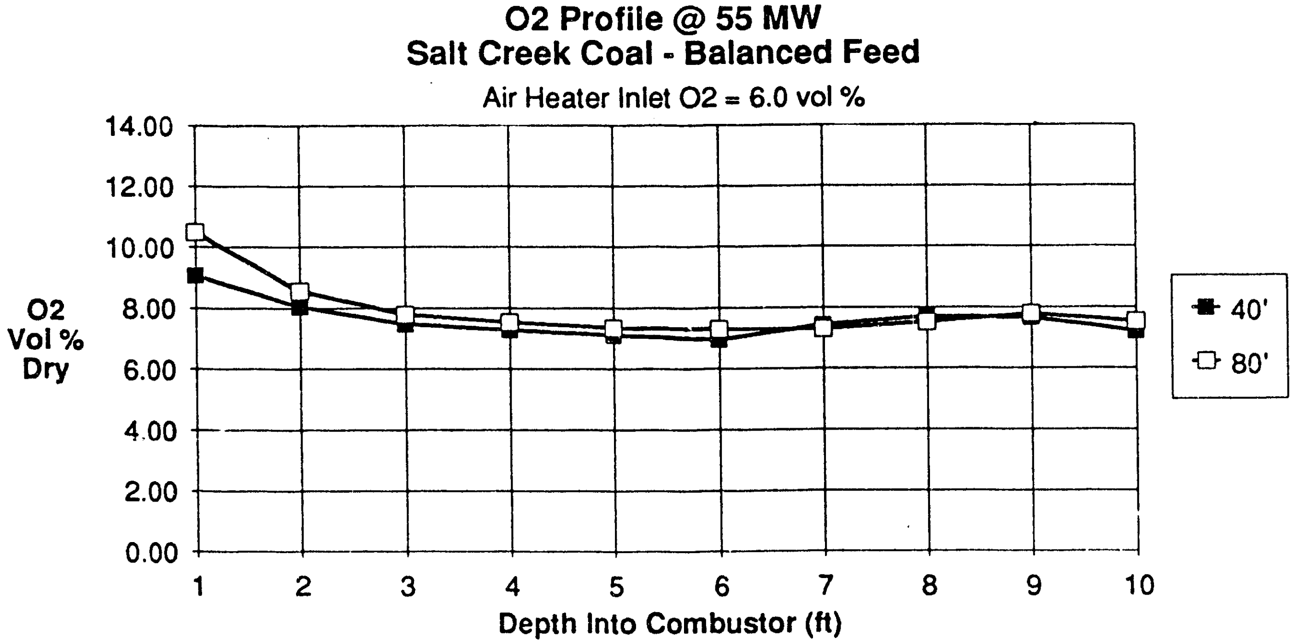
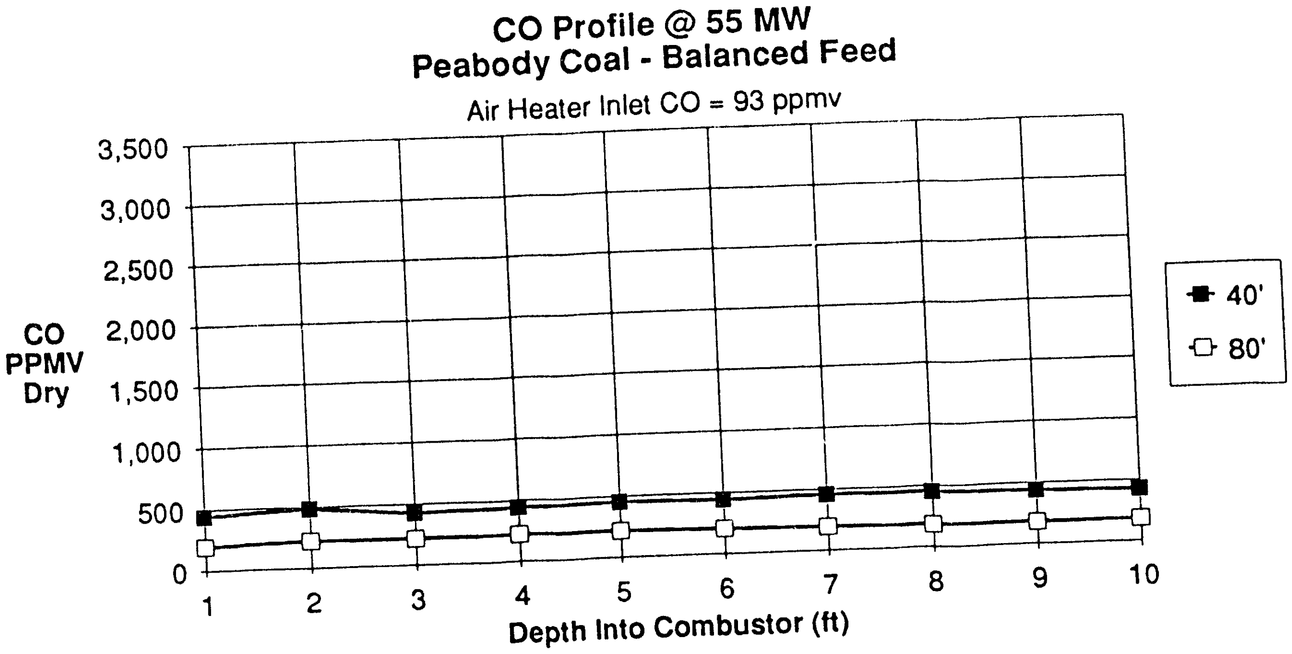


Figure 8-6. O_2 traverses for Salt Creek and Peabody coal.



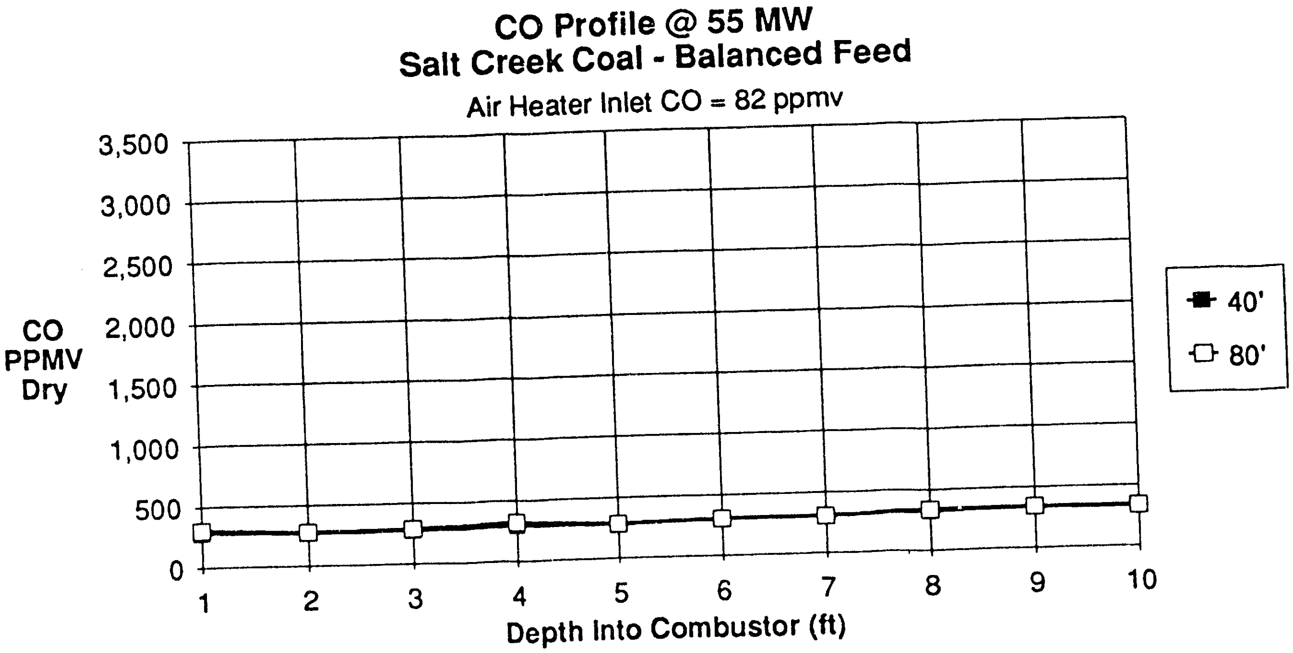
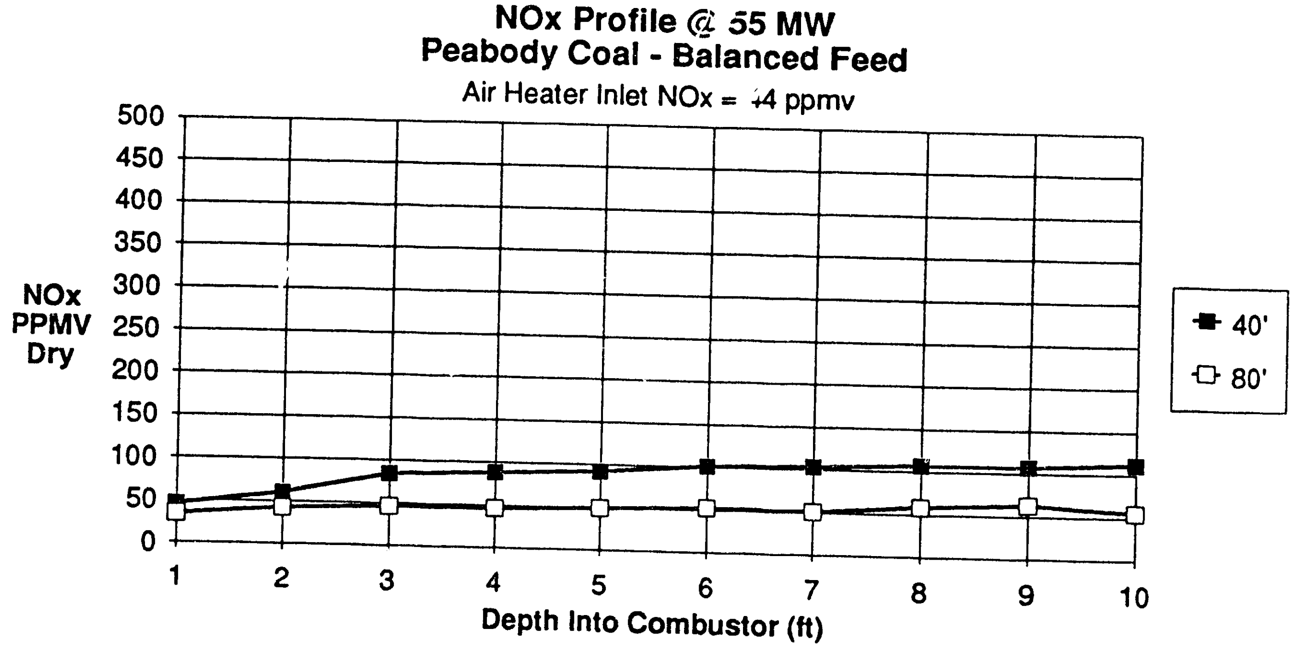


Figure 8-7. CO traverses for Salt Creek and Peabody coal.


NOx Profile @ 55 MW
Peabody Coal - Balanced Feed
Air Heater Inlet NOx = 44 ppmv

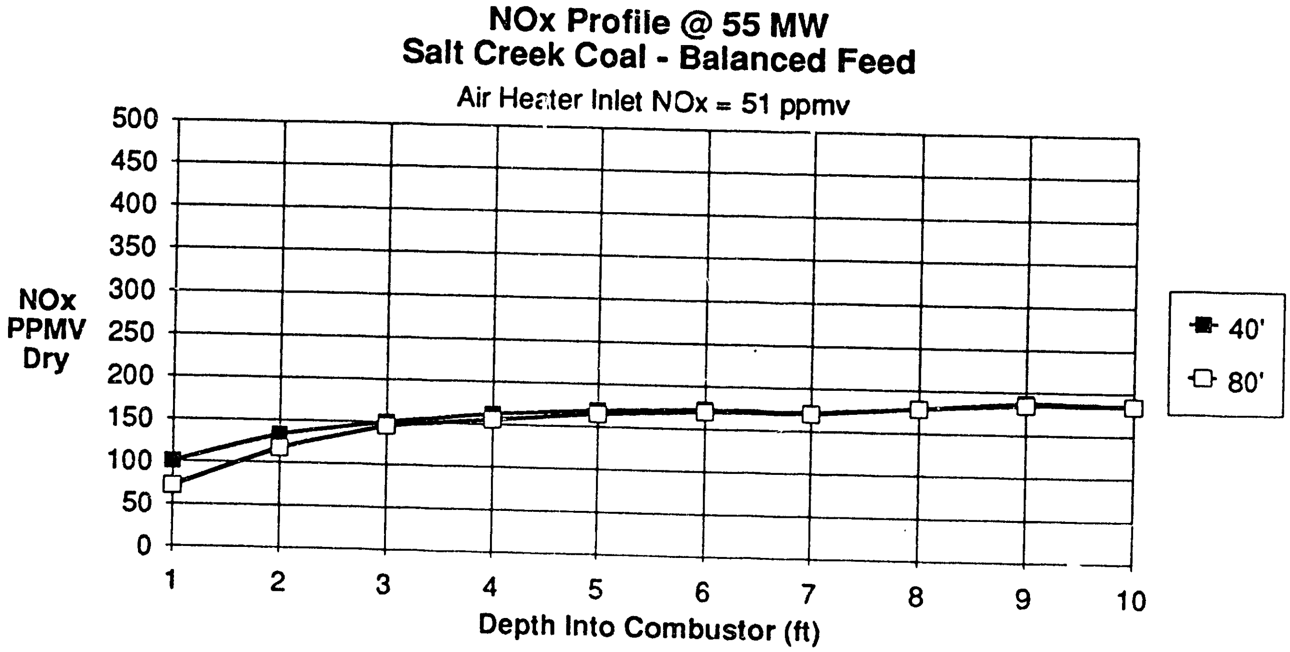
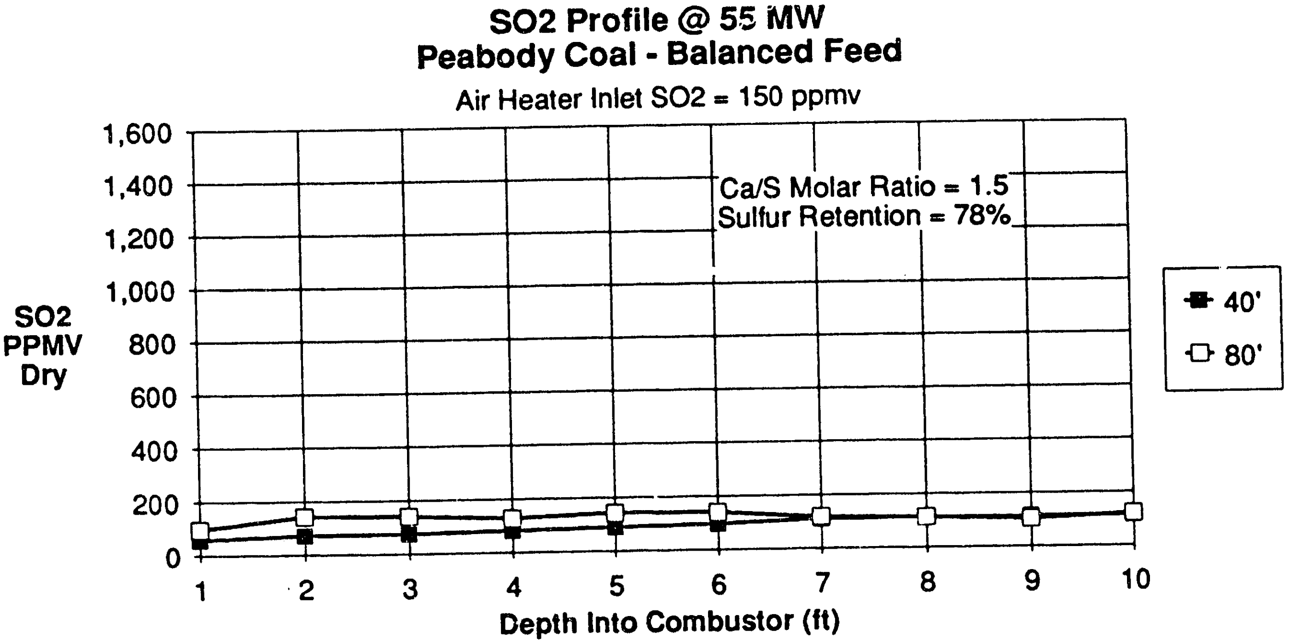

NOx Profile @ 55 MW
Salt Creek Coal - Balanced Feed
Air Heater Inlet NOx = 51 ppmv

Figure 8-8. NO_x traverses for Salt Creek and Peabody coal.



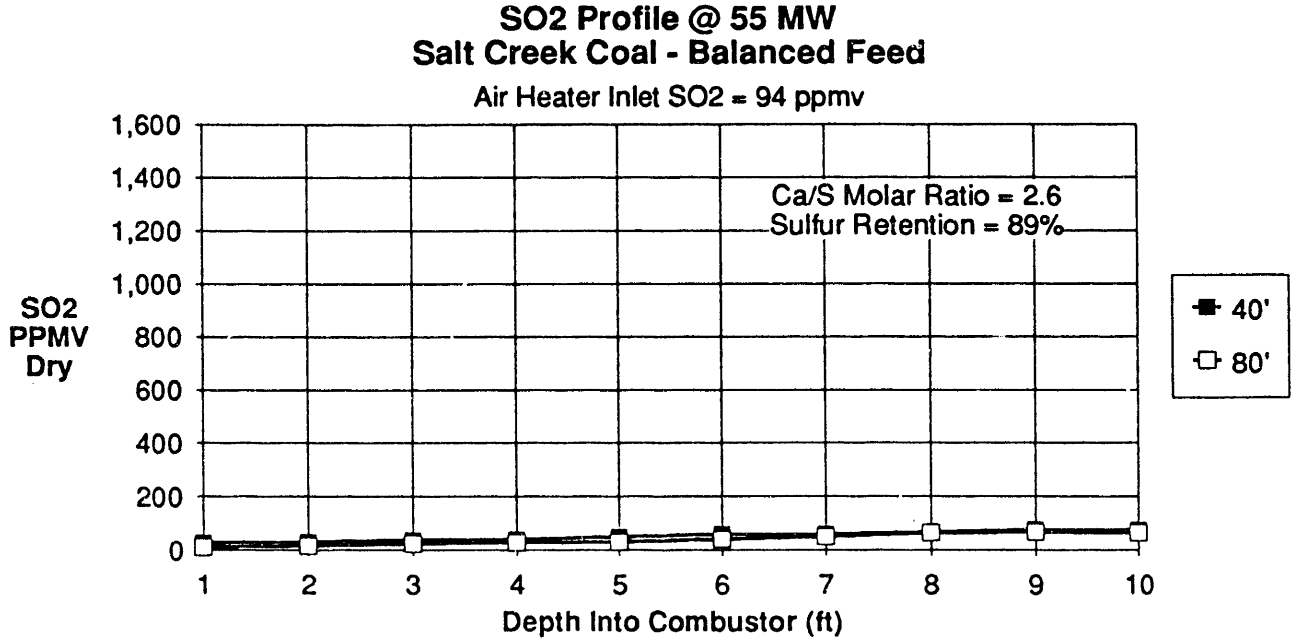


Figure 8-9. SO_2 traverses for Salt Creek and Peabody coal.

Figure 8-10 shows the O_2 profiles for the three feeder configurations. While the profile for the balanced feed is relatively flat, the two extreme feed conditions show opposite trends. The front wall feed configuration shows the oxygen concentration increasing towards the center of the furnace. The loop seal feeder configuration shows oxygen concentrations increasing towards the wall. These curves indicate that coal fed through the loop seal is forced towards the center of the furnace while coal fed at the front wall feeders apparently burns more towards the wall.

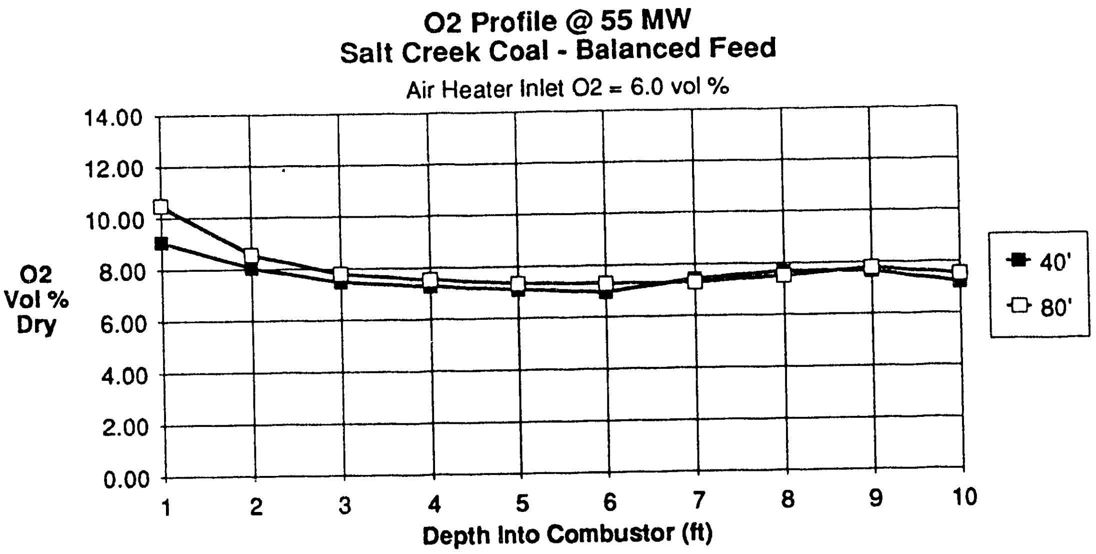
Figure 8-11 shows the CO traverses for the three feed configurations. As with the oxygen, the CO profiles indicate that the loop seal coal feed is burning towards the center of the furnace while the front wall feed burns towards the wall. Note: despite the extremely high CO levels at the 80 ft traverse plane, the CO at the air heater was 86 ppmv for the front wall test and 72 ppmv for the loop seal test. This again indicates that CO is being burned downstream of the 80 ft plane, probably in the cyclones.

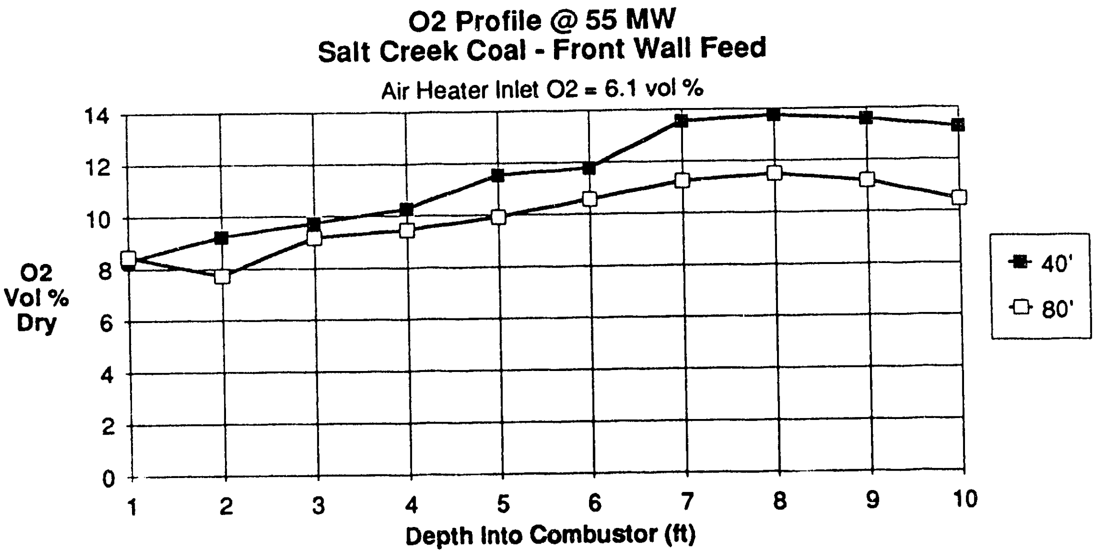
Figure 8-12 shows the NO_x traverses for the three feed configurations. The balanced feed traverses showed only slightly higher NO_x readings. The loop seal feed configuration appeared to have only a slight impact on NOx at the air heater inlet.

Figure 8-13 shows the SO_2 traverses for the three feed configurations. The traverses indicate that the loop seal feed configuration had higher SO_2 readings towards the center of the furnace than the other two configurations. This may be due to the lower O_2 readings in this region (reference figure 8-10). However, the differences are small, and are not reflected at the air heater inlet.

8.4 FUTURE TESTING

The data taken during this reporting period is not complete. Traverses remain to be taken with Salt Creek coal at 75% and 100% loads. Tests are also planned to study the effect of feeder location at other loads. These tests are planned to be conducted during 1990. Therefore, no attempt will be made to interpret the results of the FGAS traverses until all of the traverses have been completed.


O2 Profile @ 55 MW
Salt Creek Coal - Balanced Feed
Air Heater Inlet O2 = 6.0 vol %


O2 Profile @ 55 MW
Salt Creek Coal - Front Wall Feed
Air Heater Inlet O2 = 6.1 vol %

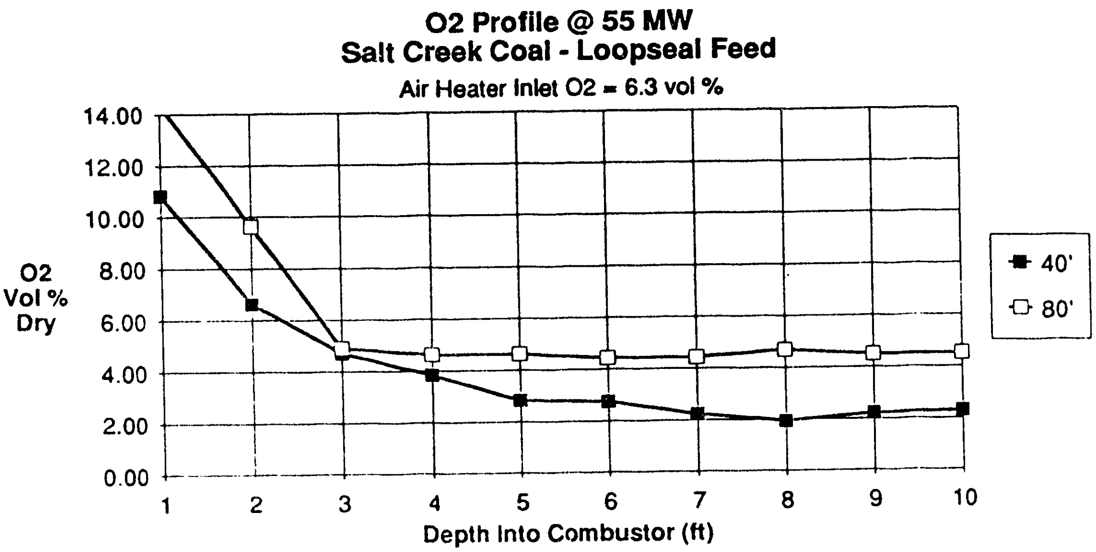
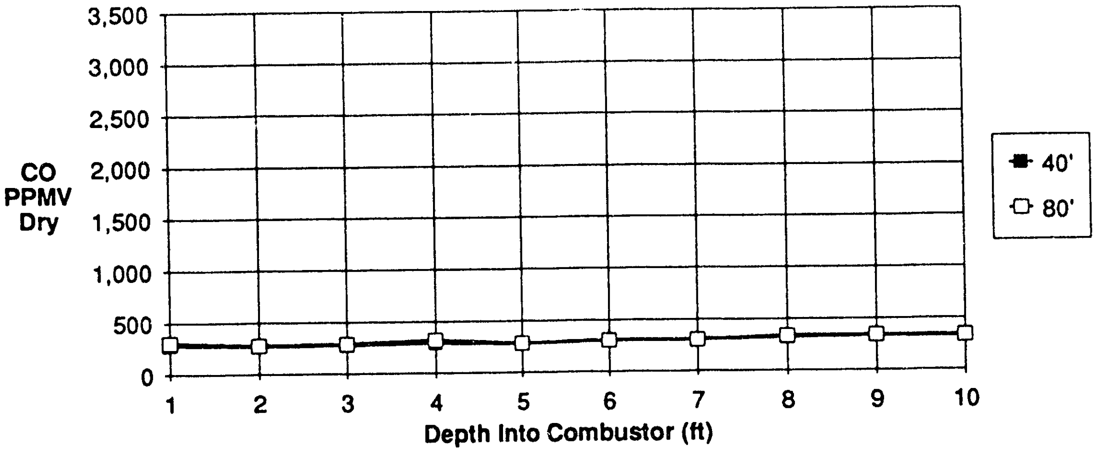
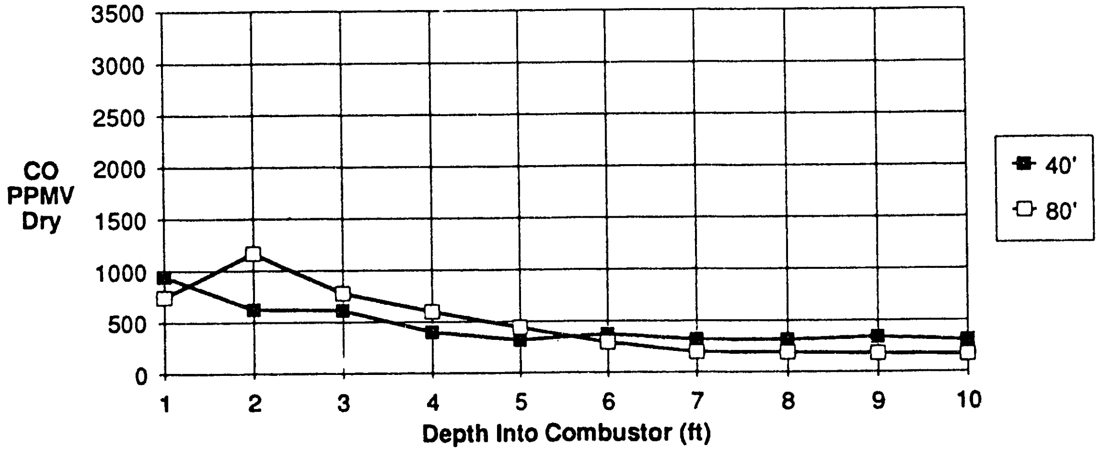

O2 Profile @ 55 MW
Salt Creek Coal - Loopseal Feed
Air Heater Inlet O2 = 6.3 vol %

Figure 8-10. Effect of coal feed configuration on O_2 traverses for Salt Creek Coal at 55 MW.

CO Profile @ 55 MW
Salt Creek Coal - Balanced Feed
Air Heater Inlet CO = 82 ppmv



CO Profile @ 55 MW
Salt Creek Coal - Front Wall Feed
Air Heater Inlet CO = 86 ppmv



CO Profile @ 55 MW
Salt Creek Coal - Loopseal Feed
Air Heater Inlet CO = 72 ppmv

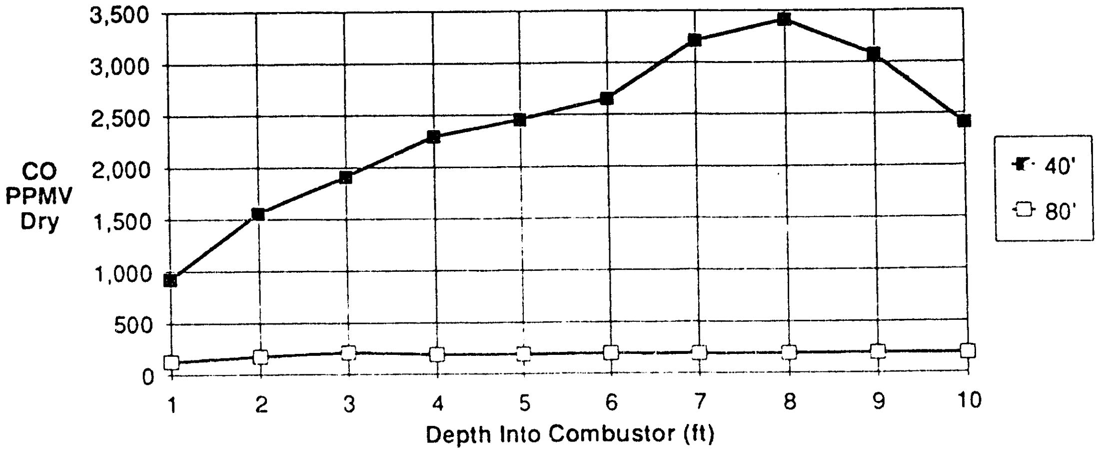
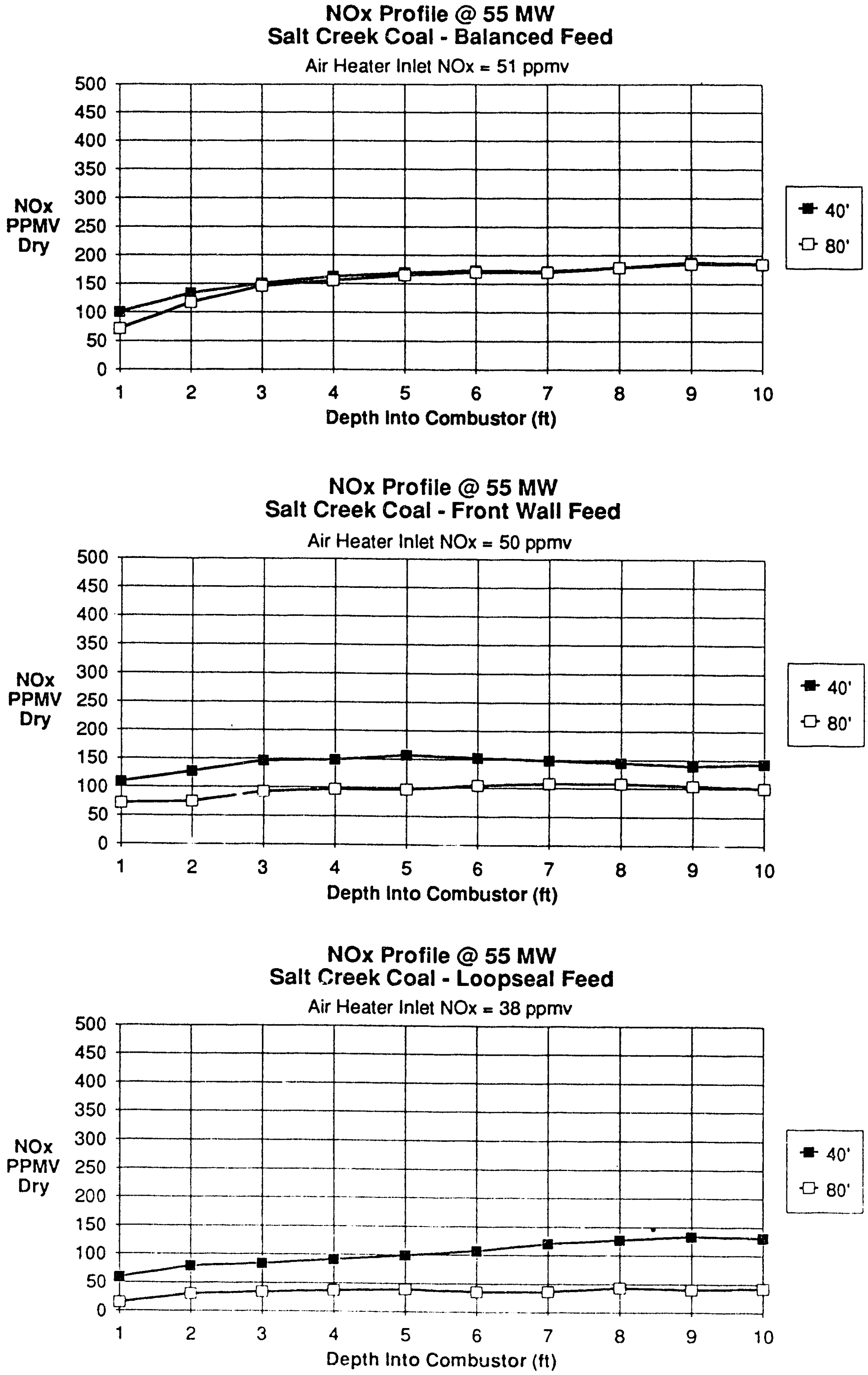


Figure 8-11. Effect of coal feed configuration on CO traverses for Salt Creek Coal at 55 MW.

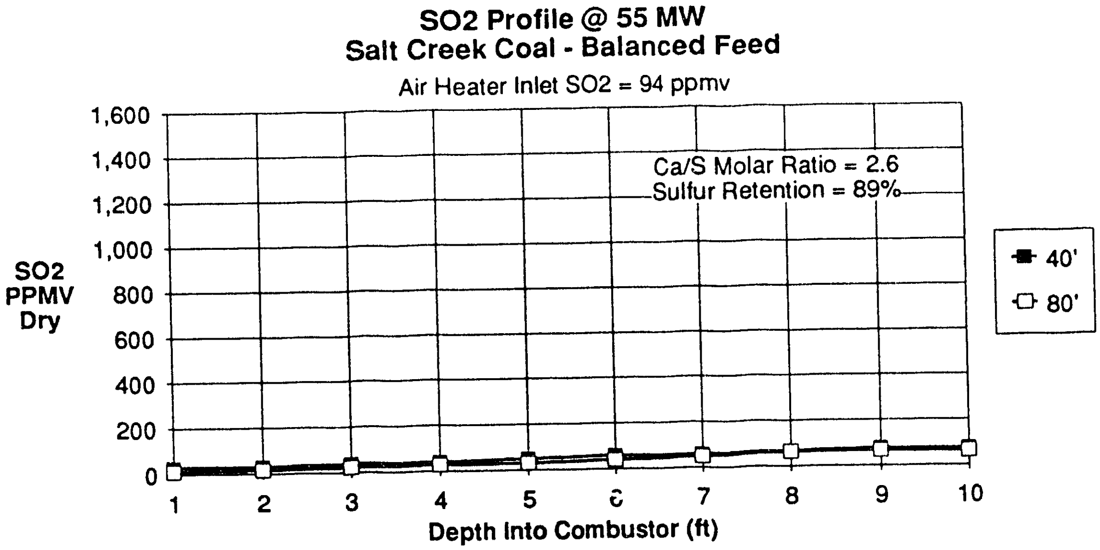


NOx Profile @ 55 MW
Salt Creek Coal - Balanced Feed
Air Heater Inlet NOx = 51 ppmv

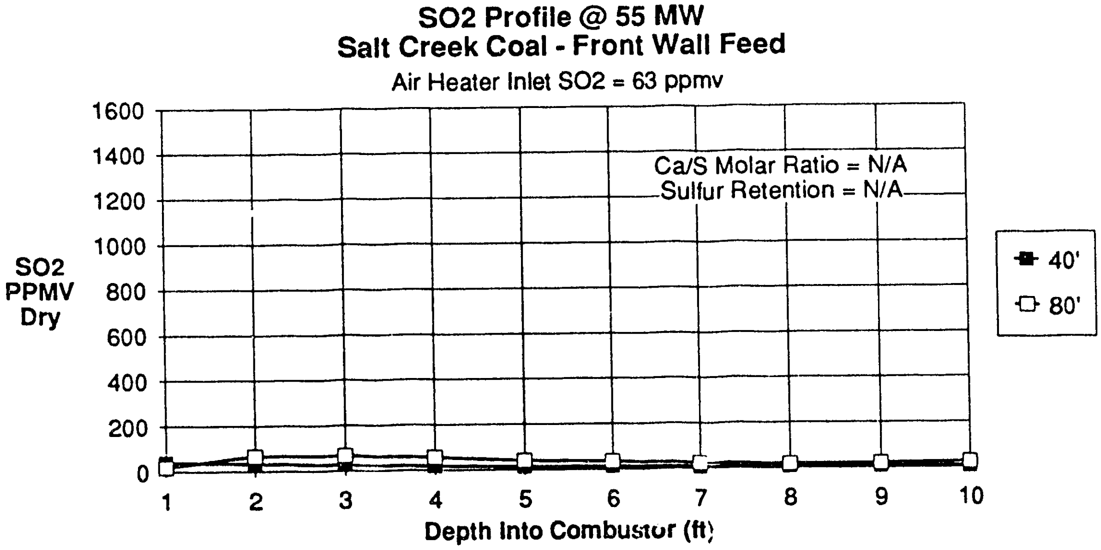
NOx Profile @ 55 MW
Salt Creek Coal - Front Wall Feed
Air Heater Inlet NOx = 50 ppmv

NOx Profile @ 55 MW
Salt Creek Coal - Loopseal Feed
Air Heater Inlet NOx = 38 ppmv

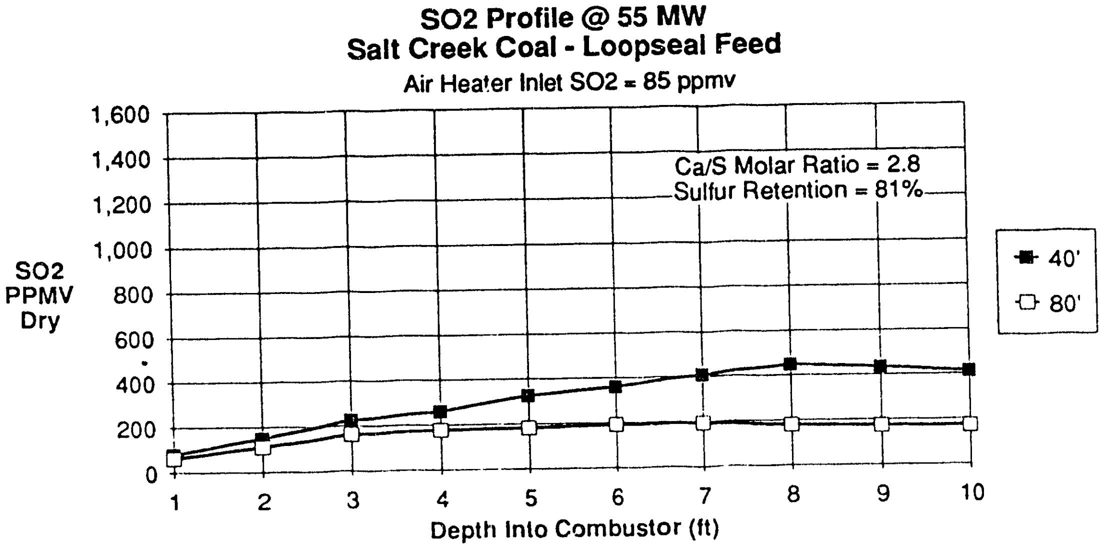
Figure 8-12. Effect of coal feed configuration on NO_X traverses for Salt Creek Coal at 55 MW.



SO2 Profile @ 55 MW
Salt Creek Coal - Balanced Feed
Air Heater Inlet SO2 = 94 ppmv



SO2 Profile @ 55 MW
Salt Creek Coal - Front Wall Feed
Air Heater Inlet SO2 = 63 ppmv



SO2 Profile @ 55 MW
Salt Creek Coal - Loopseal Feed
Air Heater Inlet SO2 = 85 ppmv

Figure 8-13. Effect of coal feed configuration on SO2 traverses for Salt Creek Coal at 55 MW.

Section 9

HEAT TRANSFER

9.1 BOILER HEAT ABSORPTION PATTERNS

At a given set of firing conditions (i.e. load, excess air, etc.) the bed temperature in a combustor is an indication of the amount of heat transfer taking place between the bed and the walls of the combustor. A heat balance taken around the Nucla boiler shows that approximately 65% of the heat released in the furnace is absorbed by the walls and superheater II within the furnace. The remainder of the heat is removed from the furnace by the hot flue gas and is transferred to the convection pass surfaces. Table 9-1 and 9-2 show the actual distribution of heat absorption for Salt Creek and Peabody coals, respectively, at various loads. Also shown on these tables are the load, excess air, and average bed temperatures for sides A and B of the boiler. The percentage of heat absorption values are based on the following measurements:

- Steam/water flow rate through the boiler component
- Boiler component inlet and outlet steam/water temperatures
- Boiler component inlet and outlet steam/water pressures

Flow rates were directly measured except for main steam flow which was calculated based on feed water, total attemperator, and blowdown flows. Fluid temperatures at the inlet and outlet of each section were also directly measured. Direct fluid pressures were only available at the steam drum inlet, the drum, and the outlet of superheater III. All other pressures were estimated based on design pressure drops.

The data show that the percentage of heat absorption in the furnace is relatively constant with load. There also appears to be little difference in the heat absorption of the furnace when firing the different fuels. In general, the heat absorption in the furnace increases slightly (0.5 to 1%) with load. This is most likely due to the fact that as the load is increased, the excess air is decreased.

Tables 9-1 and 9-2 also show a recurring problem experienced at Nucla, namely that the bed temperature in combustor B is typically higher than the temperature in combustor A, except at low loads. Attempts to discover the cause of this difference are discussed in the next section.

Table 9-1. Boiler Heat Absorption for Salt Creek Coal

Test No.	SD1	P30	P31	P49	P50	P21	P52	P39
Load MWe	105	55	82	98	98	55	55	55
Excess Air %	22.5	36.4	21.9	19.6	19.6	42.0	41.8	39.0
A Bed Temp °F	1579	1500	1562	1660	1641	1552	1551	1559
B Bed Temp °F	1550	1556	1587	1671	1677	1540	1525	1569
Furnace % of Heat Absorbed								
Combustor	56.5	58.7	58.1	55.5	56.2	56.8	56.7	57.1
SH2	11.5	10.0	11.0	11.0	11.1	9.8	9.4	9.9
Total	68.0	68.7	69.1	66.5	67.3	66.6	66.1	67.0
Backpass % of Heat Absorbed								
SH1	13.9	12.1	12.9	14.1	14.0	13.8	14.1	13.5
SH3	4.6	3.3	3.6	4.9	4.8	3.7	3.8	3.9
Eco & Hanger	10.6	12.4	11.1	11.0	10.7	12.4	12.5	12.2
Conv Cage	2.9	3.5	3.3	3.5	3.2	3.5	3.5	3.4
Total	32.0	31.3	30.9	33.5	32.7	33.4	33.9	33.0

Table 9-2. Boiler Heat Absorption for Peabody Coal

Test No.	A01	A02	A03	A04	A05	A06	A07	A08
Load MWe	100	104	104	82	82	82	55	104
Excess Air %	20.9	19.4	19.6	24.5	25.4	24.4	38.5	19.0
A Bed Temp °F	1593	1629	1593	1632	1613	1617	1533	1649
B Bed Temp °F	1671	1675	1675	1650	1650	1648	1535	1650
Furnace % of Heat Absorbed								
Combustor	55.2	55.6	55.9	55.5	55.3	55.8	57.0	55.7
SH2	11.4	11.4	11.3	10.8	10.8	10.9	9.9	11.5
Total	66.6	67.0	67.2	66.3	66.1	66.7	66.9	67.2
Backpass % of Heat Absorbed								
SH1	14.2	14.2	14.3	14.2	14.4	14.3	13.1	14.3
SH3	4.9	4.8	4.7	4.6	4.5	4.5	3.7	4.7
Eco & Hanger	11.0	11.0	10.6	11.2	11.5	10.9	12.3	10.6
Conv Cage	3.3	3.0	3.2	3.7	3.5	3.6	4.0	3.2
Total	33.4	33.0	32.8	33.7	33.9	33.3	33.1	32.8

9.2 BED TEMPERATURE ANALYSIS

Problems controlling the temperatures in the two combustors were related to a basic lack of understanding of the processes that control the bed temperature in the Nucla CFB. For example, the bed temperature is found to fluctuate daily, with excursions as large as ± 50°F under apparently similar operating conditions. Furthermore, the temperature differential between combustors A and B can be as large as 100°F while the two combustors are operating under apparently similar operating conditions. This is evidenced by data taken on March 9, 1989:

	A-Side	B-Side
Load, MW	60.6	60.6
Bed Pressure, in. wg.	23.1	24.1
O_2 % in flue gas	4.98	4.97
Mean Bed Temperature, °F	1473	1527

The mean bed temperature is the average of all temperature measurements in the region covered by the refractory (up to 144 inches above the air distributor). Note that, in spite of the higher bed pressure in combustor B, the temperature of combustor B was almost 50°F higher than the temperature in combustor A.

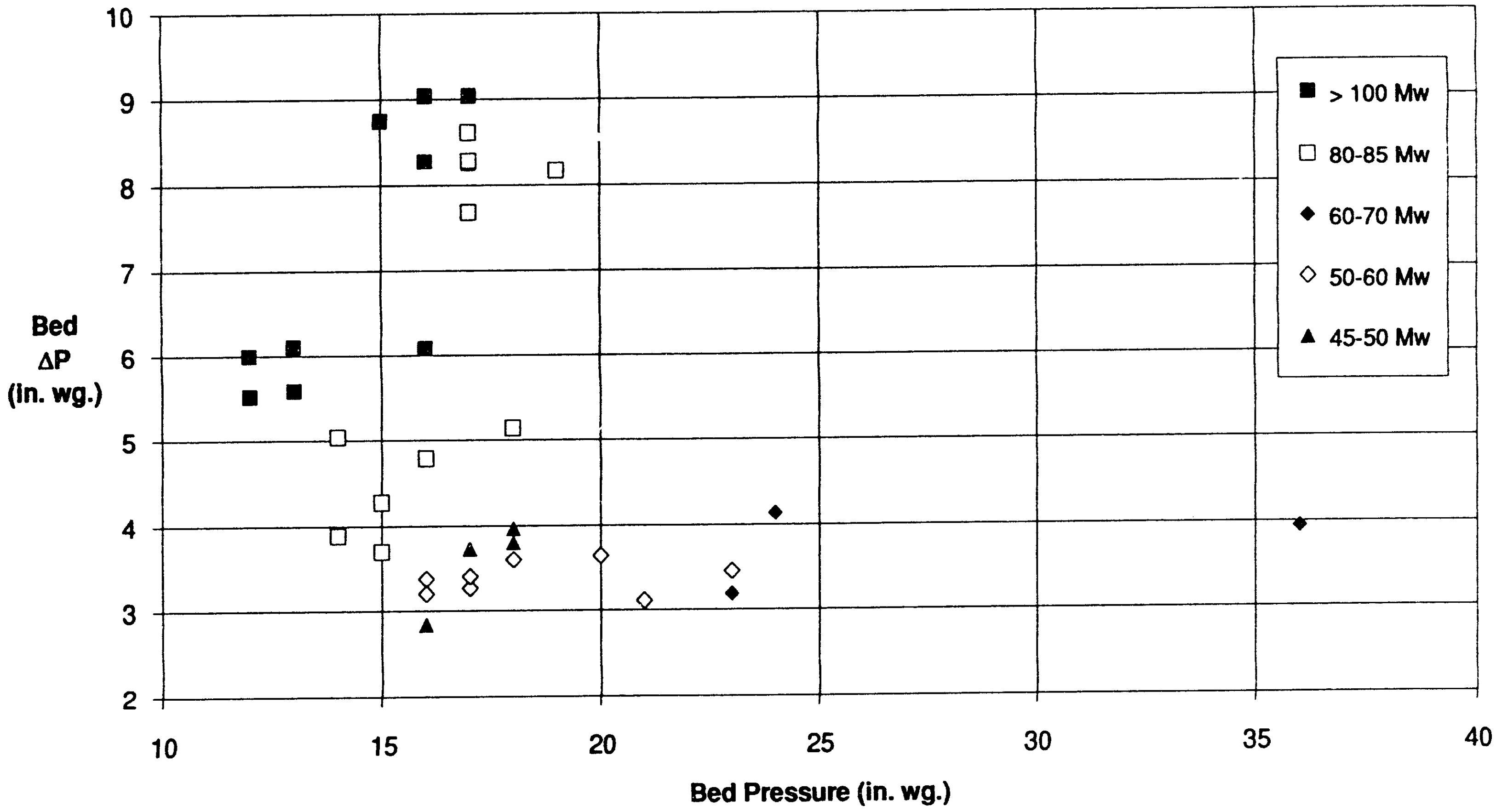
To better understand this phenomenon, an investigation was performed to determine the operating parameters that have the greatest impact on the bed temperature. Data from combustor B was studied for several steady state operating periods between March and June 1989. Combustor B was used because this combustor has several pressure taps spaced approximately 10 feet apart up the side of the combustor, enabling measurements of solids loadings in the upper region of the combustor. Table 9-3 shows the averaged data that was analyzed in this investigation. The bed pressure shown in Table 9-3 is the static pressure measured 16 inches above the air distributor. The bed ΔP shown in Table 9-3 is the pressure drop between the pressure tap located just above the secondary air ports (12 ft above the air distributor) and the pressure tap near the top of the combustor.

The bed ΔP above the secondary air ports was found to behave quite differently than the bed pressure. Figure 9-1 shows a plot of the bed ΔP as a function of the bed pressure for various loads. This figure shows that at reduced loads, the bed pressure has little influence over the bed ΔP in the upper part of the combustor. Furthermore, at the higher loads, there is still quite a bit of variation that can exist in the upper combustor ΔP at a given bed pressure. This is because changes in the particle size of the feed stock will result in more or less bed material in the elutriable size

Table 9-3. Bed Temperature Correlation for Peabody Coal

Date	Time	Bed Temp. B (°F)	Load (MW)	O2 (%)	ΔP (in. wg.)	Bed Pressure (in.wg.)	Calc Bed Temp. B (°F)
3/7/89	8:00-12:00	1520	100.4	3.32	8.76	15	1542
3/7/89	12:00-18:00	1494	100.7	4.51	9.05	16	1498
3/8/89	9:00-10:00	1524	100.7	4.01	8.28	16	1528
3/8/89	10:00-14:00	1537	100.7	3.55	8.26	17	1544
3/8/89	16:00-20:00	1522	100.5	3.55	9.05	17	1528
3/6/89	8:00-12:00	1453	79.5	3.94	8.29	17	1470
3/10/89	16:30-17:30	1485	80.5	3.84	7.69	17	1489
3/6/89	12:00-15:00	1431	79.6	4.59	8.63	17	1446
3/6/89	15:00-19:00	1425	79.5	5.48	8.17	19	1433
3/9/89	18:00-20:00	1520	60.6	4.97	4.14	24	1492
3/29/89	0:00-23:59	1420	45.4	7.37	2.85	16	1436
3/30/89	0:00-23:59	1505	56.4	4.35	3.64	20	1513
4/1/89	0:00-2:00	1531	61.0	3.70	3.95	36	1539
4/1/89	12:00-14:00	1568	61.0	3.46	3.18	23	1587
4/21/89	1:00-15:00	1643	105.2	3.27	6.09	16	1622
4/23/89	1:00-6:00	1644	73.0	3.29	3.16	20	1644
5/24/89	19:00-04:00	1483	54.9	5.73	3.20	16	1494
5/25/89	8:00-20:00	1505	54.9	5.10	3.40	17	1498
5/26/89	9:00-16:30	1498	54.9	5.10	3.60	18	1488
5/28/89	14:00-16:00	1398	46.5	6.87	3.97	18	1396
5/28/89	2:00-4:00	1404	46.6	6.82	3.73	17	1407
5/58/89	0:00-23:59	1394	46.5	6.90	3.80	18	1403
6/1/89	2:00-8:00	1482	52.8	5.50	3.37	16	1480
6/3/89	16:00-20:00	1468	52.6	5.52	3.26	17	1485
6/5/89	14:00-20:00	1563	82.5	3.83	5.15	18	1567
6/6/89	16:00-21:00	1598	82.4	3.50	4.28	15	1612
6/7/89	13:00-20:00	1614	82.4	3.51	3.89	14	1630
6/8/89	0:00-4:00	1625	82.6	3.50	3.70	15	1640
6/9/89	0:00-8:00	1583	83.1	3.50	4.79	16	1594
6/11/89	0:00-6:00	1541	55.9	4.36	3.11	21	1538
6/12/89	5:00-9:00	1521	56.0	3.91	3.45	23	1534
6/14/89	6:00-16:00	1583	84.9	3.50	5.05	14	1590
6/15/89	6:00-16:00	1616	104.9	3.36	6.11	13	1617
6/17/89	10:00-17:00	1647	103.8	3.38	5.52	12	1633
6/18/89	0:00-6:00	1640	103.8	3.30	5.59	13	1634
6/19/89	10:00-17:00	1620	104.0	3.32	6.00	12	1620

Figure 9-1. Effect of Load and Bed Pressure on Bed ΔP



range. Only bed material in the size range between the elutriable size and the cyclone cut point can contribute to the upper combustor pressure drop. Material larger than the elutriable size will remain in a dense bed at the bottom of the combustor, contributing to the bed pressure, while not contributing to the upper combustor pressure drop.

Figure 9-2 shows the influence of the upper combustor pressure drop on the bed temperature for the various load ranges studied. This figure shows that the upper combustor ΔP can have a significant impact on the bed temperature. For example, at full load, a 3.5 inch change in the upper combustor ΔP results in an almost 150°F change in bed temperature.

To quantify the effects of the various operating parameters on the bed temperature, a correlation was developed of the form:

$$T = T_{Ref}\left(\frac{Load}{Load_{Ref}}\right)^{\alpha}\left(\frac{O_2}{O_{2Ref}}\right)^{\beta}\left(\frac{\Delta P}{\Delta P_{Ref}}\right)^{\gamma} \qquad (1)$$

Where: Load = Gross load in MWe
O_2 = Flue gas oxygen at economizer outlet, Vol%
ΔP = Upper combustor pressure drop, in wg.

Test A08 was chosen as the reference test. For this test T_{Ref} = 1620°F, $Load_{Ref}$ = 104 MWe, O_{2Ref} = 3.32 vol %, and ΔP_{Ref} = 6 in wg. The correlation yielded the following exponents:

$\alpha = 0.1697$

$\beta = -0.0823$

$\gamma = -0.1153$

Figure 9-3 shows the results of the correlation for the Peabody coal tests. The data in Figure 9-3 is also shown in the last column in Table 9-3. The standard deviation of the fit was 12°F, which indicates that 68% of the bed temperature measurements fell within ±12°F of the calculated value.

The above equation predicts that a 1.5 inch pressure differential in the upper combustor would cause a difference in bed temperatures of about 40°F. Because of the importance of the upper combustor pressure drop on the bed temperature, pressure taps were permanently installed in both combustors to measure this pressure differential. These pressure elements were installed between 12 and 75 feet above the air distributor plate on the rear water wall of both combustors. Pressure transmitters were connected to these taps, and the

Figure 9-2. Effect of Load and Upper Combustor ΔP
on Bed Temperatures

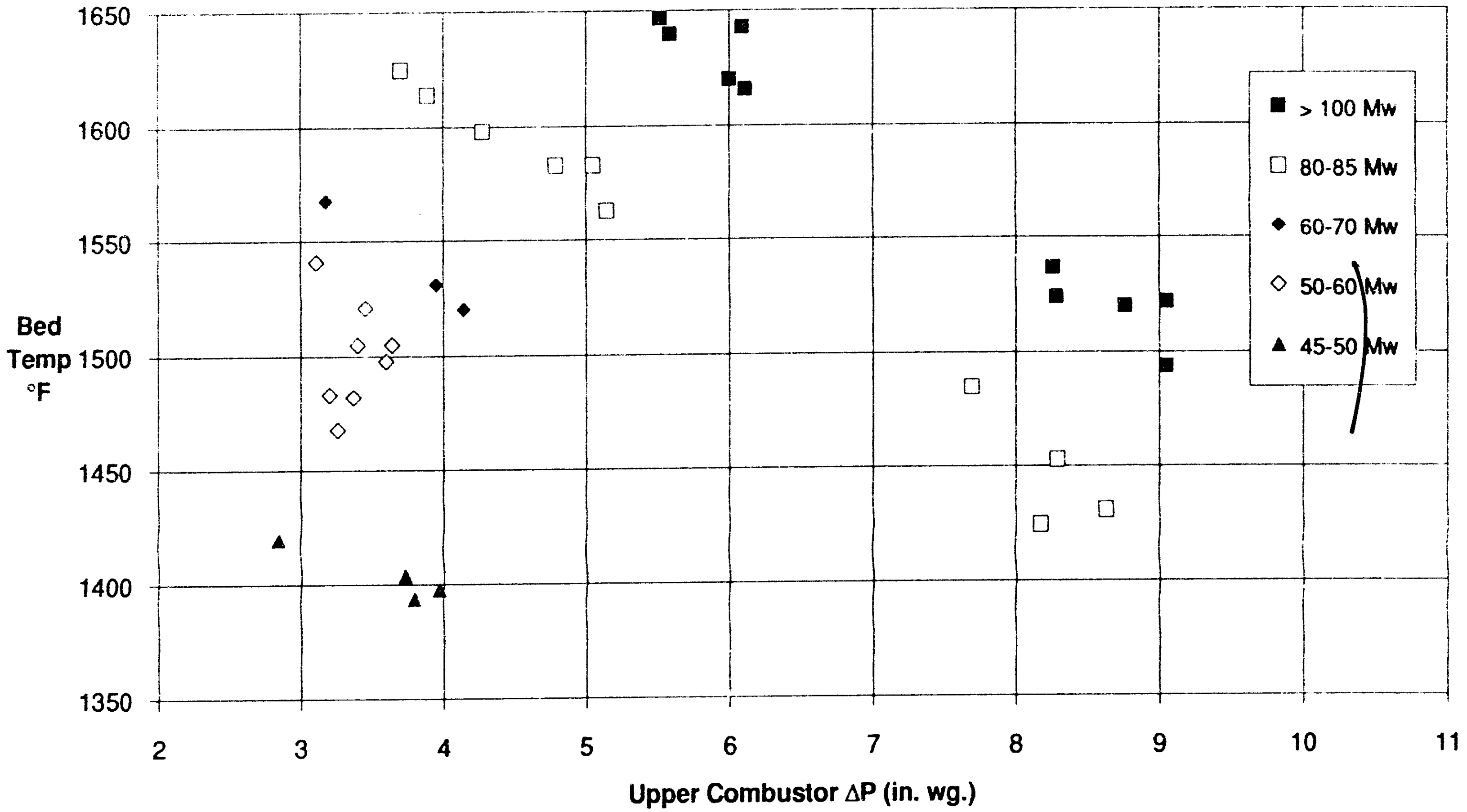
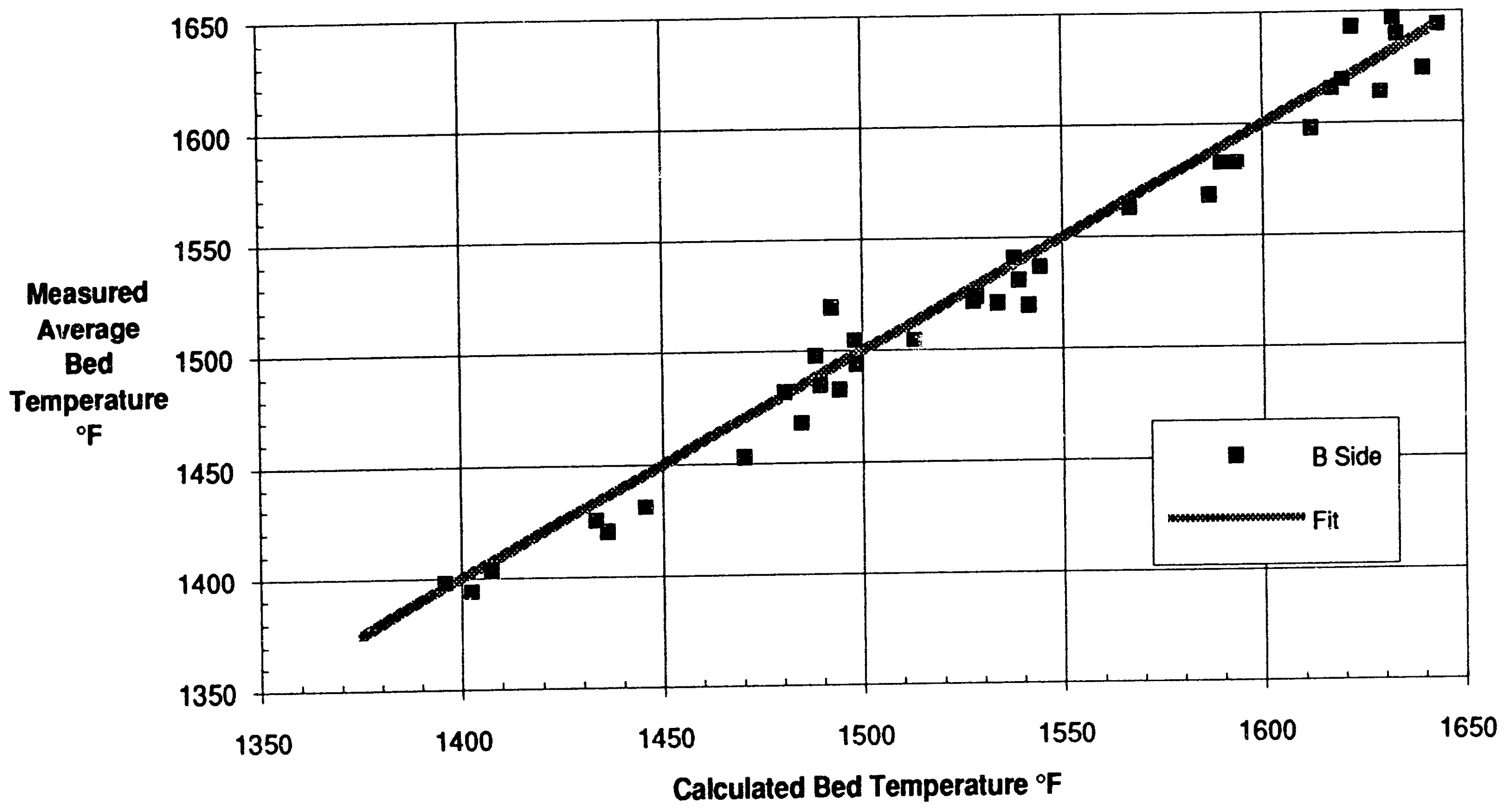


Figure 9-3. Measured Versus Predicted Bed Temperatures For Peabody Coal



points were added to the data highway and designated as points GAT6A and GAT6B.

Preliminary use of these pressure taps indicates that combustor A typically operates with a ΔP that is between 1 and 1.5 inches of water higher than combustor B at full load. Thus, the correlation given above indicates that the operating temperature differential between the two combustors is most likely caused by the difference in the upper combustor pressure drop. The reason for the differences in the ΔP are not known at this time. Possible explanations are differences in the feed stock to the two combustors, differences in the cyclone collection efficiency, or differences in the total inventory in the combustors.

During the fourth quarter of 1989 considerable efforts were expended to balance the temperature differential between the two combustors. During this time period, the unit was being switched over from the Peabody coal to Salt Creek coal. The Peabody coal was higher in ash than the Salt Creek coal. The lower ash content of the Salt Creek coal appears to have aggravated the temperature imbalance between the two combustors. After the November 13, 1989 start-up, operation at 105 MWe output showed a 100°F temperature differential between the two combustors, with combustor B being the higher temperature. In addition, the NO_x measurements at the B side of the air heater indicated that the NO_x emissions from combustor B were at most twice as high as the NO_x emissions from combustor A. These differences delayed testing until the temperature differential could be corrected.

The following operating parameters were used to attempt to change the temperature in combustor B:

- SA/PA split
- Total air flow
- Bed pressure
- Bottom ash cooler classifier velocity
- Loop seal fluidizing air

Changing the SA/PA ratio and increasing the O_2 set point 0.5 vol% resulted in, at most, a 35°F change in bed temperature. Bed pressure was increased from 16 to 23 in. wg. to influence the upper combustor ΔP. The ΔP did increase, however, the effect on combustor B was only about 25°F. An attempt to change the freeboard ΔP by altering the bottom ash classifier velocity showed no improvement in operations. This is because the maximum velocity on the ash classifier is only 8 ft/sec, which is too low to have any significant impact on a CFB operating at 16 ft/sec.

The conclusion reached by this investigation was that the operational parameters available to the operators were of little use for adjusting the bed temperature of the Nucla unit. Differences in the bed material between the two combustors suggest that the differences in the cyclone collection efficiencies may be the root cause of the temperature imbalance. The cyclones will be inspected early in 1990 to see if any improvements in operations can be made. Because of the inability to correct the temperature differences between the two combustors, it was decided to conduct the performance tests as "split combustor" tests. Gaseous emissions will be analyzed separately at both sides of the air heater inlet to measure the emissions from the two combustors. This will allow analysis of the effect of the different combustor operating conditions on the emissions. More details of split combustor tests can be found in Section 6 which gives the performance test results.

9.3 HEAT FLUX PROBE DATA

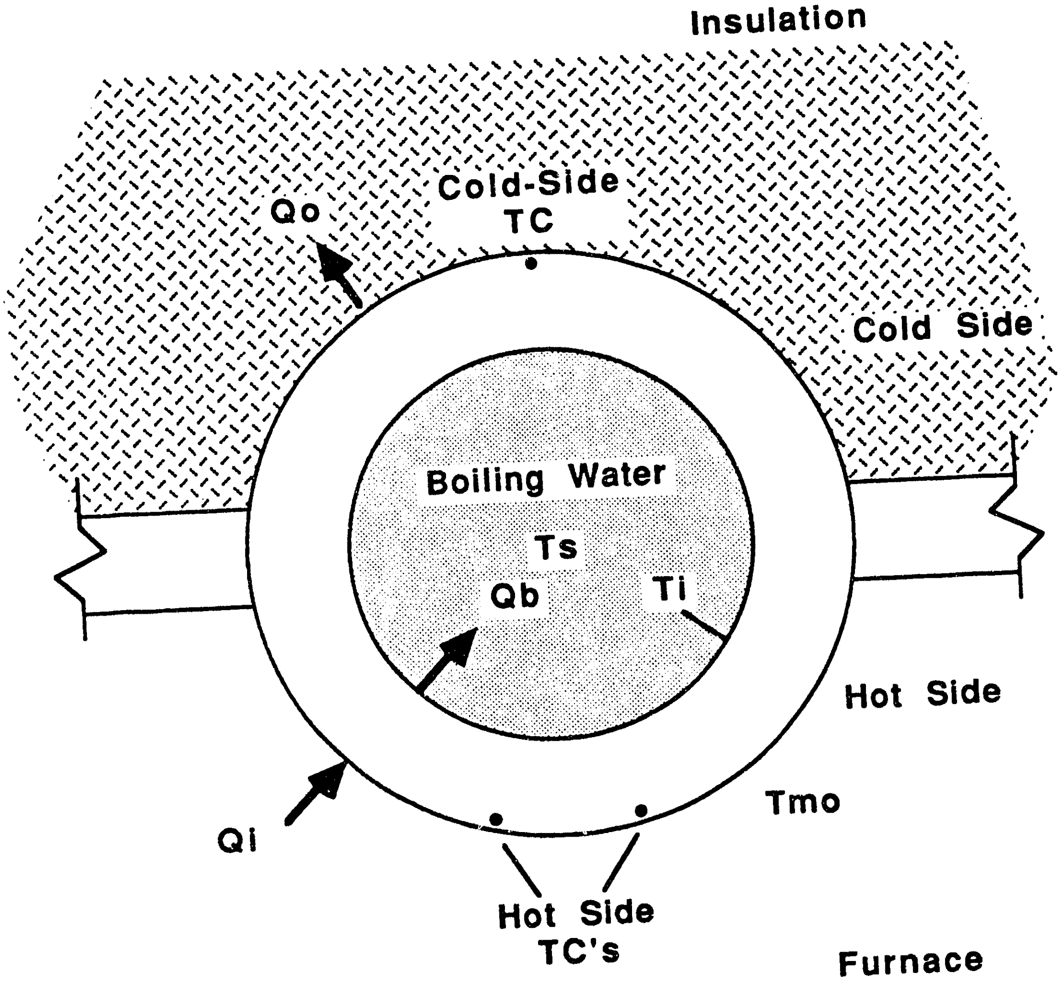
The heat flux probes installed in the freeboard were used to develop a correlation for the heat transfer in combustor B. Data used in the analysis were taken during this reporting period. Shortly after the data was taken, some of the pressure taps were disconnected and the transmitters were used elsewhere in the plant.

Table 9-4 shows the elevation above the air distributor for the chordal thermocouples and the pressure taps used for these measurements. The chordal thermocouples measure the heat flux through the boiler walls. In general, a heat flux probe is made up of two thermocouples, one near the inside of the tube and the other near the outside of the tube on the fireside of the tube. The thermocouples are separated by a known distance. With this arrangement, the temperature difference between the two thermocouples is proportional to the heat flux according to the following equation:

$$Q/A_m = \frac{K_s\ (T_{mo} - T_{mi})}{(R_o - R_i)} \quad \text{BTU/hr ft}^2 \qquad (2)$$

Where: K_s = the thermal conductivity of the boiler tube, BTU/hr/ft^2/°F/ft.
A_m = tube mean heat transfer area, ft^2.
Ro = outside tube radius, ft.
Ri = inside tube radius, ft.
T_{mo} = temperature of the outside TC, °F
T_{mi} = temperature of the inside TC, °F

The heat flux probes installed at Nucla are slightly different. Figure 9-4 shows the details of the heat flux probes installed at Nucla. The probes used in this installation have three thermocouples. Two are installed in contact with the hot face of the tube, and a third is



Geometric Data:

Ro = 1.250 in.
Ro - Ri = 0.220 in. (min)
= 0.250 - 0.260 in. (measured)

Figure 9-4. Details of the Heat Flux probe used at Nucla installed at the outside surface of the tube at the farthest point away from the furnace in the insulation. Since the heat loss through the lagging is small compared to the heat flow through the hot side of the tube ($Q_o << Q_i$) we can assume that the thermocouple located on the lagging side is measuring the bulk steam temperature, t_s. The two hot-side thermocouples are averaged to give the outside metal temperature, T_{mo}. In order to calculate the inside metal temperature on the hot side, T_{mi}, we must estimate the boiling film heat transfer coefficient.

Table 9-4

Location of Pressure Taps
and Chordal Thermocouples

Pressure Transmitter	Ft Above Air Distributor
GPT300	12
GPT301	15
GPT302	18
GPT303	22
GPT304	28
GPT305	37
GPR306	49
GPT307	62
GPT308	75
GPT309	89
Chordal Tc.	
GTE300A & B	15
GTE301A & B	18
GTE302A & B	23
GTE303A & B	28
GTE304A & B	37
GTE305A & B	49
GTE306A & B	62
GTE307A & B	75
GTE308A & B	89
GTE309A & B	101

From conservation of energy:

$$Q_i = Q_m = Q_b \tag{3}$$

Heat transfer through the wall gives:

$$Q_m = \frac{K_s A_m (T_{mo} - T_{mi})}{(R_o - R_i)} \tag{4}$$

The heat transfer through the boiling film is:

$$Q_b = h_b \, A_i \, (T_{mi} - T_s) \qquad (5)$$

Where: A_i = the inside area of the tube, ft^2.
h_b = boiling film heat transfer coefficient, $BTU/hr/ft^2/°F$.

The boiling film temperature drop has been studied extensively for this type of application. Figure 9-5 shows a plot of the boiling film ΔT as a function of the boiling film heat transfer coefficient, h_b, and the operating pressure of the steam. Since the heat flux probe is assumed to measure the quantity $(T_{mo} - T_s)$, the inside metal temperature, T_{mi}, must be determined in order to calculate the heat flux using Equation 2. The procedure followed was:

1. From the recorded thermocouple data, calculate the average chordal thermocouple temperature difference, $(T_{mo} - T_s)$.

2. Assume an approximate boiling film coefficient (h_b) and from Figure 9-5 determine the film temperature difference $(T_{mi} - T_s)$.

3. From Equation 5, calculate the rate of heat transfer $(Q_b = Q_m)$.

4. From Equation 4, calculate the metal temperature drop $(T_{mo} - T_{mi})$.

5. Check the chordal temperature drop from step 1 against the value:

$$(T_{mo} - T_s) = (T_{mo} - T_{mi}) + (T_{mi} - T_s) \qquad (6)$$

   where $(T_{mo} - T_{mi})$ is from step 4 and $(T_{mi} - T_s)$ is from step 3.

6. Repeat steps 2 through 5 until Equation 6 is satisfied.

Table 9-5 shows the results of these heat flux measurements averaged over the three zones of the combustor. Suspension density is defined as the weight per unit volume of the bed. The bed is comprised of solid particles and void spaces. The suspension density is given by:

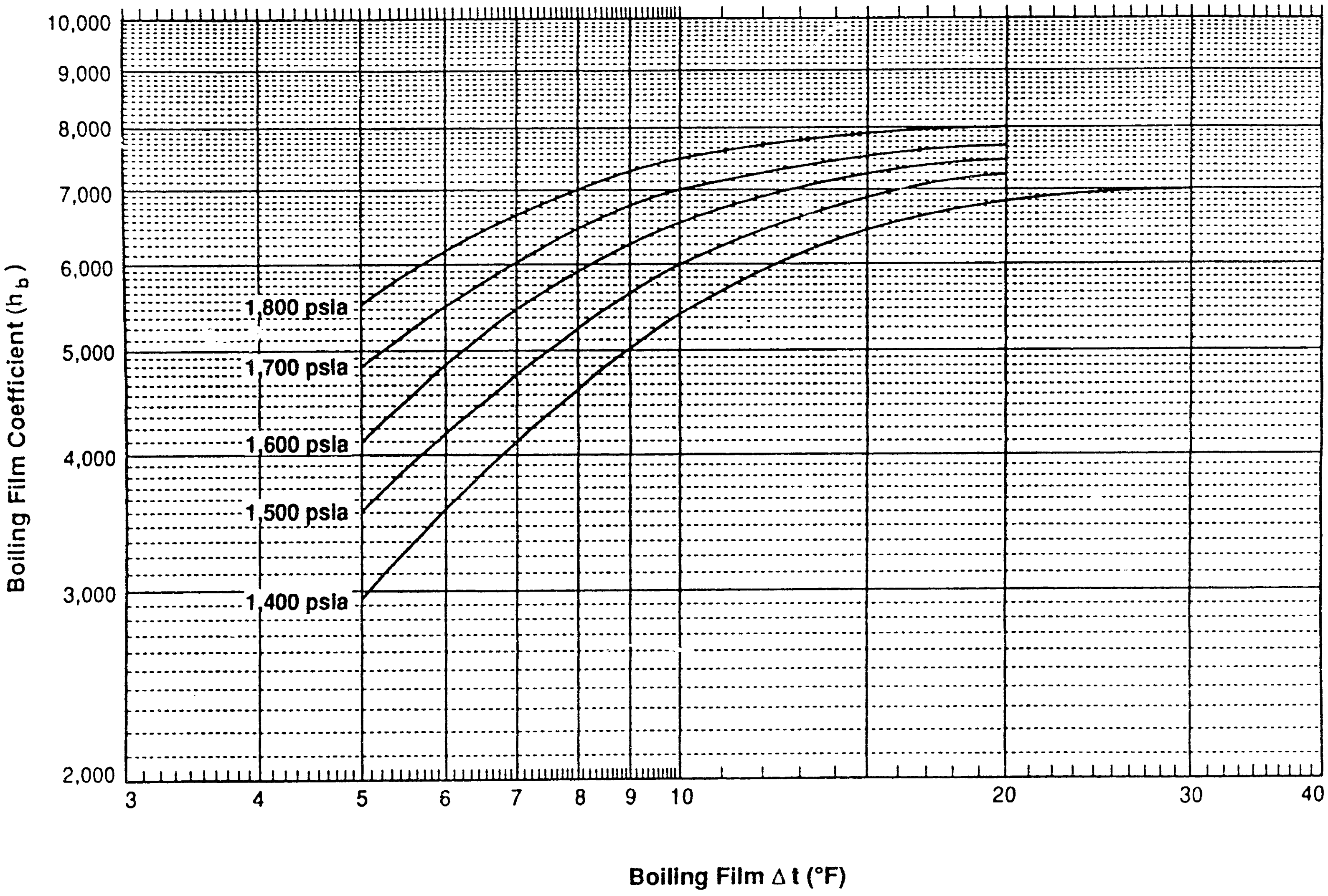


Figure 9-5. Boiling Film Coefficient versus Boiling Film ΔT.

Table 9-5. Heat Flux Data from Combustor B

Test	Unit Load MWe	Furnace Section	Height Above Grid (ft)	Heat Flux From Chordal TC's Btu/ft^2	Combustor B Bed Temp (°F)	Superficial Velocity ft/sec	Flue Gas O2 vol %	B-Bed ΔP in. wc.	Calculated Heat Flux Btu/ft^2
A03	104	LOWER	20-40	32094	1644	15.44	3.48	5.52	32094
		MIDDLE	40-70	30802	1651				31116
		UPPER	70-113	31735	1658				30588
A04	82	LOWER	20-40	28013	1589	12.96	4.20	4.09	28556
		MIDDLE	40-70	27286	1584				27568
		UPPER	70-113	28176	1579				27064
A05	82	LOWER	20-40	27559	1585	13.04	4.14	3.94	28566
		MIDDLE	40-70	27360	1584				27674
		UPPER	70-113	27826	1583				27189
A06	82	LOWER	20-40	27906	1587	13.11	4.19	4.22	28780
		MIDDLE	40-70	27409	1582				27825
		UPPER	70-113	27654	1578				27330
A07	55	LOWER	20-40	24116	1433	8.65	5.93	3.64	22500
		MIDDLE	40-70	22659	1401				21684
		UPPER	70-113	22027	1371				21272
A08	104	LOWER	20-40	31481	1614	15.10	3.41	6.04	31836
		MIDDLE	40-70	29955	1619				30875
		UPPER	70-113	30244	1624				30353
AO1	100	LOWER	20-40	34515	1644	16.82	3.69	6.16	33841
		MIDDLE	40-70	33171	1649				32785
		UPPER	70-113	33429	1653				32219
AO2	104	LOWER	20-40	32171	1639	15.97	3.46	5.81	32791
		MIDDLE	40-70	31226	1648				31837
		UPPER	70-113	31705	1657				31307
P21	55	LOWER	20-40	22757	1450	9.81	6.30	3.02	23719
		MIDDLE	40-70	21757	1418				23165
		UPPER	70-113	20990	1389				22825
P30	55	LOWER	20-40	22150	1456	9.18	5.66	2.71	22761
		MIDDLE	40-70	21609	1428				21732
		UPPER	70-113	19910	1402				21236
P31	82	LOWER	20-40	28314	1551	12.17	3.84	4.85	27743
		MIDDLE	40-70	26955	1544				26680
		UPPER	70-113	26359	1537				26150
P39	55	LOWER	20-40	23751	1475	9.39	5.96	2.95	23126
		MIDDLE	40-70	22640	1437				22506
		UPPER	70-113	21965	1403				22143
P49	98	LOWER	20-40	31103	1650	14.82	3.50	5.76	31462
		MIDDLE	40-70	29415	1644				30477
		UPPER	70-113	29931	1639				29945
P50	98	LOWER	20-40	31425	1645	14.88	3.50	5.80	31481
		MIDDLE	40-70	29704	1643				30550
		UPPER	70-113	29655	1641				30034
P52	55	LOWER	20-40	25040	1443	9.64	6.28	2.90	23416
		MIDDLE	40-70	23450	1420				22862
		UPPER	70-113	21886	1400				22507
SD1	105	LOWER	20-40	33935	1562	16.17	3.93	8.37	33753
		MIDDLE	40-70	31727	1567				32667
		UPPER	70-113	32618	1573				32091

$$\rho_s = (1 - \varepsilon)\ \rho_p \tag{7}$$

Where: ε = bed voidage
ρ_s = suspension density, lb/ft^3
ρ_p = particle density, lb/ft^3

The suspension density is calculated from the pressure profile in the combustor. The equation defining the suspension density is:

$$\rho_s = -\frac{1}{g}\left(\frac{\Delta P}{\Delta h}\right) \tag{8}$$

Where: g = the gravitational constant
h = height in ft.

Combustor B at Nucla was equipped with 10 pressure taps and transmitters at various elevations up the rear wall of the combustor. Taking the value of $\frac{\Delta P}{\Delta h}$ directly from the pressure tap readings proved difficult since the data were not always smooth. To improve the calculation of the suspension density, a second order polynomial curve was fit to the absolute pressure readings versus the logarithmic height above the grid. This function was found to give a good fit of the pressure profile. Differentiating the curve fit with respect to height yielded the pressure gradient, which was then substituted into Equation 8 above to give the suspension density as a function of height. The suspension densities were then averaged for the three zones.

Figure 9-6 shows the trend observed for the suspension density as a function of superficial velocity. Actual values of the suspension density cannot be shown due to the proprietary nature of this data. This curve shows that the suspension density is a relatively smooth function of velocity. Furthermore, the suspension density decreases with height in the combustor. Figure 9-7 shows the overall bed pressure drop versus superficial velocity. Note the similarity between this figure and the suspension density. Figure 9-8 shows the trend for the suspension density divided by the overall upper-bed ΔP versus superficial velocity. This normalized suspension density was found to be constant over the range of velocities tested. This figure suggests that the pressure profile is similar at all loads and that the magnitude of the effect is determined by the overall pressure drop above the secondary air ports.

Figure 9-9 shows the effect of superficial velocity on the heat flux measurements. Note that the heat flux is a strong function of the velocity, particularly at the higher

Figure 9-6. Suspension Density Versus Superficial Velocity

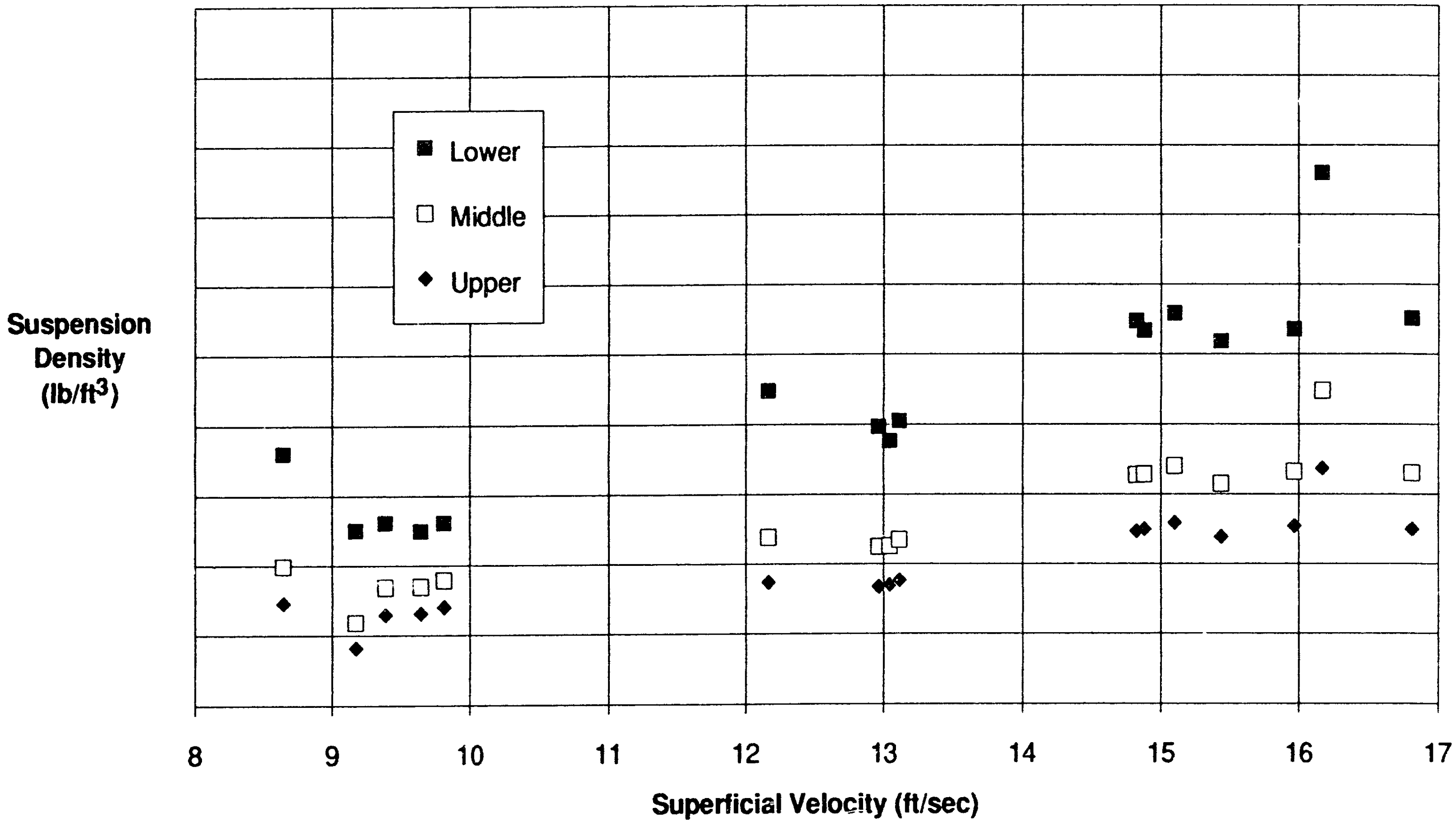


Figure 9-7. Bed ΔP Versus Superficial Velocity For Combustor B

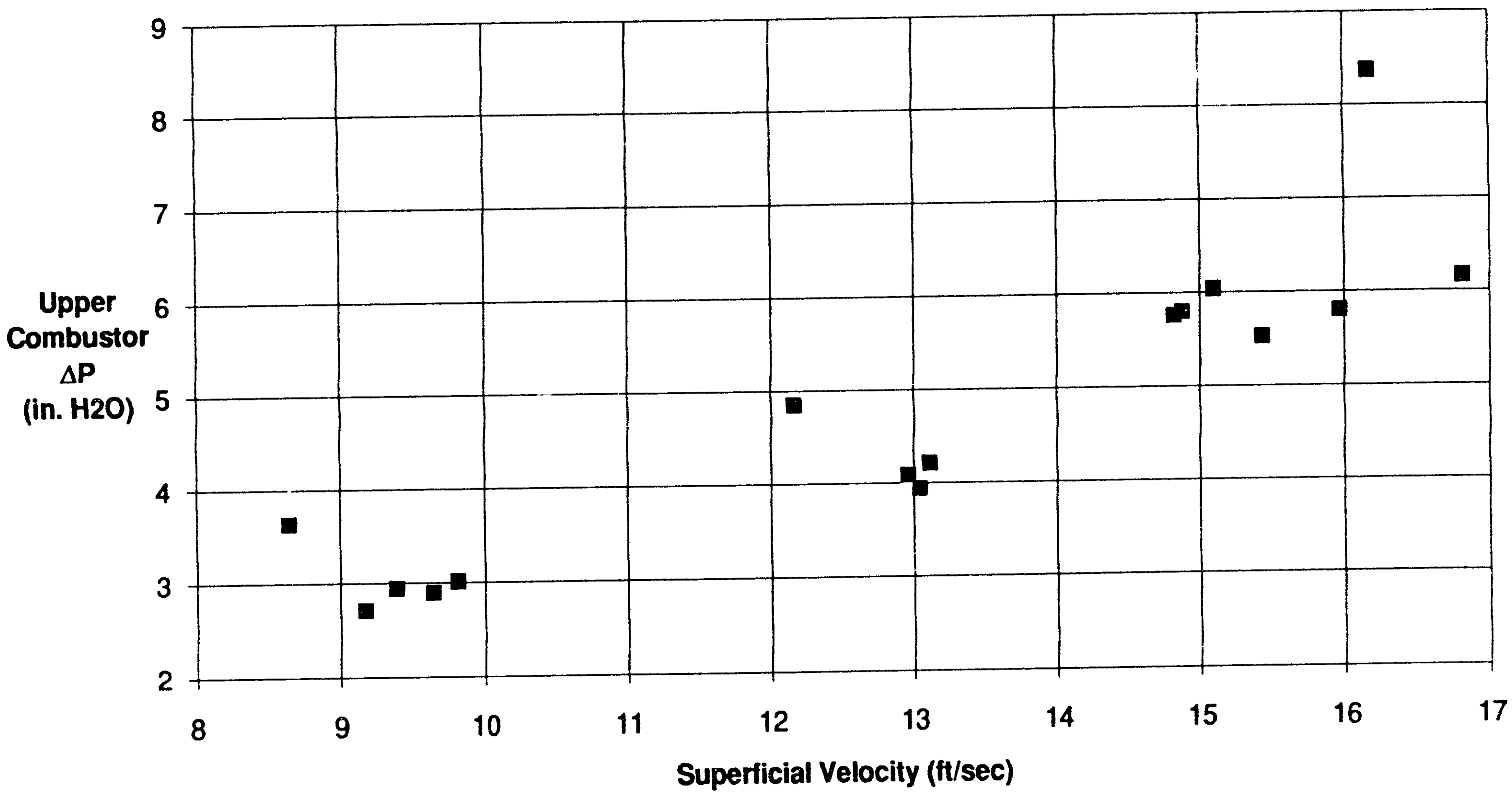


Figure 9-8. Normalized Suspension Density Versus Superficial Velocity

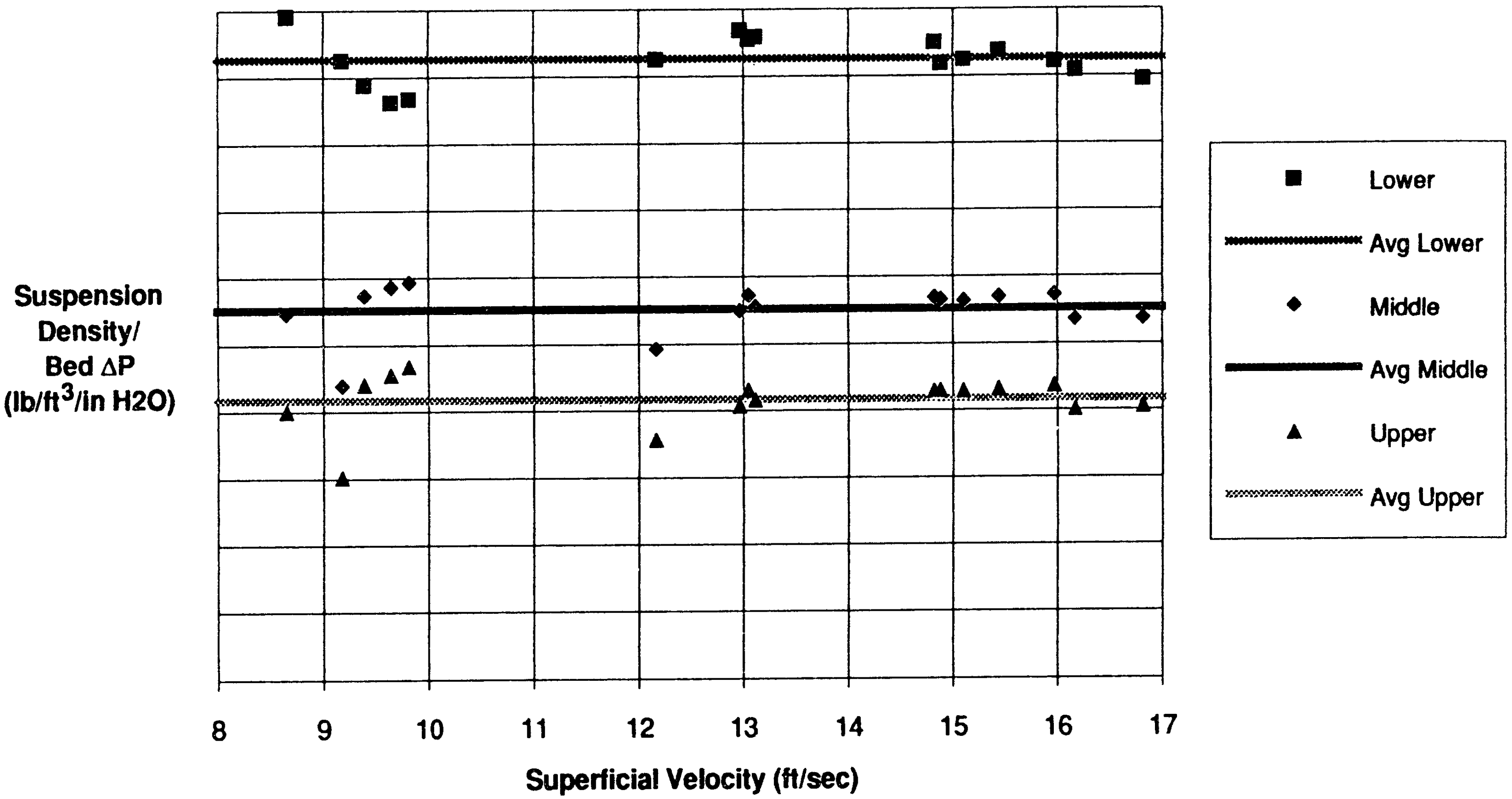
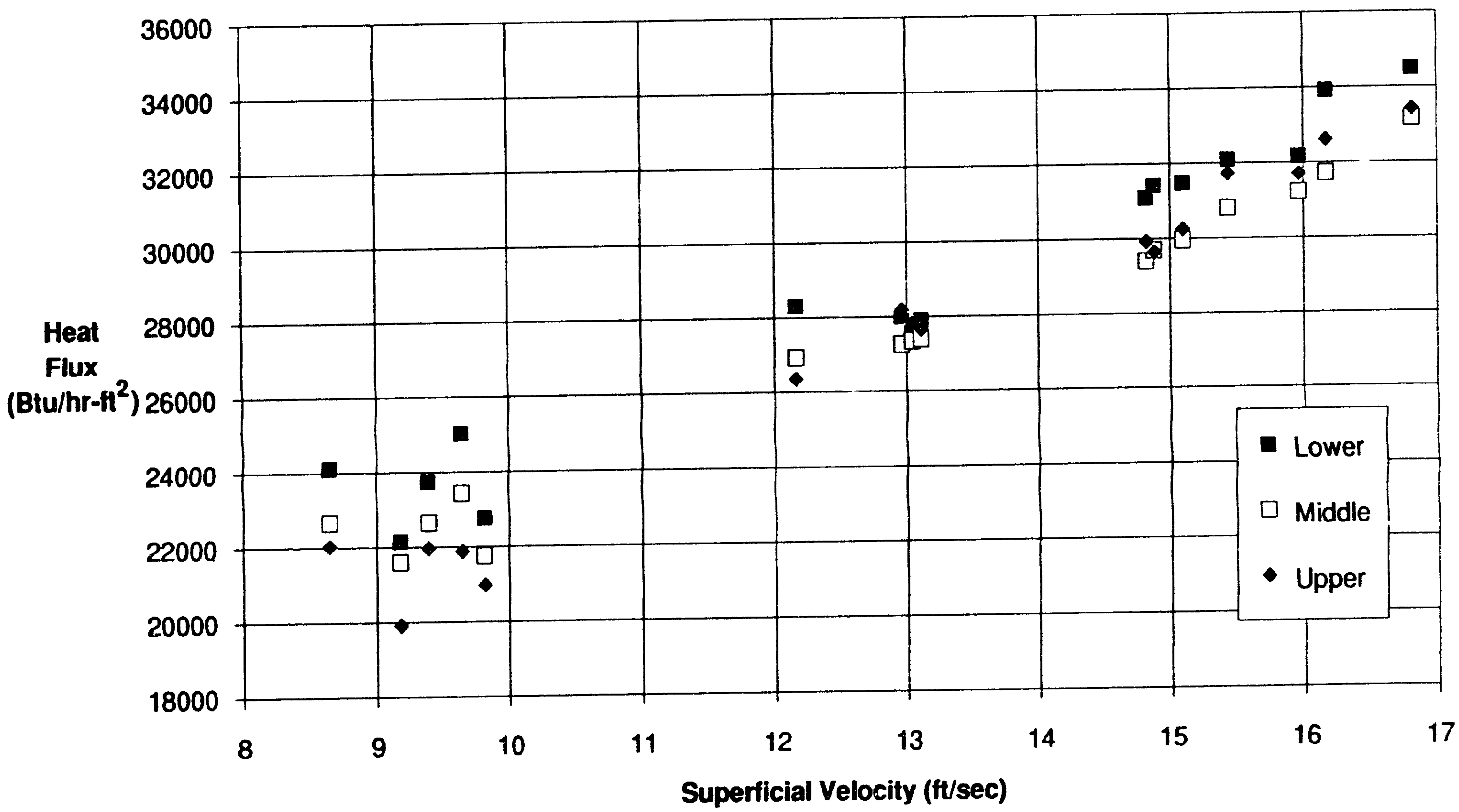


Figure 9-9. Heat Flux Versus Superficial Velocity



velocities. Furthermore, there is only a slight difference in the heat fluxes between the lower furnace and the upper furnace. The difference between the upper and lower heat fluxes averaged 1200 Btu/ft^2 and did not appear to be a function of velocity. Figure 9-10 shows the effect of suspension density on the heat flux. This figure shows that the suspension density does not strongly affect the heat flux, since the same heat flux can be obtained at densities that vary by as much as a factor of 2.

To further examine the effect of velocity and suspension density on the heat flux, a correlation of the form:

$$HF = HF_{Ref} \, (V_S)^{\alpha} \, (\rho_S)^{\beta} \qquad (9)$$

was developed. The value of HF_{Ref} was 6,984 Btu/ft^2. The correlation yielded the following values for the exponents:

$\alpha = 0.574$

$\beta = 0.062$

Note that the low value for the exponent on the suspension density indicates a very weak influence on the heat transfer. Figure 9-11 shows the results of this correlation. The standard deviation on the calculated heat flux was 795 Btu/ft^2.

The magnitude of the coefficients found in Equation 9 indicates that the effect of suspension density is very minor relative to the effect of superficial velocity. The coefficient of 0.574 for the velocity term suggests a mechanism for heat transfer similar to gas convection, which has a velocity coefficient of 0.5. However the overall magnitude of the heat transfer rate is approximately two to three times the value for simple gas convection with radiation.

Figure 9-10. Heat Flux Versus Suspension Density

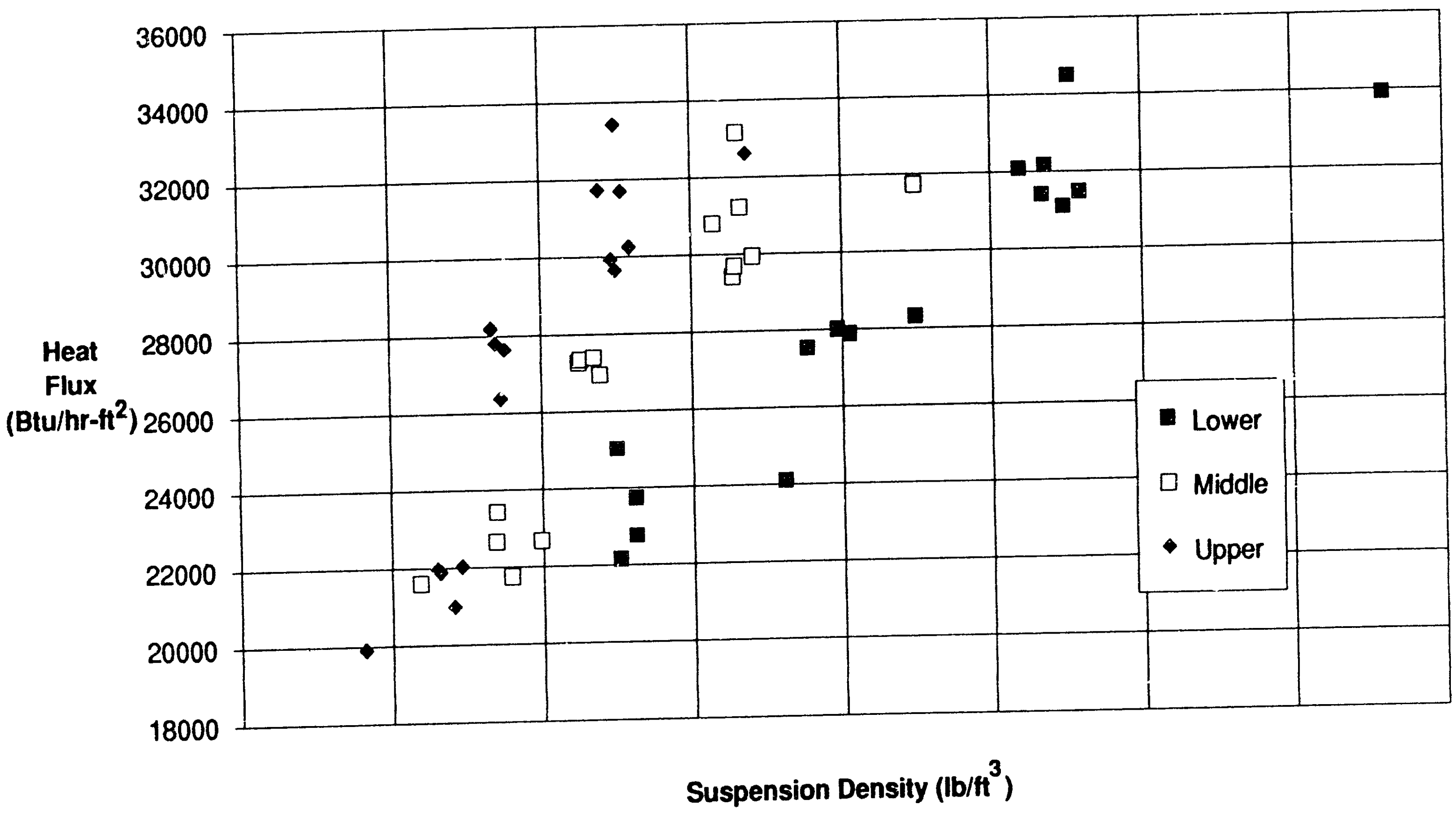
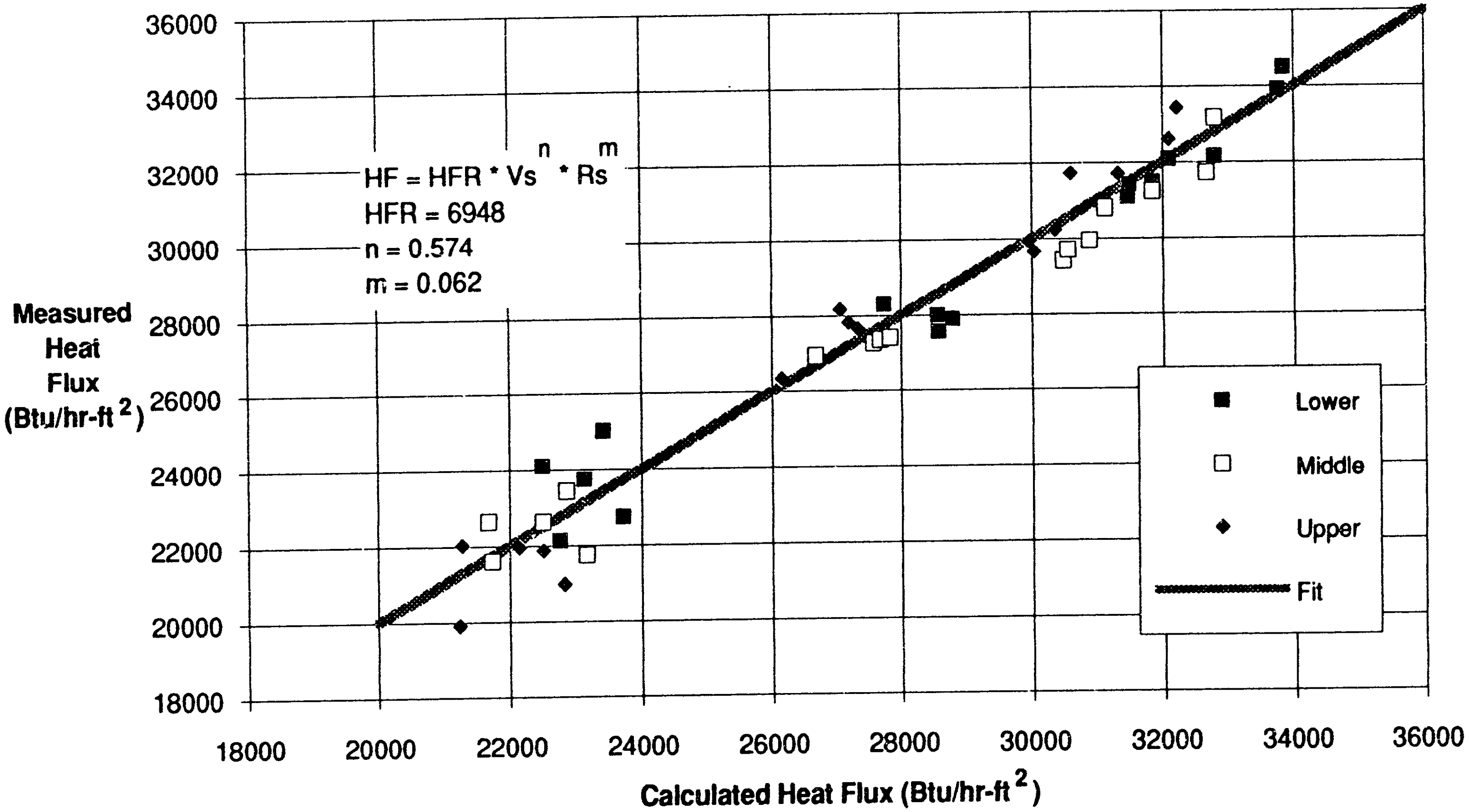


Figure 9-11. Heat Flux Correlation



Section 10

COAL AND LIMESTONE PREPARATION AND HANDLING

This section summarizes the operating experiences of the coal and limestone preparation and feed systems during 1989. The coal preparation and feed system continued to perform well without major incidents during the period. The limestone feed system has experienced difficulties maintaining high flow rates during preliminary test runs on high sulfur coal. The performance of these systems is discussed below.

10.1 SYSTEM DESCRIPTIONS

10.1.1. Coal Preparation/Delivery/and Feed Systems

The existing, refurbished Nucla station coal system provides for coal receiving, two stages of crushing, weighing, sampling (as received), live storage/reclaim, and transfer into the plant building. The system is shown schematically in Figure 10-1 and is designed from existing and new equipment.

Raw run-of-mine coal is delivered from local coal mines to the plant by truck. Two half-capacity vibrating feeders deliver coal from the unloading hopper to the primary crusher where the coal is reduced in size to approximately 7" x 0. The primary crusher discharges onto a belt conveyor via an integral belt weigh scale to a secondary "granulator-type" crusher where it is reduced in size to approximately 3/4" x 0. A single vibratory feeder delivers coal to the secondary crusher. From the secondary crusher, coal is delivered by a belt conveyor to a transfer house.

In the transfer house, coal from conveyor A drops through a diversion gate that directs the coal flow to either storage via stack-out conveyor B, or into the power plant via conveyor C. A reclaiming hopper and vibratory feeder located beneath the "rocket" on the storage pile reclaims coal and feeds it onto plant conveyor C, which delivers coal to the main plant enclosure.

The discharge from conveyor C flows into a two-way diverter/splitter that directs coal onto either or both new en-masse inclined conveyors D and E. Each of these drag chain type conveyors are rated at 127 tons/h. A new "as-fired" coal sample system is located at the discharge of conveyor C at the base of these inclined conveyors. In the event of equipment problems, an 18 ton surge hopper has been

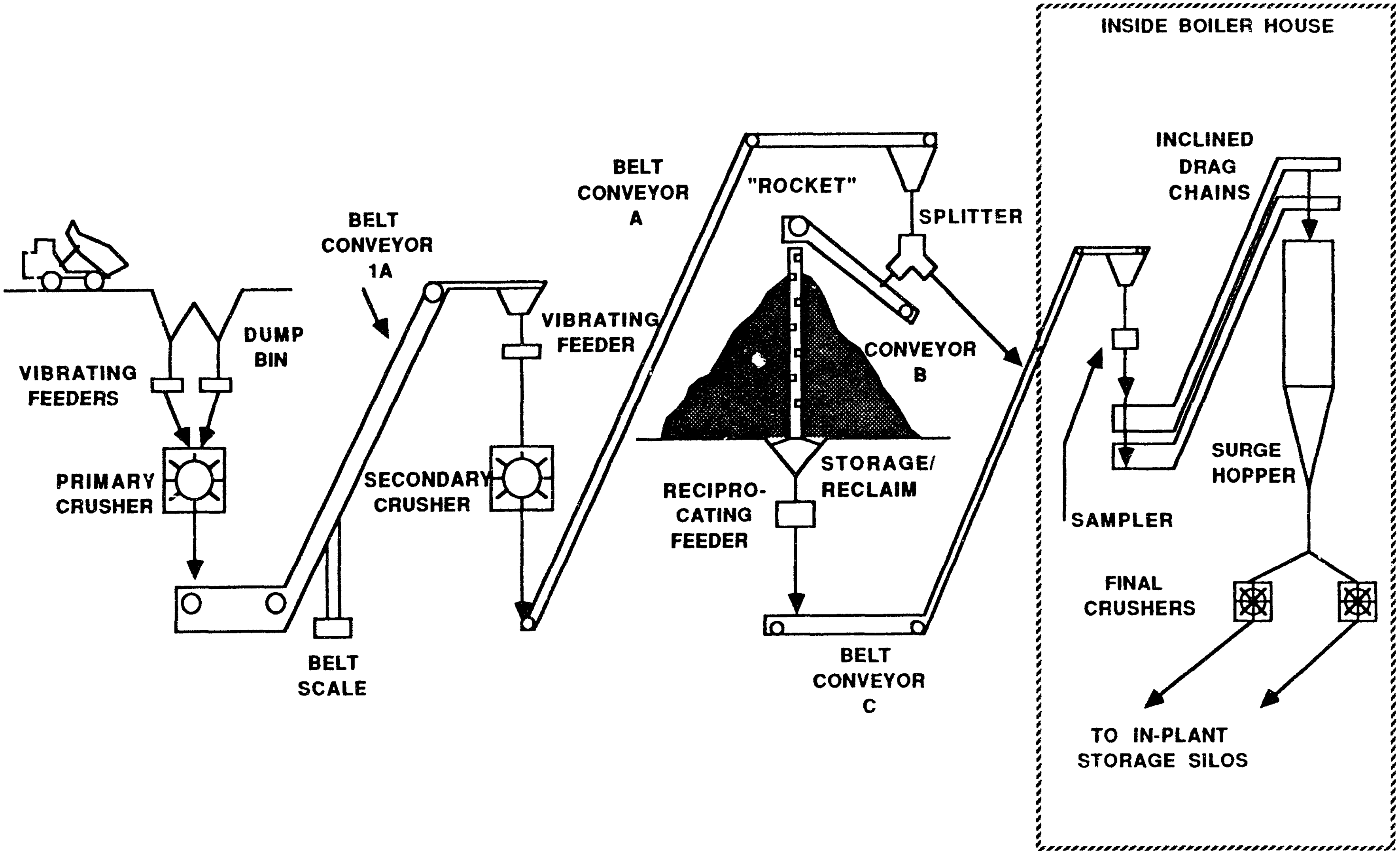


Figure 10-1. Schematic of Coal Preparation System.

installed just above the final crushers (at the discharge of the inclined conveyors) with capacity to store all coal on conveyor C (see Figure 10-2).

At the outlet of the surge hopper, a two-way splitter/diverter gate transfers coal onto either of two vibratory feeders prior to the final crushers. Both crushers operate simultaneously to accept the full output of plant conveyor C. Both are reversible impact crushers which operate at a rate of 65 tons/h and reduce the coal size from 3/4" x 0 to 1/4" x 0 required for the CFB process. Since coal is normally delivered into the plant by conveyor C on a two-shift a day basis, both coal crushers are usually in service when the plant is operating at full load.

At the outlet of the final crushers, two 54' long horizontal drag chains transfer the full output from each crusher to either or both of the in-plant coal storage silos. Three feed points are provided from each conveyor at the top of each silo to obtain a high percentage fill. The inlet openings to silo A are equipped with remotely operated slide-gates so that this silo can be bypassed (when full) to fill silo B. Silo B is equipped with manually operated slide-gates.

Each coal silo has a capacity of 215 tons and is located in front of the front wall of the CFB boiler. Silo sizing provides an 8 hour storage capacity with the boiler operating at full load. Each silo has three discharge openings designed to maintain mass flow movement to each of six boiler gravimetric feeders. Each silo discharge is equipped with a manual slide gate for isolation during maintenance on the gravimetric feeders (see Figure 10-3).

The gravimetric feeders discharge coal into the boiler via gravity and booster air flow. A motor actuated slide gate and rotary valve isolate the gravimetric feeders from the hot combustion products in the lower combustion chambers. One inclined and one horizontal drag chain-type conveyors is used to transfer coal from each of two gravimetric feeders situated along the front walls, around the side walls of each combustor, to the loop seal coal feed points.

10.1.2. Limestone Preparation and Feed System

The limestone handling system provides for receiving, transferring, storing, and preparing the limestone before it is injected into the boiler. A schematic of the system is shown in Figures 10-4 and 10-5.

Raw limestone is delivered from a local quarry by truck and is dumped into a receiving hopper equipped with a pneumatic dust suppression system. A vibrating feeder delivers the

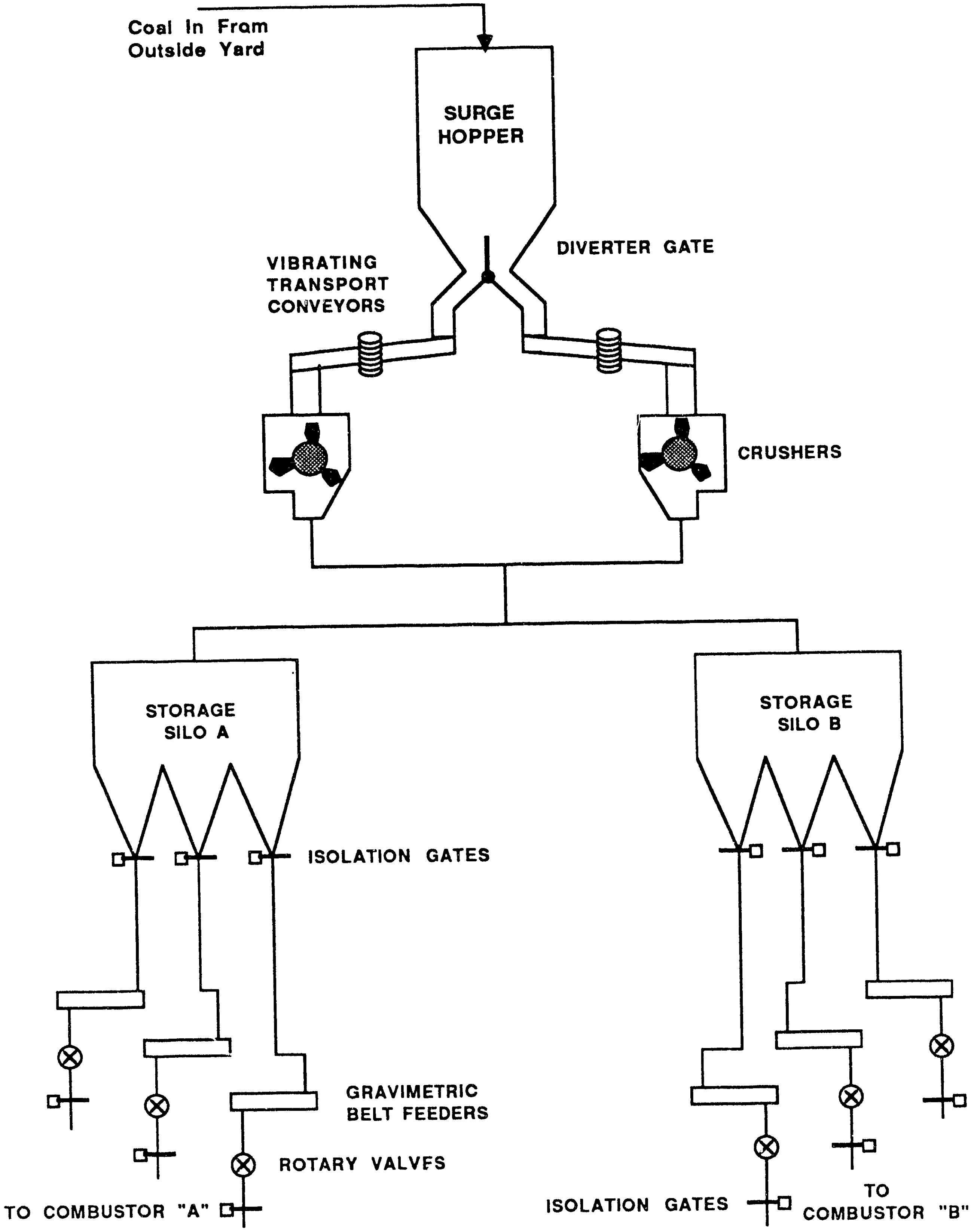


Figure 10-2. Schematic of Coal Feed System.

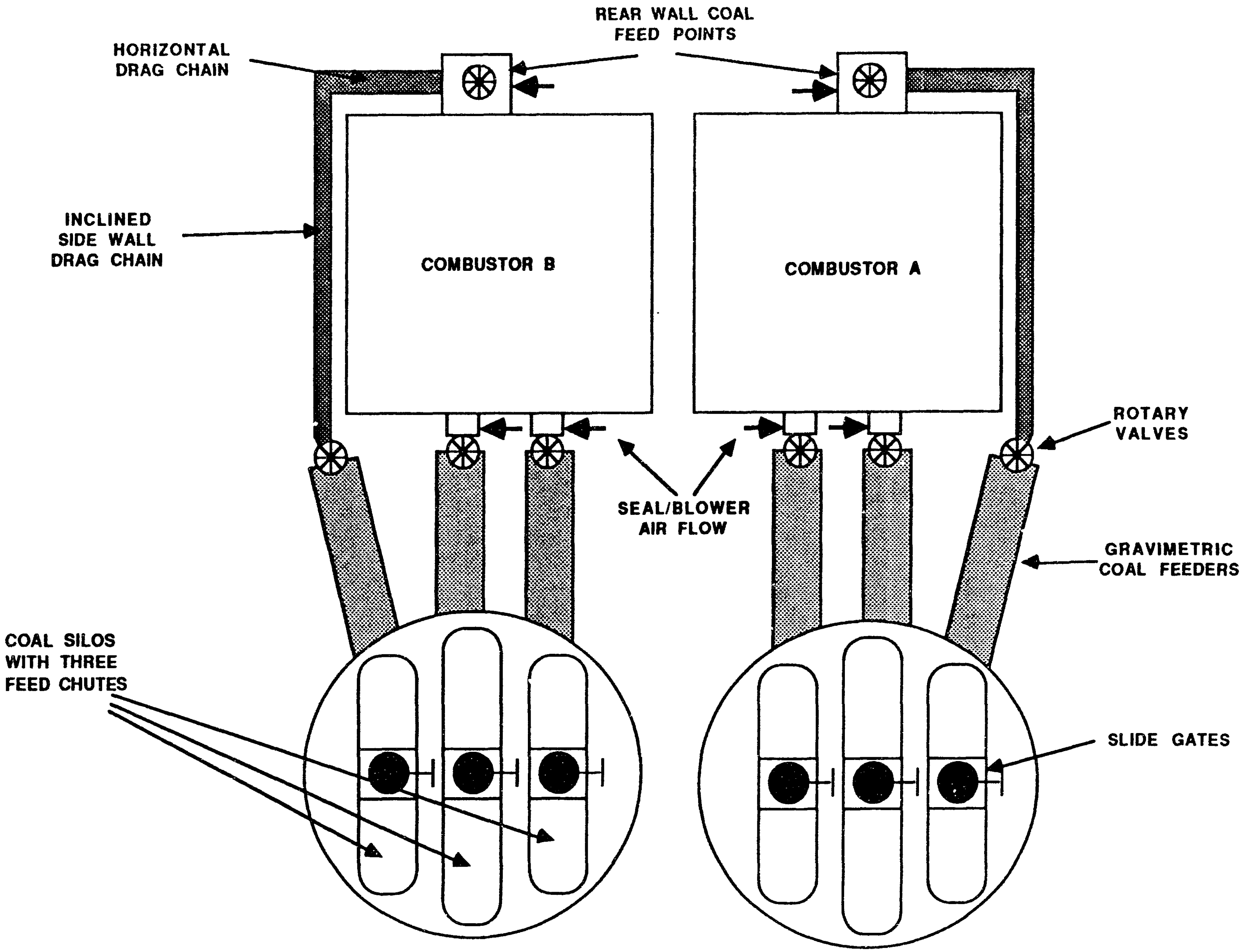


Figure 10-3. Plan View of Combustor Coal Feed Configuration.

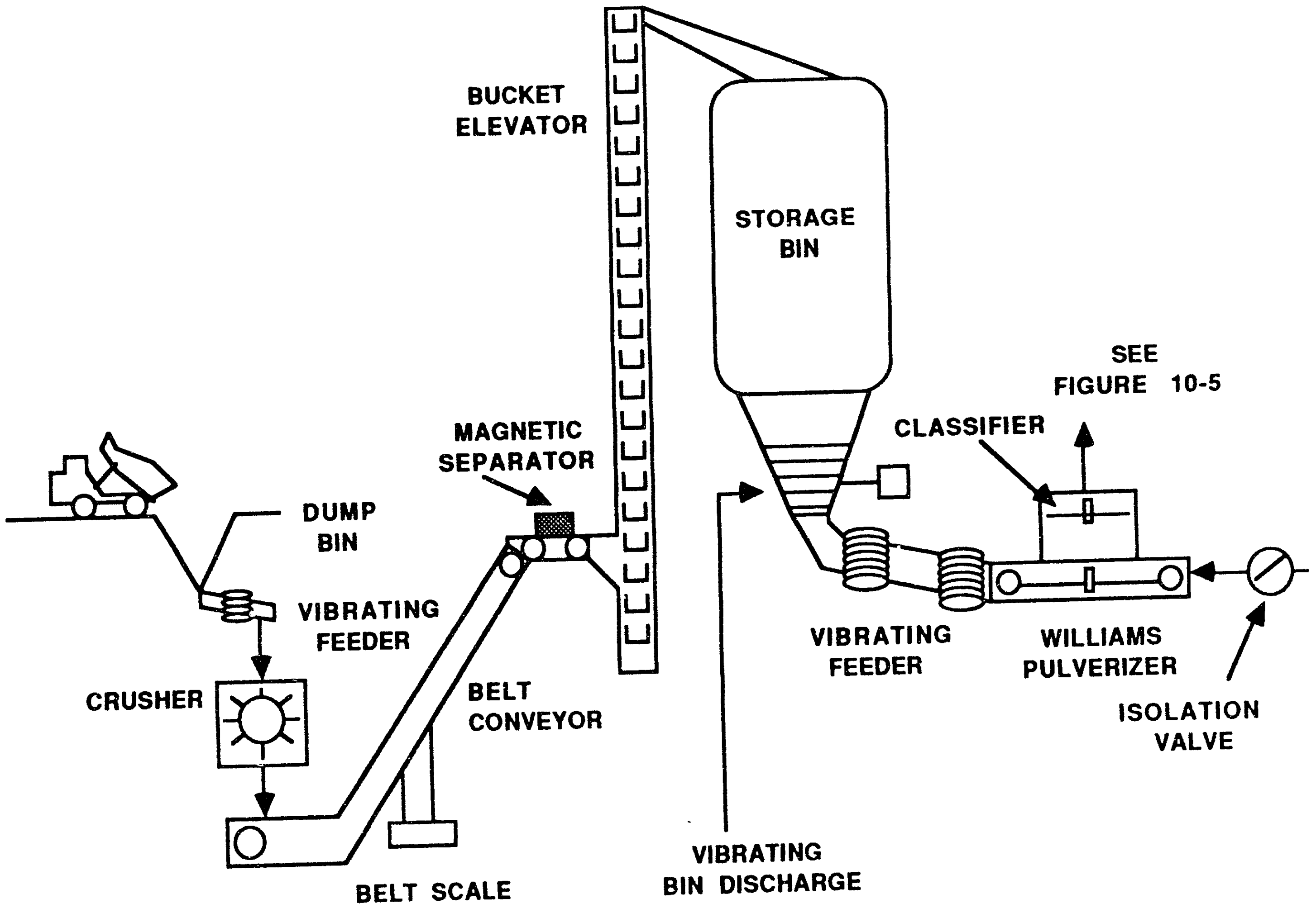


Figure 10-4. Partial Schematic of Limestone Preparation System

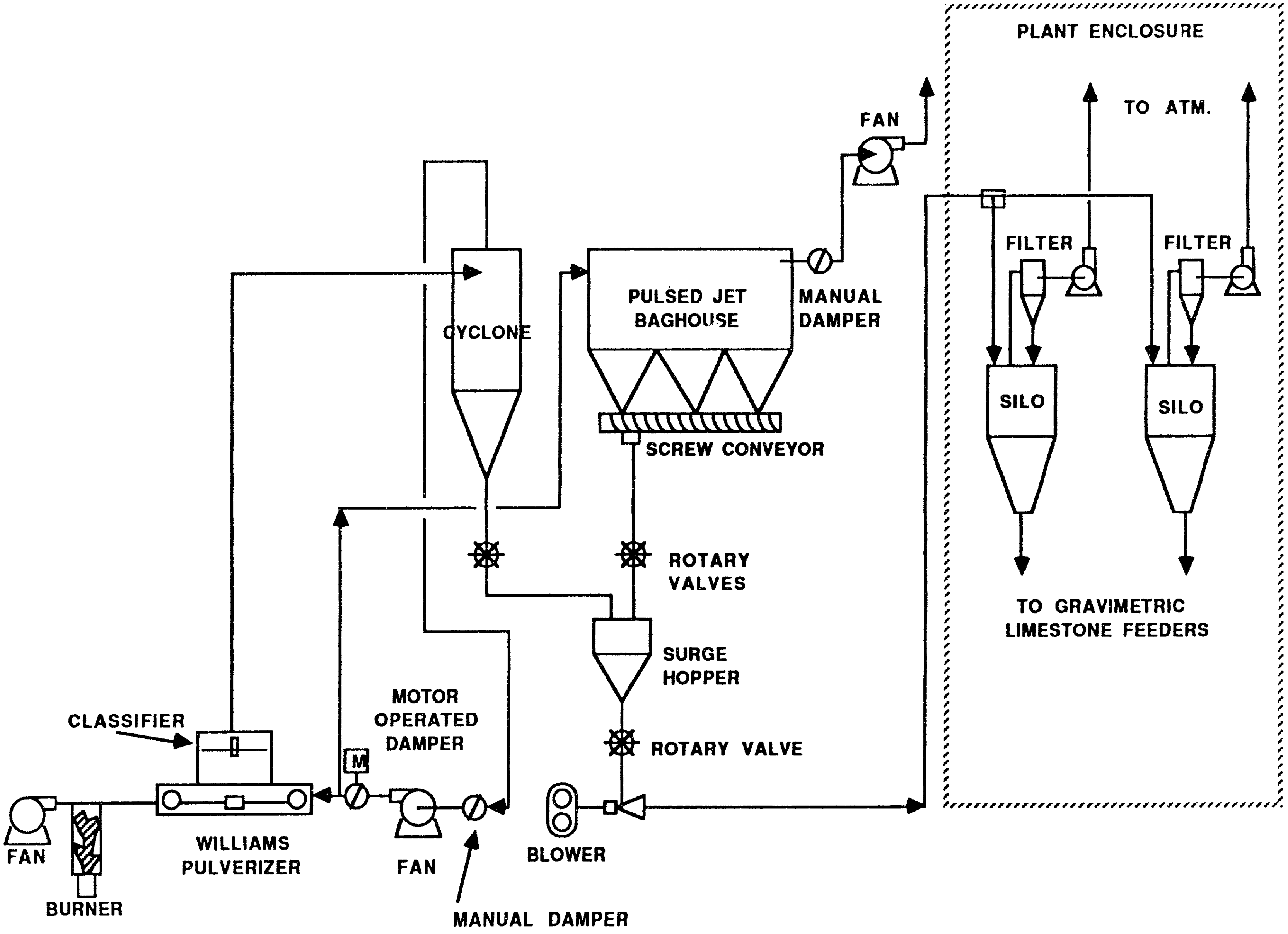


Figure 10-5. Schematic of Limestone Preparation System.

limestone into a reversible hammermill that reduces the stone from roughly 10" x 0 to 3/4" x 0. A belt conveyor, with an integral weigh scale and magnetic separator, delivers the crushed product to a bucket elevator which transfers it to an outdoor storage silo. This portion of the system is rated at 68 tons/h. The silo has a storage capacity of 772 tons which is equivalent to requirements for 70 hours of full load operation.

The storage silo transfers limestone to the pulverizer via a vibrating bin cone and vibrating feeder. The pulverizer is rated at 8.2 tons/h and reduces the 3/4" x 0 product to 150 micron average size. The pulverizer also contains a burner system shown in Figure 10-4 that dries the product to less than 1% moisture. The pulverizer is an air-swept pendulum-type roller mill. The pulverizer outlet limestone and air mixture are classified by a motor-driven spin separator that returns large size particles back to the pulverizer. Material that passes through the classifier is directed to a cyclone separator. The discharge from the cyclone returns to the inlet of the pulverizer fan which recirculates the air to the mill. Heated make-up air is provided by the fan and burner system. The separated limestone in the cyclone drops through a rotary feeder into a surge hopper (see Figure 10-5).

Transport air is bled from the pulverizer fan discharge to a fabric filter collector and exhaust fan. The entire limestone pulverizer system is maintained at a slightly negative pressure by the fabric filter exhaust fan. Collected limestone is discharged from the fabric filter via a screw feeder and rotary valve to the surge hopper, where it then joins with the cyclone collection stream.

Pulverized limestone collected in the surge hopper is transported to the inside storage silos by a pressurized pneumatic conveying system at the rate of 8.2 tons/h. The pneumatic conveying line is isolated from the surge hopper by a rotary valve. Each of the two in-plant storage silos serves one combustion chamber and has an individual storage capacity of 123 tons. This size provides storage capacity sufficient to sustain 12 hours of full-load operation on design "A" coal. Each silo is equipped with a fabric filter for collection of entrained limestone in the limestone feeder vents and the pneumatic transport air.

Processed limestone passes through a vibrating bin on the bottom of the storage silo into a weigh hopper. A piston-actuated slide gate isolation valve separates the silo from the weigh hopper. The weigh hopper is mounted on load cells, as shown in Figure 10-6, and is filled by the storage silo at a preset weight. The load cell output is electronically monitored over a period of time to obtain an integrated rate of limestone feed. Each feeder is automatically adjusted in

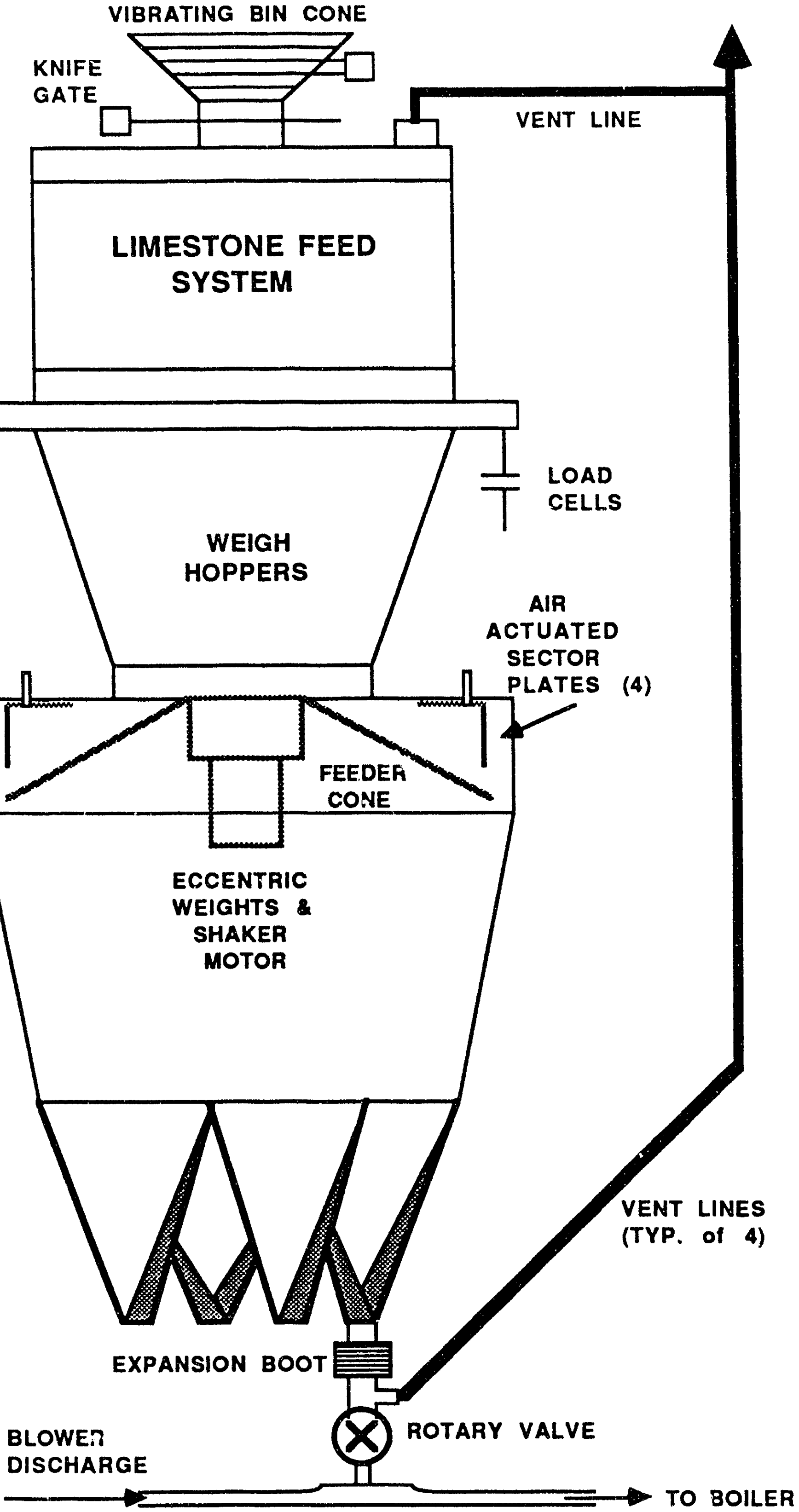


Figure 10-6. Schematic of Limestone Feed System (typical of two).

direct relationship to combustion chamber coal flow and trimmed based on the flue gas SO_2 concentration.

Limestone is fed from the weigh hopper to a second small hopper by a shaker cone that vibrates by eccentric weights attached to the shaker motor. Both of these are housed below the shaker cone in the lower storage hopper. Four piston actuated "sector" plates control the tolerance between the plates and the shaker cone, and therefore establish the rate of limestone feed to the lower hopper for a given shaker motor speed. Only opposite pairs of sector plates can be completely closed (if necessary) so that the shaker cone is still free to vibrate. From the lower hopper, limestone passes through four small conical hoppers each equipped with a rotary valve. These valves isolate the lower surge hopper from four pressurized pneumatic transport lines. Each of the four conical legs of the surge hopper has its own transport blower, transport line, and rotary valve. As mentioned, only opposite feed lines, as dictated by the relationship of the conical leg to the sector plate location, can be isolated should system repairs be required. In addition, any individual feed system can be removed from service as required by operations.

Each of the four feed lines on each limestone feed system transports limestone to the combustion chambers. A motor-actuated valve isolates each feed line from the boiler should repairs or maintenance be required. Two limestone transport lines feed directly under the coal feed ports along the front walls of the combustor. One transport line feeds to the side wall and one directly into the loop seal recycle return on the rear wall. The limestone feed locations are shown schematically in Figure 10-7.

10.2 OPERATING EXPERIENCE

10.2.1 Coal Preparation/Feed System

The coal preparation and feed system operated in a reliable manner without major incident during this reporting period covering 1989. Most repair activities were maintenance related and none resulted in unit outage time or derate during the period. These repairs are summarized below.

- During the third quarter of 1989 after approximately 8700 hours of unit operation on coal, the hammers on the final crushers shown in Figures 10-1 and 10-2 were replaced. These hammers were badly worn and resulted in oversized coal and parting material entering the combustion chambers. This has an adverse impact on the ability to remove large material from the combustion chambers and ash coolers during unit operation.

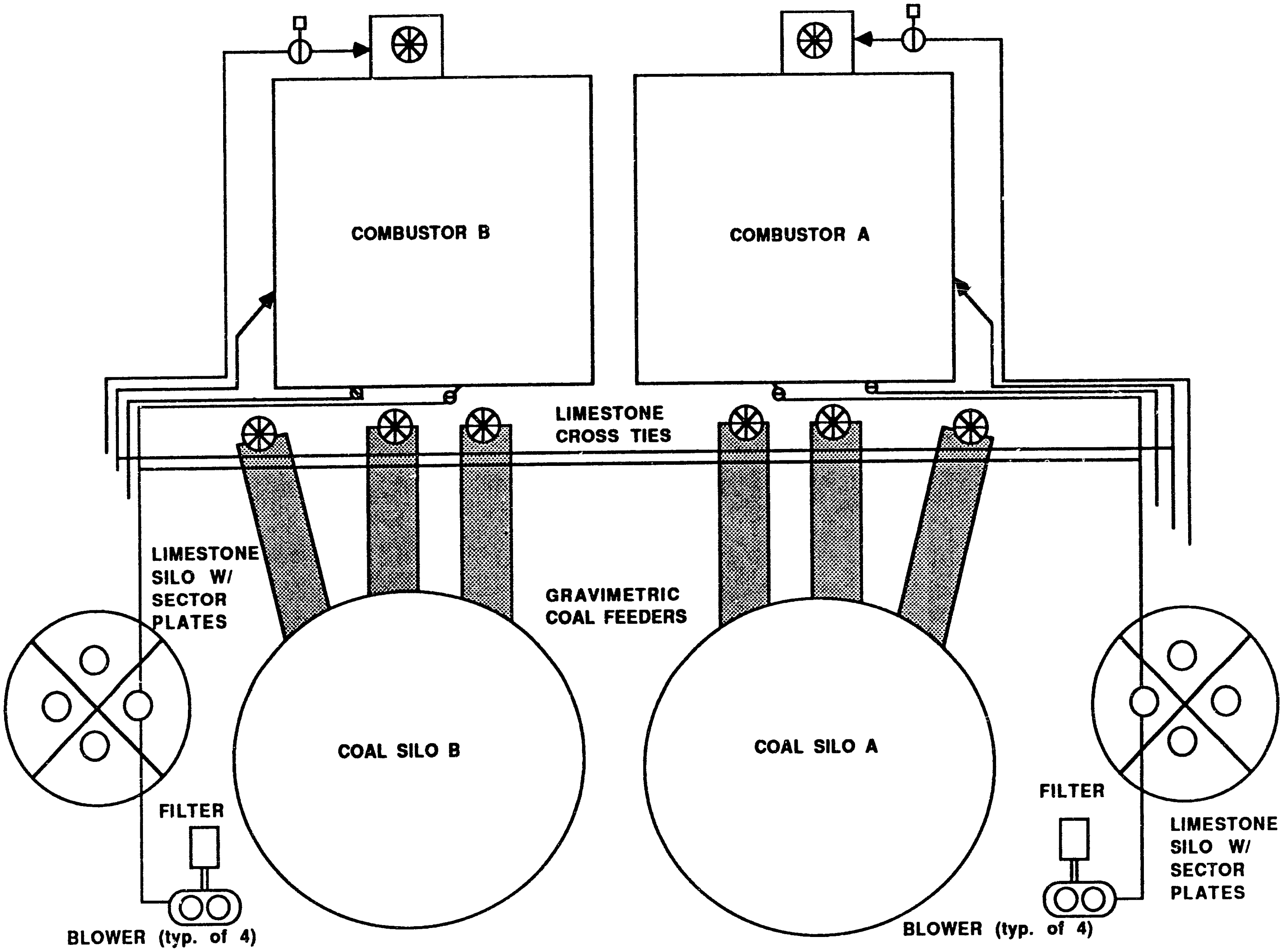


Figure 10-7. Plan View of Limestone Feed Configuration.

- On 11/24/89, 4C coal rotary valve seized. A large piece of tramp metal was removed from the rotor inlet and the feeder was returned to service. This has occurred on other occasions during this reporting period, but does not impact operating availability due to coal feeder redundancy. It should be noted however, that the temporary loss of a coal feed point results in increases in limestone feed to off-set increases in SO_2 emissions.

- On 11/26/89, one of the hanger arms on the 4B coal vibrating feeders failed and was replaced.

- On 11/30/89, the belt on the C conveyor tore and was repaired. The drive motor also failed on one occasion during the reporting period. This conveyor carries coal from storage into the plant as shown in Figure 10-1.

- On 12/23/89, the drive chain on the 4A horizontal drag chain broke and was repaired. Since each combustion chamber is equipped with three 100% capacity coal feed systems, this did not force a unit derate.

- Several coal feeder trips occurred as the result of belt misalignment on the feeders. To correct this problem, operators adjust the belt tension which interferes with the feeder calibration. This is a particular nuisance with a twin combustor design where it is necessary to balance temperatures and steam production between combustors.

10.2.2 LIMESTONE FEED SYSTEM

The limestone feed system was modified on several occasions during this reporting period in an attempt to achieve sustained high output (12,000 lbs/h per feeder) operation. This output is necessary to pass operational acceptance tests on high sulfur coal (2.5 wt.% sulfur). In general, performance of the limestone feed system during 1989 was poor and resulted in several outage extensions or unit derates in order to maintain SO_2 emissions compliance. Part of the problem was related to the random nature of system failures and the lack of instrumentation to monitor the failures. During the third quarter of 1989, pressure gauges were placed at several locations in the system for troubleshooting. Limestone feed system performance and design modifications during this reporting period are discussed below.

First Quarter 1989. During the fourth quarter of 1988, the limestone feeders experienced repeated failures of the shaker motors and eccentric weight bearings, along with leakage of prepared limestone out of the rotary valve shaft seals and into the boiler house. During the refractory repair outage in January 1989, the feeder shaker motors that drive the eccentric weights were replaced with a totally enclosed, integral motor/bearing arrangement. This new system operates at 3600 rpm versus 1800 rpm on the original system.

Following this repair, the system operated for a 16-week period at low limestone feed rates without failure. However, during subsequent operation at higher limestone feed rates for the high sulfur coal acceptance tests, the limestone feeders began tripping and the tests were aborted. The problem was believed to result from limestone backing up from the discharge line below the rotary valves and packing in around the shaker cone (see Figure 10-6). To address this problem, the discharge piping at the outlet of the rotary valve was modified on one of the eight transport lines, as shown in Figure 10-8. The modification involved the replacement of a straight run of 3" transport line with a 6" section. The rotary valve now discharges into a 6" tee such that there is no restriction at the outlet of the rotary valves.

The feeders also generated an erratic flow rate signal during periods when the storage silo above the weigh feeders is being filled with prepared limestone from the outside preparation system. This is illustrated in Figure 10-9, which shows the feed rate signal before and during times that the limestone silos are being filled. The problem is caused by the interconnection of the silo and weigh feeder vent systems. To reduce the impact on unit testing as part of the demonstration program, the silos were filled at night prior to daytime testing.

<u>2nd Quarter 1989.</u> As a result of acceptable performance of the 6" tee added to the outlet of the rotary valve on one of the eight feed trains during the previous quarter, the remaining seven lines were modified during the second quarter of 1989. Pressurizing air was also added to the outside of the shaft seals on the rotary valves to reduce leakage and improve life. No testing on high sulfur design "B" coal was completed during this period.

<u>3rd Quarter 1989.</u> The limestone feed system demonstrated poor reliability during attempts to complete operational acceptance tests on high sulfur coal during this quarter. On several occasions, the flexible rubber boot (see Figure 10-6) ruptured and considerable quantities of prepared limestone were released into the plant. This expansion boot isolates the weigh hopper from the rotary valves. The problem was attributed to blockage of the vent lines leading from the feeder to the limestone hopper. Pluggage occurs when the baghouse filter on the limestone hopper plugs or when the day bin floods the weigh hopper at high limestone feed rates and blocks off the vent line.

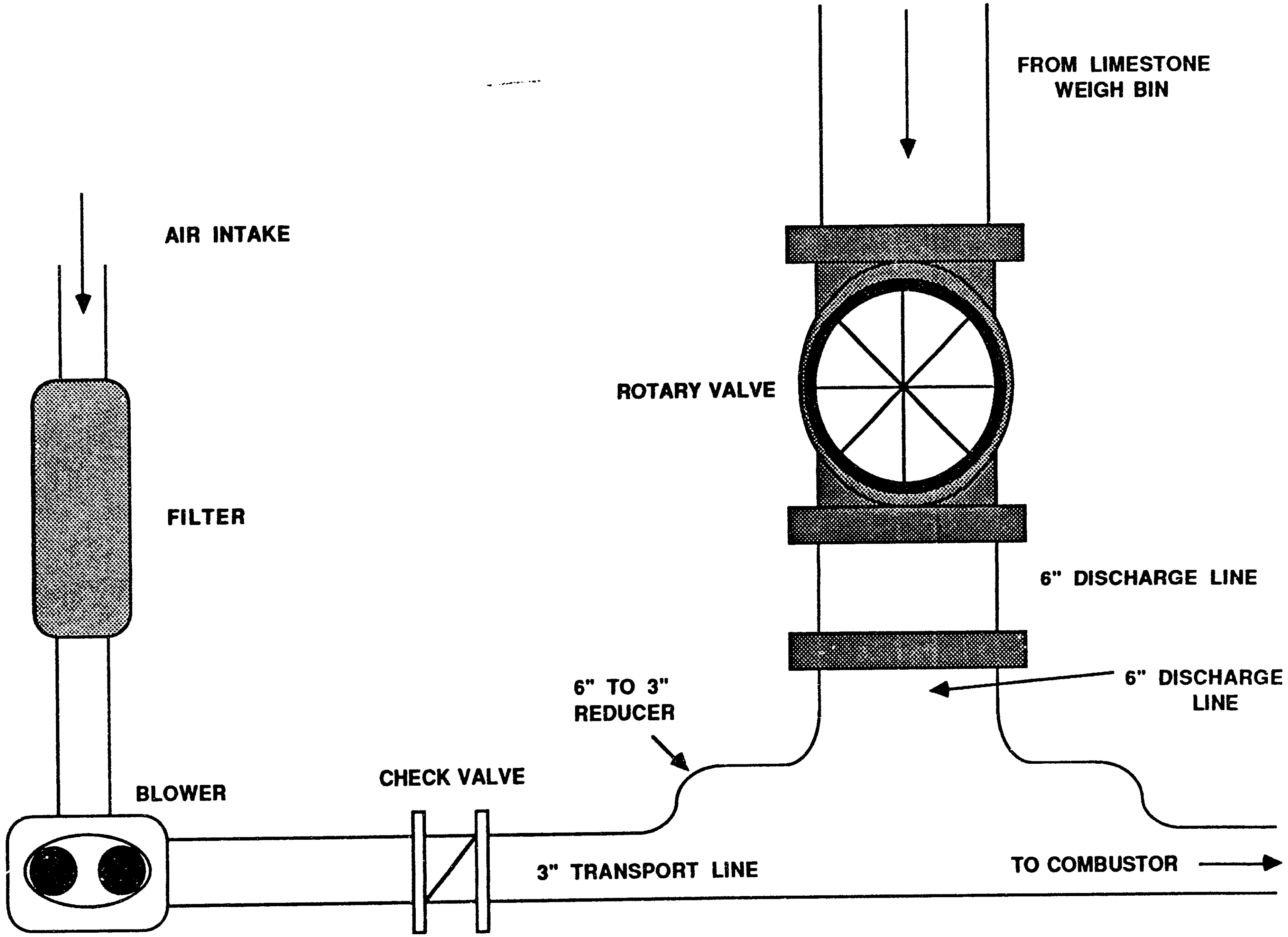


FIGURE 10-8. Limestone Feeder Transport System (typical of 4 per feeder).

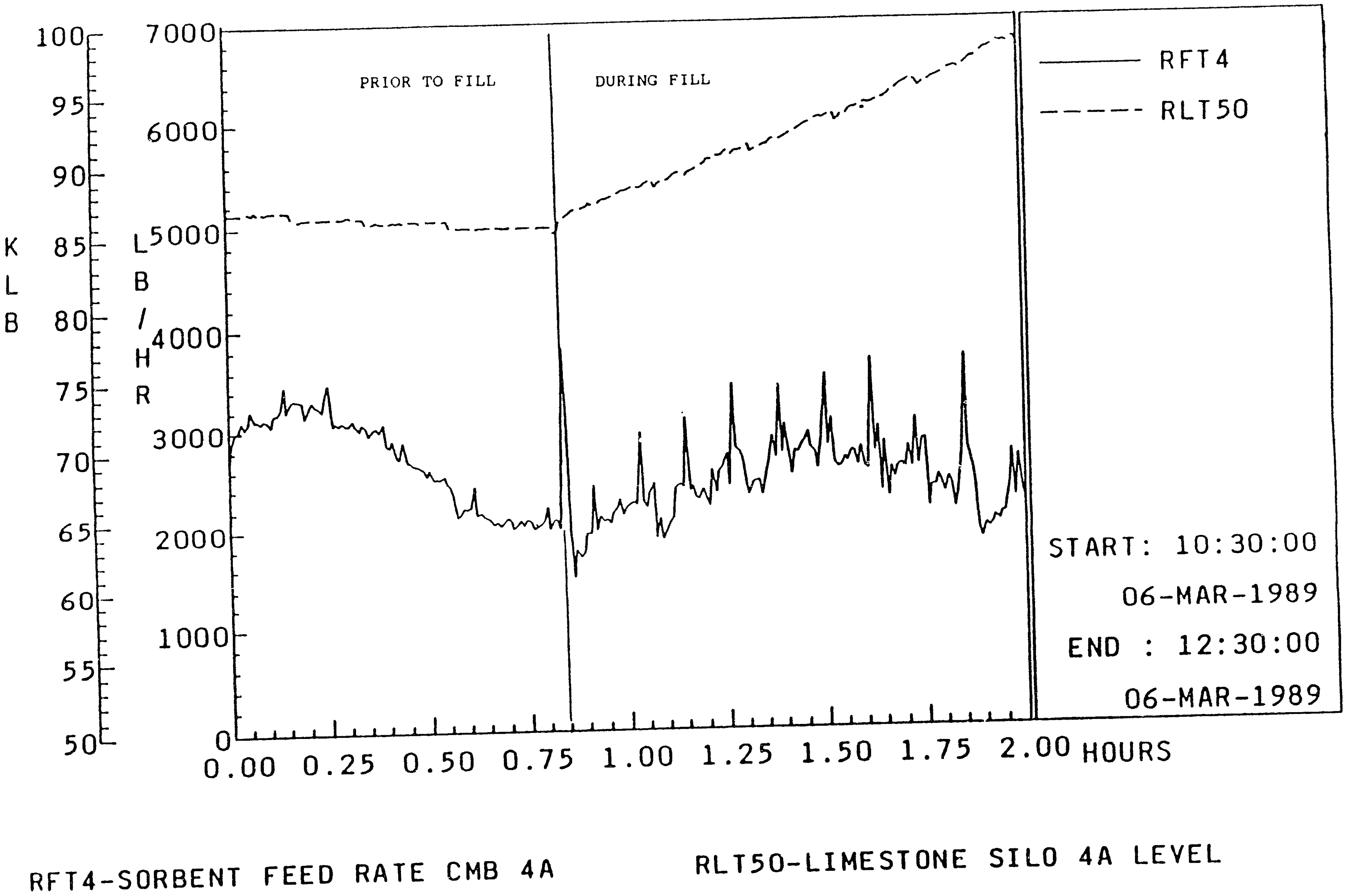


Figure 10-9. Effect of Limestone Silo Filling on the Feed Rate Signal from the Limestone Feeders.

Although limestone feeder performance was generally good at low limestone feed rates, i.e., below 4000 lbs/h per feeder, some shaker motor trips occurred at very low limestone feed rates below 1000 lbs/h. In these situations, the feed rate is usually reestablished after resetting the weigh feed system.

To circumvent the above problems and improve overall performance, new overload relays were installed during the quarter to prevent tripping of the shaker motors during low load operation. In addition, the 4B limestone feeder was instrumented and operated at flow rates up to 12,000 lbs/h. Test results revealed that the system became unstable above 6000 lb/h. Pressure measurements made at various locations on the feeder and vent system indicated rapid build-ups in pressure below the feeder cone prior to flushing of prepared limestone past the shaker cone. This was believed to result from excessive transport air leakage across the internal clearances of the rotary valves coupled with insufficient venting capacity.

4th Quarter 1989. During the last quarter of 1989, several modifications were made to the limestone feeder vent system. From test results during the previous quarter, blockage of the vent system was believed to be a cause for poor overall performance of the limestone feed system, particularly at high limestone feed rates. After several modifications, the vent line from the top of the weigh feeder was routed to the top of the coal storage silo, as opposed to the limestone storage silo. Although the demonstration program was concerned about possible contamination of the coal samples with limestone from the vent system, the desirability of a stable and reliable limestone feed system out-weighed these concerns. The new vent system was not tested for an adequate period of time at high limestone feed rates by the conclusion of 1989 to determine if problems were corrected. A full evaluation will be completed during high sulfur coal acceptance tests scheduled for early 1990.

Section 11

ASH HANDLING SYSTEM PERFORMANCE AND OPERATING EXPERIENCE

This section summarizes the operating experiences of the fly ash and bottom ash disposal systems during 1989. The fly ash disposal system has operated well on both design "A" and high ash (up to 35 wt.%) design "B" coals. Although capacity has been demonstrated, the system continues to require a degree of maintenance due to erosion in the transport line, separation equipment and high pressure drop on the transport system baghouse. The bottom ash disposal system required a major modification during the previous reporting period in order to increase the capacity of disposal equipment downstream of the ash coolers. This modification has been effective during operation on high ash design "B" coals. During 1989, a water spray cooling system was added to the ash coolers to reduce high temperatures experienced while burning high ash coal. The performance of these systems is discussed below.

11.1 SYSTEM DESCRIPTIONS

11.1.1 Bottom Ash Removal and Disposal System.

The bottom ash removal and disposal system provides for the classification, removal, cooling, transfer, storage, and disposal of bottom ash from the boiler. The system also provides for reinjection of bottom ash from the storage silo back into the combustion chambers for boiler start-up. The system includes all equipment from the combustion chamber sidewall bottom ash ports to the truck loading facility and the reinjection equipment. A schematic of the system is shown in Figures 11-1 and 11-2.

As coal and limestone are fed into the combustion chambers, the inventory of bed ash particles increases. This causes a measurable increase in the pressure required to support and circulate the weight of the bed. The pressure, and consequently the bed inventory, is controlled by extracting bed ash through the bottom ash removal system. Hot 1600°F bottom ash is removed through bottom ash ports located on the outside walls of the lower combustion chambers.

Two 100% capacity fluid bed bottom ash coolers are used to cool and classify bottom ash before it is drained through rotary valves. One variable speed rotary valve is located under each ash cooler. The cooling mediums for the bottom ash coolers consist of water walls and air provided by an ash cooling fan. The water walls are included in a closed loop

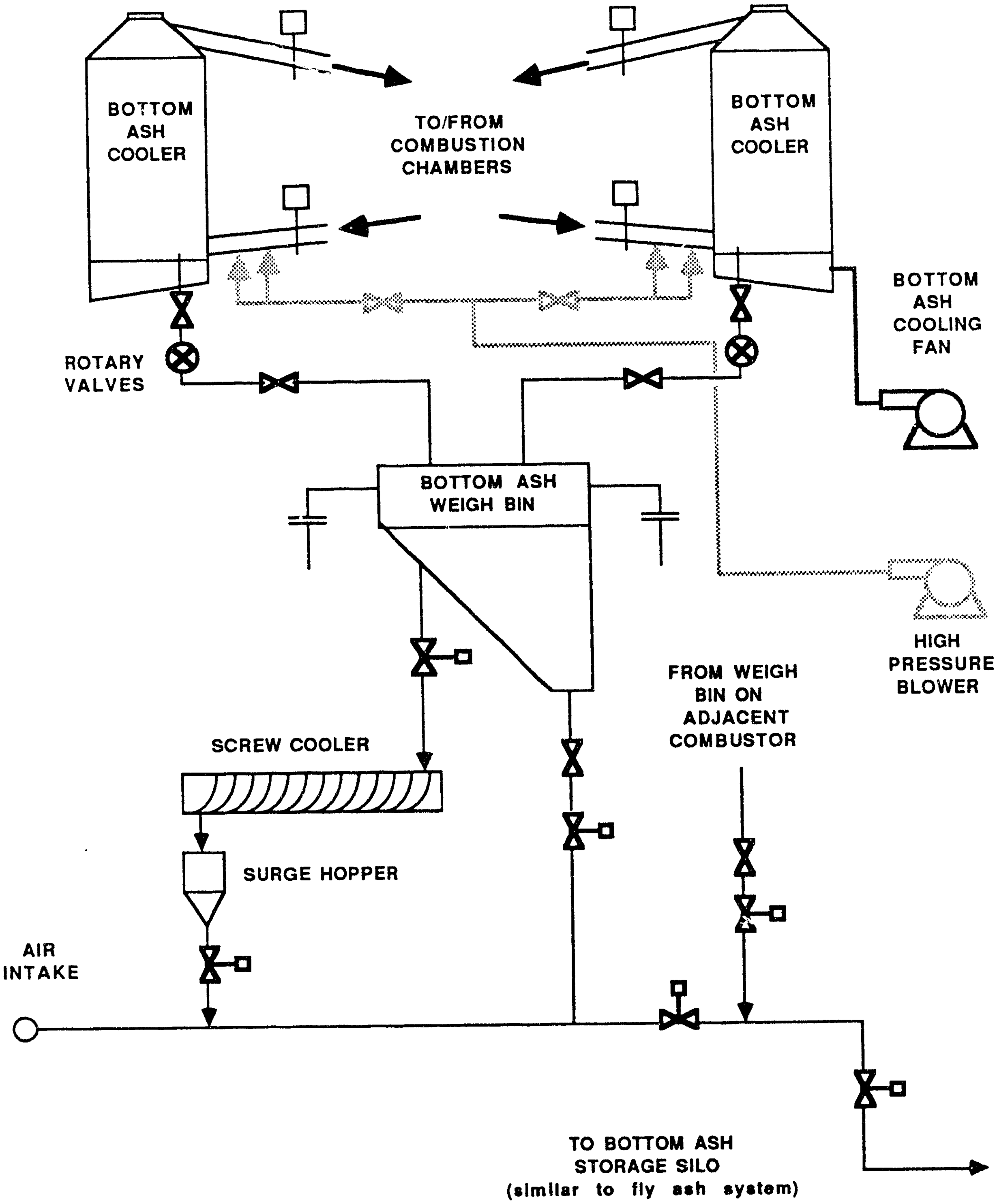


Figure 11-1. Schematic of Bottom Ash Removal System (typical of two).

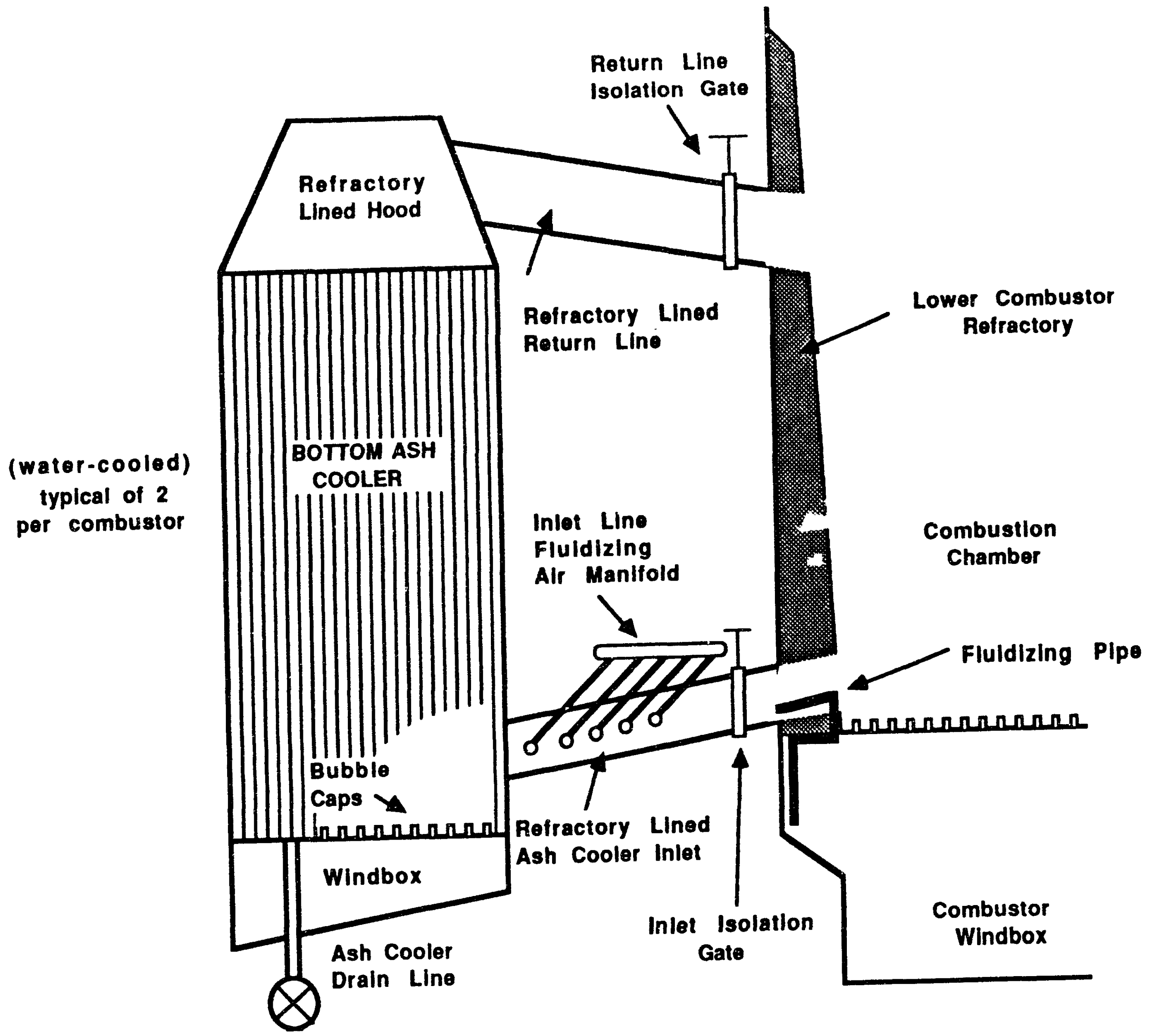


Figure 11-2. Bottom Ash Cooler Arrangement.

cooling water system which recovers heat from the bottom ash and transfers it to the low-pressure feed water system. A single fan provides air to the bottom ash coolers to cool and classify the ash.

Ash is admitted to the bottom ash coolers by means of inlet fluidizing nozzles which maintain a preset range of pressures in the ash coolers (see Figure 11-2). The cooling air and classified bed material flow from the top of the bottom ash coolers to the combustion chambers via upper return ports. Bottom ash is removed from each cooler through a drain line containing a variable-speed rotary valve. The speed is regulated by the operator to control the inventory of bed material in the ash coolers. Two fluid bed ash cooler serve each combustion chamber and discharge into a single bottom ash surge hopper which is mounted on load cells.

When a single bottom ash cooler is operating on one combustion chamber, the expected ash exit temperature is approximately 450°F and requires additional cooling. For this reason, a separate water-cooled screw conveyor is installed near the outlet of the surge hopper to provide additional cooling. During normal operation of the boiler, either both ash coolers or one ash cooler and the screw cooler on each combustion chamber are required. This arrangement provided the plant with redundancy should maintenance or repairs be necessary on one of the ash coolers. The heat removed from the screw coolers is also rejected to the closed cooling water system.

A 20 ton/h vacuum-type pneumatic conveying system is provided to transfer the bottom ash from the surge hoppers, or from the screw coolers, to the existing bottom ash storage silo. A continuously operating cyclone separator and pulsed-jet bag filter are installed on the silo roof to separate bottom ash from the conveying air. Two existing vacuum blowers, one operating and one spare, have been reconditioned and upgraded to provide the conveying motive force.

A pressurized ash reinjection subsystem is provided as part of the bottom ash handling system, which includes one gravity airlock feeder for transferring ash from the storage silo to a pressurized pneumatic conveying line. This pneumatic system conveys bottom ash back to each combustion chamber through a single reinjection port located in the loop seals on the rear wall of each combustion chamber. A single blower provides the pressurized conveying medium.

11.1.2 Fly Ash Disposal System.

The fly ash handling system provides for removal, transfer, storage, and disposal of fly ash from hoppers located on the bottom of the convection pass, air heater enclosures, and the old and new baghouse hoppers. Fly ash is transported to a 720 ton capacity storage silo before being discharging via a conditioning system to trucks for disposal. The system includes all fly ash handling equipment and components from the various collection hoppers to the fly ash storage silo and the truck loading facility. The system is shown schematically in Figure 11-3.

Two independent 27 ton/h, vacuum-type pneumatic conveying systems are provided to transfer fly ash from the collection hoppers to a new fly ash silo. One system serves the three existing baghouses; the second system services the new baghouse, the boiler convection pass hoppers and the air heater hoppers.

Fly ash is conveyed to a new 60,000 cubic foot mass flow storage silo. The two trains operate continuously and each have cyclone separators operating in series with pulsed-jet bag filters. The bag filters are sized for a maximum air-to-cloth ratio of 3.5 $acfm/ft^2$. Three identical vacuum blowers are provided; one for each fly ash conveying network and one spare.

A fly ash silo rotary drum unloader/conditioner with a capacity of 160 tons/h is provided. The unloader is fed by a screw feeder equipped with a charge hopper and operates on a batch basis. The unloader mixes a controlled amount of water with the fly ash to prevent dusting during unloading, transport, and disposal.

11.2 OPERATING EXPERIENCE

11.2.1 Bottom Ash Removal and Disposal System

During the previous reporting period in 1988, the bottom ash transport system was modified to increase disposal capacity to guaranteed levels. During 1989, operational tests were conducted on high ash and high sulfur coals as part of the unit acceptance test plan. These tests were included as part of the contractual acceptance test plan to assure proper capacity and performance of the solids feed and disposal systems. Trial tests were conducted on several occasions during 1989 and the following limitations were identified with the bottom ash disposal equipment:

- During trial acceptance tests on high ash coal in April 1989, the ash cooler inlet line from combustor A became blocked (see Figure 11-2). When this occurs on both ash coolers on one combustion chamber, it is no longer possible to remove bed material and solids inventory slowly increases in the lower combustion chamber. Although blockage of the inlet lines occurs periodically during operation on low ash Salt Creek coal, it became more frequent during operation on the high ash coal. This is

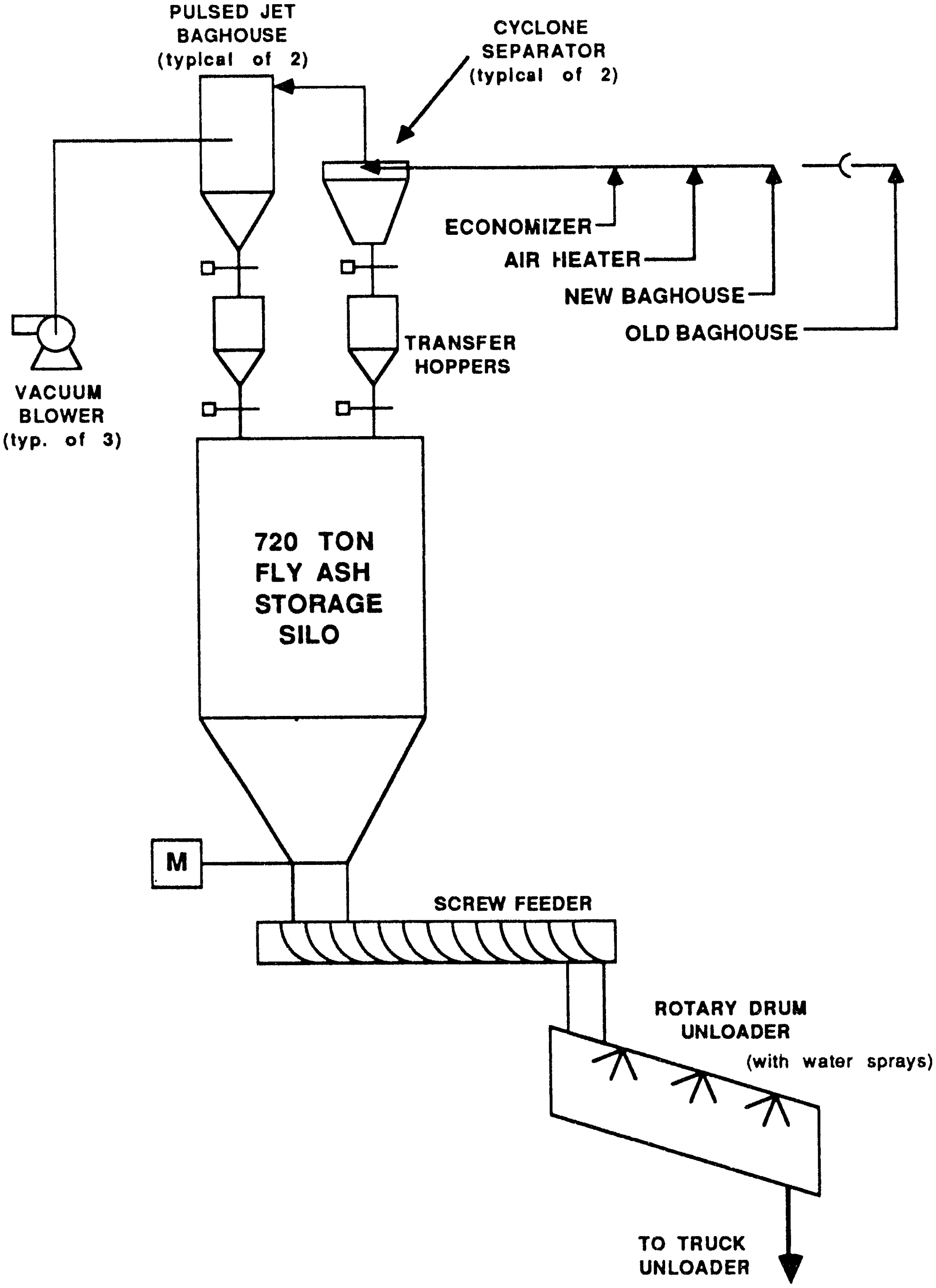


Figure 11-3. Schematic of Fly Ash Disposal System.

primarily due to the quantity of large-sized rock, or parting material, present in the incoming coal stream. During this period, the problem was exacerbated by badly worn hammers on the tertiary crushers.

To clear the blockage, operators insert an air lance through a port on the back side of the ash cooler which is aligned with the inlet line from the combustion chamber. The air lance is moved through the ash cooler and into the inlet line to clear blockages which occur. However, because the fluidizing pipe, situated at the entrance to the ash cooler inlet line in Figure 11-2, is not anchored on the side facing the ash cooler, this pipe was bent upwards by the air lance. When this occurs, it is impossible to free the inlet line.

To correct this problem, the unit was shut down in April 1989 and the fluidizing pipe was modified by anchoring the free end of the pipe into the refractory-lined ash cooler inlet line. The wall thickness of the fluidizing pipe was also increased. Since this modification to each of the four bottom ash coolers, there have been no further problems during the reporting period. On one occasion in December 1989, the inlet of one of the ash coolers became blocked with a piece of refractory and could not be cleared. The refractory was cleared during a scheduled plant outage.

Each combustion chamber is equipped with two ash coolers and one screw cooler for bottom ash removal (see Figure 11-1). One of these three coolers was installed for redundancy in the event that one of the coolers required removal for servicing or repairs. In other words, under normal operating conditions, one or the other of the ash coolers and the screw cooler, or both ash coolers (no screw cooler) were to be in service.

However, during operation on high ash coal, both ash coolers and the screw cooler were required to reduce bottom ash temperatures to acceptable levels. This level is set by the maximum permissible temperature at the inlet of the baghouse located on top of the bottom ash storage silo. Even with this off-design operating configuration, temperatures exceeded the maximum safe limit of the baghouse fabric while operating at full load on high ash coal. As a result, emergency water sprays were added to the ash coolers to reduce operating temperatures during operation on high ash coals.

During this reporting period, several iterations were made to the spray nozzle design, the water control hardware, and the controls logic. These modifications were made to correct several problems including impingement of spray water on the ash cooler water walls which caused a tube leak, and overspray which resulted in agglomerations in the ash coolers and drain line. The new design consisted of two retractable water probes on each ash cooler. Controls logic is tied into the plant's distributed control system. Spray flow is initiated if ash cooler operating temperatures are greater than 650°F or if the discharge temperature from the cooler exceeds 350°F.

In mid-November 1989, acceptance testing resumed on high ash coal with sulfur content of approximately 0.8 wt.% and an ash content of 26 wt.%. This is less than the specified level of 35 wt.% for design "B" coal due to exhaustion of these supplies from local mines. The tests were completed on 11/16/89 and final results were under review at the conclusion of the reporting period. The water sprays were removed from the ash coolers on 12/3/89 following the switch back to low ash Salt Creek coal. Ash cooler water sprays are not required for low ash fuels.

- A surge hopper is located at the outlet of each of the two water-cooled screw coolers. Bottom ash is sequentially discharged from each of the two surge hoppers into the common transport/disposal line. During the hold period for the idle surge hopper, bed material in the screw cooler would fill the surge hopper and eventually pack around the screw at the discharge end. This was primarily a problem with high ash fuels. Following the switch back to low ash fuels, modifications to the transport lines discussed in the Start-Up through 1988 Annual Technical Progress Report, and adjustments to the timing logic; this problem was corrected.

- On May 14, 1989, the bearing on the end of the screw shaft on one of the ash coolers failed and scorched the shaft. The screw was removed from the water-cooled casing and was remachined. A revised bearing lubrication schedule was instituted and there were no additional problems during the reporting period.

11.2.2 Fly Ash Disposal System

The fly ash disposal system has operated well during this reporting period. The system has demonstrated capacity and performance on high ash and high sulfur design "B" coals, design "A" Peabody coal, and Salt Creek coal. Some degree of maintenance has been required due to particle erosion. This continues to occur on bends located in the transport line, around the dump valves on each side of the transfer hoppers, and on the three-way valves located in vent lines. These vents are located on the lock hoppers between the cyclone separator and the fly ash storage silo.

As in the previous reporting period, the bag filters located downstream of the cyclone separator have plugged on several occasions during full-load operation. To restore a normal baghouse differential pressure, operators shut down the transport blowers and allow the baghouse pulsed-jet cleaning system to time through several cycles. There have been several occasions where curtailments in unit output have been required or unscheduled outages were caused by this equipment.

Section 12

BAGHOUSE OPERATION AND PERFORMANCE

12.1 OPERATIONAL AND PERFORMANCE DATA

Measurements made during the reporting period included inlet and outlet particulate loadings with both Peabody coal and Salt Creek coal. Inlet and outlet size distribution and fractional collection efficiency was calculated for Salt Creek coal. Chemical and physical analyses of the baghouse ash were performed for both coals. Flow rate and pressure drop measurements, and individual baghouse flow monitor (IBFM) measurements were also made on individual bags to compare two types of bag construction (warp-in versus warp-out). Results of these measurements are discussed in separate sections below.

12.1.1 Inlet and Outlet Particulate Loading

Inlet and outlet particulate loading measurements were made twice during 1989. The first time was on June 20 and 21, 1989 when the unit was burning Peabody coal. These tests were conducted around the unit 4 baghouse. The second test was conducted using Salt Creek coal on September 19 and 22, 1989, again around the unit 4 baghouse. Table 12-1 gives the results of both test periods.

On June 20 and 21, 1989, isokinetic measurements of the inlet and outlet dust loadings were taken around baghouse 4. These measurements were taken just after test A08 was completed, and operating conditions were not changed from this test. Isokinetic measurements of inlet and outlet dust loadings were made on both days. The inlet mass flow rate of solids was 7,350 lb/hr on June 20 and 7,066 lb/hr on June 21. The outlet mass flow rate of solids was 7.762 lb/hr on June 20 and 6.02 lb/hr on June 21. Collection efficiency averaged over the two days was 99.905%. The particulates emissions from these two tests averaged 0.0125 lb/MMBtu, which is well below the New Source Performance Standards (NSPS) of 0.03 lb/MMBtu.

On September 19 and 22, 1989, isokinetic tests were conducted while the unit was firing Salt Creek coal. During these test periods, two 96-minute tests were conducted each day at both the inlet and outlet of baghouse 4. Also during this time period, tests were conducted to determine the size distribution of the inlet and outlet baghouse streams. The size distribution data is discussed in the next section. The

Table 12-1

Nucla Unit 4 Baghouse Inlet and Outlet Particulate Concentration Data

Date	Coal	Inlet					Outlet					Particulate Emissions lb/MMBtu	Efficiency %	Penetration % (2)
		Particualte Loading		Gas Flow		Temp °F	Particulate Loading		Gas Flow		Temp °F			
		gr/acf	gr/scf	acfm	scfm		gr/acf	gr/scf	acfm	scfm				
6/20/89	Peabody	3.56	6.40	241,840(1)	133,904(1)	299	0.0037	0.0068	243,376(1)	133,904(1)	292	0.0141	99.894	0.106
6/21/89	Peabody	3.42	6.16				0.0029	0.0052				0.0109	99.915	0.085
Average	Peabody	3.49	6.28	241,840	133,904	299	0.0033	0.0060	243,376	133,904	292	0.0125	99.905	0.096
9/19/89	Salt Creek	4.34	8.85	274,000	134,300	296	0.0017	0.0036	264,900	130,000	284	0.0069	99.959	0.041
	Salt Creek	4.39	9.14	256,700	123,300	309	0.0017	0.0034	245,000	119,200	291	0.0067	99.963	0.037
9/22/89	Salt Creek	4.34	8.76	244,900	121,400	297	0.0020	0.0040	242,900	121,100	279	0.0080	99.954	0.046
	Salt Creek	4.21	8.65	254,700	124,000	309	0.0018	0.0036	240,600	118,100	289	0.0071	99.958	0.042
Average	Salt Creek	4.32	8.85	257,575	125,750	303	0.0018	0.0037	248,350	122,100	286	0.0072	99.959	0.041

(1) Flow and temperature data taken from test A08. Values assumed constant for both days of testing.

(2) Penetration is defined as (100 - collection efficiency).

average inlet concentration of the baghouse for these tests was 8.85 grains/standard cubic foot (gr/SCF). The average outlet dust loading was 0.0037 gr/SCF. Collection efficiency averaged 99.959% and the particulate emissions averaged 0.0072 lb/MMBtu.

Based on these tests, it appears that the Salt Creek coal ash had a slightly better collection efficiency over the Peabody coal ash. This may be due to different properties of the two coal ashes, or to operational problems in the baghouse during the Peabody tests.

12.1.2 Flow Rate Versus Pressure Drop

Table 12-2 lists baghouse 4 performance data for a selected number of tests. The data are plotted in Figure 12-1 as flange-to-flange pressure drop versus air-to-cloth ratio. There is considerable scatter in the data, particularly at the lower loads. Figure 12-2 shows the tubesheet pressure drop versus the air-to-cloth ratio from this data compared to the data obtained from the TVA 20 MWe baghouse. This figure shows that the Nucla baghouse, using shake/deflate cleaning, appears to be operating at a lower ΔP than the cleaning methods used at TVA.

From Figures 12-1 and 12-2, it is difficult to determine if any of the coals operate at lower bag pressure drops. This is because of the large amount of scatter in the data. The reason for this scatter can be seen in Figure 12-3. This figure shows a plot of baghouse 4 and baghouse 1's pressure drop versus time for Peabody and Salt Creek coal during operation at 60 MWe and 101 MWe. Note that at 60 MWe the pressure drop across the bags takes between 7 and 8 hours to rise after cleaning up to the pressure where another cleaning cycle will start. Since a performance test is less than 8 hours long, the pressure drop averaged over this time period will be strongly dependent on the time in the cleaning cycle when the test was started. At full load, the pressure drop rise is so fast that the unit is cleaning almost continuously. For the Salt Creek coal the rise is such that the unit operates continuously in the slow clean cycle. The Peabody coal at full load cleans about once every 3 hours. These faster cycles will improve the accuracy of the average value, thereby reducing the scatter in the data. However, the slopes of these graphs do indicate that Salt creek is building a filter cake at a faster rate than Peabody coal. This observation is validated by the higher inlet dust loadings for Salt Creek coal in Table 12-1.

12.1.3 Inlet and Outlet Particle Size Distribution

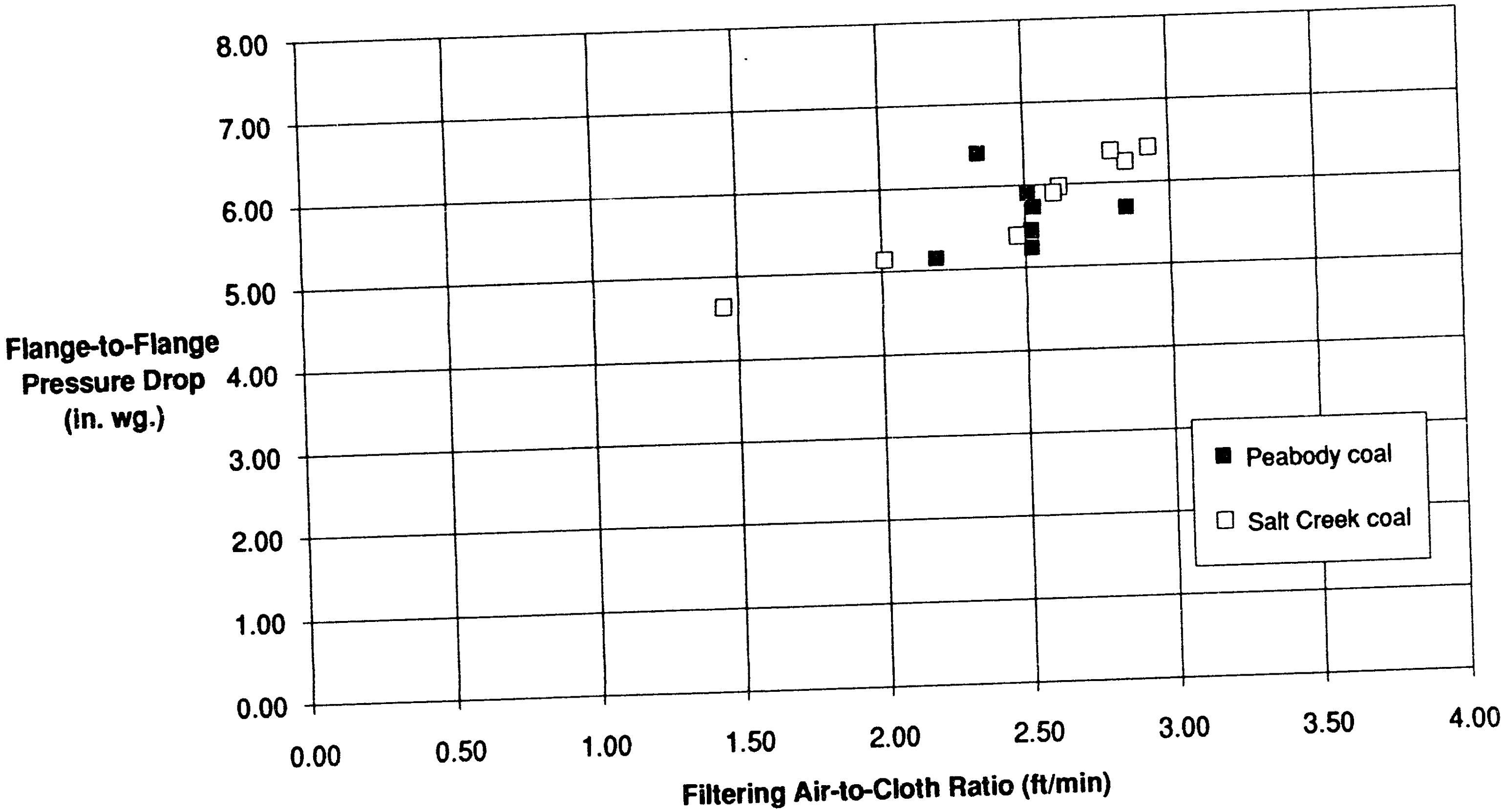
During the baghouse tests conducted from September 18 to 22, 1989, fly ash samples were collected to allow calculation of

Table 12-2

Nucla Unit 4 Baghouse Performance Data

Test Number	Date	Coal Type	Percent Oxygen	Load MWe	Ca/S Ratio	Air-Cloth Ratio	Baghouse ΔP in.wc.	Inlet Temp °F	Outlet Temp °F
PHM1,2	3/7/89	Peabody	4.2	100	1.79	2.52	5.45	-	-
PHM5a,6	3/8/89	Peabody	4.1	100	1.84	2.52	5.25	-	-
A01	4/21/89	Peabody	4.0	82	1.50	2.85	5.70	293	280
A07	5/26/89	Peabody	5.5	55	1.50	2.19	5.15	264	254
A04	6/6/89	Peabody	3.5	82	1.50	2.34	6.40	290	278
AO8	6/19/89	Peabody	3.3	104	1.50	2.51	5.91	298	268
FGAS4	6/20/89	Peabody	-	104	1.50	2.53	5.73	-	
SD1	3/13/89	Salt Creek	3.9	105	1.41	2.85	6.25	290	278
P30	3/20/89	Salt Creek	5.7	55	1.50	1.45	4.65	275	260
P31	3/21/89	Salt Creek	4.0	82	1.50	2.01	5.15	285	275
P50	7/19/89	Salt Creek	3.5	98	3.54	2.47	5.40	299	292
P39	8/9/89	Salt Creek	6.0	55	2.60	2.62	5.97	283	282
P52	8/17/89	Salt Creek	6.3	55	2.80	2.93	6.42	281	272
P55	11/29/89	Salt Creek	3.3	108	4.76	2.80	6.39	286	267
P56	11/30/89	Salt Creek	2.3	108	5.10	2.60	5.90	286	274

Figure 12-1. Nucla Baghouse #4 Pressure Drop Versus Air-to-Cloth Ratio for Peabody and Salt Creek Coal



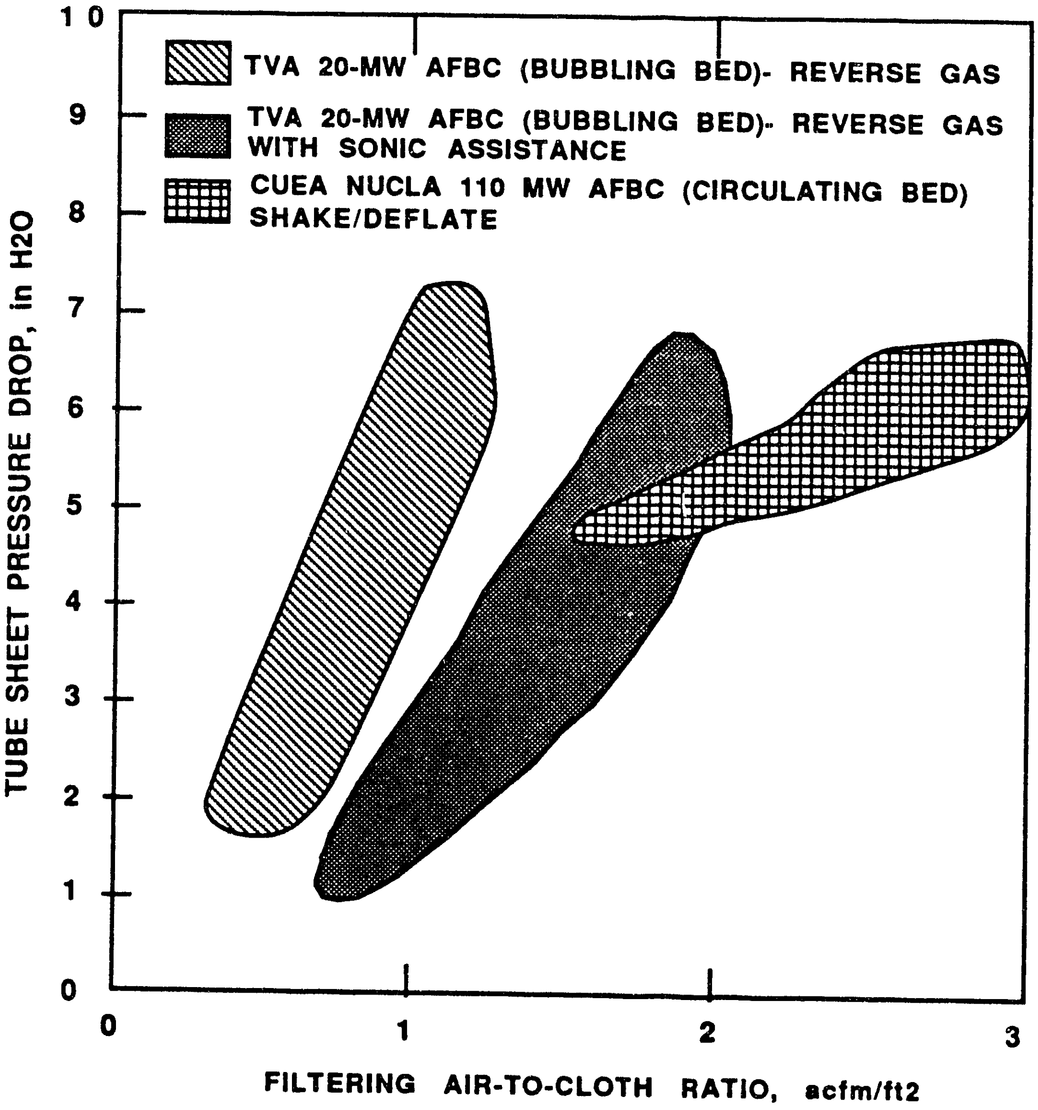


Figure 12-2. Comparison of tubesheet pressure drop versus air-to-cloth ratio for the Nucla #4 baghouse and the TVA 20MW AFBC baghouse.

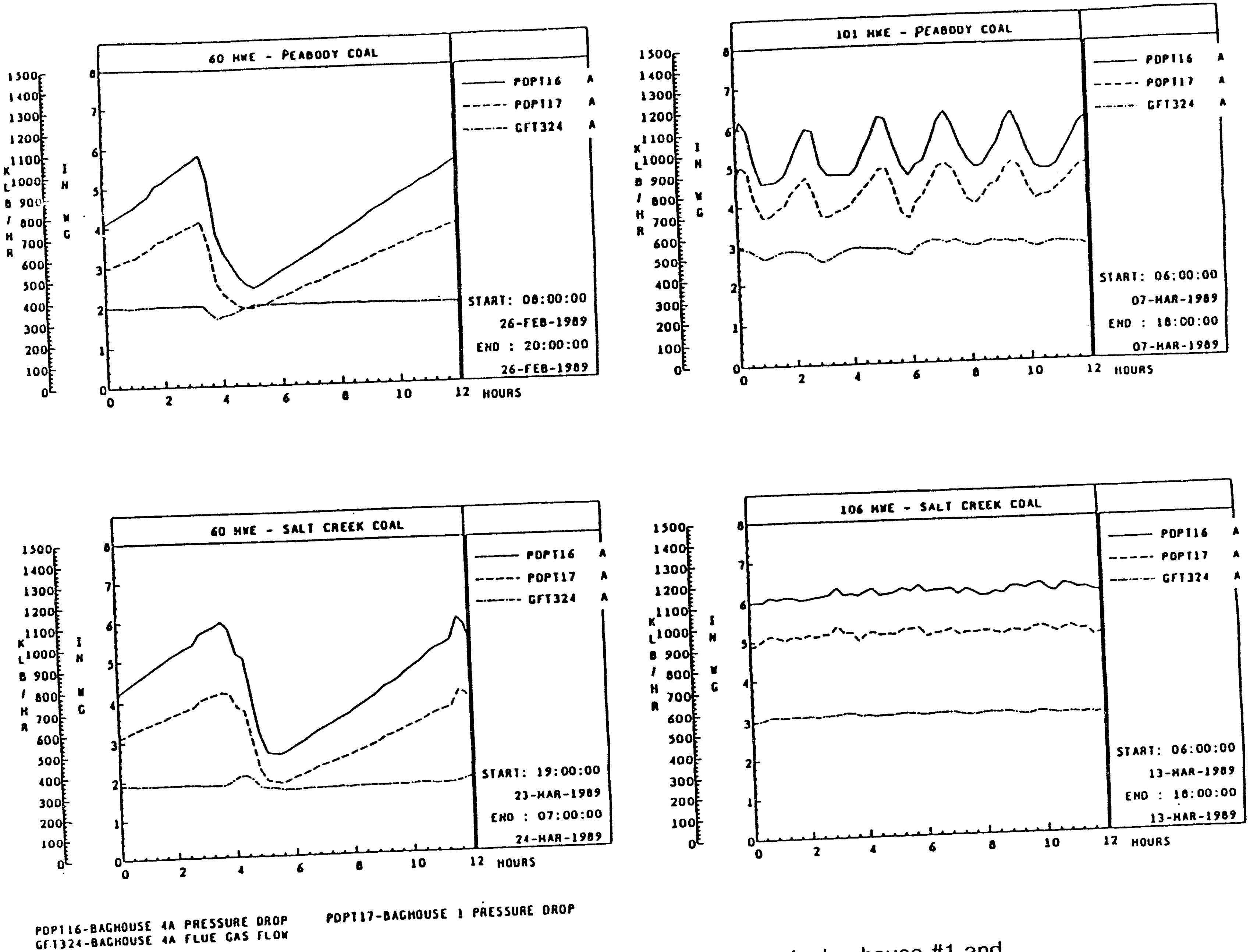


Figure 12-3. Pressure drop versus time data for baghouse #1 and #4 for Salt Creek and Peabody coals at 60 MW and 101 MW.

the fractional collection efficiency of the baghouse. Particle size distribution measurements were conducted at the inlet and outlet of baghouse 4. Sixteen inlet measurements were made using six-stage modified Brink Cascade Impactors with a cyclone precollector. Eight outlet size distributions were made using seven-stage University of Washington Mark III Source Test Cascade Impactors with an impaction-type precollector.

The mass median diameter (physical) of the particles in the inlet flue gas stream was determined to be 17.3 microns. The mass median diameter of the outlet stream was determined to be 8.3 microns. However, further analysis of the data by Southern Research Institute (SoRI), the contractor that performed the tests, revealed that the inlet particle size data were biased toward the larger particles. This was due to the small diameter nozzle required on the Brink Impactors for isokinetic sampling and the subsequent impaction losses that occurred in the cyclone precollector due to high gas velocity exiting the nozzle. In order to obtain information on the baghouse inlet particle size distribution, the mass samples collected during measurements of the inlet mass concentration (using EPA Method 17) were submitted for particle size classification. The samples were analyzed by SoRI using a BACHO analyzer.

The particle size distribution curve for the baghouse inlet sample is shown in Figure 12-4. This graph shows the cumulative weight percent of the inlet sample obtained by the BACHO analysis. The inlet distribution below 1.5 microns was estimated due to the fact that the BACHO is not able to fractionate below this particle size. The mass median diameter of the inlet sample was 7.1 microns, which is considerably smaller than the size determined by the impact cascaders. The outlet particle size distribution data are presented in Figure 12-5. This graph shows the data presented in the same manner as Figure 12-4. The mass median diameter of the outlet dust is 8.0 microns, indicating that the baghouse apparently has a higher collection efficiency on smaller particles.

The data in Figures 12-4 and 12-5, along with the data in Table 12-1, were used to calculate the fractional collection efficiency for the baghouse. The results of this calculation are shown in Figure 12-6. This figure shows that the collection efficiency does drop off slightly as the particle size increases.

12.1.4 Chemical and Physical Properties of Ash

Five samples of dustcake ash were removed from baghouse 4 and were analyzed by SoRI. Three of the samples were taken during operation with Salt Creek coal and two were taken

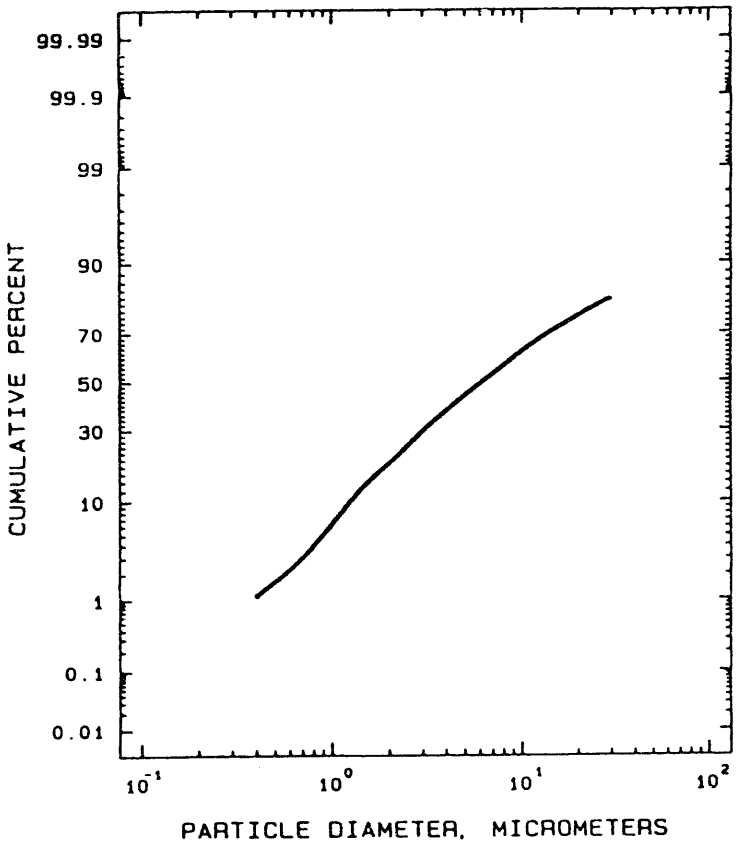


Figure 12-4. Average cumulative percent mass less than indicated size for the Nucla Unit #4 baghouse inlet September 19-22, 1989

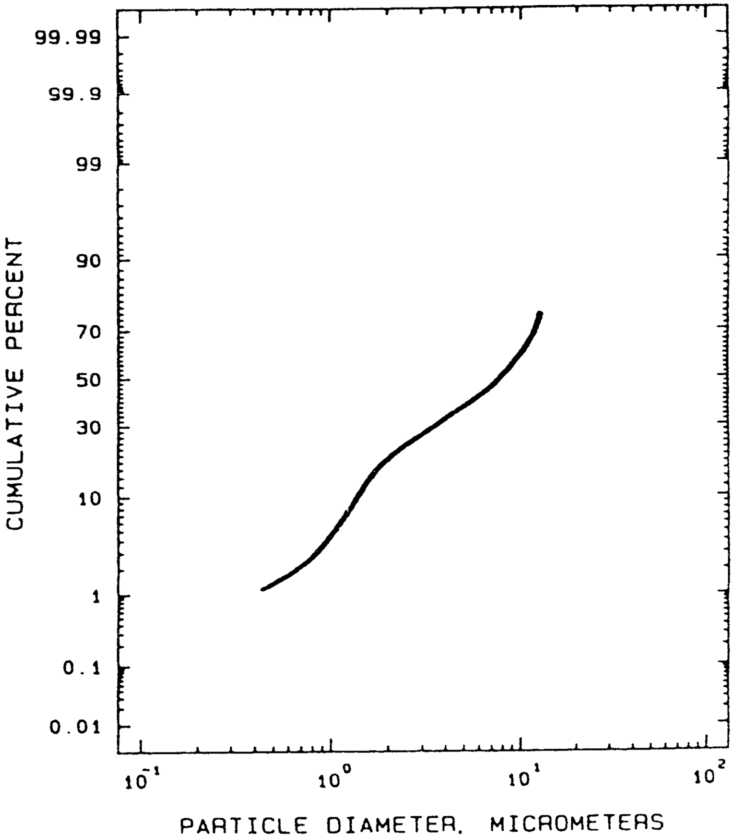


Figure 12-5. Average cumulative percent mass less than indicated size for the Nucla Unit #4 baghouse outlet September 19-22, 1989

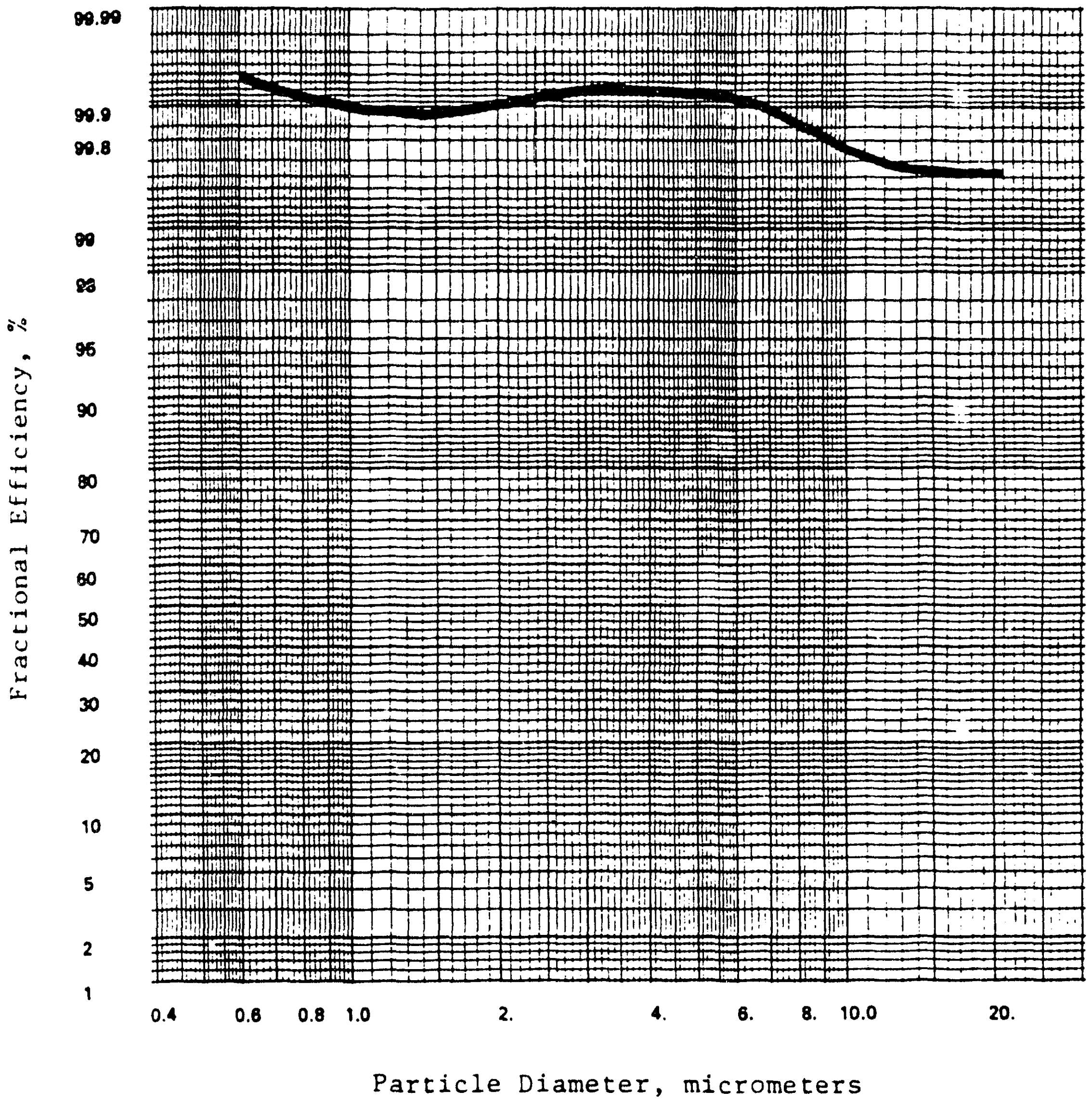


Figure 12-6. Average fractional efficiency versus particle size for the Nucla Unit #4 baghouse, September 19-22, 1989

during operation with Peabody coal. No samples were obtained during operation with Dorchester coal.

The results of the analyses are given in Table 12-3. The Salt Creek coal was found to have a higher gas flow resistance factor. The Salt Creek coal was also found to have a slightly smaller particle size. These analyses indicate that under identical operating conditions, the Salt Creek coal should operate at a higher baghouse ΔP than the Peabody coal. The increased ΔP combined with the higher inlet dust loadings can explain the operating curves that were discussed in Section 12.1.2.

12.1.5 Comparison of Warp-in Versus Warp-out Bags

Comparison of the warp-in versus warp-out bag material concentrated on measurements of the residual dust cake and measurements made with the IBFM meters. As was stated in the Start-Up through 1988 Annual Technical Progress Report, the experimental warp-in bags were installed in compartment Q of baghouse 2. The remainder of the bags in all of the baghouses were constructed with the warp-out configuration, with 75% of the texturized fill yarns facing the dirty gas. The warp-in bags in compartment Q of baghouse 2 have only 25% of the texturized yarns facing the dirty gas. IBFM flow meters were installed in six bags in compartment 2Q. Six monitors were also installed in compartment P of baghouse 2 and an additional five monitors were installed in compartment E of baghouse 4.

Bags from compartments 2Q, 2P, and 4E were removed and weighed just after a cleaning cycle to determine the weight of the residual dust cake. Three bags were removed from compartment 2P. These measurements were made during the third quarter of 1989. The weights of these bags were 12, 11, and 16 lbs. An additional four bags were removed from compartment 4E. These bags were found to weigh 15, 14 ,16, and 17 lbs. The average weight of the warp-out bags was 14.4 lb. Six bags removed from compartment 2Q were found to weigh 8, 6, 7, 6, 6, and 6 lbs, for an average weight of the warp-in bags of 6.5 lbs. A clean new bag weighs 4 pounds. Thus the residual dustcake weight was 10.4 lb for the warp-out bags and 2.5 lb for the warp-in bags. The residual dustcake areal density was 0.23 lb/ft^3 for the warp-out bags and 0.06 lb/ft^3 for the warp-in bags. These tests indicate that the warp-out bag retains a significant amount of dust cake compared to the warp-in bags.

Table 12-4 shows the IBFM results from compartments 2P and 2Q of baghouse 2. This data shows that there is apparently no significant difference between the two bags, despite the considerable differences in the residual dust cake. This result indicates that the residual dust cake does not

Table 12-3

Summary of Laboratory Analyses of Dustcake Ashes

Coal	Date Obtained	Equilibrium PH	Measured Diameters, microns			Specific Surface Area m^2/g	Compacted Bulk Porosity %	Density g/cc	Relative Gas Flow Resistance * wg min ft/lb	Morphology Factor	Effective Angle of Internal Friction *
			BACHO	Coulter	Drag-Equivalent						
Peabody	Apr-88	11.4	5.70	3.2	0.91	10.6	68.2	2.73	7.7	16.7	46.8
	Jan-89	11.2	6.49	8.8	0.91	16.1	71.5	2.65	5.8	65.9	48.0
Peabody	Average	11.3	6.1	6.0	0.9	13.4	69.9	2.7	6.8	41.3	47.4
Salt Creek	Mar-89	11.0	5.91	4.9	1.03	15.1	64.8	2.59	8.1	37.5	-
	Mar-89	11.0	4.98	4.4	0.92	15.3	65.5	2.58	10.3	34.3	-
	Sep-89	11.6	5.40	-	0.96	11.1	65.7	2.67	9.1	-	45.3
Salt Creek	Average	11.2	5.4	4.7	1.0	13.8	65.3	2.6	9.2	35.9	45.3

Chemical Analyses, wt %

Coal	Date Obtained	Li_2O	Na_2O	K_2O	MgO	CaO	Fe_2O_3	Al_2O_3	SiO_2	TiO_2	P_2O_5	SO_3	LOI	Soluble SO_4
Peabody	Apr-88	0.03	0.18	0.93	0.81	16.4	3.8	23.9	45.1	1.0	0.04	5.8	8.8	6.6
	Jan-89	0.02	0.24	0.72	0.73	14.7	8.0	23.2	41.6	1.1	0.05	7.8	10.0	8.2
Peabody	Average	0.03	0.21	0.83	0.77	15.55	5.90	23.55	43.35	1.05	0.05	6.80	9.40	7.40
Salt Creek	Mar-89	0.03	0.39	0.56	1.20	11.0	3.0	25.9	51.5	2.2	0.67	2.5	9.7	3.6
	Mar-89	0.03	0.40	0.55	1.20	11.0	3.0	26.2	50.8	2.2	0.72	2.6	9.8	3.7
	Sep-89	0.02	0.50	0.46	0.70	19.2	2.0	24.2	44.6	1.3	0.59	4.6	6.4	5.5
Salt Creek	Average	0.0	0.4	0.5	1.0	13.7	2.7	25.4	49.0	1.9	0.7	3.2	8.6	4.3

significantly contribute to the drag of the cleaned bag. Apparently the only dust that contributes to the residual drag is the dust that fills the interstices of the bag fibers.

Table 12-4
Average Flow and Pressure Drop Data
For Warp-in and Warp-out Bags

	Comp. 2Q Warp-In	Comp. 2P Warp-Out
Air-to-cloth ratio, acfm/ft^2	1.7	1.6
Pressure drop, in. wg.	5.5	5.1
Drag, in. wg./fpm	3.3	3.1
Residual drag, in. wg./fpm	2.3	2.2
Drag Coefficient, in. wg. min	13.7	13.9

12.2 SUMMARY OF BAG FAILURES

Between October 1988 and December 1989 a total of 326 bag failures had been reported. Table 12-5 lists the bag failures experienced at Nucla along with the reason for the failures. This number of failures represents approximately 7.8% of the total bags in all four baghouses. A total of 13 bags were replaced in baghouse 1, 269 in baghouse 2, 7 in baghouse 3, and 37 in baghouse 4. By far the highest rate of failures were experienced in baghouse 2.

The rate of bag failures appeared to be accelerating. During the last quarter of 1988, 123 bag failures were found. To study this problem, a representative of Southern Research Institute inspected the baghouse, along with members of the test team. The inspection was carried out in January 1989. This inspection revealed several deficiencies in the baghouses. Ash had accumulated on the clean side of all of the baghouses. Three collection trays were placed in compartments 4K and 4L at different elevations to help determine the source of these leaks. Several shaker arms in baghouses 1, 2, and 3 were found to be disconnected. Apparently when these baghouses were returned to service after several years of inactivity it was not possible to activate some of the shaker arms. The bag seams in all of the baghouses were oriented randomly, rather than in the same direction. This can cause bags to rub together during the deflate cycle. Also some bags sized for baghouse 4 were found installed in baghouse 2.

On January 18, a meeting was held to discuss the results of the inspections, and to determine a solution to the bag failure problem. A list of action items was developed. These included specific measurements of tubesheet pressure drops during operation and cleaning, to ascertain if the

Table 12-5

Page (1 of 2)

CUEA Nucla Station - Bag Failure Documentation

Date	Unit	Compartment	Number of Bags	Comment
10/5/88	2	S	1	Bottom of bag, ash abrasion
10/6/88	2	S	5	Bottom of bag, ash abrasion
10/7/88	1	T	3	Top of bag, 1 in. holes
	2	P	2	Bottom of bag, ash abrasion
	2	S	3	Bottom of bag, ash abrasion
10/13/88	2	S	3	Bottom of bag, ash abrasion
12/7/88	2	S	23	Bottom of bag, ash abrasion
12/8/88	2	P	24	Bottom of bag, ash abrasion
12/9/88	4	E	5	Rubbing on IFBM
	4	E	11	Bottom of bag, ash abrasion/impingement
12/22/88	2	Q	17	Bottom of bag, ash abrasion
12/28/88	2	S	26	Bottom of bag, ash abrasion
1/4/89	2	N	18	Bottom of bag, ash abrasion
1/16/89	1	R	3	Bottom of bag, ash abrasion
	1	S	1	Bottom of bag, ash abrasion
	2	N	8	Bottom of bag, ash abrasion
	2	P	5	Bottom of bag, ash abrasion
	2	Q	11	Bottom of bag, ash abrasion
	2	S	13	Bottom of bag, ash abrasion
	2	T	8	Bottom of bag, ash abrasion
1/17/89	2	R	4	Bottom of bag, ash abrasion
	4	E	1	Bottom of bag, ash abrasion
1/18/89	4	B	1	Rubbing on top railing
	4	E	5	Bottom of bag, ash abrasion
	4	F	1	Bottom of bag, ash abrasion
				Bottom of bag, ash abrasion
3/27/89	1	O	1	Bottom of bag, ash abrasion
	1	R	1	Bottom of bag, ash abrasion
	2	N	6	Bottom of bag, ash abrasion
	2	P	3	Bottom of bag, ash abrasion
	2	Q	1	Bottom of bag, ash abrasion
	2	R	2	Bottom of bag, ash abrasion
	2	S	3	Bottom of bag, ash abrasion
	3	Q	1	Bottom of bag, manufacturing defect
3/28/89	4	L	1	Bottom of bag, ash abrasion
6/6/89	2	S	5	Bottom of bag, ash abrasion
6/12/89	2	S	5	Bottom of bag, ash abrasion
	4	E	4	Bottom of bag, ash abrasion
6/14/89	2	Q	4	Bottom of bag, ash abrasion
9/17/89	2	Q	1	Torn by IBFM sensor
9/22/89	2	S	2	Bottom of bag, ash abrasio

Table 12-5

Page (2 of 2)

CUEA Nucla Station - Bag Failure Documentation

Date	Unit	Compartment	Number of Bags	Comment
9/25/89	2	N	12	Bottom of bag, ash abrasion
	2	T	3	Bottom of bag, ash abrasion
	2	P	3	Bottom of bag, ash abrasion
	2	Q	7	Bottom of bag, ash abrasion
	2	R	1	Bottom of bag, ash abrasion
	2	S	10	Bottom of bag, ash abrasion
9/26/89	1	R	1	Bottom of bag, ash abrasion
	1	S	1	Bottom of bag, ash abrasion
10/26/89	2	Q	2	Bottom of bag, ash abrasion
	2	S	5	Bottom of bag, ash abrasion
11/9/89	1	N	1	Bottom of bag, ash abrasion
	1	R	1	Bottom of bag, ash abrasion
11/21/89	3	S	2	Bottom of bag, ash abrasion
11/28/89	4	A	4	Bottom of bag, ash abrasion
	2	Q	5	Bottom of bag, ash abrasion
	2	P	4	Bottom of bag, ash abrasion
12/4/89	3	N	4	Torn approximately 1 ft from top
12/20/89	2	S	3	Bottom of bag, ash abrasion
12/21/89	2	S	1	Bottom of bag, ash abrasion
	2	Q	1	Bottom of bag, ash abrasion
12/26/89	2	Q	9	Bottom of bag, ash abrasion
	4	E	4	Ash impingement from failed adjacent IBFM gasket

Total Failures by Baghouse: Unit #1=13, Unit#2 =269, Unit #3 =7, Unit #4 = 37, Total = 326

Note: Ash abrasion is the primary or secondary cause for bag failure.

cleaning cycle could be contributing to the bag failure problem. Measurement, and adjustments to the deflate air flows, if needed, was also recommended. A final action item required a visual check of the baghouse cleaning cycle to determine if the system was functioning as designed.

The result of the inspection revealed the following observations:

- The cleaning sequence logic and timer settings for all four baghouses agreed with the manufacturer's recommended cleaning sequence.

- The shaker mechanisms in compartments 2N and 3Q did not operate. The shaker mechanism in compartment 3S attempted to operate, but appeared jammed. All shaker mechanisms in baghouse 4 operated correctly.

- All poppet valves and deflate butterfly valves operated properly in baghouses 1, 2, and 3. The outlet poppet valves for compartments 4E and 4F did not operate and the deflate poppet valve for compartment 4G did not operate.

- All compartment purge air poppet valves in baghouse 4 were observed to operate correctly. Each opened when the respective lower or upper compartment door was opened.

- The deflate air fan in baghouse 1 experienced repeated trips on motor overload while the baghouse was in the cleaning cycle. These trips were the result of a deflate air recirculation valve which indicated closed, but was fully open. Figure 12-7 shows the location of this valve. With both the deflate and recirculation valves open, the fan surged causing the motor to overload. The valve was repositioned, and no further trips have occurred.

A report from Grubb Filtration on the failure mechanism for five bags sent to them indicated that ash abrasion, compounded by over-inflation during cleaning, was the primary cause of the bag failures. On February 17, 1989, tests were conducted to measure the tubesheet pressure drops when the CFB was operating at 40 MWe. Measurements were made during normal operation and during the deflation air portion of the cleaning cycle. The following observations were made during these tests:

- The average deflate tubesheet pressure drop for baghouse 1 was 7.9 in. wg, for unit 2 it was 10.2 in. wg, for unit 3 it was 2.4 in.wg, and for unit 4 it was 1.5 in. wg. SoRI reported that these values were

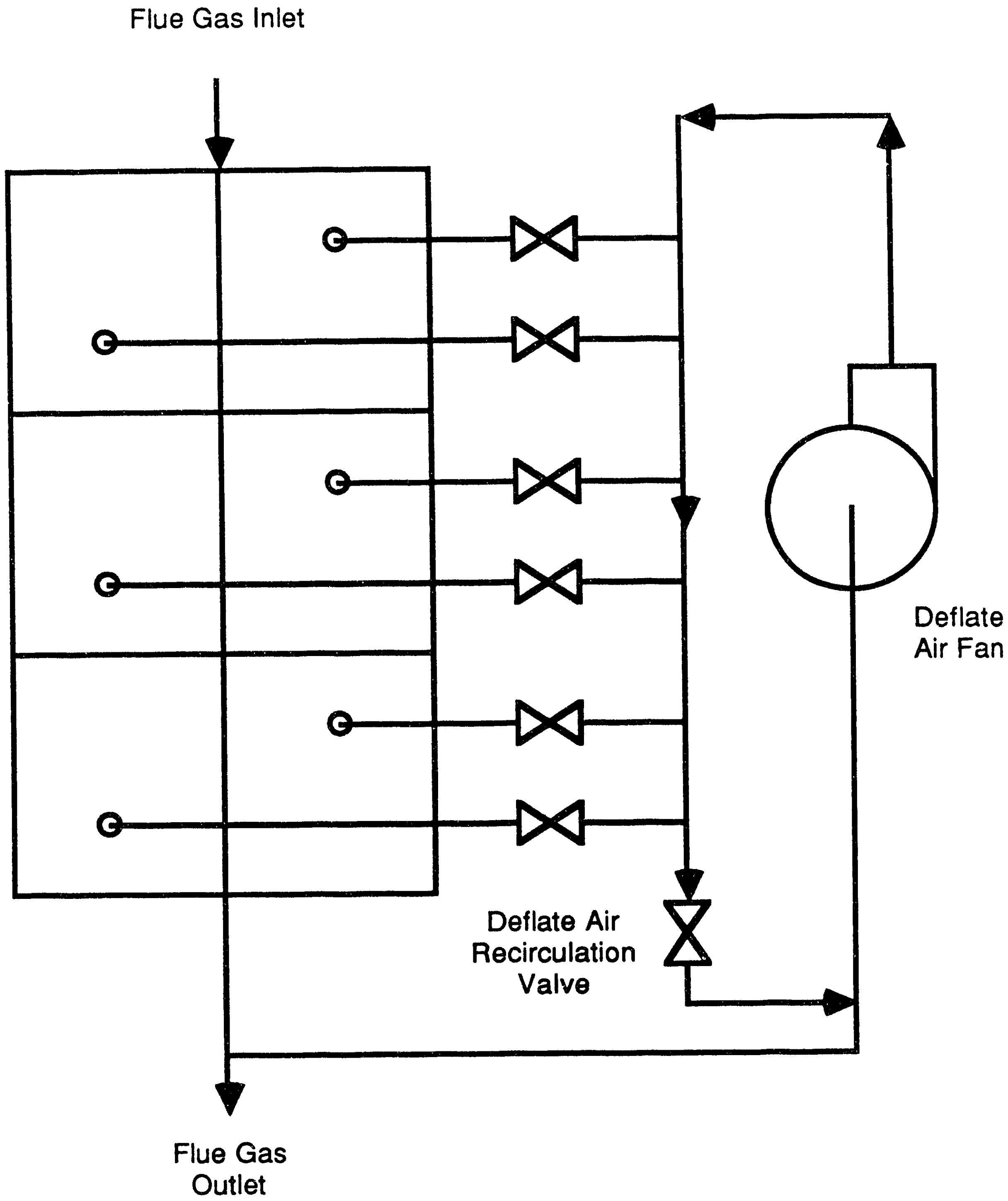


Figure 12-7. Baghouse Deflate Air Piping System

considerably higher than normal practice, which is in the range of 0.25 to 0.5 in.wg.

- As of the date of this test, 171 bag failures were experienced in unit 2. Unit 1 had only 3 bag failures. However, the deflate air damper to unit 1 was recently adjusted to match the air flow of unit 2. Thus it is quite likely that prior to this adjustment, which was made in January 1989, the deflate pressure drop was substantially lower than this measurement. No bag failures had been found in unit 3, and all 24 bags that failed in unit 4 were attributed to the IBFM sensors.

- The average in-service tubesheet pressure drop for all baghouses were in a normal range.

On March 8, 1989, the deflate air flows to baghouses 1 and 2 were reduced to match the tubesheet pressure drops in baghouses 3 and 4. A program was also implemented to replace all of the defective shaker mechanisms. This was completed by the end of 1989. Since the deflate air flows have been lowered, the rate of bag failures has decreased. In the older baghouses (units 1, 2, and 3) there were 107 failures during the fourth quarter of 1988, 90 in the first quarter of 1989, 18 in the second quarter, 37 in the third, and 38 in the fourth. The failure mechanism for most of these bags was found to be ash abrasion.

On March 27, another baghouse inspection was performed. The trays that were installed in baghouse 4 were removed and examined. The trays showed that the majority of the fly ash was collected in the lowest tray, indicating leakage around the tubesheet where the bags attach. Inspection of these seals found several instances of improper installation.

During the third quarter of 1989, EPRI presented five recommendations to Colorado-Ute to improve the bag life in the baghouses. These recommendations included:

- Replace, as necessary, all non-operational shaker arms on unit 1-3 baghouses.

- Reduce the deflation air flows to all four baghouses to provide tubesheet pressure drops in the range of 0.25 to 0.5 in.wg. at full load.

- Change the cleaning cycle logic such that the shaking cycle occurs after the deflate cycle, rather than during the deflate cycle.

- Change the cleaning cycle logic so that unit 1-3 baghouses and unit 4 baghouse initiate cleaning at the same time.

- Change the cleaning cycle times for unit 1-3 baghouses to 7 seconds delay for the fast cleaning cycle and 200 seconds delay for the slow cleaning cycle. Change the cleaning delay times for unit 4 baghouse to 10 seconds delay for the fast clean and 300 seconds for the slow cleaning cycle. This will make all four baghouses cycle in the same total time period.

Section 13

MATERIALS MONITORING PLAN

Several inspections of the boiler were completed during 1989 as part of the Demonstration Program's Materials Monitoring Test Plan. These inspections were made possible as the result of several extended unit outages to repair and modify equipment outlined in Section 1 of this report. The inspection plan was developed during 1988 and is reported in the Start-Up through 1988 Annual Technical Progress Report covering this period. Inspections during 1989 included tube thickness measurements, photographic surveys, and descriptions of equipment component condition.

The first of the major inspection outages occurred in January and February during the 39-day refractory repair outage. This inspection came after 5500 unit operating hours on coal since initial operation. The second inspection after 7200 hours of operation on coal was completed in June during the outage to modify the primary fan inlet ducting. The third inspection was completed in September after 8750 operating hours on coal during the outage initiated by a wall box water-wall tube leak on the outside of the combustor. Two additional inspections were completed in October following 9450 hours and in December following 9625 operating hours on coal. The first of these was initiated by a secondary superheater tube failure discussed in this section. The second was initiated from a controlled shutdown sequence to remove ash cooler blockages encountered during the high ash coal tests.

This section is divided into several subsections covering equipment component areas included in the inspections. The areas covered in this report are listed below:

- Windboxes
- Lower Combustor Refractory
- Air Distributor (Bubble Caps)
- Combustor Water Walls
- Superheater II Tubes
- Cyclone Refractory and Vortex Finder
- Downcomer and Loop seal Refractory and Outer Shell
- Convection Pass (Economizer and Superheaters)

13.1 WINDBOXES

The windboxes on the Nucla CFB are located below the air distribution plate and serve to direct pre-heated combustion air at 450°F through the distributor plate into each combustion chamber. Each windbox uses a plate steel construction which is welded directly to the water-cooled air distributor floor next to the point at which the floor tubes attach to an outside header (see Figure 13-1). A duct burner, used during unit start-up, is located just upstream of the windbox (see Figure 13-2). During start-up, temperatures downstream of the duct burners reach 850°F. As a result, the ductwork just upstream of the windbox is refractory-lined around all four walls. The windbox casing is not refractory-lined except for the "bullnose" section shown in the figure.

During the inspection in January, several areas of refractory downstream of the duct burner were found to have failed (cracking and loss). As originally installed, the PA duct refractory lining extended from the duct burners to the inlet of the windbox proper (even with the bullnose in Figure 13-2.). In March 1988, the sidewall refractory was extended 4 feet into the windbox in an effort to protect the sidewall plates which had warped as much as 3.5 inches out of plane in several locations. Much of this warpage appeared to be caused by distortion of the horizontal pipe stiffeners shown in Figure 13-3. These stiffeners are uncooled and are situated in front of the duct burners. Flame impingement from the burners during unit start-ups is the primary cause for this distortion. During the inspection and repairs in January and February 1989, large sections of the refractory extension had failed and the entire area was replaced. Refractory cracking and some refractory loss was also noted around the windbox bullnose, shown in Figure 13-2, just downstream of the duct burner.

During the June outage, the first three horizontal stiffeners were removed from each windbox. This was done as a result of additional refractory breakage from sidewall warpage caused by the stiffener pipes. Since this modification, windbox refractory loss has been minimal. Refractory cracking continues to be closely monitored along the roof of the ducting downstream of the start-up burner, along the windbox bullnose, and along a transition piece just upstream of the burner where the primary air duct expands into the windbox (see Figure 13-4).

As for metal components in the windboxes, the inspection in January revealed that a number of weld seams joining the windbox plates had failed. This was most pronounced in the rear corners of the windboxes, as shown in Figure 13-2. The cracks appear to have originated in the heat affected zone (HAZ) and propagated along the welds (see Figure 13-5). The surrounding base materials showed no signs of distress.

To correct this problem, the corner joints were removed and rewelded using a procedure in which all weld passes were run horizontally. In addition, the outside of the inboard corner

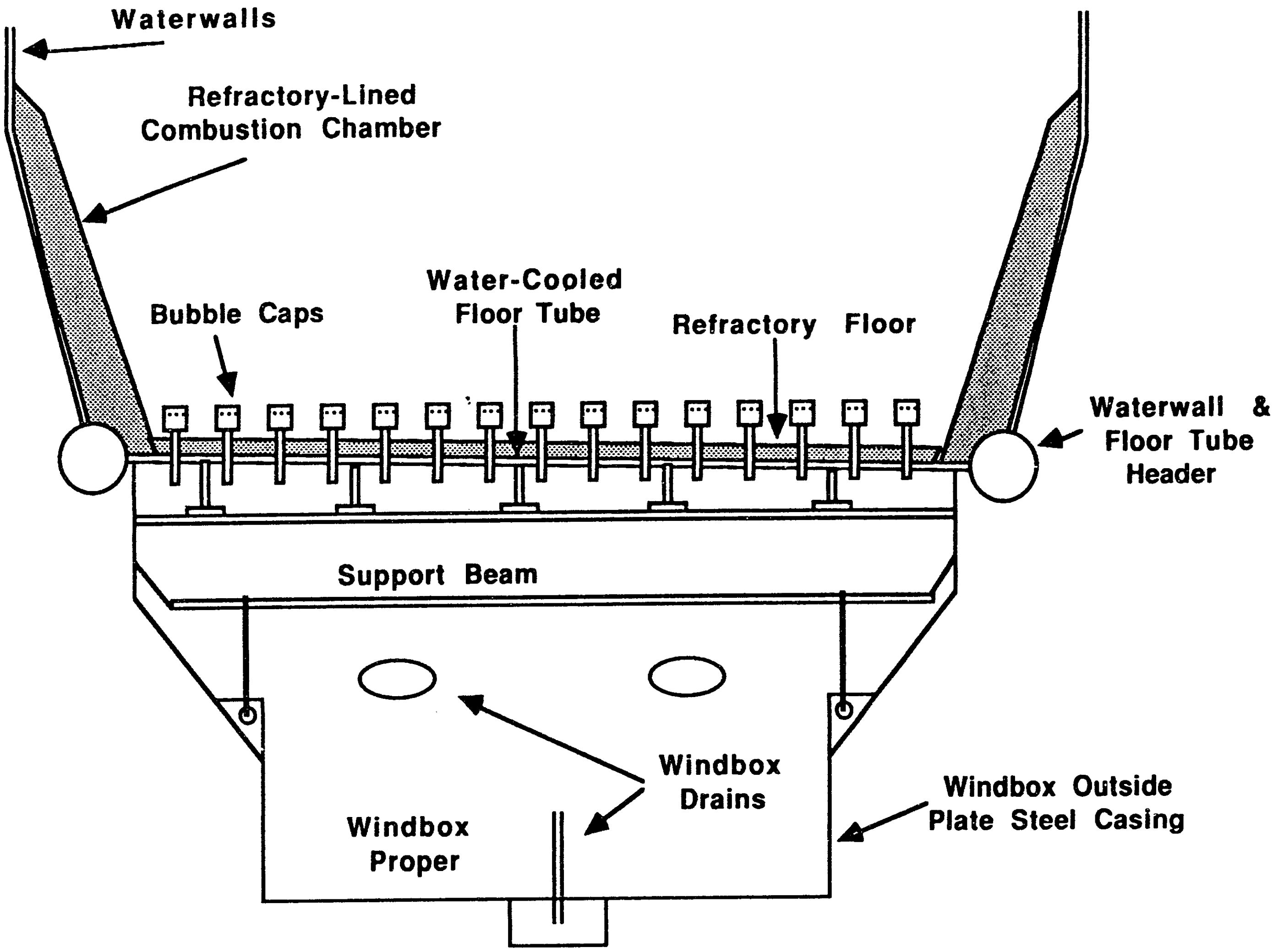


Figure 13-1. Schematic Showing Front View of Windbox Arrangement (typical of two).

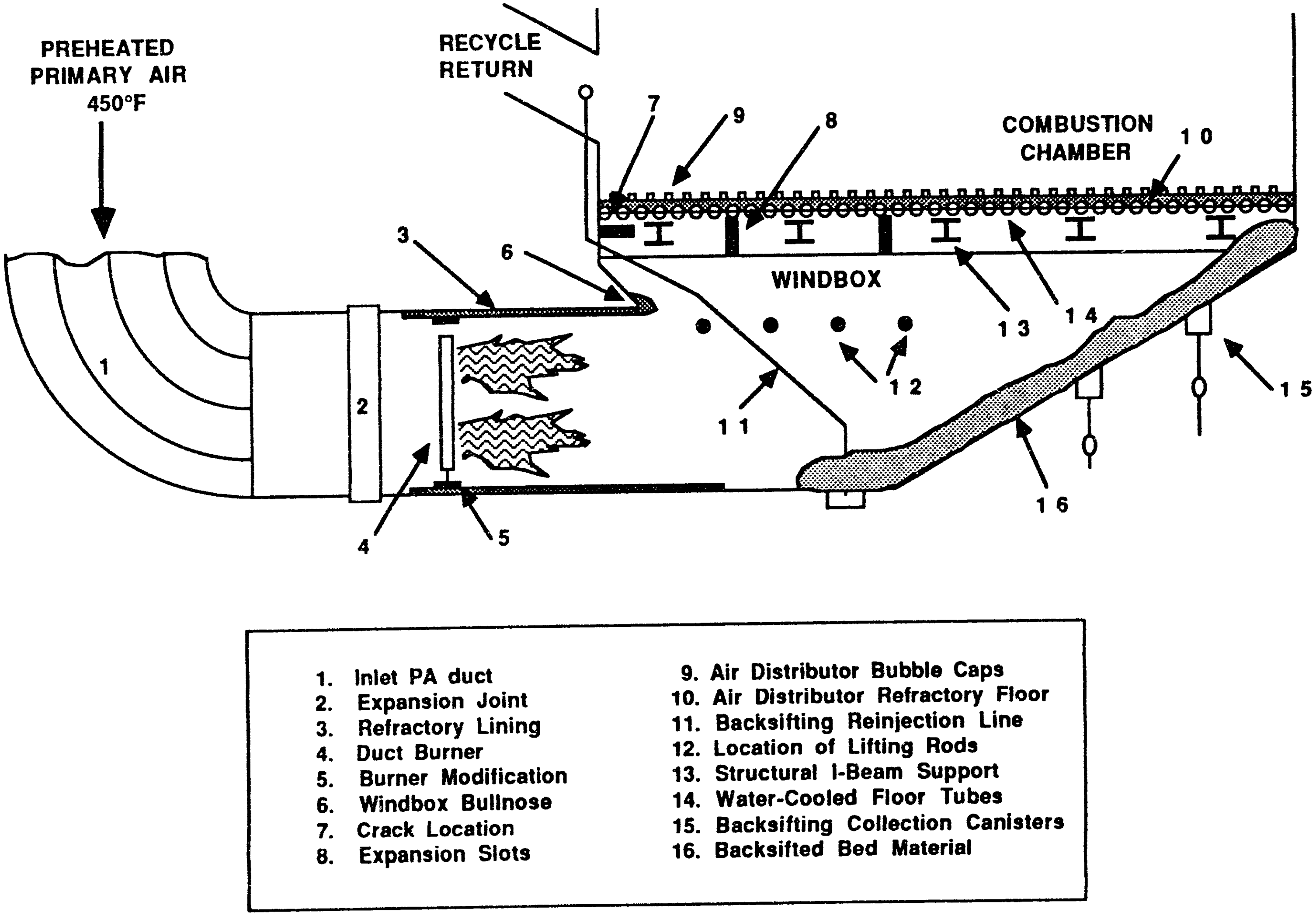


Figure 13-2. Side View Schematic of Windbox Layout (not to scale).

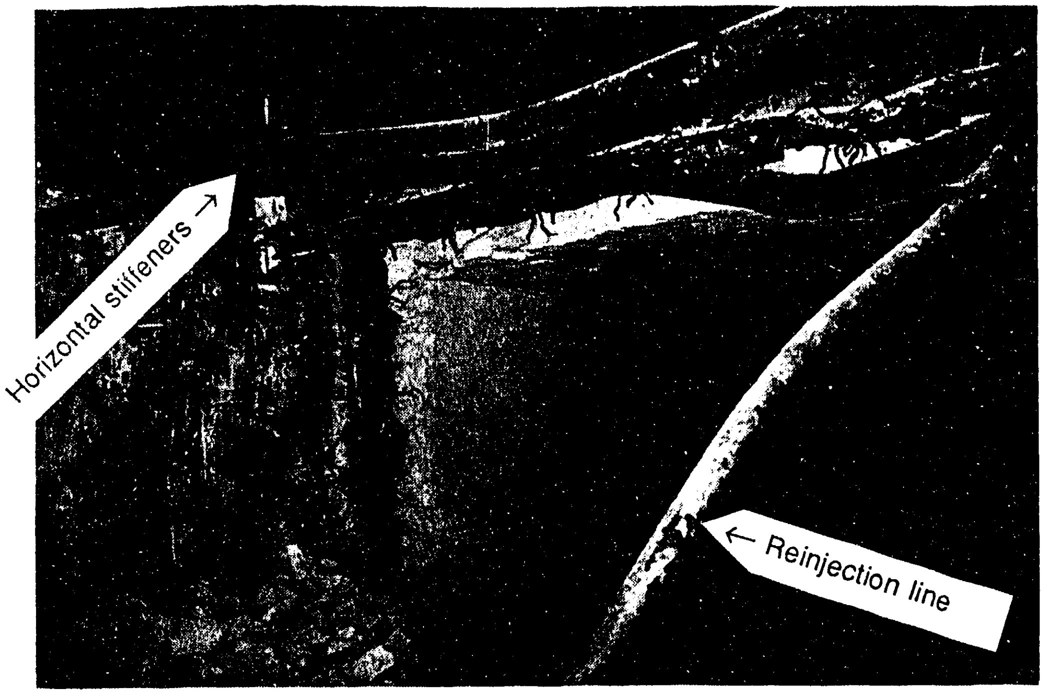


Figure 13-3. Distortion of the Windbox Horizontal Pipe Stiffeners and Reinjection Line.

Figure 13-4. Transition Piece Between Primary Air Duct and Windbox Proper.

Figure 13-5. Cracks Along Welds in the Rear Corners of the Windboxes.

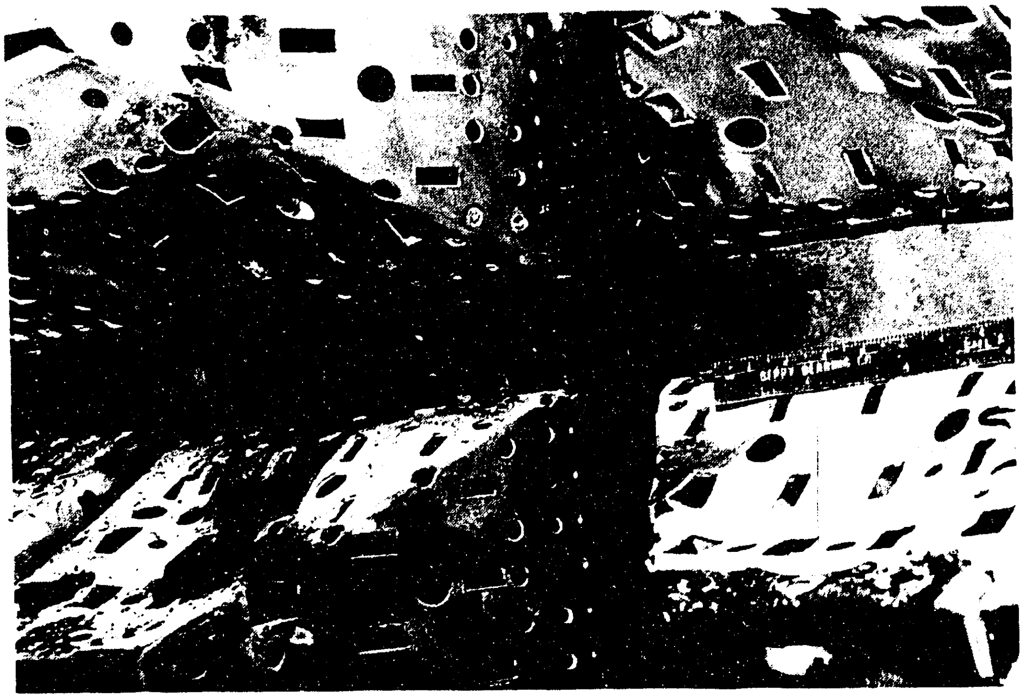


Figure 13-6. Duct Burner Fouling.

of the combustor A windbox was fitted with an experimental expansion device in February. During inspections in June, new cracks were discovered in the corners of the windboxes and were temporarily repaired by adding a weld bead over the crack. This problem remains under investigation.

The distortion of the horizontal pipe stiffeners was mentioned in connection with the discussion on the windbox refractory condition above. A similar distortion was evident with the ash reinjection line during the January outage. This is shown in Figure 13-3. The reinjection line uses windbox pressure to remove bed material that has backsifted through the air distributor bubble caps. The reinjection line extends from the floor of the windbox to the outside boiler room and back into the solids recycle line. When this line becomes blocked, as is typical following a unit shutdown, the cooling medium is lost and the line overheats from the impinging duct burner flame. This 2" diameter line was replaced during the January-February outage.

During the June inspection, the new reinjection lines were again found to be distorted and a hole had developed at an elbow on the combustor A windbox as the result of internal solids erosion. Also, a significant quantity of backsifted bed material was discovered in the windboxes around and away from the reinjection line. The build-up results from the taper on the windbox floor, which was not originally designed to collect solids as would be the case with a hopper-type construction.

Excessive amounts of backsifted bed material which accumulates in the windbox can disrupt air flow to the air distributor, particularly along the front wall as shown in Figure 13-2. To mitigate these effects, the boiler vendor installed 12" diameter drain pots in both windboxes during the June outage. Five pots were installed in each windbox - three at the top of the sloped portion (toward the front of the boiler) and two at the base of the slope. A network of 3" diameter carbon steel piping was also installed to periodically pipe the backsifted material to the bottom ash transport system.

During the September inspection, these drain systems were found to be plugged. To improve performance, valve sizes on the drain lines were changed to full port 3" valves and a 1/4" screen was placed over the drain inlet. The slope of the drain lines into the bottom ash transport line was also increased and air assist connections were added for manual clean-out.

During the final inspections in October and December, these lines were again found to be plugged. Backsifted bed material, which accumulates at higher rates during low load operation with minimum undergrid air flows, is presently removed manually during unit outages. The problem with backsifting and removal of this material from the windbox is currently under review.

The duct burner hardware is also included with the windbox inspection. During the January-February outage, the burners on each windbox were found to be fouled over at least 50 percent of the gas distribution surface. Several of the gas distribution castings that comprise a duct burner were found to be brittle and cracked (see Figure 13-6). This phenomena is known as carborization. In addition, the flame holders that make up the burner were found to be distorted and warped in several locations.

Several failed gas distribution castings were replaced during the January-February outage. During inspections in June, the same problem was noticed in other areas. To correct this problem, a stainless steel rim was installed around the perimeter of the duct burner to hold the flame closer to the gas distribution grid (see location in Figure 13-2).

During the inspection in September, fouling was discovered over approximately 20-25 percent of the distribution grid. One gas burner flange and two burner bodies were replaced on the combustor A windbox and a total of fifteen mixing plates were replaced. In addition, the stainless steel rim was removed and a 4" flat plate was mounted around the outside edge of the PA duct near the duct burner. The purpose of this flange is to force more air flow through the duct burner for better mixing and cooling of the flame holders. The effect of this modification on burner performance will be evaluated during 1990 outages.

13.2 LOWER COMBUSTOR REFRACTORY

The first annual technical progress report covering the start-up period in 1987 and 1988 discussed the condition of the lower combustor refractory. Generally, the condition of this refractory in most areas is about the same during this reporting period. Random spalling, cracking, and fine particle erosion continues to progress. This condition has not directly caused any unit outages, although loose refractory pieces have blocked the inlets to the ash coolers and can force an outage for removal (see Figure 13-7). Through 1989, refractory problems in the lower combustion chambers have been controlled by periodic maintenance during unit outages.

Cracking is particularly severe around the recycle return port on the rear wall of both combustion chambers and refractory appears to be pushing away from the substrate. The width of cracks varies from 0.25" to 1". At the cold joint along the rear wall next to the recycle return port

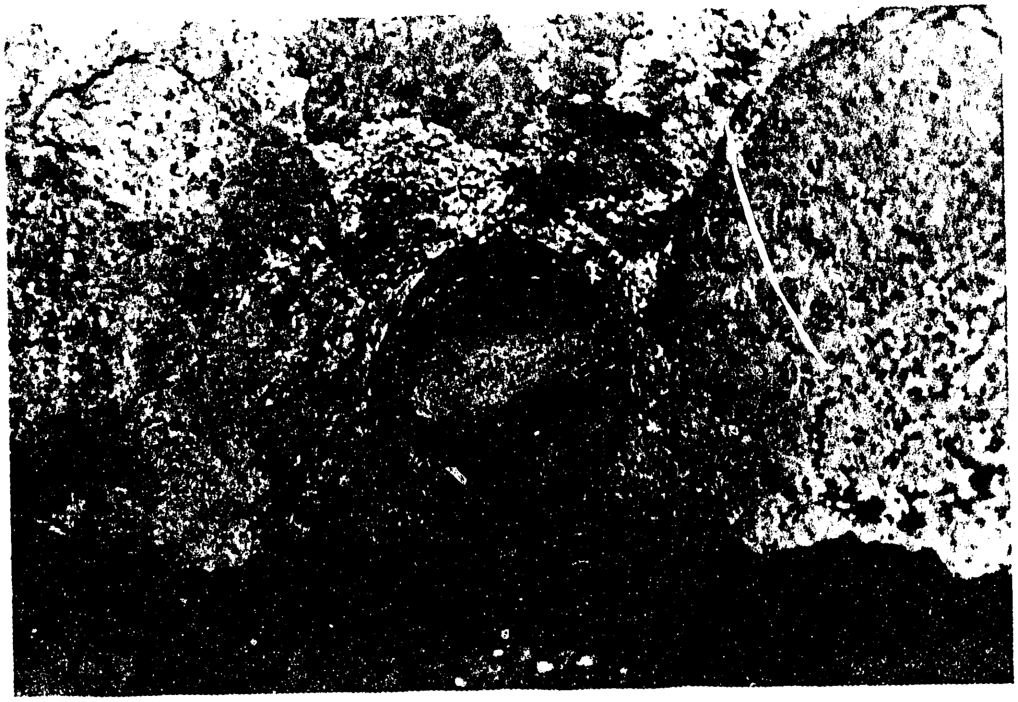


Figure 13-7. Blockage of the Ash Cooler Inlets by Refractory Pieces.

Figure 13-8. Refractory Repairs Around the Recycle Return Line (Blue Ram Refractory).

(one of three cold joints per combustor), the surfaces on each side of the joint are misaligned by as much as 3".

This has been a recurring problem during operation through 1989 and appears to result from some sort of rear wall movement. Such movement could occur during start-up and shutdown of the boiler from differential movement between the combustion chamber and cyclone downcomers and loop seals. This area was rebuilt in 1988 and again during September 1989. Cracked and spalled areas were chipped away and the entire area was replaced with a phosphate-bonded alumina "blue ram" refractory (see Figure 13-8).

Spalling of refractory surfaces is apparent at locations on all four walls of the combustion chambers. Spalling and refractory loss are more severe on the front walls, around the manways on the side walls, and along the lower 2 to 3 feet of refractory around the perimeter of the combustion chambers. Spalling begins with a small crack in the refractory that becomes packed with bed material. During repeated start-ups and shutdowns of the unit, these cracks expand when the refractory is hot and fill with bed material. During cool-down, the cracks contract and compress the material into hard layers. Eventually, the layers become thick enough and strong enough that refractory begins to spall away around the edges of the initial crack (see Figure 13-9). This type of breakage, known as "pinch spalling", also occurs along the cold joints located in each chamber.

During the January-February outage, spalled areas of refractory were chipped away and replaced with an abrasion resistant gunnite (ARG) mix and steel reinforcing fibers. For all subsequent outages, spalled refractory in the lower combustion chambers was not replaced as long as the thickness of the remaining refractory was not badly compromised and water walls or other metal components were not exposed. The refractory thickness along the water walls near the distributor plate is approximately 18 inches. In other areas where spalling is significant, the plant now uses the phosphate-bonded "blue ram" refractory for repairs. These areas include refractory around coal, limestone, start-up burner, and air port penetrations, manways, and around the recycle return ports.

At a number of locations, the refractory at the waterwall/refractory interface is "jacking" away from the water walls. The process is similar to pinch spalling in that bed material wedges between the refractory and water walls and becomes layered and packed during start-ups and shutdowns. Eventually, the upper one to two feet of refractory pushes away from the water walls and fails. This problem is exacerbated by the absence of adequate anchors in this region due to the taper on the refractory. During outages in June and September, several sections of missing refractory along

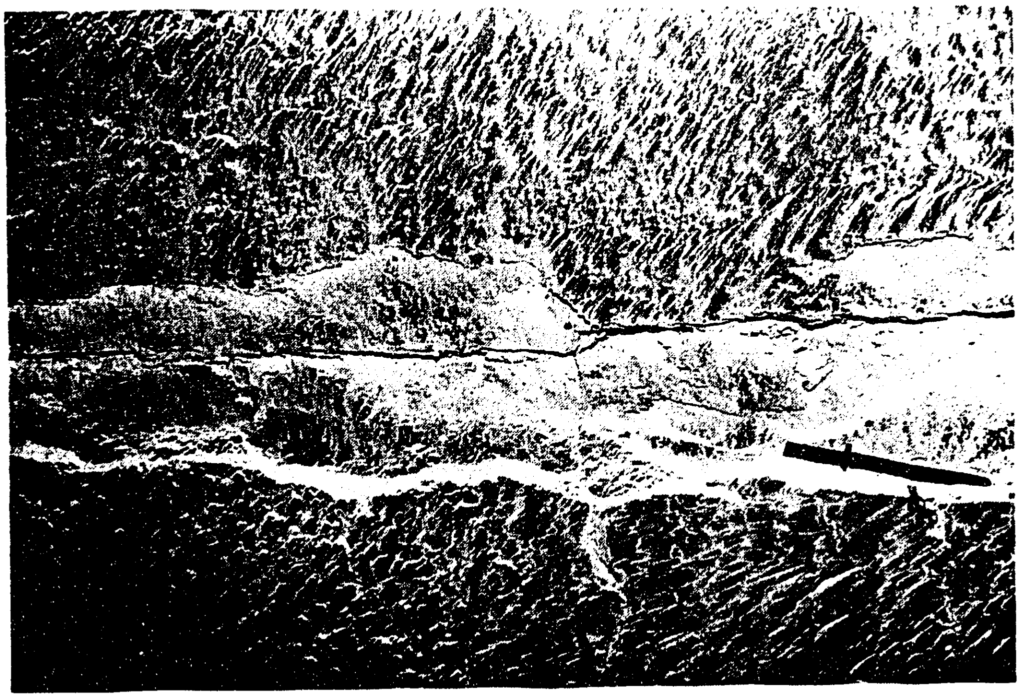


Figure 13-9. Bed Material Layering and the Beginning Stages of "Pinch Spalling".

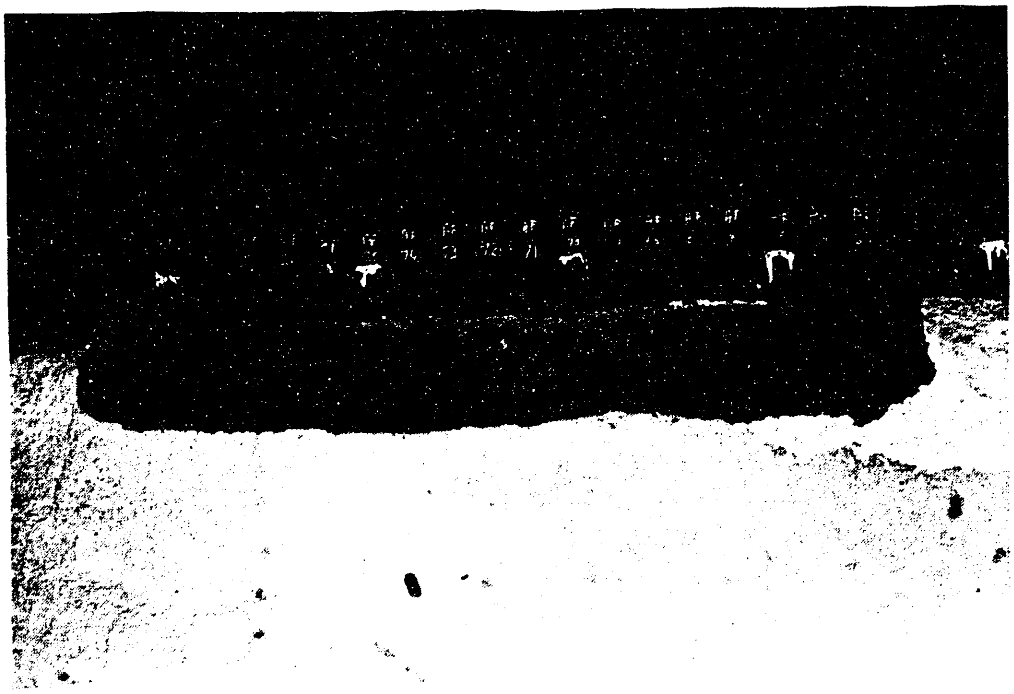


Figure 13-10. Refractory Repairs at the Water-Wall/Refractory Interface (Blue Ram Refractory).

the refractory/water-wall interface were repaired with a phosphate-bonded "blue ram" refractory (see Figure 13-10). Thin wire anchors 1/8 inch in diameter were added to the water walls along a missing two foot long section of refractory during the outage in June. During inspections in September, these anchors did not appear to be strong enough and were not added to future repairs. In addition, the blue ram repairs made in June did not appear to hold up well during inspections in the fourth quarter of 1989.

Fine particle erosion has been observed in the lower combustion chambers and is more pronounced around secondary air ports, in the front corners, and around the recycle return port on the rear wall of the combustion chambers. Fine particle erosion is characterized by exposure of the aggregate and reinforcing fibers and by wearing of the cementitious material between the aggregate. The aggregate is normally darker in color and stands out from the light (almost white) color of the cementitious material. The phosphate-bonded alumina refractory used to repair damaged refractory areas does not show signs of fine particle erosion. Through 1989, refractory damage from fine particle erosion has been minor and no repairs have been required to ameliorate eroded areas.

13.3 AIR DISTRIBUTOR BUBBLE CAPS

In the first annual technical progress report, replacement of the bubble cap retainer washer on over 4000 nozzles was reported during an outage in August 1988. Air distributor bubble caps were inspected during each of the outages in January, June, September, October, and December of 1989.

During the January outage, the bubble caps were found to be in good condition. Two missing nozzles were found in combustion chamber B and none in the combustion chamber A. The air holes in the bubble caps were also clear of packed material. The shoulders of some bubble caps in front of the recycle return port were slightly rounded.

A similar condition was observed during inspections in June. In September however, a total of 52 bubble caps in combustor A and 14 in combustor B were found to be loose or adrift. Most of these failures occurred in front of the loop seal return line. The bubble caps appear to be failing as a result of damage to the original pipe nipple during the August 1988 outage to replace the retaining washer. The new method of installation, shown in Figure 13-11, does not use a retaining washer. This new design is being implemented on an as-failed basis during unit outages. Loss of bubble caps during unit operation does not noticeably affect unit performance, although it is probable that the rate of backsifting through the pipe nipples increases without bubble caps. However, during shutdown when the bed is slumped, a

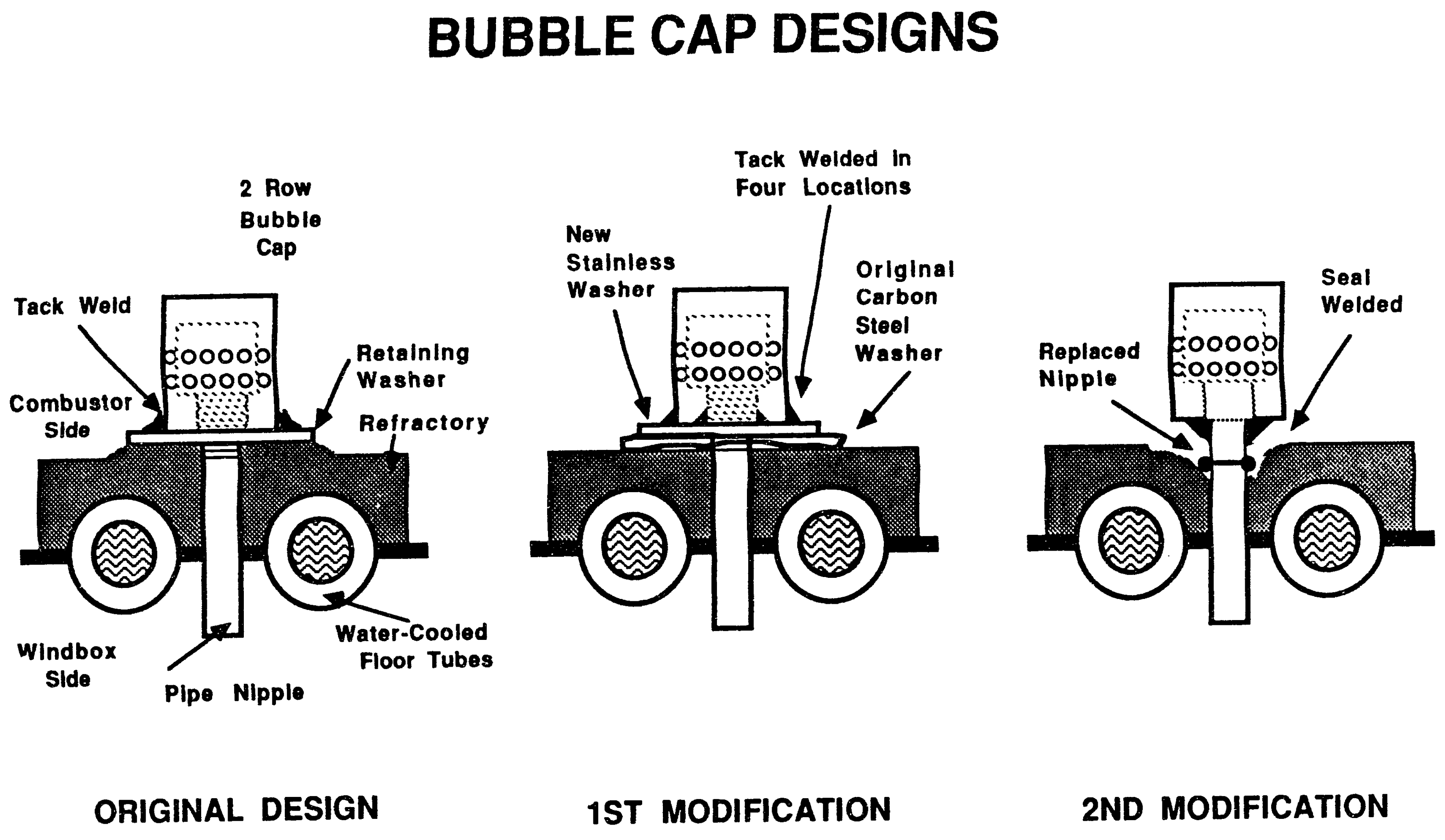


Figure 13-11. Bubble Cap Design Modifications.

considerable quantity of bed material can drain into the windbox through the open pipe nipples.

During inspections in October and December, bubble cap loss continued to be a problem. A total of 25 bubble caps were found missing or loose during the October outage. The present preventive maintenance procedure calls for checking all combustor bubble caps for tightness during outages. This is accomplished by tapping each of them with a hammer. Loose bubble caps are then replaced with the new attachment design.

Bubble cap wear also became a concern in the fourth quarter of 1989. Figure 13-12 shows typical nozzle wear after 9473 hours of operation on coal. The erosion is most pronounced in the region directly in front of the recycle return line. There is no plan for mitigating the bubble cap erosion at this time.

13.4 COMBUSTOR WATER WALLS

In January and February 1989, ultrasonic wall thickness measurements were taken on water-wall tubes at 810 locations in combustor A and 348 locations in combustor B. The purpose of these measurements was to compare similar thickness measurements taken after 600 hours and 3600 hours of unit operation on coal in an attempt to identify if any generalized erosion was occurring.

During the outage from the overheat incident in October 1987 following 600 hours of unit operation on coal, an outside contractor was hired by the boiler manufacturer to make an extensive ultrasonic thickness (UT) measurement survey in both combustion chambers. For the water walls, measurements were made on the centerline, and at ±30° from centerline on every tenth tube at various elevations. These elevations were at approximately 10 foot intervals starting at 20 feet above the distributor plate and extending to 110 feet above the grid. Additional measurements were made in locations where the walls were bowed as a result of the overheat incident.

During the January outage, the on-site test team took measurements of every twentieth tube at each elevation previously measured. These data are summarized in Tables 13-1 and 13-2. There are no indications of general erosion in combustor B. There is some minor indication of general erosion in combustor A. However, no firm conclusions can be drawn because of the degree of uncertainty in the measurements.

Water-wall tube thickness measurements are taken by wiping the dust and dirt from the surface with a soft bristle brush. Acoustic gel is then applied to the tube surface and a

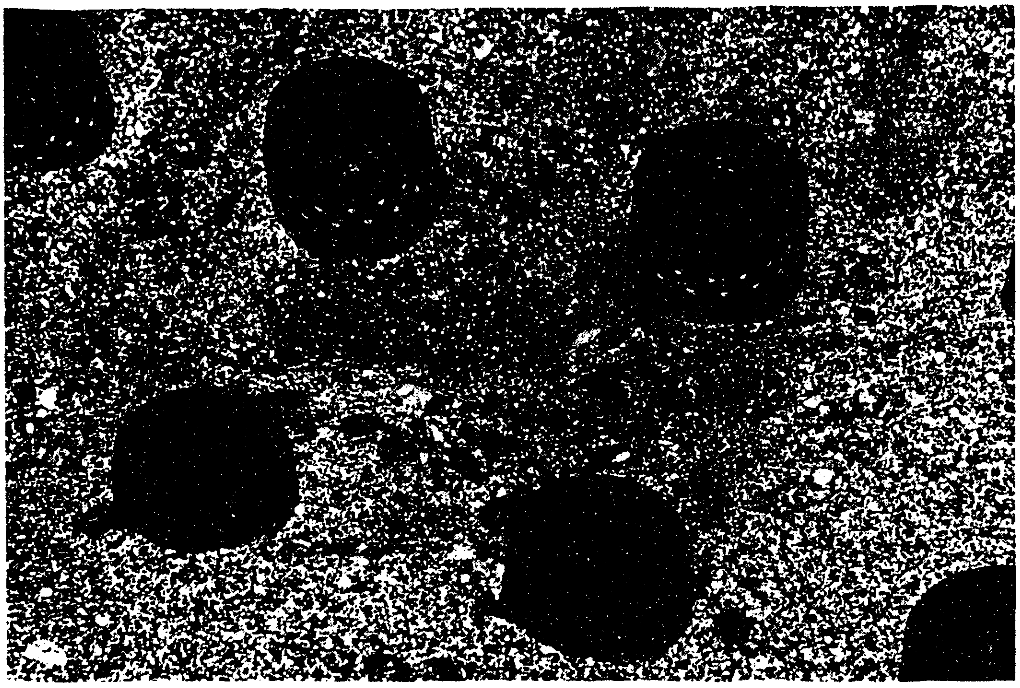


Figure 13-12. Typical Example of Bubble Cap Wear After 9437 Operating Hours.

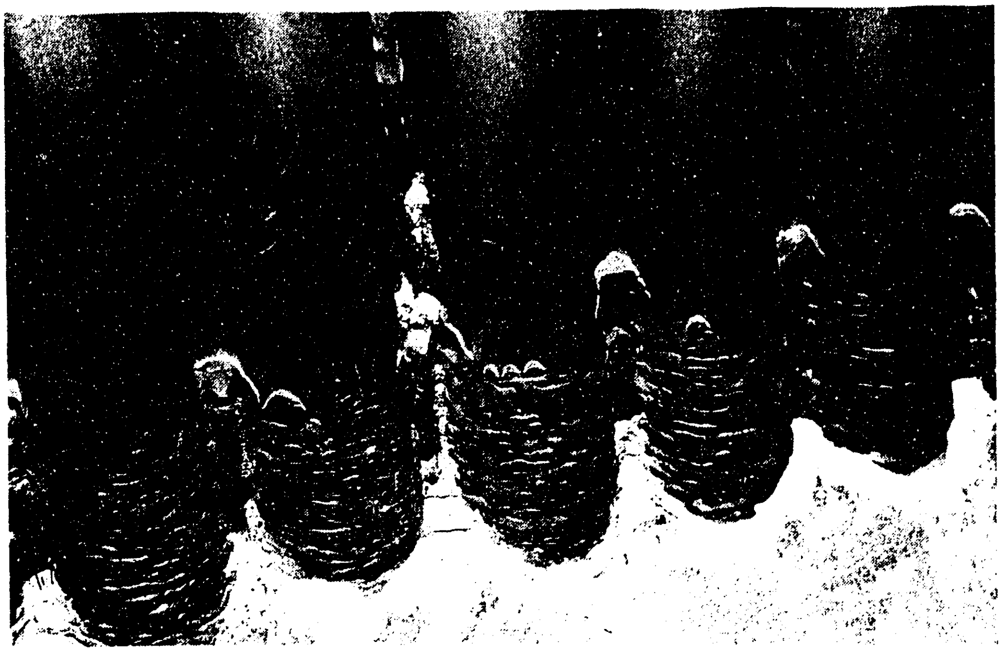


Figure 13-13. Example of Water-Wall Erosion Near the Weld Overlay at the Water-Wall/Refractory Interface.

Table 13-1

Water-Wall Tube Thickness Average Measurements at Various Elevations on Combustor A

Combustion Chamber A - Front Wall									
Elev.	600 hours			5500 hours			Difference		
ft.	Left	Center	Right	Left	Center	Right	Left	Center	Right
20	0.265	0.265	0.261	0.255	0.256	0.25	-0.011	-0.009	-0.01
23	0.282	0.264	0.267	0.259	0.252	0.257	-0.023	-0.012	-0.011
28	0.265	0.262	0.271	0.257	0.251	0.256	-0.008	-0.011	-0.016
30	0.256	0.254	0.251	0.254	0.249	0.247	-0.002	-0.006	-0.004
33	0.256	0.259	0.254	0.247	0.248	0.246	-0.01	-0.012	-0.008
36	0.265	0.254	0.255	0.253	0.244	0.246	-0.012	-0.01	-0.01
40	0.252	0.246	0.253	0.244	0.241	0.246	-0.008	-0.005	-0.007
48	0.251	0.243	0.251	0.245	0.24	0.247	-0.007	-0.002	-0.005
50	0.255	0.241	0.25	0.247	0.238	0.243	-0.008	-0.003	-0.007
52	0.252	0.247	0.251	0.248	0.242	0.245	-0.004	-0.006	-0.006
58	0.255	0.256	0.262	0.245	0.252	0.253	-0.01	-0.004	-0.009
60	0.25	0.256	0.259	0.245	0.249	0.252	-0.005	-0.007	-0.008
62	0.253	0.25	0.253	0.248	0.244	0.249	-0.005	-0.006	-0.005
70	0.258	0.254	0.25	0.254	0.245	0.248	-0.004	-0.009	-0.002
80	0.262	0.254	0.256	0.253	0.248	0.246	-0.009	-0.006	-0.01
90	0.26	0.258	0.258	0.252	0.255	0.253	-0.008	-0.003	-0.005
100	0.252	0.249	0.253	0.248	0.247	0.246	-0.004	-0.002	-0.007
110	0.252	0.247	0.254	0.247	0.244	0.248	-0.005	-0.003	-0.006
avg	0.258	0.253	0.256	0.25	0.247	0.249	-0.008	-0.006	-0.007

Combustion Chamber A - Center Wall									
Elev.	600 hours			5500 hours			Difference		
ft.	Left	Center	Right	Left	Center	Right	Left	Center	Right
20	0.266	0.262	0.262	0.256	0.249	0.253	-0.01	-0.013	-0.009
30	0.259	0.257	0.26	0.256	0.25	0.247	-0.003	-0.007	-0.013
32	0.252	0.254	0.255	0.252	0.247	0.251	0	-0.008	-0.003
34	0.257	0.255	0.259	0.242	0.244	0.248	-0.016	-0.011	-0.011
40	0.259	0.256	0.258	0.249	0.246	0.251	-0.01	-0.011	-0.007
47	0.26	0.257	0.263	0.25	0.249	0.249	-0.009	-0.007	-0.014
50	0.259	0.261	0.262	0.252	0.252	0.253	-0.007	-0.01	-0.009
53	0.258	0.261	0.261	0.254	0.25	0.25	-0.004	-0.011	-0.011
60	0.253	0.267	0.264	0.246	0.25	0.247	-0.007	-0.018	-0.017
70	0.247	0.253	0.252	0.245	0.249	0.247	-0.002	-0.003	-0.006
80	0.254	0.251	0.251	0.245	0.243	0.244	-0.009	-0.008	-0.007
90	0.249	0.251	0.248	0.246	0.243	0.244	-0.003	-0.008	-0.004
100	0.267	0.254	0.253	0.242	0.246	0.243	-0.025	-0.008	-0.01
110	0.262	0.254	0.253	0.251	0.247	0.244	-0.011	-0.007	-0.009
avg	0.257	0.257	0.257	0.249	0.247	0.248	-0.008	-0.009	-0.009

Combustion Chamber A - Rear Wall									
20	0.264	0.265	0.261	0.274	0.27	0.269	0.01	0.006	0.008
24	0.261	0.265	0.264	0.285	0.269	0.282	0.024	0.004	0.018
28	0.265	0.265	0.269	0.269	0.259	0.261	0.004	-0.006	-0.009
30	0.259	0.259	0.255	0.255	0.252	0.249	-0.004	-0.006	-0.006
40	0.258	0.252	0.255	0.259	0.256	0.255	0	0.004	0.001
50	0.252	0.254	0.256	0.243	0.242	0.246	-0.01	-0.011	-0.01
60	0.249	0.249	0.252	0.24	0.238	0.237	-0.009	-0.011	-0.015
70	0.25	0.243	0.247	0.244	0.238	0.243	-0.006	-0.005	-0.004
80	0.261	0.268	0.269	0.25	0.248	0.243	-0.011	-0.02	-0.026
90	0.266	0.264	0.267	0.249	0.239	0.247	-0.017	-0.025	-0.02
100	0.267	0.268	0.267	0.249	0.25	0.247	-0.018	-0.018	-0.02
110	0.258	0.259	0.259	0.246	0.244	0.244	-0.012	-0.015	-0.015
avg	0.259	0.259	0.26	0.255	0.25	0.252	-0.004	-0.009	-0.008

Combustion Chamber A - Side Wall									
20	0.276	0.265	0.267	0.259	0.251	0.256	-0.017	-0.015	-0.011
23	0.259	0.257	0.257	0.258	0.252	0.256	-0.001	-0.006	-0.001
24	0.257	0.254	0.262	0.261	0.245	0.254	0.004	-0.009	-0.008
26	0.257	0.256	0.266	0.256	0.243	0.247	-0.001	-0.013	-0.019
30	0.25	0.257	0.255	0.252	0.245	0.252	0.002	-0.012	-0.003
40	0.25	0.254	0.249	0.252	0.243	0.242	0.002	-0.011	-0.007
50	0.255	0.253	0.253	0.25	0.245	0.247	-0.005	-0.009	-0.006
60	0.246	0.246	0.248	0.241	0.24	0.245	-0.005	-0.006	-0.003
70	0.253	0.253	0.253	0.25	0.253	0.251	-0.003	0	-0.003
80	0.254	0.256	0.257	0.241	0.239	0.245	-0.013	-0.018	-0.012
90	0.256	0.251	0.264	0.246	0.244	0.244	-0.01	-0.007	-0.02
100	0.256	0.259	0.255	0.246	0.244	0.243	-0.01	-0.015	-0.012
110	0.253	0.249	0.26	0.241	0.241	0.246	-0.012	-0.008	-0.014
avg	0.255	0.255	0.257	0.25	0.245	0.248	-0.005	-0.01	-0.009

Table 13-2

Water-Wall Tube Thickness Average Measurements at Various Elevations on Combustor B

Combustion Chamber B - Rear Wall									
Elev.	600 hours			5500 hours			Difference		
ft.	Left	Center	Right	Left	Center	Right	Left	Center	Right
20	0.25	0.257	0.26	0.255	0.256	0.258	0.006	-0.001	-0.003
30	0.259	0.256	0.266	0.26	0.263	0.26	0.001	0.007	-0.006
40	0.252	0.248	0.252	0.255	0.251	0.259	0.003	0.003	0.007
50	0.249	0.246	0.251	0.25	0.245	0.253	0.001	-0.001	0.002
60	0.254	0.253	0.25	0.25	0.251	0.249	-0.005	-0.003	-0.001
70	0.256	0.253	0.247	0.246	0.251	0.25	-0.01	-0.002	0.004
80	0.257	0.259	0.249	0.247	0.256	0.249	-0.01	-0.003	0.001
90	0.25	0.251	0.247	0.254	0.255	0.265	0.004	0.004	0.019
100	0.254	0.255	0.259	0.254	0.251	0.255	0.001	-0.004	-0.004
110	0.261	0.256	0.253	0.263	0.257	0.259	0.002	0.001	0.007
avg	0.254	0.253	0.253	0.253	0.253	0.255	-0.001	0	0.002

Combustion Chamber B - Side Wall									
Elev.	600 hours			5500 hours			Difference		
ft.	Left	Center	Right	Left	Center	Right	Left	Center	Right
20	0.257	0.251	0.251	0.258	0.255	0.254	0.001	0.004	0.003
30	0.257	0.258	0.251	0.252	0.26	0.256	-0.005	0.003	0.005
40	0.258	0.26	0.262	0.254	0.259	0.255	-0.004	-0.001	-0.007
50	0.248	0.253	0.255	0.252	0.258	0.26	0.005	0.005	0.005
60	0.251	0.245	0.244	0.257	0.252	0.251	0.006	0.007	0.008
70	0.255	0.252	0.257	0.257	0.251	0.252	0.002	-0.001	-0.006
80	0.257	0.249	0.242	0.26	0.253	0.249	0.003	0.004	0.008
90	0.257	0.247	0.249	0.258	0.252	0.252	0.002	0.005	0.003
100	0.261	0.255	0.257	0.264	0.261	0.258	0.003	0.006	0.001
110	0.249	0.254	0.248	0.26	0.264	0.263	0.011	0.011	0.015
avg	0.255	0.252	0.251	0.257	0.256	0.255	0.002	0.004	0.003

Combustion Chamber B - Front Wall									
20	0.264	0.256	0.256	0.263	0.262	0.263	-0.001	0.007	0.007
30	0.266	0.258	0.257	0.271	0.258	0.256	0.005	0.001	-0.001
40	0.258	0.26	0.261	0.262	0.254	0.246	0.005	-0.006	-0.015
50	0.259	0.248	0.249	0.255	0.254	0.245	-0.005	0.007	-0.004
60	0.257	0.266	0.259	0.251	0.255	0.262	-0.006	-0.011	0.003
70	0.252	0.254	0.259	0.254	0.259	0.265	0.002	0.005	0.006
80	0.257	0.256	0.259	0.259	0.263	0.268	0.002	0.008	0.009
90	0.264	0.261	0.266	0.264	0.261	0.27	0.001	0	0.004
100	0.257	0.261	0.259	0.255	0.259	0.265	-0.002	-0.002	0.006
110	0.257	0.265	0.258	0.26	0.263	0.26	0.004	-0.002	0.002
avg	0.259	0.258	0.258	0.259	0.259	0.26	0	0.001	0.002

Combustion Chamber B - Center Wall									
	0.254	0.253	0.257	0.26	0.259	0.26	0.005	0.006	0.003
30	0.255	0.253	0.254	0.259	0.26	0.258	0.004	0.007	0.003
40	0.257	0.257	0.257	0.263	0.263	0.258	0.006	0.006	0.001
42	0.257	0.259	0.257	0.261	0.261	0.258	0.004	0.002	0.001
44	0.258	0.259	0.256	0.261	0.266	0.256	0.003	0.007	0
50	0.26	0.256	0.255	0.263	0.263	0.262	0.004	0.007	0.008
58	0.254	0.256	0.258	0.263	0.261	0.262	0.009	0.005	0.004
60	0.257	0.255	0.255	0.263	0.259	0.257	0.006	0.004	0.002
62	0.256	0.258	0.254	0.258	0.259	0.256	0.002	0.002	0.002
70	0.256	0.254	0.256	0.261	0.256	0.255	0.004	0.002	-0.001
80	0.25	0.253	0.258	0.257	0.252	0.256	0.006	-0.001	-0.002
90	0.247	0.252	0.256	0.253	0.254	0.259	0.006	0.002	0.003
100	0.247	0.256	0.259	0.253	0.259	0.262	0.006	0.004	0.003
110	0.257	0.254	0.257	0.252	0.256	0.252	-0.005	0.002	-0.005
avg	0.255	0.255	0.256	0.259	0.259	0.258	0.004	0.004	0.002

Krautkramer-Branson DM-2 UT measurement device is used to take the readings. The DM-2 is calibrated with a stainless steel test button 0.261 inches thick before taking readings at each elevation on a wall.

Although generalized erosion is not obvious, localized water-wall erosion was observed during the January outage at the refractory/water-wall interface. Localized erosion in the areas protected by weld overlay were observed on some tubes on the side and front walls and on the north half of the center wall in combustor A, and on the north half of the side and center walls, and the east half of the front wall of combustor B. The general pattern for the erosion was a narrow, vertical groove. Figure 13-13 is a typical pattern of an eroded tube.

Measurements of tube wall thickness in the eroded area is difficult because the erosion marks are typically too narrow for a UT probe head (0.25 in. diameter). To document and track the progress of these erosion marks, the test team relied on photographs and plaster castings of the tubes.

Between 3600 and 5500 hours of unit coal operation, it is apparent that the localized erosion is progressing. After 3600 hours of operation, it was possible to insert a UT probe head into nine localized erosion patterns. During the January outage following 5500 hours, the UT head could be inserted into a total of 32 tubes. Measurements indicate an average metal loss in and around these areas of approximately 0.048 inches.

Two types of scale deposit were observed on the water walls in combustion chamber A during the January outage. The first is a brownish scale that covers most of the water walls and has an estimated thickness of 0.015 in. The second type of scale is a magnetite with a black, shiny appearance and a thickness of approximately 0.005 in. The browinsh scale was formed on the water walls during the overheat incident in September 1987.

During the June outage, additional weld overlay was applied to a total of 127 tubes at the water-wall/refractory interface. Inspection of these tubes in September indicated that the new weld overlay was wearing away at a significant rate. Also during this outage, UT thickness measurements were made at the water-wall/refractory interface approximately 1 inch above the top of the weld overlay on every fifth tube in each combustor. Measurements were taken on the centerline and at ±30° on each side of centerline. These data are summarized in Tables 13-3 and 13-4. It is difficult to draw any firm conclusions regarding generalized erosion from these data.

Table 13-3

Generalized Tube Erosion Measurements at Waterwall/Refractory Interface Following 8754 Operating Hours

"A" - SIDE WALL				"A" FRONT WALL				"A" CENTER WALL				"A" REAR WALL			
TUBE	LEFT	CNTR	RIGHT	TUBE	LEFT	CNTR	RIGHT	TUBE	LEFT	CNTR	RIGHT	TUBE	LEFT	CNTR	RIGHT
AS1	NA	0.272	NA	AF1	NA	0.259	NA	AC1	NA	0.268	NA	AR1	NA	0.255	NA
AS5	0.265	0.263	0.265	AF5	0.25	0.256	0.253	AC5	0.258	0.255	0.265	AR5	0.263	0.258	0.25
AS10	0.26	0.26	0.257	AF10	0.256	0.259	0.244	AC10	0.256	0.252	0.26	AR10	0.258	0.262	0.267
AS15	0.262	0.261	0.252	AF15	0.259	0.259	0.258	AC15	0.273	0.259	0.26	AR15	0.253	0.246	0.259
AS20	0.253	0.253	0.275	AF20	0.253	0.26	0.256	AC20	0.252	0.252	0.26	AR20	0.256	0.261	0.26
AS25	0.263	0.27	0.265	AF25	0.255	0.262	0.266	AC25	0.254	0.59	0.266	AR25	0.248	0.249	0.25
AS30	0.271	0.263	0.266	AF30	0.259	0.265	0.268	AC30	0.258	0.27	0.255	AR30	0.249	0.245	0.263
AS35	0.268	0.262	0.272	AF35	0.256	0.248	0.256	AC35	0.26	0.269	0.26	AR35	0.266	0.263	0.263
AS40	0.257	0.258	0.256	AF40	0.257	0.256	0.264	AC40	0.251	0.266	0.254	AR40	0.256	0.26	0.258
AS45	0.257	0.265	0.267	AF45	0.249	0.246	0.251	AC45	0.253	0.248	0.255	AR45	0.263	0.264	0.261
AS51	0.25	0.257	0.26	AF50	0.26	0.264	0.272	AC50	0.254	0.248	0.254	AR50	0.241	0.244	0.258
AS56	0.251	0.258	0.252	AF55	0.261	0.255	0.273	AC55	0.254	0.246	0.251	AR55	0.251	0.25	0.253
AS61	0.249	0.258	0.258	AF60	0.256	0.259	0.253	AC60	0.233	0.231	0.241	AR60	0.249	0.248	0.257
AS66	0.258	0.255	0.266	AF65	0.269	0.27	0.258	AC65	0.26	0.254	0.248	AR65	0.258	0.275	0.26
AS71	0.25	0.251	0.259	AF70	0.259	0.248	0.258	AC70	0.255	0.265	0.252	AR70	0.26	0.27	0.273
AS76	0.253	0.256	0.261	AF75	0.252	0.257	0.26	AC75	0.23	0.23	0.232	AR75	0.258	0.264	0.261
AS81	0.256	0.251	0.262	AF80	0.26	0.265	0.266	AC80	0.258	0.256	0.258	AR80	0.268	0.273	0.266
AS86	0.254	0.261	0.261	AF85	0.265	0.25	0.256	AC85	0.264	0.273	0.266	AR85	0.255	0.259	0.26
AS90	0.261	0.261	0.252	AF88	NA	0.267	NA	AC90	0.253	0.251	0.248	AR88	NA	0.259	NA
AS94	NA	0.252	NA					AC94	NA	0.263	NA				
avg	0.258	0.259	0.261	avg	0.257	0.258	0.26	avg	0.254	0.256	0.255	avg	0.256	0.258	0.26

"B" - SIDE WALL				"B' FRONT WALL				"B" CENTER WALL				"B" REAR WALL			
TUBE	LEFT	CNTR	RIGHT	TUBE	LEFT	CNTR	RIGHT	TUBE	LEFT	CNTR	RIGHT	TUBE	LEFT	CNTR	RIGHT
BS1	NA	0.251	NA	BF1	NA	0.268	NA	BC1	NA	0.27	NA	BR1	NA	0.247	NA
BS5	0.259	0.265	0.268	BF5	0.268	0.273	0.263	BC5	0.262	0.26	0.268	BR5	0.253	0.25	0.252
BS10	0.26	0.27	0.255	BF10	0.265	0.267	0.256	BC10	0.263	0.267	0.246	BR0	0.264	0.276	0.267
BS15	0.258	0.262	0.258	BF15	0.266	0.265	0.251	BC15	0.283	0.277	0.279	BR15	0.274	0.276	0.275
BS20	0.272	0.273	0.267	BF20	0.264	0.253	0.25	BC20	0.261	0.275	0.266	BR20	0.254	0.257	0.267
BS25	0.261	0.263	0.258	BF25	0.266	0.26	0.53	BC25	0.264	0.268	0.26	BR25	0.264	0.267	0.267
BS30	0.256	0.269	0.26	BF30	0.269	0.265	0.245	BC30	0.267	0.275	0.273	BR30	0.259	0.25	0.256
BS35	0.265	0.262	0.261	BF35	0.269	0.266	0.249	BC35	0.254	0.262	0.262	BR35	0.273	0.27	0.26
BS40	0.244	0.259	0.255	BF40	0.255	0.257	0.246	BC40	0.257	0.27	0.258	BR40	0.257	0.264	0.249
BS45	0.257	0.254	0.26	BF45	0.258	0.255	0.26	BC45	0.262	0.262	0.251	BR45	0.258	0.261	0.26
BS50	0.243	0.262	0.266	BF50	0.247	0.247	0.255	BC50	0.247	0.245	0.241	BR50	0.261	0.251	0.249
BS56	0.26	0.262	0.261	BF55	0.26	0.256	0.269	BC55	0.261	0.258	0.247	BR55	0.257	0.252	0.248
BS61	0.245	0.264	0.251	BF60	0.238	0.258	0.274	BC60	0.256	0.266	0.26	BR60	0.261	0.264	0.264
BS66	0.248	0.261	0.258	BF65	0.235	0.262	0.271	BC65	0.271	0.269	0.26	BR65	0.251	0.254	0.247
BS71	0.262	0.272	0.271	BF70	0.25	0.263	0.268	BC70	0.269	0.258	0.263	BR70	0.251	0.265	0.262
BS76	0.264	0.266	0.256	BF75	0.247	0.255	0.26	BC75	0.251	0.267	0.261	BR75	0.253	0.266	0.262
BS81	0.254	0.262	0.261	BF80	0.268	0.26	0.252	BC80	0.258	0.255	0.263	BR80	0.261	0.265	0.257
BS86	0.26	0.261	0.255	BF85	0.257	0.257	0.255	BC85	0.266	0.263	0.271	BR85	0.267	0.262	0.27
BS91	0.253	0.258	0.252	BF88	NA	0.289	NA	BC90	0.267	0.267	0.253	BR88	NA	0.246	NA
BS94	NA	0.249	NA					BC94	NA	0.265	NA				
avg	0.257	0.262	0.26	avg	0.258	0.262	0.257	avg	0.262	0.265	0.26	avg	0.26	0.26	0.26

ALL MEASUREMENTS ARE IN INCHES

LOCATION: BOTTOM OF WATERWALL (ABOVE WELD OVERLAY)

MATERIAL: SA210; OD: 2.5"; MIN. WALL THICKNESS: 0.220"

Table 13-4

Changes in Waterwall Tube Thickness Between 600 and 8754 Hours of Operation

"A" - SIDE WALL				"A" FRONT WALL				"A" CENTER WALL				"A" REAR WALL			
TUBE No.	600 hours	8754 hours	delta thick	TUBE No.	600 hours	8754 hours	delta thick	TUBE No.	600 hours	8754 hours	delta thick	TUBE No.	600 hours	8754 hours	delta thick
AS1	0.262	0.272	0.01	AF1	0.26	0.259	-0.001	AC1	0.264	0.268	0.004	AR1	0.257	0.255	-0.002
AS5	0.264	0.263	-0.001	AF5	0.272	0.256	-0.016	AC5	0.263	0.255	-0.008	AR5	0.259	0.258	-0.001
AS10	0.268	0.26	-0.008	AF10	0.265	0.259	-0.006	AC10	0.254	0.252	-0.002	AR10	0.266	0.262	-0.004
AS15	0.266	0.261	-0.005	AF15	0.268	0.259	-0.009	AC15	0.254	0.259	0.005	AR15	0.267	0.246	-0.021
AS20	0.263	0.253	-0.01	AF20	0.262	0.026	-0.002	AC20	0.253	0.252	-0.001	AR20	0.266	0.261	-0.005
AS25	0.271	0.27	-0.001	AF25	0.279	0.262	-0.017	AC25	0.258	0.259	0.001	AR25	0.25	0.249	-0.001
AS30	0.264	0.263	-0.001	AF30	0.262	0.265	0.003	AC30	0.261	0.27	0.009	AR30	0.25	0.245	-0.005
AS35	0.269	0.262	-0.007	AF35	0.264	0.248	-0.016	AC35	0.269	0.269	0	AR35	0.266	0.263	-0.003
AS40	0.264	0.258	-0.006	AF40	0.263	0.256	-0.007	AC40	0.263	0.266	0.003	AR40	0.258	0.26	0.002
AS45	0.268	0.265	-0.003	AF45	0.272	0.246	-0.026	AC45	0.245	0.248	0.003	AR45	0.273	0.264	-0.009
AS51	0.263	0.257	-0.006	AF50	0.254	0.264	0.01	AC50	0.245	0.248	0.003	AR50	0.261	0.244	-0.017
AS56	0.261	0.258	-0.003	AF55	0.262	0.255	-0.007	AC55	0.246	0.246	0	AR55	0.261	0.25	-0.011
AS61	0.258	0.258	0	AF60	0.251	0.259	0.008	AC60	0.232	0.231	-0.001	AR60	0.265	0.248	-0.017
AS66	0.265	0.255	-0.01	AF65	0.248	0.27	0.022	AC65	0.254	0.254	0	AR65	0.264	0.258	-0.006
AS71	0.269	0.251	-0.018	AF70	0.27	0.248	-0.022	AC70	0.266	0.265	-0.001	AR70	0.274	0.275	0.001
AS76	0.265	0.256	-0.009	AF75	0.264	0.257	-0.007	AC75	0.24	0.23	-0.01	AR75	0.28	0.27	-0.01
AS81	0.269	0.251	-0.018	AF80	0.255	0.265	0.01	AC80	0.26	0.256	-0.004	AR80	0.273	0.264	-0.009
AS86	0.265	0.261	-0.004	AF85	0.253	0.25	-0.003	AC85	0.271	0.273	0.002	AR85	0.277	0.273	-0.004
AS90	0.277	0.261	-0.016	AF88	0.264	0.267	0.003	AC90	0.257	0.251	-0.006	AR88	0.261	0.259	-0.002
AS94	0.254	0.252	-0.002					AC94	0.263	0.263	0				
avg	0.265	0.259	-0.006	avg	0.263	0.258	-0.004	avg	0.256	0.256	0	avg	0.265	0.258	-0.007

"B" - SIDE WALL				"B' FRONT WALL				"B" CENTER WALL				"B" REAR WALL			
TUBE No.	600 hours	8754 hours	delta thick	TUBE No.	600 hours	8754 hours	delta thick	TUBE No.	600 hours	8754 hours	delta thick	TUBE No.	600 hours	8754 hours	delta thick
BS1	0.257	0.251	-0.006	BF1	0.259	0.268	0.009	BC1	0.259	0.27	0.011	BR1	0.246	0.247	0.001
BS5	0.264	0.265	0.001	BF5	0.255	0.273	0.018	BC5	0.251	0.26	0.009	BR5	0.248	0.25	0.002
BS10	0.268	0.27	0.002	BF10	0.256	0.267	0.011	BC10	0.252	0.267	0.015	BR0	0.267	0.276	0.009
BS15	0.255	0.262	0.007	BF15	0.265	0.265	0	BC15	0.262	0.277	0.015	BR15	0.273	0.276	0.003
BS20	0.272	0.273	0.001	BF20	0.254	0.253	-0.001	BC20	0.249	0.275	0.026	BR20	0.257	0.257	0
BS25	0.25	0.263	0.013	BF25	0.257	0.26	0.003	BC25	0.253	0.268	0.015	BR25	0.262	0.267	0.005
BS30	0.258	0.269	0.011	BF30	0.256	0.265	0.009	BC30	0.256	0.275	0.019	BR30	0.254	0.25	-0.004
BS35	0.262	0.262	0	BF35	0.266	0.266	0	BC35	0.256	0.262	0.006	BR35	0.26	0.27	0.01
BS40	0.249	0.259	0.01	BF40	0.26	0.257	-0.003	BC40	0.255	0.27	0.015	BR40	0.263	0.264	0.001
BS45	0.256	0.254	-0.002	BF45	0.256	0.255	-0.001	BC45	NA	NA	NA	BR45	0.254	0.261	0.007
BS50	0.26	0.262	0.002	BF50	0.251	0.247	-0.004	BC50	NA	NA	NA	BR50	0.254	0.251	-0.003
BS56	0.261	0.262	0.001	BF55	0.254	0.256	0.002	BC55	0.251	0.258	0.007	BR55	0.256	0.252	-0.004
BS61	0.263	0.264	0.001	BF60	0.264	0.258	-0.006	BC60	0.26	0.266	0.006	BR60	0.263	0.264	0.001
BS66	0.253	0.261	0.008	BF65	0.266	0.262	-0.004	BC65	0.265	0.269	0.004	BR65	0.251	0.254	0.003
BS71	0.267	0.272	0.005	BF70	0.262	0.263	0.001	BC70	0.258	0.258	0	BR70	0.272	0.265	-0.007
BS76	0.266	0.266	0	BF75	0.257	0.255	-0.002	BC75	0.25	0.267	0.017	BR75	0.26	0.266	0.006
BS81	0.255	0.262	0.007	BF80	0.254	0.26	0.006	BC80	0.255	0.255	0	BR80	0.266	0.265	-0.001
BS86	0.261	0.261	0	BF85	0.256	0.257	0.001	BC85	0.27	0.263	-0.007	BR85	0.266	0.262	-0.004
BS91	0.254	0.258	0.004	BF88	0.278	0.289	0.011	BC90	0.26	0.267	0.007	BR88	0.267	0.246	-0.021
BS94	0.253	0.249	-0.004					BC94	0.26	0.265	0.005				
avg	0.259	0.262	0.003	avg	0.259	0.262	0.003	avg	0.257	0.266	0.009	avg	0.26	0.26	0

ALL MEASUREMENTS ARE IN INCHES
LOCATION: BOTTOM OF WATERWALL (ABOVE WELD OVERLAY)
MATERIAL: SA210; OD: 2.5"; MIN. WALL THICKNESS: 0.220"

Measurements were also taken of localized erosion at the refractory/water-wall interface during the September outage. Tube wall thickness measurements were made in eroded areas wide enough to insert the UT measurement probe. Table 13-5 summarizes all measurements of localized erosion taken at the refractory/water-wall interface. Tube thickness measurements above the overlay, in the eroded area, and the difference between these measurements are listed in the table. Due to the uneven surfaces in the eroded areas and the poor repeatability of the thickness measurements, it is difficult to draw firm conclusions about the rate at which the depths of the eroded areas may be increasing.

As for all inspections through 1989, localized erosion at the water-wall/refractory interface is most pronounced along the side walls of the combustion chambers closest to the front wall, along the front wall, and in the corners of the combustion chamber. Very little erosion is present along the rear wall of both combustion chambers and along the side walls closest to the rear walls.

13.5 SUPERHEATER II TUBES

During the January outage, the test team completed 176 thickness measurements on the superheater II tubes in combustor A and 96 in combustor B. The measurements were distributed evenly across each of the superheater panels and were taken on the centerline of the tubes only. Table 13-6 summarizes the data and compares it with similar measurements made by an outside testing contractor after 600 hours of operation. The exact measurement location was not marked (to avoid erosion initiation sites) so that the two measurements are not directly comparable. The differences in the average readings in these tables is not significant enough to allow firm conclusions to be drawn.

Localized erosion was observed in one area on the secondary superheater during the January outage. The location was on the top of tube 2 (second from the bottom) on panel 1 on the side wall of combustor B. A flat spot approximately 10 feet long had formed on the top of the tube. Ultrasonic measurements taken on the tube indicate a wall thickness of 0.174 inches in the eroded area versus a thickness of 0.195 inches in the non-eroded area. No corrective action was taken and the area will be monitored closely in the future.

Inspections of the secondary superheater surface were not completed again until a tube failure in October. This failure occurred on October 13 with the unit operating at 105 MWe gross and was caused by a unit MFT from high furnace draft pressure. The pressure was caused by steam release through ruptures in the radiant superheater tubes near the top of the combustor B and water flashing to steam from

Table 13-5

Summary of Tube Thickness Measurements at the Waterwall/Refractory Interface for Localized Erosion

	3600 HOURS THICKNESS			5500 HOURS THICKNESS			7622 HOURS THICKNESS			8754 HOURS THICKNESS		
TUBE #	ERODED AREA	UNERODED AREA	Δ	ERODED AREA	UNERODED AREA	Δ	ERODED AREA	UNERODED AREA	Δ	ERODED AREA	UNERODED AREA	Δ
AC4	NA	NA	NA	0.28	0.261	0.019	0.275	0.264	0.011	0.284	0.262	0.022
AC6	NA	NA	NA	0.263	0.258	0.005	0.258	0.26	-0.002	0.254	0.257	-0.003
AC8	NA	NA	NA	0.253	0.259	-0.006	0.253	0.258	-0.005	0.255	0.26	-0.005
AC13	NA	NA	NA	0.301	0.289	0.012	0.29	0.28	-0.01	0.279	0.278	0.001
AC17	NA	NA	NA	0.247	0.263	-0.016	0.24	0.25	0.01	0.242	0.251	-0.009
AC23	0.255	0.26	-0.005	0.259	0.263	-0.004	0.249	0.265	-0.016	0.243	0.265	-0.022
AC25	0.25	0.257	-0.007	0.244	0.258	-0.014	0.248	0.258	-0.01	0.252	0.258	-0.006
AC26	NA	NA	NA	0.27	0.255	0.015	0.251	0.258	-0.007	0.252	0.253	-0.001
AC28	0.272	0.269	0.003	0.254	0.28	-0.026	0.246	0.276	-0.03	0.248	0.27	-0.022
AC29	NA	NA	NA	0.267	0.273	-0.006	0.263	0.276	-0.013	0.248	0.273	-0.025
AC30	NA	NA	NA	0.264	0.26	0.004	0.252	0.266	-0.014	0.244	0.272	-0.028
AC32	NA	NA	NA	0.25	0.268	-0.018	0.25	0.26	-0.01	0.243	0.264	-0.021
AC36	NA	NA	NA	0.242	0.252	-0.01	0.242	0.246	-0.004	0.235	0.254	-0.019
AC37	NA	NA	NA	0.24	0.254	-0.014	0.227	0.246	-0.019	0.234	0.256	-0.022
AC38	0.258	0.252	0.006	0.262	0.26	0.002	0.258	0.256	0.002	0.28	0.268	0.012
AC39	NA	NA	NA	0.306	0.256	0.05	0.28	0.258	0.022	0.285	0.266	0.019
AC40	NA	NA	NA	0.28	0.264	0.016	0.265	0.253	0.012	0.268	0.266	0.002
BS9	0.268	0.261	0.007	0.271	0.262	0.009	0.268	0.26	0.008	0.256	0.254	0.002
BS11	0.26	0.256	0.004	0.262	0.252	0.01	0.265	0.263	0.002	0.262	0.256	0.006
BS12	0.248	0.258	-0.01	0.266	0.252	0.014	0.265	0.254	0.011	0.236	0.25	-0.014
BS18	0.264	0.252	0.012	0.25	0.251	-0.001	0.25	0.259	-0.009	0.228	0.249	-0.021
BS19	0.258	0.245	0.0013	0.261	0.255	0.006	0.268	0.253	0.015	0.261	0.252	0.009
BS24	NA	NA	NA	0.265	0.264	0.001	0.258	0.258	0	0.247	0.257	-0.01
BF34	NA	NA	NA	0.249	0.264	-0.015	0.243	0.267	-0.024	0.226	0.263	-0.037
BF42	NA	NA	NA	0.214	0.234	-0.02	0.224	0.239	-0.015	0.196	0.233	-0.037
BF49	NA	NA	NA	0.257	0.265	-0.008	0.245	0.263	-0.018	0.232	0.264	-0.032
BF59	NA	NA	NA	0.243	0.265	-0.022	0.235	0.263	-0.028	0.226	0.243	-0.017
BF68	NA	NA	NA	0.249	0.259	-0.01	0.246	0.261	-0.015	0.263	0.266	-0.003
BF69	NA	NA	NA	0.246	0.257	-0.011	0.242	0.26	-0.018	0.253	0.258	-0.005
BF70	NA	NA	NA	0.289	0.269	0.02	0.286	0.259	0.027	0.242	0.256	-0.014
BF74	NA	NA	NA	0.236	0.227	0.009	0.242	0.234	0.008	0.232	0.232	0
BC6	NA	NA	NA	NA	NA	NA	0.238	0.247	-0.009	NA	NA	NA
BC7	NA	NA	NA	NA	NA	NA	0.24	0.245	-0.005	NA	NA	NA
BC8	NA	NA	NA	NA	NA	NA	0.254	0.257	-0.003	NA	NA	NA
BC9	NA	NA	NA	NA	NA	NA	0.24	0.256	-0.016	NA	NA	NA
BC10	NA	NA	NA	NA	NA	NA	0.255	0.25	0.005	NA	NA	NA
BC12	NA	NA	NA	NA	NA	NA	0.261	0.249	0.012	NA	NA	NA
BC13	NA	NA	NA	NA	NA	NA	0.252	0.262	-0.01	NA	NA	NA
BC14	NA	NA	NA	NA	NA	NA	0.235	0.244	-0.009	NA	NA	NA
BC15	NA	NA	NA	NA	NA	NA	0.253	0.261	-0.008	NA	NA	NA
BC20	NA	NA	NA	NA	NA	NA	0.278	0.242	0.036	NA	NA	NA

- Readings affected by grinding.

Table 13-6

Summary of Average Secondary Superheater Tube Thickness Measurements

Combustion Chamber A					Combustion Chamber B				
Location		Huntington	Test Team	Delta	Location		Huntington	Test Team	Delta
Center Wall:					Center Wall:				
SH Panel 1	Tubes 1 - 32	0.193	0.186	-0.007	SH Panel 1	Tubes 1 - 32	0.193	0.196	0.002
	Tubes 33 - 64	0.221	0.214	-0.008		Tubes 33 - 64	0.219	0.225	0.006
SH Panel 2	Tubes 1 - 32	0.194	0.191	-0.003	SH Panel 2	Tubes 1 - 32	0.192	0.194	0.002
	Tubes 33 - 64	0.211	0.212	0.001		Tubes 33 - 64	0.224	0.226	0.002
SH Panel 3	Tubes 1 - 32	0.19	0.187	-0.003	SH Panel 3	Tubes 1 - 32	0.193	0.193	0
	Tubes 33 - 64	0.223	0.226	0.004		Tubes 33 - 64	0.221	0.225	0.004
SH Panel 4	Tubes 1 - 32	0.191	0.188	-0.004	SH Panel 4	Tubes 1 - 32	0.196	0.198	0.002
	Tubes 33 - 64	0.218	0.213	-0.006		Tubes 33 - 64	0.22	0.222	0.002
			avg.=	-0.003				avg. =	0.002
Front Wall:					Front Wall:				
SH Panel 1	Tubes 1 - 32	0.197	0.196	-0.001	SH Panel 1	Tubes 1 - 32	0.188	0.192	0.005
	Tubes 33 - 64	0.249	0.249	0		Tubes 33 - 64	0.241	0.247	0.007
SH Panel 2	Tubes 1 - 32	0.198	0.191	-0.007	SH Panel 2	Tubes 1 - 32	0.175	0.191	0.017
	Tubes 33 - 64	0.242	0.242	0		Tubes 33 - 64	0.253	0.258	0.005
SH Panel 3	Tubes 1 - 32	0.188	0.185	-0.003	SH Panel 3	Tubes 1 - 32	0.188	0.19	0.002
	Tubes 33 - 64	0.243	0.24	-0.003		Tubes 33 - 64	0.251	0.256	0.005
SH Panel 4	Tubes 1 - 32	0.191	0.187	-0.004	SH Panel 4	Tubes 1 - 32	0.189	0.191	0.002
	Tubes 33 - 64	0.247	0.239	-0.008		Tubes 33 - 64	0.251	0.253	0.003
			avg.=	-0.003				avg. =	0.005
Side Wall:					Side Wall:				
SH Panel 1	Tubes 1 - 32	0.181	0.186	0.006	SH Panel 1	Tubes 1 - 32	0.182	0.196	0.014
	Tubes 33 - 64	0.246	0.0254	0.008		Tubes 33 - 64	0.257	0.266	0.009
SH Panel 2	Tubes 1 - 32	0.197	0.194	-0.003	SH Panel 2	Tubes 1 - 32	0.189	0.197	0.009
	Tubes 33 - 64	0.248	0.251	0.002		Tubes 33 - 64	0.243	0.249	0.006
SH Panel 3	Tubes 1 - 32	0.19	0.189	0	SH Panel 3	Tubes 1 - 32	0.189	0.197	0.009
	Tubes 33 - 64	0.25	0.248	-0.003		Tubes 33 - 64	0.243	0.249	0.006
SH Panel 4	Tubes 1 - 32	0.197	0.0186	-0.01	SH Panel 4	Tubes 1 - 32	0.189	0.197	0.009
	Tubes 33 - 64	0.253	0.241	-0.012		Tubes 33 - 64	0.243	0.249	0.006
			avg.=	-0.002				avg. =	0.008
		Overall Average		-0.003			Overall Average		0.005

subsequent ruptures in combustor water-wall tubes in close proximity to the superheater.

Figure 13-14 shows the relative location of the damaged tubes. Close-up details of the tubes are shown in Figure 13-15. A total of five damaged superheater tubes from panel #2, five from panel #1, five water-wall tubes from the rear wall, and fifteen water-wall tubes from the center wall were removed and replaced.

The initial superheater tube failure was caused by particle erosion on the outside of the tube on a return elbow. This erosion is a localized phenomena and is apparent in locations where the combustor geometry is conducive to solids channeling, such as in the combustor corners (see Figure 13-16), around the superheater return elbows (where this failure occurred), and around water-wall support tubes. Erosion is also apparent on tubes in the lower panels that protrude out of plane from the remaining tubes in a panel. Erosion was also found on tubes on the back side of the superheater panel that was repaired during this outage. This is particularly alarming since these locations are not visible during normal inspections.

To prevent future erosion failures on the lower panels where solids loadings are the highest, a four inch shelf was placed around three walls of the combustion chambers just above the top tube on panel #2. The shelves are scalloped to fit around the tubes and refractory is used to fill the gaps. This arrangement is shown in Figures 13-17 and 13-18. Tube thickness measurements were also taken in various locations where solids flow channeling is suspected in order to monitor the erosion rate and the effect of the shelf in preventing erosion. Performance will be carefully monitored in 1990.

13.6 CYCLONE REFRACTORY AND VORTEX FINDER

In January and February, a 39-day outage was used to modify and repair refractory in the cyclones, downcomers, and loop seals. In the cyclones, refractory cracking was severe along the bullnoses in each cyclone and along the inlet spiral shelves. Refractory spalling was visible along the cold joints in the conical sections of the cyclones. The upper barrel refractory, and the refractory on the cyclone outlets remained in relatively good condition (see schematic in Figure 13-19).

The refractory vendor cited several reasons for the poor performance of the refractory through the first quarter of 1989. First, breakage and spalling may have resulted from excessive shrinkage of the abrasion resistant layer due to high water content during installation. The high water content could be attributed to low refractory mix temperatures which necessitates the addition of water to

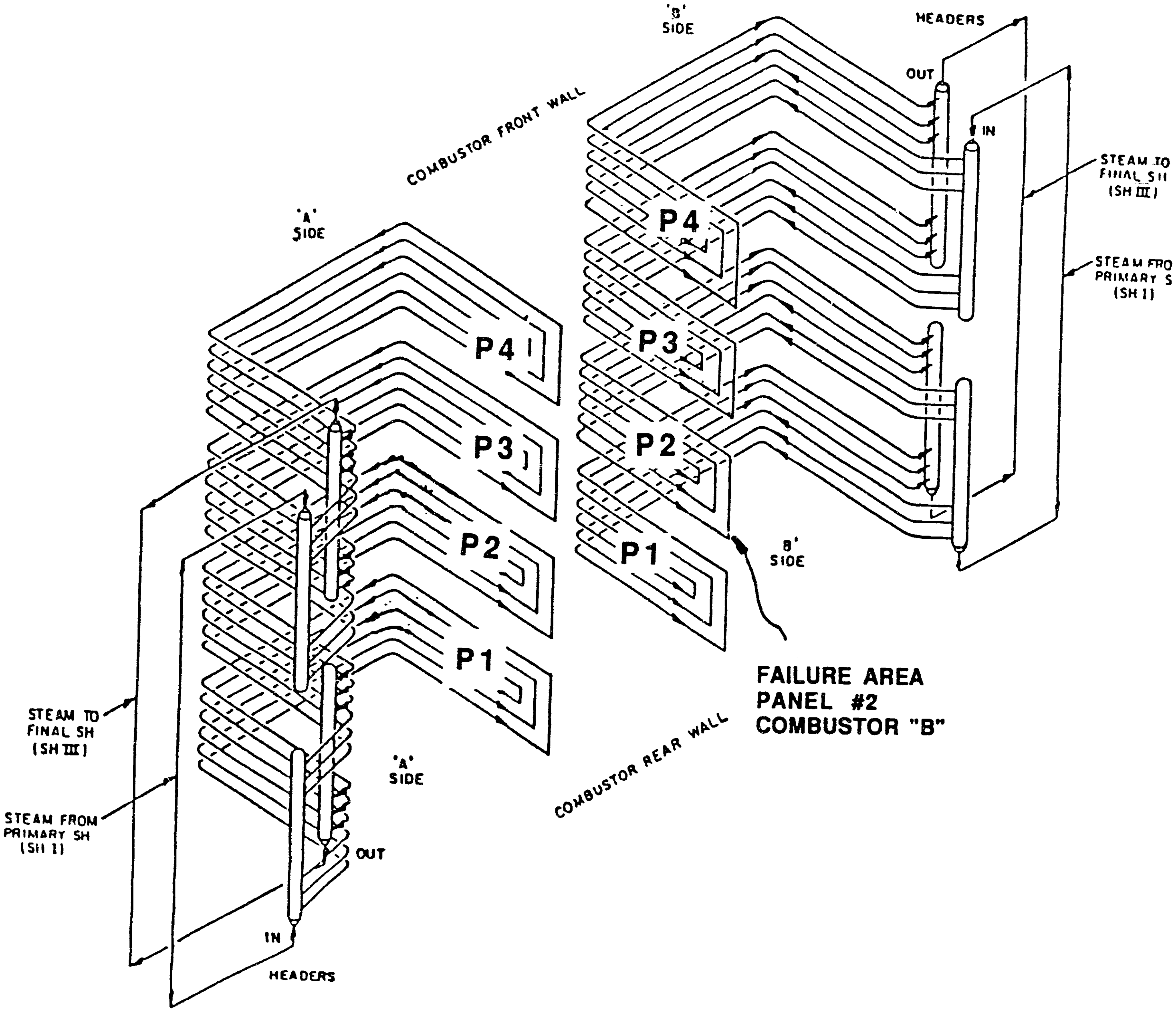


Figure 13-14. Schematic Showing Location of Damaged Secondary Superheater Tubes

Figure 13-15. Damaged Secondary Superheater Tubes.

Figure 13-16. Eroded Secondary Superheater Tubes in Combustion Chamber Corner.

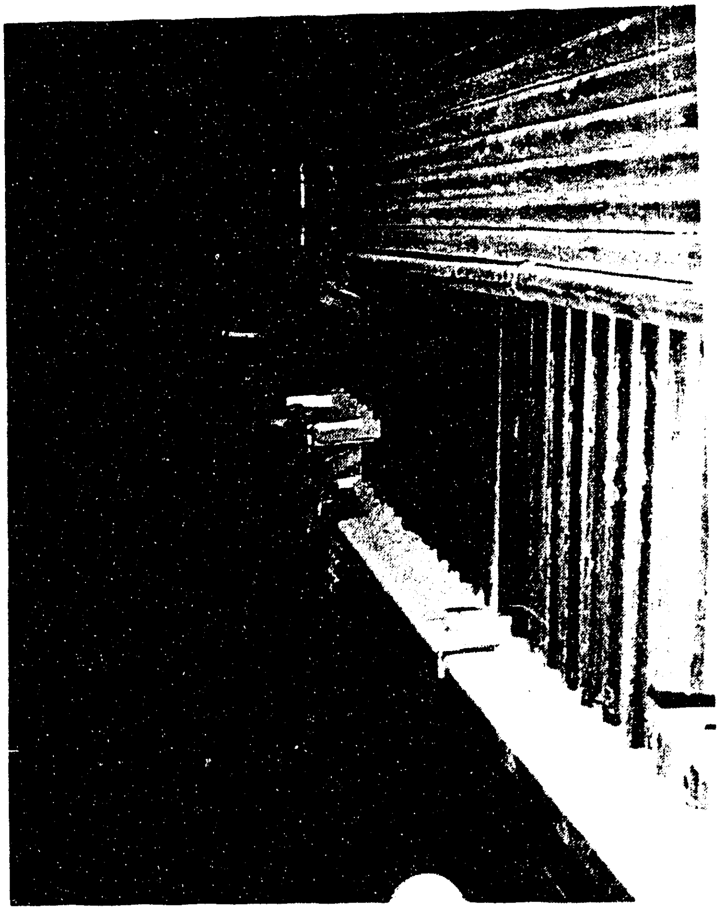


Figure 13-17. Arrangement of Protective Secondary Superheater Shelf (View From Above).

Figure 13-18. Arrangement of Protective Secondary Superheater Shelf (View From Below).

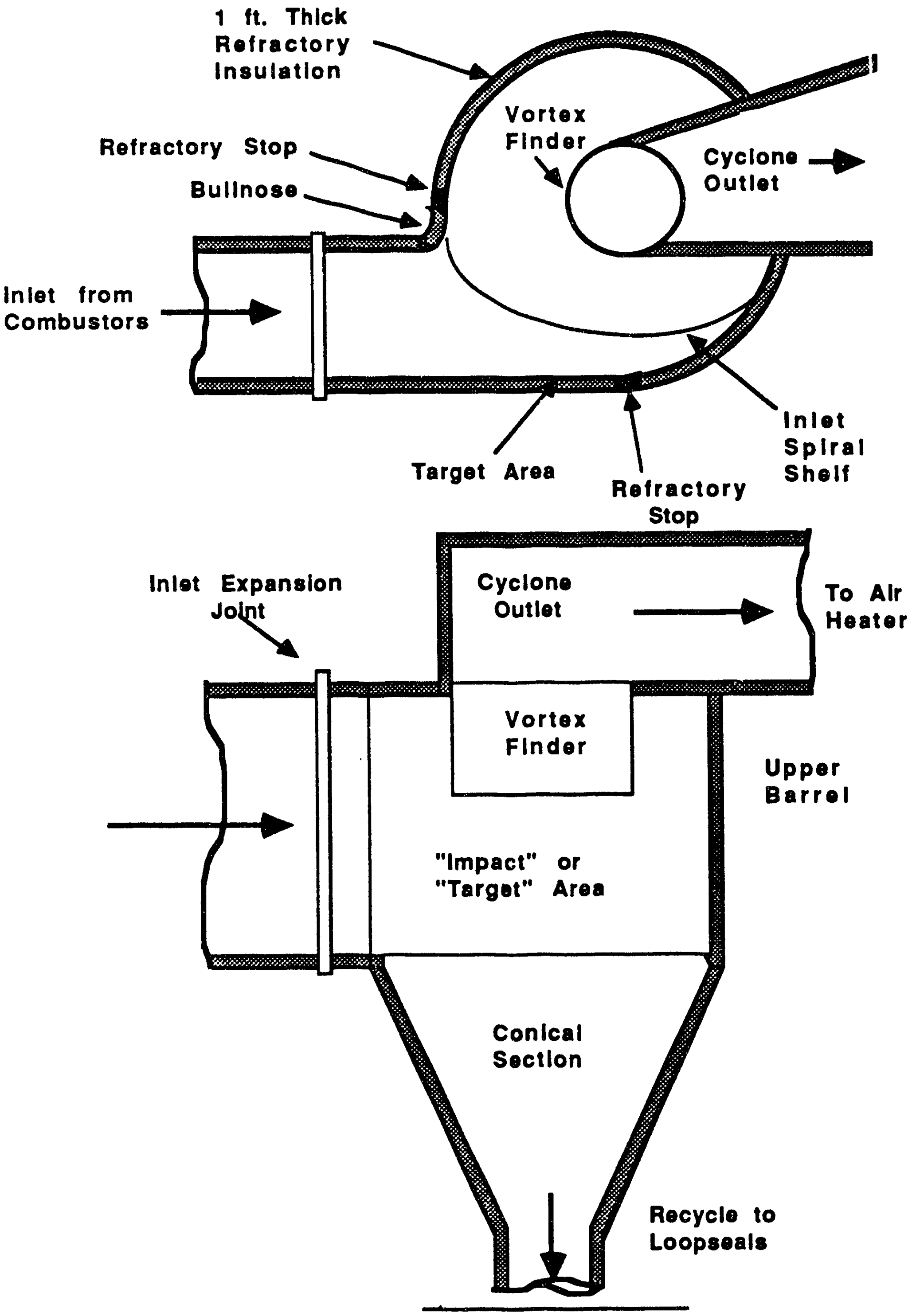


Figure 13-19. Schematic of Cyclone Arrangement (typical of two)

improve workability. Second, the original gunnite process for the abrasion resistant refractory layer proceeded in a downward fashion starting from the top of the cyclone. This resulted in "rebound" material falling on lower construction joint surfaces and anchor bars and led to poor bonding. Finally, vertical and horizontal cold joints left over from construction must be prepared with 90° angles to the outside metal surfaces during the original installation. Improper control of these interfaces causes the joints to push apart during expansion.

To correct the above problems, the abrasion resistant layer of refractory was completely removed in the conical portion of both cyclones. New anchor studs were installed and a new abrasion resistant layer was gunned into place. Bulkheads (stop bars) were installed at two locations in the upper cyclone area in both cyclones (see location in Figure 13-19). These bulkheads are designed to alleviate stresses from thermal expansion that has caused cracking around the bullnose at the cyclone inlets. The bullnose was completely replaced in the combustor A cyclone and was repaired in the combustor B cyclone (see Figure 13-20). Also, the upper cyclone rim that forms the inlet transition was patched or replaced in both cyclones (see Figure 13-21).

During the inspection in June, significant cracks were noted along the bullnoses of both cyclones. This observation pointed to the ineffectiveness of the bulkheads in reducing the stresses on the bullnose. The inlet spiral shelves could not be inspected due to a build-up of bed material on the shelf. Also, the cyclone inlet expansion joint packing material was found to be eroded away and the joint opening was approximately 3.5 to 4 inches in locations. The normal opening is 1.5 inches. This area was repacked with a ceramic blanket insulation during the outage.

During the September outage, cracking along the bullnose had progressed. Crack openings as wide as 4 inches were observed. Also, pinch spalling in the conical portion of the cyclone was beginning to advance once again along horizontal cold joints, resulting in some refractory loss. The cyclone inlet expansion joint packing was also replaced during this outage. During outages in October and December, upper cyclone refractory condition was found to be similar to that observed during the September outage.

Also during the September outage, the vortex finder in cyclone B was found to be distorted, as shown in Figures 13-22 and 13-23. This distortion is believed to affect the fractional collection efficiency of the cyclone. This would cause the bed size distribution between the two chambers to be different, which may account for the difference in operating temperatures between combustors. The vortex finder is scheduled to be repaired in early 1990.

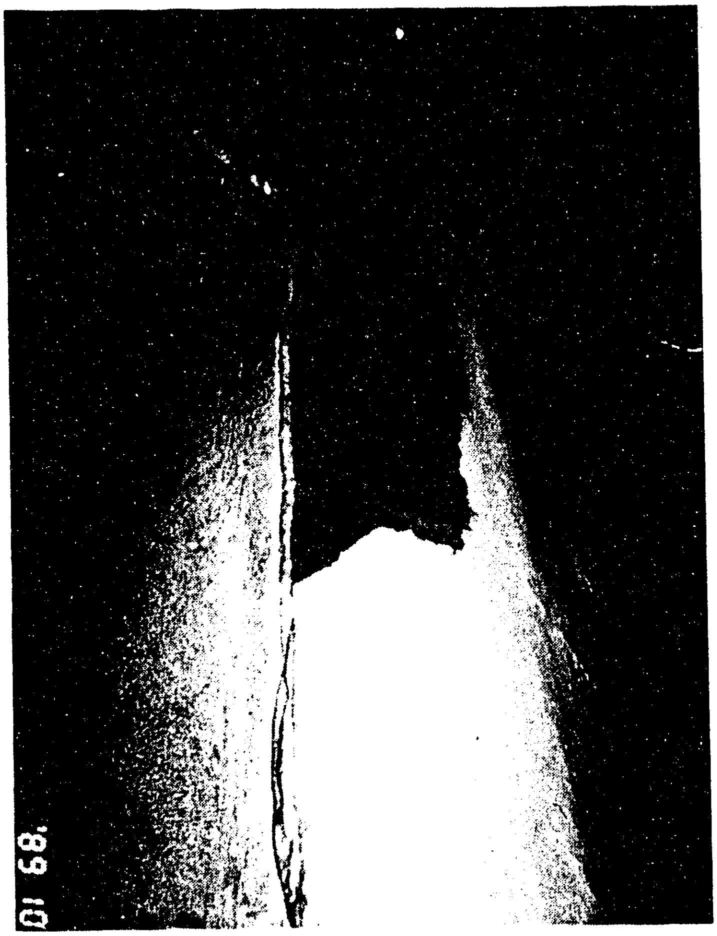


Figure 13-20. Cyclone "Bullnose" Section at Inlet.

Figure 13-21. Upper Cyclone Inlet Spiral.

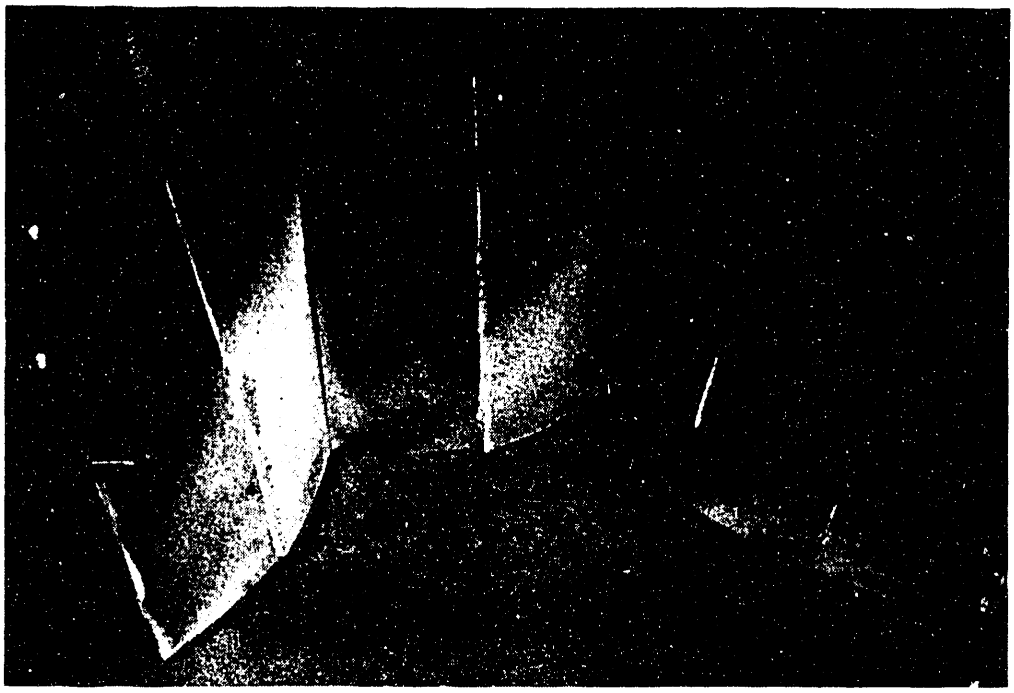


Figure 13-22. Warped Cyclone Vortex Finder (View From Inside).

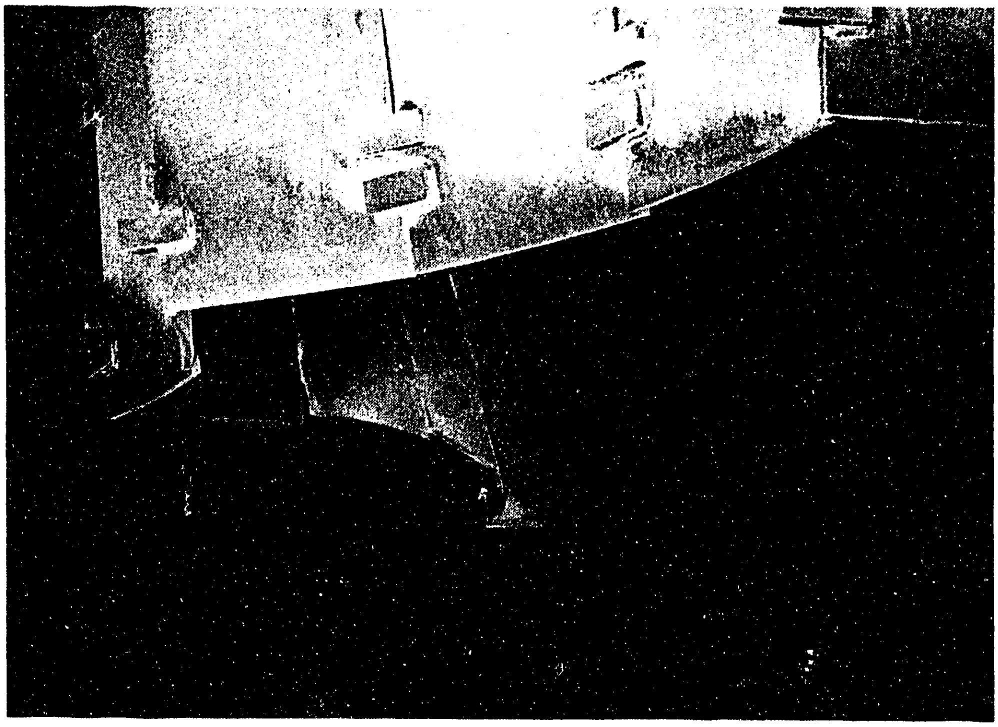


Figure 13-23. Warped Cyclone Vortex Finder (View From Outside).

13.7 DOWNCOMER AND LOOP SEAL REFRACTORY AND OUTSIDE SHELL

Failure of the refractory in the archway of the loop seals in early January advanced the start of a planned refractory repair outage by several weeks. The hot spot that resulted on the outside loop seal shell casing is shown in Figure 13-24. Upon inspection of the loop seals, the cast arches in the bottom of both loop seals were found to have failed (see Figure 13-25). Refractory cracking and erosion at other locations in the loop seals was common. A schematic of the loop seal is shown in Figure 13-26.

After removing the refractory in the loop seals during this outage, several cracks were found in the steel shells forming the loop seal casing. Several of these cracks had formed in the heat affected zone of a weld connecting two plates together. During the outage, these cracks were ground out and rewelded. Structural plates were added in certain locations for additional strength.

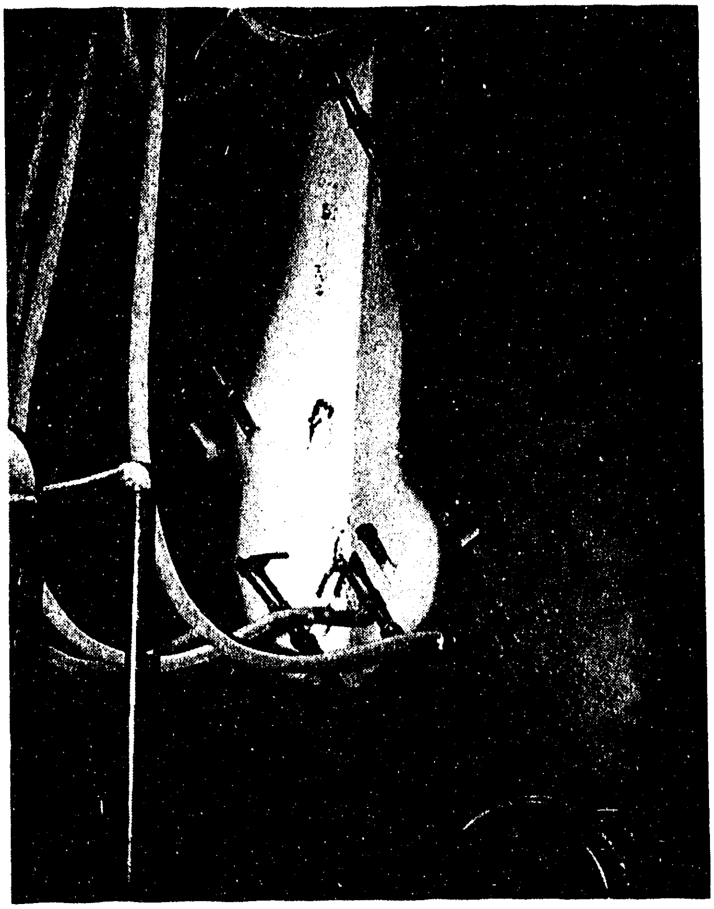
As originally installed, the loop seal refractory was a combination of cast-in-place and gunned refractories. This material was replaced with a combination of cast-in-place refractory, gunned refractory, and firebrick. Figure 13-27 shows the cast-in-place arch in loop seal B. Figure 13-28 shows the nearly completed firebrick installation at the bottom of cyclone downcomer A. The cast refractory arch is also shown in Figure 13-28.

Also during the outage, the cyclone downcomer refractory was inspected. Several loose sections of the lining were removed on both downcomers. An abrasion resistant refractory was reapplied to these surfaces to bring them flush with the existing refractory.

During inspections in June and October, the loop seal refractory was found to be in good condition. Some cracking was observed in the loop seal arches and minor pinch spalling was observed on the gunned-on refractory sections. Pinch spalling was also observed along the joints between adjacent fireclay brick. However, the spalled area is confined to the face area of the brick and does not spread. No additional repairs were required to the loop seals during 1989 following the refractory replacement in January and February.

The repairs made to the cyclone downcomers in January and February did not hold up well, as was discovered during inspections throughout the remainder of the year. The inside refractory surface forming the interior cylinder became uneven and rough. No additional repairs were made to this area in 1989 following the repairs in January and February.

Figure 13-24. Hot Spot on Outside of Loop Seal.



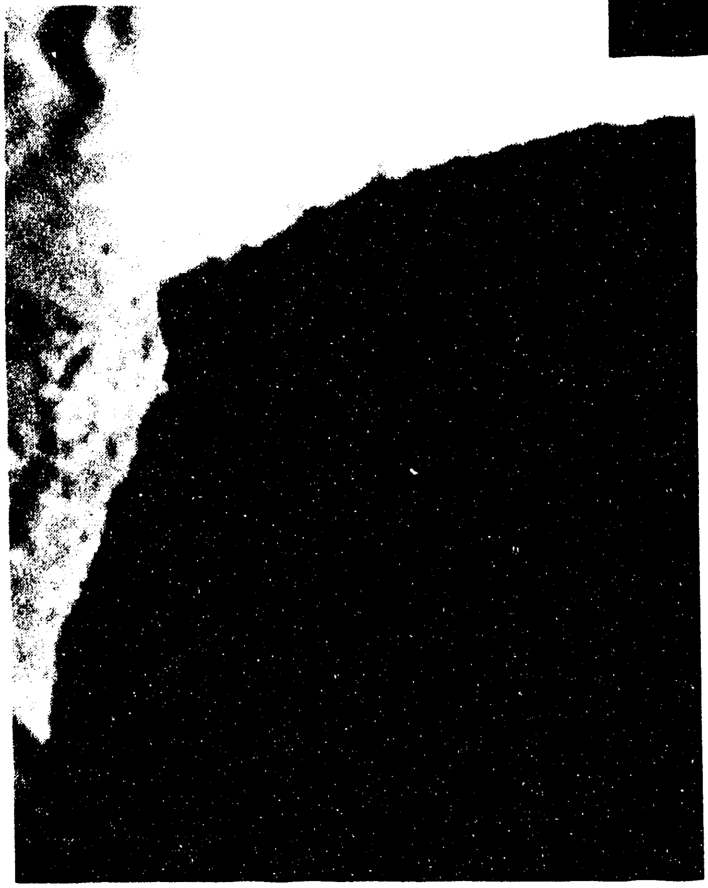


Figure 13-25. Damaged Loop Seal Archway.

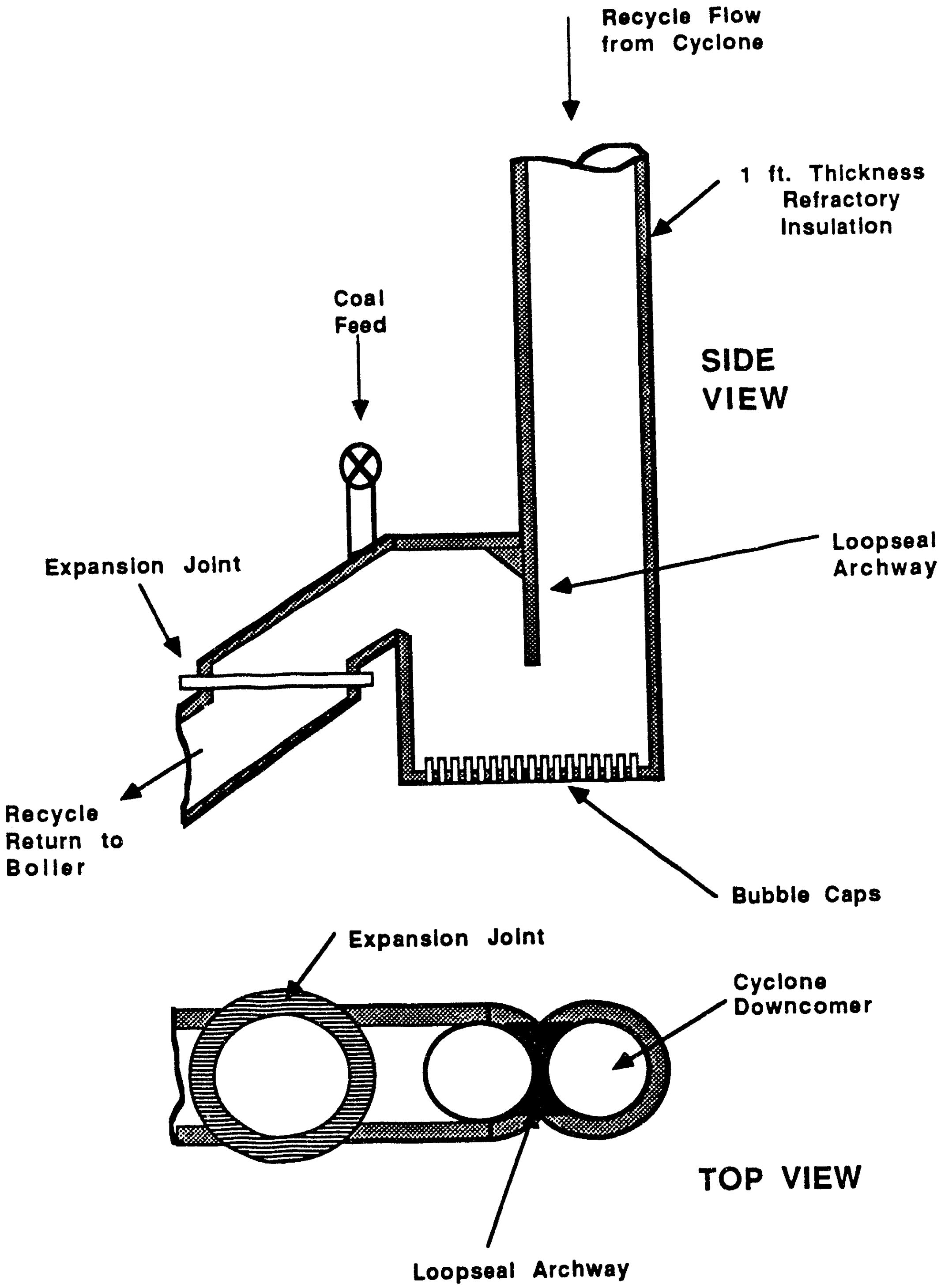


Figure 13-26. Schematic of Loopseal Arrangement.

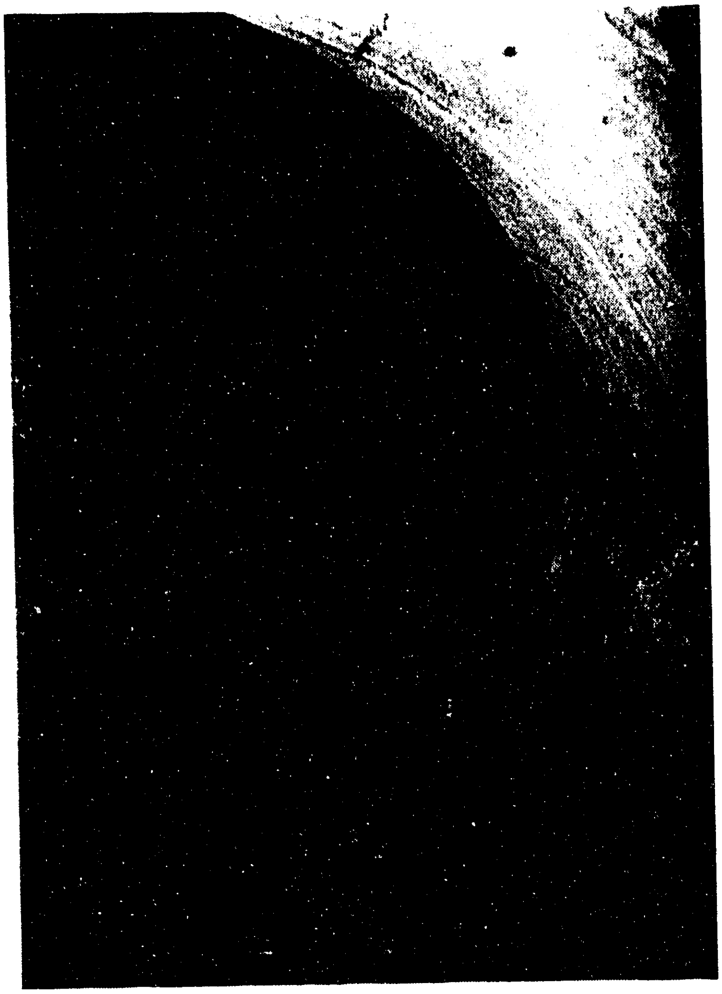


Figure 13-27. New Cast-In-Place Loop Seal Archway.

Figure 13-28. Firebrick Installation in Loop Seal.

13.8 CONVECTION PASS

In June following 7622 hours of boiler operation on coal, UT measurements were made at three locations on four water-cooled hanger tubes at the top of the convection section. The measurement locations are shown in Figure 13-29 and the data are summarized in Table 13-7.

Previously, measurements were taken at five locations on the same four hanger tubes in August 1988 after 3600 hours of boiler operation. These measurements are also shown in the table. While direct comparison of results indicate a slight decrease in tube thickness between January and June 1989, the change in thickness is within the expected uncertainty range associated with the UT device. No pattern of localized erosion was apparent from a visual inspection of the tubes.

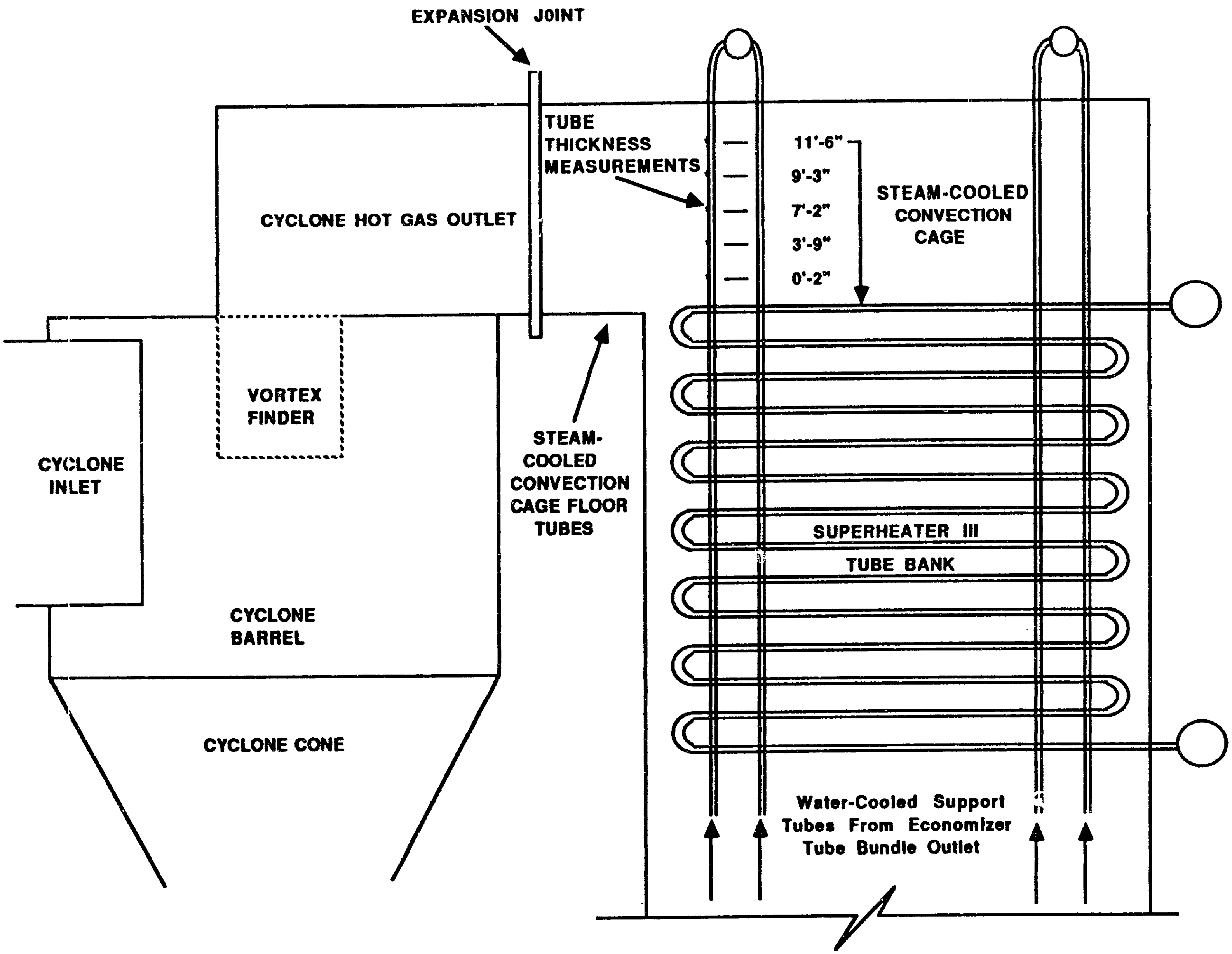


Figure 13-29. Location of Convection Pass Tube Thickness Measurements.

Table 13-7

Water-Cooled Hanger Tube Thickness Measurements at Inlet to Convection Pass

MATERIAL: SA 210 A1, 1.75" OD, 0.240" MWT

All Measurements are in Inches

Tube No.	Location On Tube	Thickness at - 30° off Centerline		Thickness at Centerline		Thickness at + 30° off Centerline	
		7620 hours	3600 hours	7620 hours	3600 hours	7620 hours	3600 hours
AW	1	N/A	0.276	N/A	0.266	N/A	0.264
AW	2	N/A	0.281	N/A	0.274	N/A	0.272
AW	3	0.276	0.281	0.265	0.282	0.269	0.278
AW	4	0.283	0.283	0.28	0.277	0.273	0.286
AW	5	0.259	0.275	0.262	0.272	0.265	0.284
AE	1	N/A	0.284	N/A	0.283	N/A	0.285
AE	2	N/A	0.28	N/A	0.288	N/A	0.284
AE	3	0.277	0.282	0.282	0.292	0.278	0.283
AE	4	0.278	0.286	0.282	0.296	0.28	288
AE	5	0.273	0.279	0.269	0.274	0.274	0.283
BW	1	N/A	0.272	N/A	0.261	N/A	0.274
BW	2	N/A	0.262	N/A	0.275		0.279
BW	3	0.264	0.276	0.261	0.268	0.286	0.283
BW	4	0.268	0.278	0.265	0.277	0.264	0.276
BW	5	0.264	0.273	0.271	0.278	0.273	0.284
BE	1		0.282		0.268		0.266
BE	2		0.272		0.273		0.285
BE	3	0.254	0.268	0.26	0.266	0.26	0.277
BE	4	0.261	0.27	0.262	0.27	0.263	0.271
BE	5	0.257	0.269	0.263	0.278	0.269	0.283
	AVG:	0.268	0.276	0.269	0.276	0.27	0.279

Section 14

RELIABILITY MONITORING

The reliability monitoring plan for the Nucla CFB was conceived by the Electric Power Research Institute as a means of developing an equipment reliability database strictly for atmospheric fluidized bed combustion (AFBC) boilers. The intent was to complement and expand on the NERC/GADS database for fossil-fired units. The new database would accommodate plant equipment components and causes for failure unique to this new technology. The database could then be used for the following:

- Predicting the availability of future commercial AFBC plants
- Evaluating the reliability of proposed designs
- Assessing the impact of design changes on system reliability
- Evaluating life extension work on specific plant components
- Allocating research and development funds for reliability improvement

By tracking the frequency of equipment failures, the equipment run time between failures, and the time required for repair, it was intended to predict the mean time to failure (MTTF) and mean time to repair (MTTR) for specific AFBC plant equipment components. This quantitative information could then be used as a planning tool to satisfy the objectives outlined above.

Accomplishing this plan required three steps. First, uniform codes, established by EPRI, were given to plant equipment components on three utility AFBC's under construction or in start-up: Northern States Power's 125 MWe Black Dog Bubbling Bed AFBC, TVA's 160 MWe Bubbling Bed AFBC, and Colorado-Ute Electric Association's 110 MWe Nucla CFB. This would eventually allow direct comparisons to be made between these three plants. Second, the equipment codes, cause of failure codes, and time required for repair were added to the plant maintenance work request forms. This information could be manually or automatically collected into a database. Third, equipment component run times were collected by either the plant digital control system (DCS) or by a host computer using specially developed software.

14.1 DEVELOPMENT OF UNIFORM EQUIPMENT CODES

The first step was completed during the cold-mode shakedown period of the Demonstration Program and is reported in the 1987-1988 Annual Technical Progress Report. Fifteen digit numbers were assigned to approximately 620 pieces of plant equipment to a level of detail consistent with that presented on the P&ID drawings. This equipment breakdown is listed in the 1987-1988 Annual Technical Progress Report. As an example, the limestone feed system was broken down into transport blowers, transport piping, weigh system, rotary valves, bin shaker, isolation gate, shaker motor, vent system, etc. For identical equipment used on several systems, i.e., two limestone feed systems, each equipment component was given a unique equipment identification number. The same numbering scheme was also used at the other demonstration plants.

14.2 MAINTENANCE WORK REQUEST SOFTWARE

To accomplish the second step, an initial version of a software program called PERFORM was developed by EPRI during the cold-mode shakedown period for generating hard copy maintenance work requests (MWR's). This program contains the uniform equipment codes assigned to each piece of plant hardware in step 1 (see Reliability Monitoring Database pages 1 through 9). As MWR's are generated by the plant, the cause and nature of the failure (if any), the work priority of the problem (1. Immediate Action Required, 2. Possible Curtailment, 3. At Earliest Convenience, 4. Outage Item), the hours required for repair, the date, and other information are automatically stored in a database. The software allows MWR's to be sorted by maintenance request (MR) number, equipment ID number, and date. This software was first used at the Nucla CFB during the fourth quarter of 1988 to generate maintenance work requests.

During the first quarter of 1989, final modifications were completed to the format of the PERFORM software summary reports. Each summary report now prints a three-line summary output which includes such entries as MR number, CUEA equipment number, equipment description, date originated, MR status (open/closed), and the problem description. After debugging the software on the test program's PC, the software was loaded onto the CUEA PC located in the control room. CUEA operating personnel began using the PERFORM software to generate MR's late in June 1989. Test program personnel also entered MR forms from hard copy beginning from October 1988 when the plant completed acceptance tests on design "A" coal.

RELIABILITY MONITORING DATABASE - 1

CUEA No.			EPRI No.			Description	TAG No.
002409001494001	C4		02147010	03	01	SERVICE WATER PIPING	CLT62
002409001001001	C4		02147010	01	01	SERVICE WATER SYSTEM MISC	CLT62
002409001601001	C5					SERVICE WATER VALVES, MISC	CLT62
002413001001001	C4		02146010	06	01	INST AIR SYS PIPES AND VLVS	CPT50
002413001560001	C4	2	02146010	04	01	INSTR AIR RECEIVER TANKS	CPT50
002413001601001	C4		02146010	05	01	INSTR AIR SAFETY VALVES	CPT50
002613001001001	C3		02146002	01	01	INSTRUMENT AIR SYSTEM	CPT50
002413001222001	C4		02146010	01	01	INSTR AIR COMPRESSOR 4A	CZS1
002413001851001	C4		02146010	01	01	INSTR AIR COMPRESSOR 4A MOTOR	CZS1
002413001183001	C4		02146010	02	01	INSTR AIR COMPRESSOR AFTER COOLER	CZS1
002413501222001	C4		02146010	03	01	SERVICE AIR COMPRESSOR 4A	CZS2
002413501851001	C4		02146010	03	01	SERVICE AIR COMPRESSOR 4A MOTOR	CZS2
002413501222003	C4		02146010	03	03	SERVICE AIR COMPRESSOR STANDBY	CZS2,3,51
002413501850001	C4		02146010	03	01	SERVICE AIR COMPRESSOR STANDBY MTR	CZS2,3,51
002413501560001	C4	2	02146010	04	01	SERVICE AIR RECEIVER TANKS	CZS2,3,51
002413501601001	C4		02146010	05	01	SERVICE AIR SAFETY VALVES	CZS2,3,51
002413501001001	C4		02146010	06	01	SERVICE AIR SYS PIPES AND VLVS	CZS2,3,51
002413501222002	C4		02146010	03	02	SERVICE AIR COMPRESSOR 4B	CZS3
002413501851002	C4		02146010	03	02	SERVICE AIR COMPRESSOR 4B MOTOR	CZS3
002413501850002	C4		02146010	03	01	SERVICE AIR COMPRESSOR EMERG MTR	CZS51
002413501222004	C4		02146010	03	04	SERVICE AIR COMPRESSOR EMERGENCY	CZS51
002601501001001	C		02141611	01	01	BOILER STEAM DRUM, MISC	DPT1
002601501001002	N		02141611	03	01	BOILER STM DRUM, INTERNALS	DPT1
002601501587001	C	3	02141611	02	01	BOILER STM DRUM, SAFETY VALVES	DPT1
002601503545001	C		02141409	03	01	BOILER WATER COOLED HANGER RODS	DPT1
002601511545001	C		02141409	01	01	BOILER WATER WALL 4A TUBES	DPT1
002601511545002	C		02141409	01	02	BOILER WATER WALL 4B TUBES	DPT1
002601511545003	C2		02141409	02	01	BOILER WTR WALL 4A HNGR TUBES	DPT1
002601511545004	C2		02141409	02	02	BOILER WTR WALL 4B HNGR TUBES	DPT1
002601503001001	C		02141407	01	01	ECONOMIZER TUBES, CONV. PASS	DPT1
002601502545002	C		02141405	05	01	SUPERHEAT 4A TBS,SEC,RAD.FRBD	DPT1
002601502545003	C		02141405	05	02	SUPERHEAT 4B TBS,SEC,RAD.FRBD	DPT1
002601502587001	C	1	02141211	01	01	SUPERHEAT SAFETY VALVES	DPT1
002601502545004	C		02141404	01	01	SUPERHEAT TUBES,FNSHG,CON.PASS	DPT1
002601502545001	C		02141406	01	01	SUPERHEAT TUBES,PRI,CONV.PASS	DPT1
002602002290001	C3		02143401	01	02	FEEDWATER HTR 4D, HIGH PRESS	EPT3
002602002290002	C3		02143401	01	01	FEEDWATER HTR 4E, HIGH PRESS	EPT3
002602001494001	C4		02143610	01	01	FEEDWATER PIPING	EPT3
002602001579002	C		02143213	02	01	FEEDWATER REG VALVE-STARTUP 3"	EPT3
002602001579001	C		02143213	01	01	FEEDWATER REGULATOR VLV - 8"	EPT3
002601508709004	C2		02143243	02	04	ATTEMPERATOR 4D, FLOW ELEMENT	ETCV10
002601508001004	C		02143243	01	04	ATTEMPERATOR 4D, MISC	ETCV10
002601508582004	C2		02143243	03	04	ATTEMPERATOR 4D, SPRAY VALVE	ETCV10
002601508709001	C2		02143243	02	01	ATTEMPERATOR 4A, FLOW ELEMENT	ETCV7
002601508001001	C		02143243	01	01	ATTEMPERATOR 4A, MISC	ETCV7
002601508582001	C2		02143243	03	01	ATTEMPERATOR 4A, SPRAY VALVE	ETCV7
002601508709002	C2		02143243	02	02	ATTEMPERATOR 4B, FLOW ELEMENT	ETCV8
002601508001002	C		02143243	01	02	ATTEMPERATOR 4B, MISC	ETCV8
002601508582002	C2		02143243	03	02	ATTEMPERATOR 4B, SPRAY VALVE	ETCV8
002601508709003	C2		02143243	02	03	ATTEMPERATOR 4C, FLOW ELEMENT	ETCV9
002601508001003	C		02143243	01	03	ATTEMPERATOR 4C, MISC	ETCV9
002601508582003	C2		02143243	03	03	ATTEMPERATOR 4C, SPRAY VALVE	ETCV9
002602001852002	C		02143104	04	02	BOILER FEED PUMP 4B MOTOR	EZS1
002602001500002	C		02143104	01	02	BOILER FEED PUMP 4B, MISC	EZS1
002602001001001	C		02143050	01	01	FEEDWATER SYSTEM INSTR.& CNTRL	EZS1,2
002602001852001	C		02143104	04	01	BOILER FEED PUMP 4A MOTOR	EZS2
002602001500001	C		02143104	01	01	BOILER FEED PUMP 4A, MISC	EZS2
002601514494001	C4		02144010	03	01	PROPANE FUEL PIPING	GASFLOW
002601514001001	C4		02144010	01	01	PROPANE FUEL SYS - MISC	GASFLOW
002601514601001	C4		02144010	04	01	PROPANE FUEL VALVES	GASFLOW
002601503705001	C		02140056	01	03	GAS ANALYZER-O2, ECON IN EAST	GAT9A
002601503705002	C		02140056	01	04	GAS ANALYZER-O2, ECON IN WEST	GAT9B
002605509130001	C2		02141503	03	01	BAGHOUSE BAL DFT DMPR (OLD/#4)	GMT20
002604506710001	C2		02145401	07	01	BTM ASH CLR 4A INLET AERATION	GPT4
002604506710002	C2		02145401	07	02	BTM ASH CLR 4B INLET AERATION	GPT4
002604506710003	C2		02145401	07	03	BTM ASH CLR 4C INLET AERATION	GPT4
002604506710004	C2		02145401	07	04	BTM ASH CLR 4D INLET AERATION	GPT4
002601516181001	C2		02149201	02	01	RECYCLE LOOP SEAL 4A AIR NZLS	GPT4
002601516001001	C		02149201	05	01	RECYCLE LOOP SEAL 4A FLUID SYS	GPT4
002601516181002	C2		02149201	02	02	RECYCLE LOOP SEAL 4B AIR NZLS	GPT4

RELIABILITY MONITORING DATABASE - 2

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002603509266001	C4	02141610	01	01	BOILER DUCT - PRIMARY AIR	GWM325
002601510181001	N	02141620	03	01	DISTR PLATE 4A AIR NOZZLES	GWM325
002601510181002	N	02141620	03	02	DISTR PLATE 4B AIR NOZZLES	GWM325
002601510263001	N	02141620	01	01	DISTRIBUTOR PLATE 4A, MISC	GWM325
002601510263002	N	02141620	01	02	DISTRIBUTOR PLATE 4B, MISC	GWM325
002603509709001	C2	02141621	01	01	PA 4A AIR FOIL, 4A	GWM325
002603509709002	C2	02141621	01	02	PA 4A AIR FOIL, 4B	GWM325
002603509228001	C2	02141622	02	01	PA 4A DAMPER AUTO CONTRLR, 4A	GWM325
002603509228002	C2	02141622	02	02	PA 4A DAMPER AUTO CONTRLR, 4B	GWM325
002603509130001	C2	02141622	01	01	PA 4A DAMPER, 4A	GWM325
002603509130002	C2	02141622	01	02	PA 4A DAMPER, 4B	GWM325
002603509250001	C	02141140	02	01	PA 4A FAN COUPLING	GWM325
002603509516001	C	02141140	04	01	PA 4A FAN DC REACTOR, 4A	GWM325
002603509516002	C	02141140	04	02	PA 4A FAN DC REACTOR, 4B	GWM325
002603509860001	C	02141140	07	01	PA 4A FAN ISOLATION TRANSFORMR	GWM325
002603509562001	C	02141140	09	01	PA 4A FAN LUBE OIL CONSOLE	GWM325
002603509852001	C	02141140	11	01	PA 4A FAN MOTOR	GWM325
002606531228004	C	02141140	13	01	PA 4A FAN VARI SD DR CNTR-STRT	GWM325
002606531228003	C	02141140	12	01	PA 4A FAN VARI SPD DR CNTR-RUN	GWM325
002603509340001	C	02141140	01	01	PA 4A FAN, MISC	GWM325
002603007290001	C	02141404	01	01	AIR PREHEATER - TUBULAR	GWM327
002408509228001	C	02140003	01	01	BOILER AIR FLOW/DRAFT CONTRL	GWM327
002603001266001	C4	2141615	01	01	BOILER DUCT - FLUE GAS	GWM327
002408509228003	N	02140005	01	01	COMBUSTION CONTROL	GWM327
002603001250001	C	02141102	02	01	ID FAN 4A COUPLING	GWM327
002603001516001	C	02141102	04	01	ID FAN 4A DC REACTOR, 4A	GWM327
002603001516002	C	02141102	04	01	ID FAN 4A DC REACTOR, 4B	GWM327
002603001860001	C	02141102	07	01	ID FAN 4A ISOLATION TRANSFORMR	GWM327
002603001560001	C	02141102	08	01	ID FAN 4A LUBE OIL CONSOLE	GWM327
002603001560002	C	02141102	10	01	ID FAN 4A LUBE OIL PUMP	GWM327
002603001852001	C	02141102	11	01	ID FAN 4A MOTOR	GWM327
002606531228002	C	02141102	13	01	ID FAN 4A VARI SD DR CNTR-STRT	GWM327
002606531228001	C	02141102	12	01	ID FAN 4A VARI SPD DR CNTR-RUN	GWM327
002603001341001	C	02141102	01	01	ID FAN 4A, MISC	GWM327
002603004001001	C2	02141613	01	01	STACK	GWM327
002603511266001	C4	02141610	02	01	BOILER DUCT - SECONDARY AIR	GZS2
002603511709001	C2	02141623	01	01	SA 4A AIR FOIL 4A	GZS2
002603511709002	C2	02141624	01	02	SA 4A AIR FOIL 4B	GZS2
002603511228001	C2	02141624	02	01	SA 4A DAMPER AUTO, 4A	GZS2
002603511228002	C2	02141624	02	02	SA 4A DAMPER AUTO, 4B	GZS2
002603511130001	C2	02141624	01	01	SA 4A DAMPER, 4A	GZS2
002603511130002	C2	02141624	01	02	SA 4A DAMPER, 4B	GZS2
002606504228006	C	02141141	14	01	SA 4A FAN BACKUP STARTER	GZS2
002603511250001	C	02141141	02	01	SA 4A FAN COUPLING	GZS2
002603511516001	C	02141141	04	01	SA 4A FAN DC REACTOR	GZS2
002603511860001	C	02141141	07	01	SA 4A FAN ISOLATION TRANSFORMR	GZS2
002603511852001	C	02141141	11	01	SA 4A FAN MOTOR	GZS2
002606531228005	C	02141141	12	01	SA 4A FAN VARI SPD DR CONTR	GZS2
002603511341001	C	02141141	01	01	SA 4A FAN, MISC	GZS2
002601516341001	C	02149127	01	01	RECYCLE HP FLUID BLOWER 4A	GZS4A
002601516851001	C	02149127	03	01	RECYCLE HP FLUID BLOWER 4A MTR	GZS4A
002601516250001	C	02149127	02	01	RECYCLE HP FLUID BLWR 4A CPLNG	GZS4A
002601516341002	C	02149127	01	02	RECYCLE HP FLUID BLOWER 4B	GZS4B
002601516851002	C	02149127	03	02	RECYCLE HP FLUID BLOWER 4B MTR	GZS4B
002601516250002	C	02149127	02	02	RECYCLE HP FLUID BLWR 4B CPLNG	GZS4B
002604506130002	C2	02145401	02	02	BOM ASH CLR 4B AIR CNTRL DMPR	GZS5
002604506263001	C2	02145401	05	01	BOTTOM ASH CLR 4A DISTR PLATE	GZS5
002604506263002	C2	02145401	05	02	BOTTOM ASH CLR 4B DISTR PLATE	GZS5
002604506263003	C2	02145401	05	03	BOTTOM ASH CLR 4C DISTR PLATE	GZS5
002604506263004	C2	02145401	05	04	BOTTOM ASH CLR 4D DISTR PLATE	GZS5
002604506181001	C2	02145401	04	01	BOTTOM ASH COOLER 4A AIR NZL	GZS5
002604506264001	C2	02145401	06	01	BOTTOM ASH COOLER 4A DRAIN	GZS5
002604506181002	C2	02145401	04	02	BOTTOM ASH COOLER 4B AIR NZL	GZS5
002604506264002	C2	02145401	06	02	BOTTOM ASH COOLER 4B DRAIN	GZS5
002604506181003	C2	02145401	04	03	BOTTOM ASH COOLER 4C AIR NZL	GZS5
002604506264003	C2	02145401	06	03	BOTTOM ASH COOLER 4C DRAIN	GZS5
002604506181004	C2	02145401	04	04	BOTTOM ASH COOLER 4D AIR NZL	GZS5
002604506264004	C2	02145401	06	04	BOTTOM ASH COOLER 4D DRAIN	GZS5
002604506341001	C	02145101	01	01	BOTTOM ASH COOLING FAN	GZS5

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CUEA No.			EPRI No.			Description	TAG No.
002504506250001	C		02145101	01	02	BOTTOM ASH COOLING FAN CPLNG	GZS5
002604506851001	C		02145101	01	03	BOTTOM ASH COOLING FAN MOTOR	GZS5
002604501351001	C		02145665	01	01	BOTTOM ASH ROTARY AIR LOCK 4A	GZS5
002604501351002	C		02145665	01	02	BOTTOM ASH ROTARY AIR LOCK 4B	GZS5
002604501351003	C		02145665	01	03	BOTTOM ASH ROTARY AIR LOCK 4C	GZS5
002604501351004	C		02145665	01	04	BOTTOM ASH ROTARY AIR LOCK 4D	GZS5
002604506130001	C2		02145401	02	01	BTM ASH CLR 4A AIR CNTRL DMPR	GZS5
002604506709001	C2		02145401	03	01	BTM ASH CLR 4A AIR FLOW SNSR	GZS5
002604506709002	C2		02145401	03	02	BTM ASH CLR 4A AIR FLOW SNSR	GZS5
002604506130003	C2		02145401	02	03	BTM ASH CLR 4C AIR CNTRL DMPR	GZS5
002604506709003	C2		02145401	03	03	BTM ASH CLR 4C AIR FLOW SNSR	GZS5
002604506130004	C2		02145401	02	04	BTM ASH CLR 4D AIR CNTRL DMPR	GZS5
002604506709004	C2		02145401	03	04	BTM ASH CLR 4D AIR FLOW SNSR	GZS5
002604506374001	C		02145401	09	01	BTM ASH COOLER 4A SLIDE GATE	GZS5
002604506251001	N		02145401	01	01	BTM ASH COOLER 4A, MISC	GZS5
002604506374002	C		02145401	09	02	BTM ASH COOLER 4B SLIDE GATE	GZS5
002604506251002	N		02145401	01	02	BTM ASH COOLER 4B, MISC	GZS5
002604506374003	C		02145401	09	03	BTM ASH COOLER 4C SLIDE GATE	GZS5
002604506251003	N		02145401	01	03	BTM ASH COOLER 4C, MISC	GZS5
002604506374004	C		02145401	09	04	BTM ASH COOLER 4D SLIDE GATE	GZS5
002604506251004	N		02145401	01	04	BTM ASH COOLER 4D, MISC	GZS5
002604506378001	C2		02145661	02	01	BTM ASH HPR 4A COLD DIV GATE	GZS5
002604506378003	C2		02145661	03	01	BTM ASH HPR 4A HOT DIV GATE	GZS5
002604506378002	C2		02145661	02	02	BTM ASH HPR 4B COLD DIV GATE	GZS5
002604506378004	C2		02145661	03	02	BTM ASH HPR 4B HOT DIV GATE	GZS5
002604505850001	C		02145665	02	01	BTM ASH ROTARY AIR LCK 4A MTR	GZS5
002604505850002	C		02145665	02	02	BTM ASH ROTARY AIR LCK 4B MTR	GZS5
002604505850003	C		02145665	02	03	BTM ASH ROTARY AIR LCK 4C MTR	GZS5
002604505850004	C		02145665	02	04	BTM ASH ROTARY AIR LCK 4D MTR	GZS5
002602502290001	C3		02143402	01	02	FEEDWATER HTR 4A, LOW PRESS	HFT3
002602502290002	C3		02143402	01	01	FEEDWATER HTR 4B, LOW PRESS	HFT3
002602503290001	C3		02143410	01	04	DEAERATOR, (HEATER 4C) UNIT 4	HLT3
002602501001001	C3		02148410	01	02	CONDENSER, UNIT 4	HPT72
002602501510001	C3		02143110	01	07	HOTWELL PUMP 4A	HZS1
002602501850001	C3		02143110	02	07	HOTWELL PUMP 4A MOTOR	HZS1
002602501510002	C3		02143110	01	08	HOTWELL PUMP 4B	HZS2
002602501850002	C3		02143110	02	08	HOTWELL PUMP 4B MOTOR	HZS2
002614501001001	C3		02140648	01	01	AUX STM(#s 002614501xxxxxxx)	JPT1
002602501397001	C3		02148410	02	04	CONDENSER #4 HTWLL (DRN RCVR)	KPT2
002602002495001	C4	2	02143401	02	01	FEEDWATER HTR, HP-EXTR PPING	KPT2
002602502495001	C4	8	01243402	02	01	FEEDWATER HTR, LP EXTR PPING	KPT2
002600104598001	C		02142329	26	04	TURBINE CONTROL VALVES, UNIT 4	KPT2
002900106495001	C4		02142329	36	04	TURBINE EXT PIPING, UNIT 4	KPT2
002600106581001	N		02142329	28	04	TURBINE EXTRACT VLVS, UNIT 4	KPT2
002600100001001	C2		02142329	01	04	TURBINE, MISC UNIT 4	KPT2
002701001001001	C3		02142330	03	01	GENERATOR EXCITER, UNIT 1	LMW1
002700500001001	C		02142330	01	01	GENERATOR UNIT 1, MISC	LMW1
002606501001001	C4		02142710	01	01	TRANSFORMER, UNIT 1 GENERATOR	LMW1
002801001001001	C3		02142330	03	02	GENERATOR EXCITER, UNIT 2	LMW2
002800500001002	C		02142330	01	02	GENERATOR UNIT 2, MISC	LMW2
002706501001001	C4		02142710	01	02	TRANSFORMER, UNIT 2 GENERATOR	LMW2
002901001001001	C3		02142330	03	03	GENERATOR EXCITER, UNIT 3	LMW3
002900500001003	C		02142330	01	03	GENERATOR UNIT 3, MISC	LMW3
002806501001001	C4		02142710	01	03	TRANSFORMER, UNIT 3 GENERATOR	LMW3
002702501397001	C3		02148410	02	01	CONDENSER #1 HTWLL (DRN RCVR)	LPT64
002700104598001	C		02142329	26	01	TURBINE CONTROL VALVES, UNIT 1	LPT64
002600106495001	C4		02142329	36	01	TURBINE EXT PIPING, UNIT 1	LPT64
002700106581001	C		02142329	28	01	TURBINE EXTRACT VLVS, UNIT 1	LPT64
002700100001001	C2		02142329	01	01	TURBINE, MISC UNIT 1	LPT64
002802501397001	C3		02148410	02	02	CONDENSER #2 HTWLL (DRN RCVR)	LPT65
002800104598001	C		02142329	26	02	TURBINE CONTROL VALVES, UNIT 2	LPT65
002700106495001	C4		02142329	36	02	TURBINE EXT PIPING, UNIT 2	LPT65
002800106581001	N		02142329	28	02	TURBINE EXTRACT VLVS, UNIT 2	LPT65
002800100001001	C2		02142329	01	02	TURBINE, MISC UNIT 2	LPT65
002902501397001	C3		02148410	02	03	CONDENSER #3 HTWLL (DRN RCVR)	LPT66
002900104598001	C		02142329	26	03	TURBINE CONTROL VALVES, UNIT 3	LPT66
002800106495001	C4		02142329	36	03	TURBINE EXT PIPING, UNIT 3	LPT66
002900106581001	N		02142329	28	03	TURBINE EXTRACT VLVS, UNIT 3	LPT66
002900100001001	C2		02142329	01	03	TURBINE, MISC UNIT 3	LPT66
002702502290001	C3		02143402	01	08	FEEDWATER HTR 1A, LOW PRESS	NFT105

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CUEA No.		EPRI No.			Description	TAG No.
002702502290002	C3	02143402	01	07	FEEDWATER HTR 1B, LOW PRESS	NFT105
002802502290001	C3	02143402	01	06	FEEDWATER HTR 2A, LOW PRESS	NFT106
002802502290002	C3	02143402	01	05	FEEDWATER HTR 2B, LOW PRESS	NFT106
002902502290001	C3	02143402	01	04	FEEDWATER HTR 3A, LOW PRESS	NFT107
002902502290002	C3	02143402	01	03	FEEDWATER HTR 3B, LOW PRESS	NFT107
002702503290001	C3	02143410	01	01	DEAERATOR, (HEATER 1C) UNIT 1	NLT58
002802503290001	C3	02143410	01	02	DEAERATOR, (HEATER 2C) UNIT 2	NLT63
002902503290001	C3	02143410	01	03	DEAERATOR, (HEATER 3C) UNIT 3	NLT68
002702501001001					UNIT 1 CONDENSER	NPT108
002802501001001					UNIT 2 CONDENSER	NPT109
002902501001001					UNIT 3 CONDENSER	NPT110
002702501510001	C3	02143110	01	01	HOTWELL PUMP 1A	NZS11
002702501850001	C3	02143110	02	01	HOTWELL PUMP 1A MOTOR	NZS11
002702501510002	C3	02143110	01	02	HOTWELL PUMP 1B	NZS12
002702501850002	C3	02143110	02	02	HOTWELL PUMP 1B MOTOR	NZS12
002702503850001	C3	02143120	02	01	CONDENSATE FORW PUMP 1A MTR	NZS13
002702503500001	C3	02143120	01	01	CONDENSATE FORW PUMP 1A, MISC	NZS13
002802501510001	C3	02143110	01	03	HOTWELL PUMP 2A	NZS21
002802501850001	C3	02143110	02	03	HOTWELL PUMP 2A MOTOR	NZS21
002802501510002	C3	02143110	01	04	HOTWELL PUMP 2B	NZS22
002802501850002	C3	02143110	02	04	HOTWELL PUMP 2B MOTOR	NZS22
002802503850002	C3	02143120	02	02	CONDENSATE FORW PUMP 2A MTR	NZS23
002802503500002	C3	02143120	01	02	CONDENSATE FORW PUMP 2A, MISC	NZS23
002902501510001	C3	02143110	01	05	HOTWELL PUMP 3A	NZS31
002902501850001	C3	02143110	02	05	HOTWELL PUMP 3A MOTOR	NZS31
002902501510002	C3	02143110	01	06	HOTWELL PUMP 3B	NZS32
002902501850002	C3	02143110	02	06	HOTWELL PUMP 3B MOTOR	NZS32
002902503850003	C3	02143120	02	03	CONDENSATE FORW PUMP 3A MTR	NZS33
002902503500003	C3	02143120	01	03	CONDENSATE FORW PUMP 3A, MISC	NZS33
002601511517001	C	02141400	06	01	BOILER BED ZONE 4A REFRACTORY	0001X195
002601511570001	C	02141400	02	01	BOILER CASING	0001X195
002601515517001	C2	02141801	02	01	BOILER CYCLONE 4A REFRACTORY	0001X195
002601515530001	C	02141801	01	01	BOILER CYCLONE, COMB 4A	0001X195
002616008001001	C2	02141400	03	01	BOILER FRAMING	0001X195
002616008001001	C2	02141400	04	01	BOILER INSULATION	0001X195
002616008001002	C2	02141400	05	01	BOILER LAGGING	0001X195
002604506517001	C2	02145401	08	01	BTM ASH COOLER 4A REFRACTORY	0001X195
002604506517002	C2	02145401	08	02	BTM ASH COOLER 4B REFRACTORY	0001X195
002601510517001	N	02141620	02	01	DISTRIBUTOR PLT COMB 4A REFRCT	0001X195
002601516844001	C	02149201	03	01	RECYCLE LOOP SEAL 4A EXP JNT	0001X195
002601516517003	C2	02149201	06	01	RECYCLE LOOP SEAL 4A REFRCTRY	0001X195
002601516435001	C	02149201	01	01	RECYCLE LOOP SEAL, COMB 4A	0001X195
002601511517002	C	02141400	06	02	BOILER BED ZONE 4B REFRACTORY	0003X115
002601515517002	C2	02141801	02	02	BOILER CYCLONE 4B REFRACTORY	0003X115
002601515530002	C	02141801	01	02	BOILER CYCLONE, COMB 4B	0003X115
002604506517003	C2	02145401	08	03	BTM ASH COOLER 4C REFRACTORY	0003X115
002604506517004	C2	02145401	08	04	BTM ASH COOLER 4D REFRACTORY	0003X115
002601510517002	N	02141620	02	02	DISTRIBUTOR PLT COMB 4B REFRCT	0003X115
002601516844002	C	02149201	03	02	RECYCLE LOOP SEAL 4B EXP JNT	0003X115
002601516517004	C2	02149201	06	02	RECYCLE LOOP SEAL 4B REFRCTRY	0003X115
002601516435002	C	02149201	01	02	RECYCLE LOOP SEAL, COMB 4B	0003X115
002601514190005	C	02141662	02	05	BURNER, START-UP, 4E	OFT10
002601514190006	C	02141662	02	06	BURNER, START-UP, 4F	OFT12
002601514190008	C	02141662	01	01	BURNER 4A, PRIMARY AIR DUCT	OFT14
002601514190007	C	02141662	01	02	BURNER 4B, PRIMARY AIR DUCT	OFT16
002601514190001	C	02141662	02	01	BURNER, START-UP, 4A	OFT2
002601514190002	C	02141662	02	02	BURNER, START-UP, 4B	OFT4
002601514190003	C	02141662	02	03	BURNER, START-UP, 4C	OFT6
002601514190004	C	02141662	02	04	BURNER, START-UP, 4D	OFT8
002605506340001	C	02141503	10	01	BAGHOUSE #4 PURGE AIR FAN	PSWI71
002605505850001	C	02141503	11	02	BAGHOUSE #4 PURGE AIR FAN MTR	PSWI71
002605505341001	N	02141503	06	04	BAGHOUSE #4 DEFLATE AIR FAN	PSWI72
002605505850004	N	02141503	07	04	BAGHOUSE #4 DEFLATE FAN MOTOR	PSWI72
002605505341002	C	02141503	06	01	BAGHOUSE #1 DEFLATE AIR FAN	PSWO10
002605505850001	C	02141503	07	01	BAGHOUSE #1 DEFLATE FAN MOTOR	PSWO10
002605505341003	N	02141503	06	02	BAGHOUSE #2 DEFLATE AIR FAN	PSWO11
002605505850002	N	02141503	07	02	BAGHOUSE #2 DEFLATE FAN MOTOR	PSWO11
002605505341004	N	02141503	06	03	BAGHOUSE #3 DEFLATE AIR FAN	PSWO12
002605505850003	N	02141503	07	03	BAGHOUSE #3 DEFLATE FAN MOTOR	PSWO12
002603502350002	C	02144621	01	02	COAL FEEDER 4B GRAVAMTRIC MISC	QFT1

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CUEA No.		EPRI No.			Description	TAG No.
002603502850002	C4	02144621	02	02	COAL FEEDER 4B GRAVAMTRIC MTR	QFT1
002603502850008	C	02144622	02	02	COAL FEEDER 4B MOTOR - ROTARY	QFT1
002603502378002	C2	02144626	01	02	COAL FEEDER 4B ROTARY ISO GATE	QFT1
002603502540002	C	02144623	01	02	COAL FEEDER 4B SCALE	QFT1
002603502377002	C	02144624	01	02	COAL FEEDER 4B SLIDE GATE	QFT1
002603502228002	C	02144625	01	02	COAL FEEDER 4B SPEED CONTROL	QFT1
002603502351002	C	02144622	01	02	COAL FEEDER 4B - ROTARY MISC	QFT1
002603502350003	C	02144621	01	03	COAL FEEDER 4C GRAVAMTRIC MISC	QFT2
002603502850003	C4	02144621	02	03	COAL FEEDER 4C GRAVAMTRIC MTR	QFT2
002603502850009	C	02144622	02	03	COAL FEEDER 4C MOTOR - ROTARY	QFT2
002603502378003	C2	02144626	01	03	COAL FEEDER 4C ROTARY ISO GATE	QFT2
002603502540003	C	02144623	01	03	COAL FEEDER 4C SCALE	QFT2
002603502377003	C	02144624	01	03	COAL FEEDER 4C SLIDE GATE	QFT2
002603502228003	C	02144625	01	03	COAL FEEDER 4C SPEED CONTROL	QFT2
002603502351003	C	02144622	01	03	COAL FEEDER 4C - ROTARY MISC	QFT2
002603502244003	C	02144630	01	01	COAL CONVEYOR 4A HORIZ MISC	QFT25
002603502850015					COAL CONVEYOR 4A HORIZ MTR	QFT25
002603502244001	C	02144630	01	02	COAL CONVEYOR 4A INCLINED MISC	QFT25
002603502850013	C	02144630	04	02	COAL CONVEYOR 4A INCLINED MTR	QFT25
002603502350001	C	02144621	01	01	COAL FEEDER 4A GRAVAMTRIC MISC	QFT25
002603502850001	C4	02144621	02	01	COAL FEEDER 4A GRAVAMTRIC MTR	QFT25
002603502850007	C	02144622	02	01	COAL FEEDER 4A MOTOR - ROTARY	QFT25
002603502378001	C2	02144626	01	01	COAL FEEDER 4A ROTARY ISO GATE	QFT25
002603502540001	C	02144623	01	01	COAL FEEDER 4A SCALE	QFT25
002603502377001	C	02144624	01	01	COAL FEEDER 4A SLIDE GATE	QFT25
002603502228001	C	02144665	01	01	COAL FEEDER 4A SPEED CONTROL	QFT25
002603502351001	C	02144622	01	01	COAL FEEDER 4A - ROTARY MISC	QFT25
002603502244004	C	02144630	01	03	COAL CONVEYOR 4D HORIZ MISC	QFT26
002603502850016	C	02144630	04	03	COAL CONVEYOR 4D HORIZ MTR	QFT26
002603502244002	C	02144630	01	04	COAL CONVEYOR 4D INCLINED MISC	QFT26
002603502850014	C	02144630	04	04	COAL CONVEYOR 4D INCLINED MTR	QFT26
002603502350004	C	02144621	01	04	COAL FEEDER 4D GRAVAMTRIC MISC	QFT26
002603502850004	C4	02144621	02	04	COAL FEEDER 4D GRAVAMTRIC MTR	QFT26
002603502850010	C	02144622	02	04	COAL FEEDER 4D MOTOR - ROTARY	QFT26
002603502378004	C2	02144626	01	04	COAL FEEDER 4D ROTARY ISO GATE	QFT26
002603502540004	C	02144623	01	04	COAL FEEDER 4D SCALE	QFT26
002603502377004	C	02144624	01	04	COAL FEEDER 4D SLIDE GATE	QFT26
002603502228004	C	02144625	01	04	COAL FEEDER 4D SPEED CONTROL	QFT26
002603502351004	C	02144622	01	04	COAL FEEDER 4D - ROTARY MISC	QFT26
002603502350006	C	02144621	01	06	COAL FEEDER 4F GRAVAMTRIC MISC	QFT3
002603502850006	C4	02144621	02	06	COAL FEEDER 4F GRAVAMTRIC MTR	QFT3
002603502850012	C	02144622	02	06	COAL FEEDER 4F MOTOR - ROTARY	QFT3
002603502378006	C2	02144626	01	06	COAL FEEDER 4F ROTARY ISO GATE	QFT3
002603502540006	C	02144623	01	06	COAL FEEDER 4F SCALE	QFT3
002603502377006	C	02144624	01	06	COAL FEEDER 4F SLIDE GATE	QFT3
002603502228006	C	02144625	01	06	COAL FEEDER 4F SPEED CONTROL	QFT3
002603502351006	C	02144622	01	06	COAL FEEDER 4F - ROTARY MISC	QFT3
002603502350005	C	02144621	01	05	COAL FEEDER 4E GRAVAMTRIC MISC	QFT4
002603502850005	C4	02144621	02	05	COAL FEEDER 4E GRAVAMTRIC MTR	QFT4
002603502850011	C	02144622	02	05	COAL FEEDER 4E MOTOR - ROTARY	QFT4
002603502378005	C2	02144626	01	05	COAL FEEDER 4E ROTARY ISO GATE	QFT4
002603502540005	C	02144623	01	05	COAL FEEDER 4E SCALE	QFT4
002603502377005	C	02144624	01	05	COAL FEEDER 4E SLIDE GATE	QFT4
002603502228005	C	02144625	01	05	COAL FEEDER 4E SPEED CONTROL	QFT4
002603502351005	C	02144622	01	05	COAL FEEDER 4E - ROTARY MISC	QFT4
002601503705003	C	02140057	01	01	GAS ANALYZER-SO2, ECON 4A OUT	RAT1
002601503705004	C	02140057	01	02	GAS ANALYZER-SO2, ECON 4B OUT	RAT2
002606001352002	C4				SORB SILO 4B VIBR BIN DISCH	RFT13
002606030529002	C2	02144665	04	02	SORBENT LOS WT FDR 4B SCTR PLT	RFT13
002606030378002	C	02144665	05	02	SORBENT LOS WT FDR 4B SLD GATE	RFT13
002606030228002	C	02144665	02	02	SORBENT LOSS WT FDR 4B MICPROS	RFT13
002606030350002	C	02144665	01	02	SORBENT LOSS WT FDR 4B MISC	RFT13
002606030850002	C	02144665	03	02	SORBENT LOSS WT FDR 4B MOTOR	RFT13
002606030245002	C 4	02144664	01	02	SORBENT TRANSPORT PIPING, 4B	RFT13
002606001352001					SORB SILO 4A VIBR BIN DISCH	RFT4
002606030529001	C2	02144665	04	01	SORBENT LOS WT FDR 4A SCTR PLT	RFT4
002606030378001	C	02144665	05	01	SORBENT LOS WT FDR 4A SLD GATE	RFT4
002606030228001	C	02144665	02	01	SORBENT LOSS WT FDR 4A MICPROS	RFT4
002606030350001	C	02144665	01	01	SORBENT LOSS WT FDR 4A MISC	RFT4
002606030850001	C	02144665	03	01	SORBENT LOSS WT FDR 4A MOTOR	RFT4

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CUEA No.			EPRI No.			Description	TAG No.
002606030245001	C	4	02144664	01	01	SORBENT TRANSPORT PIPING, 4A	RFT4
002408509228002	N		02140005	01	01	Ca/S RATIO CONTROL	RFT4,13
002606030185005	C		02144663	01	05	SORBENT BLOWER 4E, MISC	RZS16A
002606030850005	C		02144663	02	05	SORBENT BLOWER MOTOR, 4E	RZS16A
002606030579005	C2		02144667	01	05	SORBENT BOILER ISO GATE VLV 4E	RZS16A
002606030351005	C		02144666	01	05	SORBENT ROTARY FEEDER 4E MISC	RZS16A
002606030350013	C		02144666	02	05	SORBENT ROTARY FEEDER 4E MTR	RZS16A
002606030185006	C		02144663	01	06	SORBENT BLOWER 4F, MISC	RZS16B
002606030850006	C		02144663	02	06	SORBENT BLOWER MOTOR, 4F	RZS16B
002606030579006	C2		02144667	01	06	SORBENT BOILER ISO GATE VLV 4F	RZS16B
002606030351006	C		02144666	01	06	SORBENT ROTARY FEEDER 4F MISC	RZS16B
002606030350014	C		02144666	02	06	SORBENT ROTARY FEEDER 4F MTR	RZS16B
002606030185007	C		02144663	01	07	SORBENT BLOWER 4G, MISC	RZS16C
002606030850007	C		02144663	02	07	SORBENT BLOWER MOTOR, 4G	RZS16C
002606030579007	C2		02144667	01	07	SORBENT BOILER ISO GATE VLV 4G	RZS16C
002606030351007	C		02144666	01	07	SORBENT ROTARY FEEDER 4G MISC	RZS16C
002606030350015	C		02144666	02	07	SORBENT ROTARY FEEDER 4G MTR	RZS16C
002606030185008	C		02144663	01	08	SORBENT BLOWER 4H, MISC	RZS16D
002606030850008	C		02144663	02	08	SORBENT BLOWER MOTOR, 4H	RZS16D
002606030579008	C2		02144667	01	08	SORBENT BOILER ISO GATE VLV 4H	RZS16D
002606030351008	C		02144666	01	08	SORBENT ROTARY FEEDER 4H MISC	RZS16D
002606030350016	C		02144666	02	08	SORBENT ROTARY FEEDER 4H MTR	RZS16D
002606030185001	C		02144663	01	01	SORBENT BLOWER 4A, MISC	RZS7A
002606030850001	C		02144663	02	01	SORBENT BLOWER MOTOR, 4A	RZS7A
002606030579001	C2		02144667	01	01	SORBENT BOILER ISO GATE VLV 4A	RZS7A
002606030351001	C		02144666	01	01	SORBENT ROTARY FEEDER 4A MISC	RZS7A
002606030350009	C		02144666	02	01	SORBENT ROTARY FEEDER 4A MTR	RZS7A
002606030185002	C		02144663	01	02	SORBENT BLOWER 4B, MISC	RZS7B
002606030850002	C		02144663	02	02	SORBENT BLOWER MOTOR, 4B	RZS7B
002606030579002	C2		02144667	01	02	SORBENT BOILER ISO GATE VLV 4B	RZS7B
002606030351002	C		02144666	01	02	SORBENT ROTARY FEEDER 4B MISC	RZS7B
002606030350010	C		02144666	02	02	SORBENT ROTARY FEEDER 4B MTR	RZS7B
002606030185003	C		02144663	01	03	SORBENT BLOWER 4C, MISC	RZS7C
002606030850003	C		02144663	02	03	SORBENT BLOWER MOTOR, 4C	RZS7C
002606030579003	C2		02144667	01	03	SORBENT BOILER ISO GATE VLV 4C	RZS7C
002606030351003	C		02144666	01	03	SORBENT ROTARY FEEDER 4C MISC	RZS7C
002606030350011	C		02144666	02	03	SORBENT ROTARY FEEDER 4C MTR	RZS7C
002606030185004	C		02144663	01	04	SORBENT BLOWER 4D, MISC	RZS7D
002606030850004	C		02144663	02	04	SORBENT BLOWER MOTOR, 4D	RZS7D
002606030579004	C2		02144667	01	04	SORBENT BOILER ISO GATE VLV 4D	RZS7D
002606030351004	C		02144666	01	04	SORBENT ROTARY FEEDER 4D MISC	RZS7D
002606030350012	C		02144666	02	04	SORBENT ROTARY FEEDER 4D MTR	RZS7D
002603005460001	C4		02140027	01	01	OPACITY MONITORING SYSTEM	SAT50
002603005705002						GAS ANALYZER-NOX CEM	SAT51
002603005705003						GAS ANALYZER-SO2 CEM	SAT52
002604503528001	C		02145125	01	01	FLYASH EXHAUSTER 4A MISC	TAEA52A
002604503851001	C		02145125	02	01	FLYASH EXHAUSTER 4A MOTOR	TAEA52A
002604503528002	C		02145125	01	02	FLYASH EXHAUSTER 4B MISC	TAEB52A
002604503851002	C		02145125	02	02	FLYASH EXHAUSTER 4B MOTOR	TAEB52A
002604503528003	C		02145125	01	03	FLYASH EXHAUSTER 4C MISC	TAEC52A
002604503851003	C		02145125	02	03	FLYASH EXHAUSTER 4C MOTOR	TAEC52A
002604506251005	C		02145402	01	01	BOTTOM ASH 4A SCREW COOLER	TCSA52AS,F
002604506850001	C		02145402	02	01	BTM ASH SCREW COOLER 4A MOTOR	TCSA52AS,F
002604506251006	C		02145402	01	02	BOTTOM ASH 4B SCREW COOLER	TCSB52AS,F
002604506850002	C		02145402	02	02	BTM ASH SCREW COOLER 4B MOTOR	TCSB52AS,F
002604503590004	C	14	02145216	01	01	BAGHOUSE 4 TRANS LINE ISO VLV	TPT31
002604503330002	C		02141503	09	04	BAGHOUSE ASH MECH SEP FILTR 4B	TPT31
002604503530002	C		02141503	09	02	BAGHOUSE ASH MECH SEPARATOR 4B	TPT31
002605503850001	C		02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4A	TPT31
002605503850002	C		02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4B	TPT31
002605503850003	C		02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4C	TPT31
002605503850004	C		02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4D	TPT31
002605503850005	C		02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4E	TPT31
002605503850006	C		02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4F	TPT31
002605503850007	C		02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4G	TPT31
002605503850008	C2		02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4H	TPT31
002605503850009	C		02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4J	TPT31
002605503850010	C		02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4K	TPT31
002605503850011	C		02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4L	TPT31
002605503850012	C		02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4M	TPT31

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CUEA No.			EPRI No.			Description	TAG No.
002605503330004	C	1440	02141503	02	04	BAGHOUSE #4 BAGS	TPT31
002604503590004	N	12	02141503	05	04	BAGHOUSE #4 CMP HPR DUST VALVE	TPT31
002605503525004	C	12	02141503	12	04	BAGHOUSE #4 SHAKER	TPT31
002605508130001	C		02141503	04	01	BAGHOUSE #4, BYPASS DAMPER 1	TPT31
002605508130002	C		02141503	04	02	BAGHOUSE #4, BYPASS DAMPER 2	TPT31
002605508130003	C		02141503	04	03	BAGHOUSE #4, BYPASS DAMPER 3	TPT31
002601503001004	C		02141503	01	04	BAGHOUSE #4, MISC	TPT31
002604503245001	C		02145640	01	01	FLYASH TRANSPORT PIPING	TPT31,34
002604503330001	C		02141503	09	03	BAGHOUSE ASH MECH SEP FILTR 4A	TPT34
002604503530001	C		02141503	09	01	BAGHOUSE ASH MECH SEPARATOR 4A	TPT34
002605503850013	C		02141503	13	01	BAGHOUSE SHAKER MOTOR, COMP 1N	TPT34
002605503050014	C		02141503	13	01	BAGHOUSE SHAKER MOTOR, COMP 1P	TPT34
002605503850015	C		02141503	13	01	BAGHOUSE SHAKER MOTOR, COMP 1Q	TPT34
002605503850016	C		02141503	13	01	BAGHOUSE SHAKER MOTOR, COMP 1R	TPT34
002605503850017	C		02141503	13	01	BAGHOUSE SHAKER MOTOR, COMP 1S	TPT34
002605503850018	C		02141503	13	01	BAGHOUSE SHAKER MOTOR, COMP 1T	TPT34
002605503850019	C		02141503	13	02	BAGHOUSE SHAKER MOTOR, COMP 2N	TPT34
002605503850020	C		02141503	13	02	BAGHOUSE SHAKER MOTOR, COMP 2P	TPT34
002605503850021	C		02141503	13	02	BAGHOUSE SHAKER MOTOR, COMP 2Q	TPT34
002605503850022	C		02141503	13	02	BAGHOUSE SHAKER MOTOR, COMP 2R	TPT34
002605503850023	C		02141503	13	02	BAGHOUSE SHAKER MOTOR, COMP 2S	TPT34
002605503850024	C		02141503	13	02	BAGHOUSE SHAKER MOTOR, COMP 2T	TPT34
002605503850025	C		02141503	13	03	BAGHOUSE SHAKER MOTOR, COMP 3N	TPT34
002605503850026	C		02141503	13	03	BAGHOUSE SHAKER MOTOR, COMP 3P	TPT34
002605503850027	C		02141503	13	03	BAGHOUSE SHAKER MOTOR, COMP 3Q	TPT34
002605503850028	C		02141503	13	03	BAGHOUSE SHAKER MOTOR, COMP 3R	TPT34
002605503850029	C		02141503	13	03	BAGHOUSE SHAKER MOTOR, COMP 3S	TPT34
002605503850030	C		02141503	13	03	BAGHOUSE SHAKER MOTOR, COMP 3T	TPT34
002605503330001	C	672	02141503	02	01	BAGHOUSE #1 BAGS	TPT34
002604503590001	C2	6	02141503	05	01	BAGHOUSE #1 CMP HPR DUST VALVE	TPT34
002605503525001	C	6	02141503	12	01	BAGHOUSE #1 SHAKER	TPT34
002601503001001	C		02141503	01	01	BAGHOUSE #1, MISC	TPT34
002605503330002	C	672	02141503	02	02	BAGHOUSE #2 BAGS	TPT34
002604503590002	N	6	02141503	05	02	BAGHOUSE #2 CMP HPR DUST VALVE	TPT34
002605503525002	C	6	02141503	12	02	BAGHOUSE #2 SHAKER	TPT34
002601503001002	C		02141503	01	02	BAGHOUSE #2, MISC	TPT34
002605503330003	C	672	02141503	02	03	BAGHOUSE #3 BAGS	TPT34
002604503590003	N	6	02141503	05	03	BAGHOUSE #3 CMP HPR DUST VALVE	TPT34
002605503525003	C	6	02141503	12	03	BAGHOUSE #3 SHAKER	TPT34
002601503001003	C		02141503	01	03	BAGHOUSE #3, MISC	TPT34
002604505330001	C		02145667	01	01	BOTTOM ASH CONVEYING BAG FILTR	TPT39
002604505245001	C		02145665	01	01	BOTTOM ASH TRANSPORT PIPING	TPT39
002604505330001	N		02145662	02	01	BTM ASH MECHANICAL SEP FILTER	TPT39
002604505530001	C		02145662	01	01	BTM ASH MECHANICAL SEPARATOR	TPT39
002604506222001	N		02145666	05	01	BTM ASH SILO PULS CLNG CMP	TPT39
002604505850005	C		02145666	06	01	BTM ASH SILO PULS CLNG CMP MTR	TPT39
002604505280001	C		02145123	01	01	BOTTOM ASH EXHAUSTER 4A	TSEA52A
002604505851001	C		02145123	02	01	BOTTOM ASH EXHAUSTER 4A MTR	TSEA52A
002604505280002	C		02145123	01	02	BOTTOM ASH EXHAUSTER 4B	TSEB52A
002604505851002	C		02145123	02	02	BOTTOM ASH EXHAUSTER 4B MTR	TSEB52A
002600112252001	C4		02142329	12	04	TURBINE OIL COOLER U4	VPT50
002600112330001	C4		02142329	15	04	TURBINE OIL FILTER U4	VPT50
002600112850001	C4		02142329	10	04	TURB OIL AUX LUBE PMP MTR U4	VZS1A
002600112509001	C4		02142329	09	04	TURBINE OIL AUX LUBE PMP U4	VZS1A
002604003851002	C4		02148109	02	02	CONDENSER CIRC PMP 4A MTR	WZS1
002604003500002	C4		02148109	01	02	CONDENSER CIRC PUMP 4A	WZS1
002604001001001	N		02148425	01	04	COOLING TOWER #4A	WZS1,2
002604003851001	C4		02148109	02	01	CONDENSER CIRC PMP 4B MTR	WZS2
002604003500001	C4		02148109	01	01	CONDENSER CIRC PUMP 4B	WZS2
002504003851001	C4		02148109	02	01	CONDENSER CIRC PMP 1 MTR	WZS61
002504003499001	C4		02148109	01	01	CONDENSER CIRC PUMP 1	WZS61
002504001001001	C3		02148425	01	01	COOLING TOWER EXISTING	WZS61,62,63
002504003851002	C4		02148109	02	02	CONDENSER CIRC PMP 2 MTR	WZS62
002504003499002	C4		02148109	01	02	CONDENSER CIRC PUMP 2	WZS62
002504003851003	C4		02148109	02	03	CONDENSER CIRC PMP 3 MTR	WZS63
002504003499003	C4		02148109	01	03	CONDENSER CIRC PUMP 3	WZS63
002604008290001	C		02145102	03	01	BOTTOM ASH COOLING WTR HT EXCH	XFT300
002604506545001	C2		02145401	10	01	BTM ASH COOLER 4A WATERWALLS	XFT300
002604506545002	C2		02145401	10	02	BTM ASH COOLER 4B WATERWALLS	XFT300
002604506545003	C2		02145401	10	03	BTM ASH COOLER 4C WATERWALLS	XFT300

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CUEA No.			EPRI No.			Description	TAG No.
002604506545004	C4		02145401	10	04	BTM ASH COOLER 4D WATERWALLS	XFT300
002604004290001	C4		02148010	02	04	CLOSED COOLING WTR CLR 4A	XZS1
002604004850001	C4		02148010	04	01	CLOSED COOLING WTR PMP MTR 4A	XZS1
002604004500001	C4		02148010	03	04	CLOSED COOLING WTR PUMP 4A	XZS1
002604004001001	C4		02148010	01	01	CLOSED COOLING WATER SYS	XZS1,2
002604004560001	C4		02148010	05	01	CLOSED COOLING WTR HEAD TANK	XZS1,2
002604004290002	C4		02148010	02	05	CLOSED COOLING WTR CLR 4B	XZS2
002604004850002	C4		02148010	05	01	CLOSED COOLING WTR PMP MTR 4B	XZS2
002604004500002	C4		02148010	03	05	CLOSED COOLING WTR PUMP 4B	XZS2
002604008850001	C		02145102	02	01	BOTTOM ASH CLNG WTR PMP 4A MTR	XZS4
002604008500001	C		02145102	01	01	BOTTOM ASH COOLING WTR PMP, 4A	XZS4
002604008500002	N		02145102	02	02	BOTTOM ASH CLNG WTR PMP 4B MTR	XZS6
002604008290002	N		02145102	01	02	BOTTOM ASH COOLING WTR PMP, 4B	XZS6
002607002001001	C4		01240740	01	01	ELECTRICAL UNINTER PWR SUP	YAL44
002607001001001	C4		01240740	01	01	ELECTRICAL SW GEAR 125V DC	YAL46
002606502001001	C4		01240710	01	01	ELECTRICAL ISO-PHASE BUSS	YAM14
002601001001001	C3		02142330	03	04	GENERATOR EXCITER, UNIT 4	YAM14
002600500001004	C		02142330	01	04	GENERATOR UNIT 4, MISC	YAM14
002906501001001	C4		02142710	01	04	TRANSFORMER, UNIT 4 GENERATOR	YAM14
002606508837001	C4		01240702	01	01	ELECTRICAL SW GEAR 4160V	YVM23
002406505001001	C4	6	02142713	01	01	TRANSFORMERS, LOAD CENTER	YVM23
002406503001001	C4		02142711	01	01	TRANSFORMER, UNIT AUX	YVM23
002601504187001	C		02141009	01	01	AIR HTR SOOTBLOWER #1	
002601504187002	C		02141009	01	02	AIR HTR SOOTBLOWER #2	
002601504187003	C		02141009	01	03	AIR HTR SOOTBLOWER #3	
002601504187004	C		02141009	01	04	AIR HTR SOOTBLOWER #4	
002604504350001	C		02145663	01	01	BOTTOM ASH REINJ (NUVA) FDR	
002604504280001	N		02145124	01	01	BOTTOM ASH REINJECT BLWR MISC	
002604504850001	N		02145124	02	01	BOTTOM ASH REINJECT BLWR MTR	
002004504245002	C		02145664	01	01	BOTTOM ASH REINJECTION PIPING	
002612001001001	C4		02144640	01	01	COAL CONVEYOR 1A MISC	
002612001850001	C4		02144640	02	01	COAL CONVEYOR 1A MOTOR	
002612001001002	C4		02144640	01	02	COAL CONVEYOR A MISC	
002612001850002	C4		02144640	02	02	COAL CONVEYOR A MOTOR	
002612001001003	C4		02144640	01	03	COAL CONVEYOR B MISC	
002612001850003	C4		02144640	02	03	COAL CONVEYOR B MOTOR	
002612001001004	C4		02144640	01	04	COAL CONVEYOR C MISC	
002612001850004	C4		02144640	02	04	COAL CONVEYOR C MOTOR	
002612005398001	C4					COAL CONVEYOR SURGE HOPPER	
002612015540001	C4		2144013	01	01	COAL CONVEYOR WEIGHTOMETER	
002612006530001	C4		02144640	03	01	COAL CONVEYOR - MAG SEP	
002612010255003	C		02144631	01	01	COAL CRUSHER 4A	
002612010851001	N		02144631	02	01	COAL CRUSHER 4A,MTR	
002612010255004	C		02144631	01	02	COAL CRUSHER 4B	
002612010851002	N		02144631	02	02	COAL CRUSHER 4B,MTR	
002612001244005						COAL HANDL INCL CONVEYOR D MISC	
002612010850005						COAL HANDL INCL CONVEYOR D MTR	
002612001244006						COAL HANDL INCL CONVEYOR E MISC	
002612010850006						COAL HANDL INCL CONVEYOR E MTR	
002612009352001	C4		02144640	04	01	COAL HANDL PRIMARY FEEDER # 1	
002612001376001	C4	3	02144235	01	01	COAL HANDLING FLOP GATES	
002612009352002	C4		02144640	04	02	COAL HANDLING PRIMARY FEEDER # 2	
002612002374001						COAL HDL TRIP CONVEY MAN SLIDE GATES	
002612002378001						COAL HDL TRIP CONVEY PNEUMA SLIDE GATES	
002612005398007						COAL HDL TRIPPER CONVEYOR F MISC	
002612005850007						COAL HDL TRIPPER CONVEYOR F MTR	
002612005398008						COAL HDL TRIPPER CONVEYOR G MISC	
002612005850008						COAL HDL TRIPPER CONVEYOR G MTR	
002612010255001						COAL PRIMARY CRUSHER	
002612010850003						COAL PRIMARY CRUSHER MTR	
002612009352004	C4		02144640	04	04	COAL RECLAIM VIBRATION FEEDER	
002612014515001	C5					COAL SAMPLING SYS- AUTO AS FIRED	
002612014515002	C5					COAL SAMPLING SYS- AUTO AS REC	
002612010255002						COAL SECONDARY CRUSHER	
002612009352003	C4		02144640	04	03	COAL SECONDARY CRUSHER FEEDER	
002612010850004						COAL SECONDARY CRUSHER MTR	
002612009352005	C4		02144640	04	05	COAL VIBRATING FEEDER 4A	
002612009352006	C4		02144640	04	06	COAL VIBRATING FEEDER 4B	
002408509001001	C2		02140005	01	01	COMPUTER, WDPF	
002612012001001	C4		02144090	01	01	DUST COLLECTION SYSTEM-COAL	

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CUEA No.			EPRI No.			Description
002606009001001	C4		02144091	01	01	DUST COLLECTION SYSTEM-SORB
002613302001001	C4		01240728	01	01	ELECTRICAL RELAYS - MISC
002606508838001	C4		01240705	01	01	ELECTRICAL SW GEAR 480V
002604503500002	C		02147102	01	01	FLYASH CND WTR PMP (OLD) MISC
002604503500001	C		02147102	01	02	FLYASH COND WTR PMP 4A MISC
002604503850001	C		02147102	02	02	FLYASH COND WTR PMP 4A MTR
002604503850002	C		02147102	02	01	FLYASH COND WTR PMP (OLD) MTR
002604503850003	C		02145641	09	01	FLYASH PLS AIR CLNG CMP 4A MTR
002604503850004	C		02145641	09	02	FLYASH PLS AIR CLNG CMP 4B MTR
002604503222001	C		02145641	08	01	FLYASH PULSE AIR CLNG CMP 4A
002604503222002	C		02145641	08	02	FLYASH PULSE AIR CLNG CMP 4B
002604503291001	C		02145642	01	01	FLYASH UNLOADER
002604503850005	C		02145642	02	01	FLYASH UNLOADER MOTOR
002604503242001	C		02145643	01	01	FLYASH UNLOADER SCRW CONV
002604503850006	C		02145643	02	01	FLYASH UNLOADER SCRW CONV MTR
002603005705001						GAS ANALYZER-CO2 CEM
002409001519001	C4		02147010	06	01	SERV WTR TRAVELING SCREENS
002409001500001	C4	2	02147010	04	01	SERVICE WATER PUMP MISC
002409001851001	C4	2	02147010	05	01	SERVICE WATER PUMP MOTOR
002601504228002	C		02141007	01	01	SOOTBLOWER CONTROLS
002601504185001	C		02141008	01	01	SOOTBLOWER CONV PASS #1
002601504185010	C		02141008	01	10	SOOTBLOWER CONV PASS #10
002601504185011	C		02141008	01	11	SOOTBLOWER CONV PASS #11
002601504185012	C		02141008	01	12	SOOTBLOWER CONV PASS #12
002601504185002	C		02141008	01	02	SOOTBLOWER CONV PASS #2
002601504185003	C		02141008	01	03	SOOTBLOWER CONV PASS #3
002601504185004	C		02141008	01	04	SOOTBLOWER CONV PASS #4
002601504185005	C		02141008	01	05	SOOTBLOWER CONV PASS #5
002601504185006	C		02141008	01	06	SOOTBLOWER CONV PASS #6
002601504185007	C		02141008	01	07	SOOTBLOWER CONV PASS #7
002601504185008	C		02141008	01	08	SOOTBLOWER CONV PASS #8
002601504185009	C		02141008	01	09	SOOTBLOWER CONV PASS #9
002601504579001	C		02141007	01	02	SOOTBLOWER STM SUP VLV
002606001001001	C2		02144660	01	01	SORB PREP (#S 002606001xxx)
002606001302001	C4		02144672	01	01	SORBENT BUCKET ELEVATOR
002606001394001	C4		02144671	04	01	SORBENT CHUTE/HOPPER
002606001850001	C4		02144671	02	01	SORBENT CONVEYOR MTR-BELT
002606001540001	C4		02144014	01	01	SORBENT CONVEYOR WEIGHTMTR
002606001240001	C4		02144671	01	01	SORBENT CONVEYOR - BELT
002606002255001	C3		02144661	01	01	SORBENT CRUSHER
002606001352001	C4		02144671	03	01	SORBENT FEEDER VIBRATING
002606001530001	C4		02144673	01	01	SORBENT MAG SEPARATOR-BELT
002606001388001	C4		02144662	03	01	SORBENT PLVRZR AIR HTR/DRY
002606002440001	C4		02144662	01	01	SORBENT PULVERIZER
002606009246001	C4		02144662	04	01	SORBENT PULVERIZER CYCL
002606009001001	C4		02144662	05	01	SORBENT PULVERIZER DST COL
002606001341001	C4		02144662	06	01	SORBENT PULVERIZER FAN
002606001851001	C4		02144662	02	01	SORBENT PULVERIZER MOTOR
002606030245003	N		02144664	01	03	SORBENT TRANS X-PIPING (4A-B)
002700112850001	C4		02142329	10	01	TURB OIL AUX LUBE PMP MTR U1
002800112850001	C4		02142329	10	02	TURB OIL AUX LUBE PMP MTR U2
002900112850001	C4		02142329	10	03	TURB OIL AUX LUBE PMP MTR U3
002700112509002	C4		02142329	09	01	TURBINE OIL AUX LUBE PMP U1
002800112509001	C4		02142329	09	02	TURBINE OIL AUX LUBE PMP U2
002900112509001	C4		02142329	09	03	TURBINE OIL AUX LUBE PMP U3
002700112252001	C4		02142329	12	01	TURBINE OIL COOLER U1
002800112252001	C4		02142329	12	02	TURBINE OIL COOLER U2
002900112252001	C4		02142329	12	03	TURBINE OIL COOLER U3
002700112330001	C4		02142329	15	01	TURBINE OIL FILTER U1
002800112330001	C4		02142329	15	02	TURBINE OIL FILTER U2
002900112330001	C4		02142329	15	03	TURBINE OIL FILTER U3

14.3 ACCUMULATING EQUIPMENT RUN TIME DATA

To complete the third step, software was developed to run on the Demonstration Program's DEC VAX computer which is tied directly into the plant's Westinghouse WDPF control system. Analog and digital information are recorded on the VAX via the WDPF for over 540 points. These data are used to accumulate run times for the 620 pieces of equipment identified as part of reliability monitoring.

At periodic intervals, i.e., once per month, data from the Perform software identified in step 2 are collected along with the run time data in step 3. The data collected for step 3 are transferred to a Lotus Symphony spreadsheet on floppy disk. Both sets of data are then transferred to an off-site EPRI contractor for analysis and comparison with the other demonstration programs.

14.4 SUMMARY OF INITIAL MAINTENANCE REQUEST DATA

During the third quarter of 1989, MR data were compiled for the coal and limestone feed systems to evaluate the quantity and quality of data collected since October 1988. For the coal feed system, data were subdivided into rotary valves, gravimetric feeders, and other including isolation gates, control and weighing systems, and drag chains. For the limestone feed system, MR data was subdivided into the weigh feeder, blowers, rotary valves, and other including vent lines, transport lines, and isolation gates. The results are shown in Figures 14-1 and 14-2. A total of 32 MR's were completed on the coal system and 55 MR's were completed on the limestone feed system during this period. The gravimetric feeders on the coal feed system and the rotary valves on the limestone feed system were responsible for half of the MR's written on these equipment areas.

Combining these data with equipment run time (step 3) will yield information on mean time to failure and mean time to repair. This information will be compiled for all equipment areas by EPRI's contractor during future operating periods.

Figure 14-1. Limestone Feed System Maintenance Request Summary

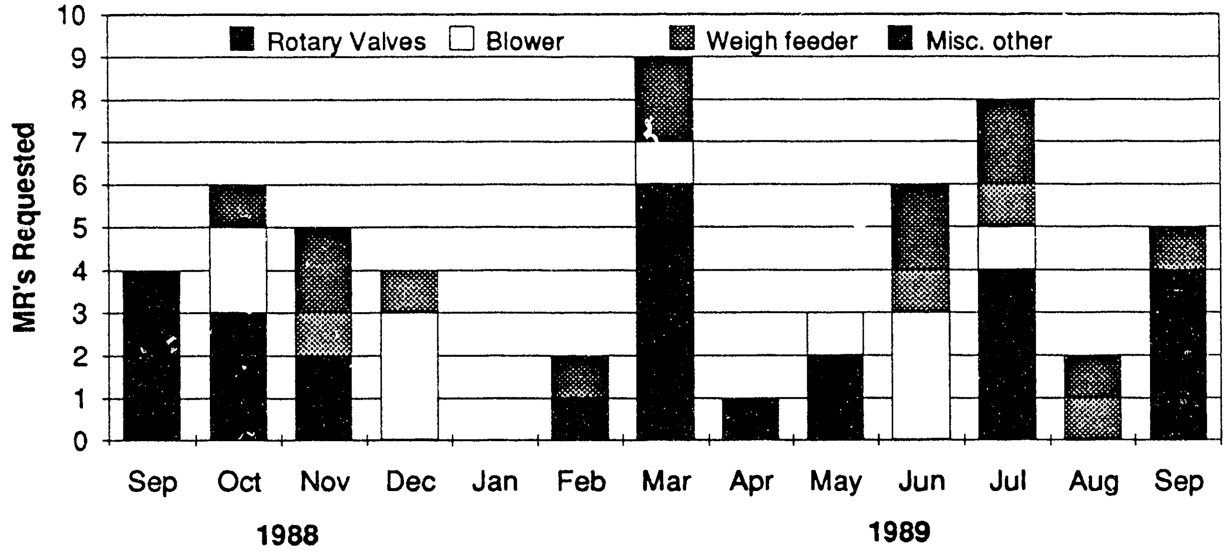
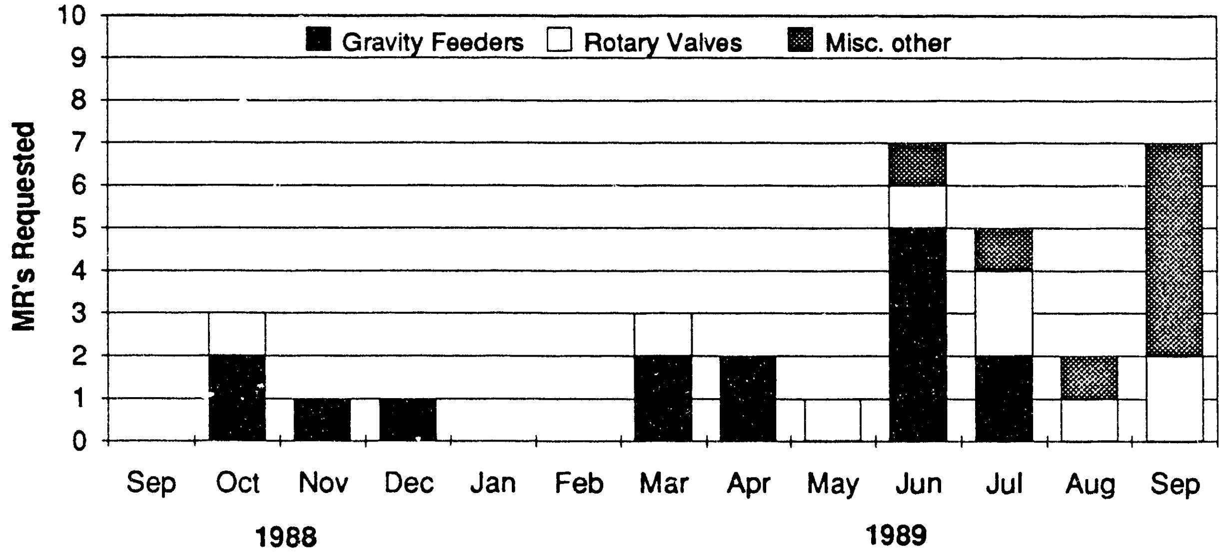


Figure 14-2. Coal Feed System Maintenance Request Summary



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