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NUCLA Circulating Atmospheric Fluidized Bed Demonstration Project

1988 Annual Report

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FOREWORD

This Annual Report on Colorado-Ute Electric Association's (CUEA) Nucla Circulating Fluidized Bed (CFB) Demonstration Program covers the period from February 1987 through December 1988. During this period, the unit completed initial start-up of the CFB boiler and all auxiliary equipment, reached full-load operation in March 1988, and completed the first phase of contractual acceptance tests in October 1988. The Demonstration Program engineering staff began mobilizing on-site in February 1987 and completed preparatory activities required for the start of unit performance testing through the remainder of 1988. This report summarizes activities related to unit operations and to Demonstration Program preparation during the first 2 years of plant operation.

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 largest operational plant.

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 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 ten week 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 on site of a permanent 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 that commenced during this reporting period. These include cold-mode shakedown and calibration, plant commercial performance statistics, unit start-up (cold), coal and limestone preparation and handling, ash handling system performance and operating experience, tubular air heater, baghouse operation and performance, materials monitoring, and reliability monitoring. During this reporting period, the cold-mode shakedown and calibration plan was completed.

During the next reporting period, plant operations and the boiler vendor will make efforts to complete contractual acceptance testing on high ash and high sulfur coals. To achieve this, repairs will be necessary on sections of refractory in the cyclones and loop seals, and improved performance will be required on the primary air fan and limestone feed system. Activities related to these areas are scheduled during the first quarter of 1989. The test program will commence with the Hot Mode Test Plan once the boiler is available. This test plan establishes the data acquisition and solids sampling requirements, test duration, and time to steady-state for all future performance tests. Efforts will also proceed in each of the remaining 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 and the Bechtel Corporation. The following individuals from CUEA are responsible for the implementation of the DOE agreement:

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CUEA, Inc. would like to acknowledge the Electric Power Research Institute (EPRI) 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 the first two years of unit operation and test program progress on Colorado-Ute Electric Association's (CUEA) Nucla CFB Demonstration Program. In particular, the report covers progress from February 1987 through the end of 1988. This period included the initial start-up of the first utility-owned and operated circulating fluidized bed boiler in the United States and the largest of its kind in the world.

The starting date of this first annual report marks the point at which the test program's engineering staff mobilized permanently on-site. This group consisted of a project manager from the Electric Power Research Institute (EPRI), employees on loan from utilities and private organizations to EPRI and CUEA, the test program contractor selected by EPRI in August 1986, and CUEA engineering staff. The progress of this group through 1987 and 1988 consisted largely of implementing the Cold Mode Shakedown Test Plan. This test plan is the first activity to be completed in the conduct of a full-scale demonstration program. It involves calibration of test instrumentation, commissioning the data acquisition computer system, developing specialized software, procuring and commissioning equipment for the solids preparation laboratory and other specialized test instrumentation, development of detailed test plans and procedures, and training test personnel. Details of this effort are discussed in Section 3 of this report, which provides some understanding of the scope and level of effort required for preparation of other Demonstration Programs.

In addition, the test program made progress in other test plan areas which are covered in this report. Preparation for the Hot Mode Test Plan commenced during the third and fourth quarters of 1988. This plan is implemented after the Cold Mode Shakedown Plan and involves testing to determine times to steady state, solids and instrument data acquisition frequencies, and test duration. These results form the template for all future steady-state performance tests on the boiler.

During the period, the test program also monitored the performance of the coal and limestone preparation and handling systems, the fly ash and bottom ash disposal systems, the baghouses, and CFB-related materials such as boiler tubes and refractory. Highlights of problems and solutions are presented. Plant commercial operating statistics for the period are presented along with data from two cold unit start-ups. Progress on the development of a reliability monitoring program is also presented.

Section 2 of this report chronologically summarizes the plant operating history for the first two years of unit operation. During this period, the plant operated on coal for a total of 5260 hours. In the second half of 1988, after a significant portion of the initial start-up and shakedown phases of unit operations were essentially complete, the plant averaged an operating availability of 53.0 % and a capacity factor of 34.5 %. During August of this period, the plant was off-line for modifications to the bottom ash conveying system and for repairs to the air distributor bubble caps and cyclone refractory. Excluding this month, these numbers increase to 63.5 % and 41.3 %, respectively.

Since sustained unit operation on coal only (no propane assistance) was achieved in July 1987 through the end of 1988, a total of eight unit outages lasting more than one week occurred. Three of these outages were planned maintenance and inspection outages initiated from controlled shutdown sequences. There were numerous other short-term outages during the reporting period lasting from several hours to several days. In 1988, the unit was restarted from all of the above outages a total of approximately 100 times.

In an attempt to categorize operating problems that occurred in the first two years of unit operation, three general areas have been identified. First, many of the problems initiating unit outages were routine in nature and can be attributed to normal start-up of a new coal-fired power plant. The problems are typically associated with balance-of-plant equipment. A second group of problems can be attributed to design or construction inadequacies. Still a third group of problems may be ascribed to the new technology and scale-up uncertainties. These three areas are discussed in more detail below. This is preceded by a summary of operating milestones during this reporting period.

1.1 OPERATING MILESTONES

From initial coal fires in June 1987 through the overheat incident in late September 1987, the plant's operating objectives were to bring the new boiler on line and shakedown/debug auxiliary and balance-of-plant equipment. During August and September 1987, the new CFB boiler was operated in manual control with the objective of producing steam so that each of the four turbine-generator sets could be sequentially brought into service and total plant load could be increased. This activity was largely completed just prior to the overheat incident on September 29, 1987, with only one turbine-generator set requiring additional tuning and calibration.

The overheat incident, described in Section 2.2, required a 10 week outage for repairs. The boiler was then restarted in mid-December 1987 with the objective of calibrating the air flow monitors and tuning the controls system in discreet load step increases up to 100% maximum continuous rating (MCR). This activity was completed in late March 1988 with all control loops operating in automatic control and the plant reaching sustained full-load operation.

CUEA and the boiler vendor then prepared for full-load acceptance tests on design "A" coal. This fuel is a locally-mined western bituminous coal with a highly variable heating value and ash/sulfur content. Specific boiler performance criteria, such as sulfur capture, emissions, boiler efficiency, auxiliary power consumption, exhaust gas pressure drop, etc., were guaranteed by the boiler vendor during acceptance tests with this coal at full load. Only emissions compliance was guaranteed at reduced loads. The contract performance properties of this fuel are listed in Table 1-1 below. Also listed are the fuel properties for design "B" coal. This fuel was also part of contractual acceptance testing, but differed from design "A" coal in that only operational performance was guaranteed at full load with emissions compliance. The objective was to test the solids feed and disposal systems on the new plant when burning high ash and high sulfur fuels.

The first acceptance test on design "A" coal was conducted on July 7, 1988. This test passed all guarantees except the Ca/S molar ratio requirement of 1.5 for 70% sulfur reduction and not greater than 0.4 lbs SO_2/MMBtu. The test was conducted a second time on October 7, 1988 and passed all guarantees.

Following completion of acceptance tests on design "A" coal, CUEA and the boiler vendor began burning high ash coal (up to 35 wt.% ash) in preparation for the full-load operational tests on design "B" coal. These tests were specifically designed to demonstrate full-load performance of the boiler and the fly ash and bottom ash removal and disposal systems. Tests were also conducted with a high sulfur (up to 2.5 wt.% sulfur) design "B" coal which were designed to demonstrate performance of the boiler and the limestone feed system. This is actually a different fuel than the high ash design "B" coal. Initial testing identified deficiencies in the bottom ash removal and disposal system and the limestone feed system. At the conclusion of 1988, problems with the bottom ash disposal system appeared to be corrected, but some deficiencies persisted in removing bottom ash from the boiler. Modifications and testing on the limestone feed system also continued through the end of 1988.

Table 1-1. Fuel Analysis of Design "A" and "B" Coals.

COAL	DESIGN A	DESIGN B
Source	Nucla, Co	Nucla, Co
PROXIMATE ANALYSIS (% by weight)		
Moisture	5.8	6
Volatile	26.9	21
Fixed Carbon	41.2	40
Ash	26.1	33 **
Total	100	100
ULTIMATE ANALYSIS (% by weight)		
Carbon	55.17	46.41
Hydrogen	3.63	3.6
Sulfur	0.73	2.5 **
Oxygen	7.51	7.5
Nitrogen	0.98	0.9
Chlorine	0.04	0.04
Moisture	5.86	6
Ash	26.08	33.05
Total	100	100
Gross Heating Value		
(as-fired) J/kg	10.26 MM	8.47 MM
Btu/lb	9693	8000
Surface Moisture (as-fired, % by weight)	3.74	4
Ash Softening Temperatures (reducing atmosphere) °C/°F		
Initial Deformation	1454/2650	1454/2650
Softening	1482/2700	1482/2700
Fluid	1482/2700	1482/2700

** 2.5% sulfur and 33.0% ash for coal "B" does not occur at the same time.

Operating plans for the first quarter of 1989 included the completion of the high ash and high sulfur coal acceptance tests and the initiation of Hot Mode Phase I demonstration program testing. Milestones for the operating period from 1987 through 1988 are listed in Table 1-2 below.

Table 1-2. Operational Milestones for 1987-1988.

Date	Event
March 1987	- Completed logic checks on the primary and secondary air fans and start-up burners. - First propane fires on start-up burners. - Completed boil-out (degreasing).
April 1987	- Completed 66 steam blows on new boiler.
May 1987	- Loaded combustion chambers with sand bed in preparation for operation on coal. - First steam flow to the new 74 MWe turbine on propane fires only.
June 1987	- First coal fires with propane assistance.
July 1987	- First unsupported coal fires (no propane assistance). - Baghouse bags conditioned and baghouse placed in service. - First use of limestone feed system. - Sootblowers placed in service.
August 1987	- Steam blows on extraction line to three 12.5 MWe turbines.
September 1987	- All turbine-generator sets commissioned except for final tuning of set #3. - Overheat incident on September 29, 1987.
January 1988	- Three element drum level control is placed in-service and the boiler operates off the boiler master for the first time.
March 1988	- Achieved full-load of 110 MWe gross output.
May 1988	- Completed certification of stack continuous emissions monitoring system.
July 1988	- Completed stack source emissions tests for compliance with state regulations. - Conducted first unit acceptance test on design "A" coal.
August 1988	- Achieved a maximum load of 117 MWe. - Completed acceptance tests on new 74 MWe turbine. Included load ramps at 1 MWe/min.
October 1988	- Completed second acceptance test on design "A" coal.
November/ December 1988	- Testing with high ash and high sulfur design "B" coals.

1.2 ROUTINE START-UP PROBLEMS WITH BALANCE-OF-PLANT EQUIPMENT

The following list of operating problems which occurred in the first two years of unit operations. These can be attributable to start-up of a new coal-fired utility boiler. The list is by no means comprehensive, but includes items which delayed the start-up schedule or caused derates in unit output. Some of the problems may be attributable to the plant's location, such as difficulties in retaining an adequate inventory of propane which often delayed the start-up schedule. Problems with the existing 12.5 MWe turbine-generator sets could also be attributed to repowering of an existing station. For simplicity, these have been grouped within this heading.

1. The propane start-up system for the Nucla CFB consists of a storage tank, two vaporizers, and several pressure reducing stations. A storage tank was selected over a natural gas supply line during the new plant design by economic factors related to the remote location of the plant and the distance to the nearest natural gas supply line. Maintaining an adequate inventory of propane was often difficult due to the remote plant location. This was particularly troublesome during initial start-up and shakedown of the plant when the unit is restarted numerous times or must run for long periods on propane to cure refractory, commission turbines, verify logic, etc. In addition, a defective excess flow valve located inside the propane storage tank, and vaporizer problems early on in the start-up, delayed the schedule.

2. There were repeated problems synchronizing the new 74 MWe generator during early start-up along with numerous occurrences during the first two years of operation involving loss of excitation. The excitor collector ring failed in the fourth quarter of 1988 and forced an extended unit outage.

3. Miscellaneous steam leaks on several separate occasions forced load reductions or unit outages for repairs. These included safety valves, the emergency relief valve (ERV), attemperator spray valves, deaerator steam line flange, a valve to the drum level switch, and miscellaneous leaks on the existing 12.5 MWe turbine-generator sets. The automatic extraction valve to the old turbines also required repairs during a unit outage.

4. Repairs to the valve linkage on the new 74 MWe turbine governor valves forced an outage early in the unit start-up.

5. Numerous coal feeder trips during the first two years of operation either caused reductions in load or, on one occasion, forced a boiler MFT (main fuel trip) since one feeder on one combustion chamber was down for repairs and the remaining two sequentially tripped.

6. Frozen pressure lines on the baghouse and ID fan during cold winter months caused unit MFT trips on several occasions.

7. Low pressure and or leaks on the turbine generator hydraulic system and electrohydraulic control (EHC) system forced load reductions and one outage.

8. A gear box failure on the coal reclaim conveyor and isolated problems with coal delivery equipment.

9. Induced draft (ID) fan coupling failure between motor and fan rotor.

10. Condensate forwarding pump failures on units 1 and 3 during separate occurrences.

11. Instrument air compressor failure.

12. Uninterrupted power supply (UPS) failure on plants digital distributed control system (DCS).

13. Problems with the demineralizer train delayed a series of start-ups due to inadequate condensate make-up supply.

14. Boiler feed pump drain line leakage, an outboard seal leak, and stuck/failed recirculation line valves.

15. Loss of power to input/output module on the plants digital distributed control system.

16. Ruptured baghouse bags forced load curtailments on various occasions due to opacity restrictions.

17. Poor feedwater chemistry due to high silica forced pressure reductions and load curtailments.

18. A drain line rupture on turbine-generator #1 forced a load curtailment.

19. One MFT resulted from faulty readings on the furnace draft pressure switches.

20. One outage was required to repair sticky main steam throttle valves.

1.3 PROBLEMS ASSOCIATED WITH DESIGN OR CONSTRUCTION INADEQUACIES

The following problems have been categorized as being related to design or construction inadequacies. Some of these problems could also fall into the third category of being CFB or new technology-related. These are identified where appropriate.

1. Early on in start-up, the combustion chambers experienced several occurrences of bed material leakage to the outside boiler building. Upon inspection, gaps in the waterwall membrane were found at various locations. These short approximately 6" long gaps were used during construction as lifting slots to raise the waterwall panels into place. Following erection, these slots were not closed. This is more significant with CFB technology due to the presence of a circulating bed media in the boiler.

2. During initial plant start-up, interference developed between the main steam drain line and the boiler feed pump recirculation line. A unit outage was required for repairs.

3. In September 1987, a steam leak developed on the secondary superheater panel 1 in the "B" combustion chamber. A total of 12 superheater tubes were damaged or had failed along with several waterwall tubes. The problem was attributed to porosity in field welds during construction. An additional 36 welds were replaced during a later outage.

4. A leak was discovered during a hydrostatic test on a field weld on the superheater III inlet header. Correcting this problem delayed a unit start-up.

5. Primary air dampers were freezing up during initial operation. The problem was attributed to inadequately sized actuators on the damper drives. These were replaced with larger actuators which corrected the problem.

6. During the overheat incident on September 29, 1987, the bolts which connect the centerwall buckstays between the two combustion chambers remained in tact. This caused considerable warpage to all waterwalls on the "A" combustion chamber and to the centerwall on the "B" combustion chamber. This is discussed in more detail in Section 7 of this report. This problem might also be categorized as CFB or new technology-related.

7. The limestone feed system displayed poor performance through this reporting period. This is discussed in more detail in Section 4 of this report. Although this problem might be considered new technology-related, the basic principal of operation and the requirements of operation represent standard solids flow technology. In this case, several features of the limestone feed system design were identified during this reporting period as being inadequate.

8. A problem with cross-leakage of primary air into the secondary air flow path was identified during 1987. This leakage occurred across the tube sheets that separate the primary and secondary air flow paths in the multiple pass tubular air heater. Flue gas flows through the air heater

inside the tubes and primary and secondary air flow on the shell side. During construction, 1/2" gaps were left along the tube sheet floor separating the primary and secondary air flow paths where four preassembled sections of the air heater were joined together. These gaps or seams were welded closed which substantially reduced, but did not eliminate, air heater cross leakage. This problem might also be considered new technology-related since this type of air heater arrangement is not common in a pulverized coal fired application.

9. The bubble caps that attach to the air distributor plate on the bottom of each combustion chamber are retained by a washer that is welded to the bubble cap and to a pipe nipple that extends up through the water-cooled distributor floor. During construction, carbon steel washers were used instead of the specified stainless steel. These washers failed during the first year of unit operation and were replaced in August 1988. Bubble caps also appear under the new technology-related heading because of other unforeseen difficulties.

10. During preliminary testing with high ash design "B" coal, the bottom ash disposal system was found to be undersized. The equipment vendor eventually redesigned the system with a simpler piping configuration and higher transport velocities, as discussed in Section 5. This problem might also be considered new technology-related since the equipment vendor claimed that higher transport velocities were required because of a small percentage of large-sized bottom ash material that was not present in the pilot-plant test burns.

11. The primary air fan did not meet test block operating performance through this reporting period. This is discussed in more detail in Section 2.4. The manufacturer conducted tests on three occasions during the second half of 1988 to identify the problem. These tests either initiated or extended unit outages. Although this type of fan is common on utility plants, the problem might be considered new technology-related since CFB boilers require higher static discharge pressures for comparable flows on a pulverized coal fired plant.

12. The fly ash unloading silo experienced high fugitive dust emissions on the shaft seals of the screw unloader located on the bottom of the silo. This did not cause any unit outages or load curtailments but a significant amount of maintenance was required to reduce the leakage. CUEA has suggested that the basic problem results from using a mass flow silo design for fly ash unloading.

13. SO_2 and O_2 analyzers used for combustion and emissions control to each combustion chamber were originally located at

the outlets of each cyclone. This arrangement allowed the emissions from each chamber to be measured before mixing occurred in the common convection pass. However, the analyzers were not designed for the high temperatures associated with the cyclone outlets (1600 °F) and failed early on in start-up. Eventually, the O_2 analyzers were moved to the economizer inlet and the SO_2 analyzers were moved to the air heater inlet. Although some gas mixing between the two combustion chambers occurs by the time the flue gas reaches these locations, the new arrangement has resulted in good analyzer performance and combustion chamber control. This problem could also be considered new technology-related.

1.4 PROBLEMS ASSOCIATED WITH CFB OR NEW TECHNOLOGY

The following list of problems developed during the first two years of unit operations and can be considered CFB or new technology-related.

1. Over-temperature and clinkering in the ash coolers and ash cooler drain lines required outage time for repairs. As discussed in more detail in Section 5, the operating logic for the ash coolers was eventually changed such that constant fluidizing velocities were maintained by adjusting the air flow to the coolers. The original logic was based on constant air mass flow which exacerbated the problem with clinkering. Limits on operating temperature were also added to the control logic. This appears to have corrected this problem. During preliminary testing with high ash coal, the coolers appeared to be undersized, as evidenced by high operating temperatures with high bottom ash throughputs. The coolers also appear to have difficulty handling large bottom ash particles (>1") as evidenced by blockage in the inlet lines from the combustion chambers. These problems remain under investigation.

2. Cracks at welds in the windbox casing resulted in loss of bed material to the outside plant. These cracks did not cause any outages or load curtailments, but did require some degree of maintenance during the reporting period.

3. Backsifting of bed material from the combustion chambers into the windbox was not anticipated during design of the plant. The windbox geometry is not configured ideally to remove this material. Backsifted bed material builds in the windboxes over time (2 to 4 weeks), particularly at half load when air flows through the distributor plate are at a minimum and backsifting rates are the highest. Eventually, material must be shoveled from the windboxes during unit outages so that there is no interference with air flow to the distributor plate. There was also concern over the impact of

the added weight on the windbox design, particularly in reference to problems identified in item 2 above. A reinjection line was added to the windbox floors in January 1988 to move accumulated material back into the loop seals using windbox pressure as the moving force. This reinjection line has not proven to be entirely effective during this reporting period.

4. Bubble cap retention was mentioned in Section 1.3 above as a design/construction problem. However, following replacement of the carbon steel retaining washers with stainless steel, bubble caps continued to fail in the region in front of the loop seals. A new type of design may be required to eliminate this problem. In addition, to reduce backsifting into the windbox, new bubble caps with a steeper drill angle on the air holes were installed around the perimeter of the combustor and in front of the recycle return line. The effectiveness of this design modification remains under investigation.

5. The overheat incident on September 29, 1987 can be classified as technology-related. Although there were many complex factors involved in the incident, damage occurred when fans were restarted to cool the boiler down following a watertube leak. Accumulated unburned coal that was overfed to the combustion chambers prior to the leak ignited during the fan restart. The accumulation of unburned fuel in a hot slumped bed is unique to the fluidized-bed technology. It is not a problem with CFB's as long as accurate coal flows, air flows, and oxygen measurements are available. The overheat incident is discussed in more detail in Section 2.2.

6. During February 1988, a watertube leak developed on an air distributor plate floor tube in the "A" combustion chamber. The cause of this leak was due to differential expansion between the water-cooled floor tube header and the windbox casing. The leak also occurred in the "B" combustion chamber at the same location during unit restart following repairs to the "A" combustion chamber. The problem was not anticipated and was corrected by cutting expansion slots into the windbox casing.

7. A watertube leak occurred on the rear wall of combustion chamber "A" at the recycle return wall box. The cause was due to differential expansion between the wall box enclosure and the rear wall watertubes. Stiffener plates were added to correct this problem.

8. Surging of recycled solids flow collected by the cyclones and returned to the combustion chambers occurred during instances from February through April 1988. When this occurs, bed inventory inside the combustion chambers oscillates and either forces load reductions or, in several instances, unit trips due to low primary air flow immediately

following a surge. The problem can occur when solids inventory in the combustion chambers and recycle loop is too high. However, during this period, it is believed to be more commonly associated with refractory accumulation in the loop seals. Refractory that becomes dislodged in the cyclones collects in the bottom of the loop seals and disrupts air and solids flow. The boiler vendor conducted a series of tests in March 1988 which resulted in the addition of new fluidizing pipes up the sides of the recycle leg above the loop seal. Fluidizing air flows to the bottom of the loop seal were also redistributed. Along with maintaining proper solids inventory during unit operation, these modifications corrected the problem with loop seal surging.

9. During the reporting period, there were numerous secondary air (SA) fan trips and a lesser number of trips on the primary air (PA) and induced draft (ID) fans. These typically occur during power fluctuations that are typical in a plant sited in a remote location. These fans use variable speed drives, which are more efficient at low load operation than fixed speed fans. However, the electronic circuitry that controls these variable speed drives appears to be sensitive to the these fluctuations. Although variable speed drives have been employed for some years in applications other than CFB's, the application represents new technology to CUEA and has been included in this category. The problem is not CFB related.

10. Refractory spalling and breakage has occurred throughout areas of the lower combustion chambers, cyclones, and loop seals. This is discussed in greater detail in Section 7. Although refractory is used in the oil refining industry in catalytic crackers, the application in CFB's requires thicker layers of insulating and abrasion resistant materials to reduce shell temperatures. Although some of the problems at Nucla have been identified by the boiler vendor as being installation related, the application in this environment represents a new technology application and therefore, has been included in this category.

11. During operation on low ash coals, a temperature differential of as high as 100°F has been observed between combustion chambers. When this occurs, high limestone feed rates are required on the chamber with the high operating temperatures to maintain SO_2 emission compliance. In some instances, it has forced load reductions because of the inability of the limestone feeders to maintain flow (see Section 1.3). This is one of the reasons cited for the failure of the Ca/S ratio requirement during the first acceptance test on July 7, 1990. This problem is unique to the Nucla CFB twin combustion chamber design and may not be a generic CFB issue.

1.5 TEST PROGRAM DEVELOPMENT

This report summarizes progress made by the on-site test team in preparing for detailed unit performance testing and the initiation of the test plans identified in the Detailed Test Plan. Significant progress was made during this reporting period in completing the Cold Mode Shakedown Test Plan. This is the first step in the conduct of a test program and involved calibrating instruments, commissioning the data acquisition system, developing and debugging specialized software, procuring and commissioning the solids preparation laboratory and other specialized instrumentation, developing procedures, and training test personnel. The two acceptance tests performed by CUEA and the boiler vendor in July and October 1988 served to test the readiness of the test team for Hot Mode testing scheduled in early 1989. Details of Cold Mode Shakedown activities are discussed in Section 3 of this report.

This report also discusses progress made in other Demonstration Program test plan areas. These include monitoring the performance of the coal and limestone preparation and feed systems discussed in Section 4, and the fly ash and bottom ash disposal systems in Section 5. Baghouse operational performance and preliminary testing is discussed in Section 6. An initially high bag failure rate reported in this section was attributed to improper initial set-up of the bag cleaning deflate pressure. Readjustment of this pressure appears to have resolved this issue.

Waterwall and superheater tube measurements, along with refractory and component inspections as part of the Materials Monitoring Test Plan, are discussed in Section 7. Through this reporting period, no generalized waterwall or superheater tube erosion has been measure, although some localized erosion has been observed at the waterwall/refractory interface.

Section 9 contains data from two cold start-ups during the reporting period. The start-up sequence is identified in this section along with future test plans. Section 10 discusses progress made in resolving issues prior to the initiation of the hot Mode Test Plan in 1989. Finally, progress made in the development of a Reliability Monitoring Program is discussed in Section 11.

1.6 FUTURE TEST PLANS

Following completion of the high sulfur and high ash acceptance tests by CUEA and the boiler vendor in early 1989, the test program will commence with the Hot Mode Test Plan. This plan requires approximately one week of detailed unit testing at various unit outputs to identify times to reach steady-state, data acquisition requirements for test instrumentation and solids sampling, and required test duration to assure accuracy and reliability of the results. Also during the period, the on-site test team could proceed with testing and development of other test plan areas.

Section 2

PLANT OPERATING HISTORY

2.1 OVERVIEW

Following the completion of construction in early 1987, the plant was first fired with propane on March 23; the date of the first coal firing was June 10. The plant operated on coal for a total of 710 hours in 1987, with a maximum power level of 63 MWe (gross). The plant operated on coal for a total of 4723 hours in 1988. The total coal hours from plant start-up to the end of December, 1988 were 5433.

Section 2.1.1 contains a description of plant operations. Section 2.1.2 summarizes operating problems during the same period of operation, and includes Table 2-1, a partial summary of unit outages from July 1987 to December 1988. Figure 2-1 is a plot of monthly coal hours from June 1987 through December 1988. Section 2.2 describes plant operations at the time of the overheat incident on September 29, 1987. Section 2.3 describes boiler acceptance tests conducted during 1988.

2.1.1 Plant Operations

Highlights of Plant Operation from 3/20/87 to 12/31/88

1987

Date	Description
3/20	Primary and secondary air fans and start-up burner logic checks.
3/23	First propane fires.
3/27-29	Boil out.
4/5-20	Main steam blows.
5/20-29	First steam to new turbine generator 4 (TG4) on propane; generator synchronized.
6/10	First coal firing with supplemental propane.
6/11-21	High combustor B temperatures (1800°F) and clinker formation on 6/11. Clinkers removed and combustors refilled with sand.

6/22-30	Start-up burner firing rate limited by defective excess flow valve on propane tank. Replaced valve after tank was emptied.
7/8-11	First unsupported coal firing. Limestone feed initiated. New baghouse placed in service.
7/14-19	Plant on-line between 35 and 58 MWe. Soot blowers placed in service.
7/20-23	Plant on-line between 35 and 40 MWe. Steam blows on extraction lines to turbine generators 1-3 completed. Plant having difficulty building bed material.
7/24-8/3	Maintenance outage. Repaired boiler casing where bed material was leaking out.
8/4-9	Completed extraction line steam blows. Repair of additional casing leaks between loop seal and back boiler wall.
8/10-16	Unit restarted. Generator trip on TG4; high steam pressures lifted safety valves and emergency relief valve (ERV) which were repacked and repaired during the outage.
8/17-26	Unit on-line on coal on 8/17. Controlled shutdown to correct interference of main steam drain line with boiler feed pump recirculation line.
8/31-9/1	Bed material casing leak found on combustor A. Significant amount of bed material discovered in windbox of combustor A.
9/2-16	During restart on coal, combustor B steam leak developed on Superheater II (SHII), panel 1. Total of 12 superheat tubes affected. Water wall leak in the same vicinity due to steam washing. Clinker found along front wall in combustor B. Boiler inspection and SHII repair 9/4-16.
9/18-26	Unit 4 on line at 50-55 MWe. Commissioning work on units 1-3. Problems with ash cooler and ash cooler drain plugging. Weight of accumulated bed material in windbox apparently caused casing leakage in combustor B. Unit shutdown required for repair.
9/27-28	Units 2, 3, and 4 in service at 63 MWe. PA dampers sticking. O_2 indication erratic. Indication of ash cooler and bed pressure tap blockage.

9/29-30	Boiler overheat incident. Tube rupture on combustor B water-wall support tube for SHII forced shutdown. Combustor A overheated during fanning for cool down from unburned coal left in chamber. Boiler structural damage and wall warpage due to differential expansion between combustors. See Section 2.2 for more detail.
10/1-12/12	Repair outage. Performed structural and metallurgical examination. Conducted ultrasonic testing (UT) of boiler water walls and superheaters. Replaced hanger rods, expansion joints, six center buckstays and combustor A insulation. Removed clinkers from both chambers. Partially straightened combustor A and B water-wall tubes. Reset boiler hanger rod tension. Modified loop seal refractory as well as ash coolers and ash cooler drains. Installed new PA damper drives. Installed additional O_2 analyzers at economizer inlet. Performed air foil calibrations. Resolved secondary air (SA) fan trip problem. Calibrated coal feeders. Added new safety interlocks to distributed control system (DCS). Installed windbox recycle lines for backsifting. Reset coal crushers for 1/4" x 0". The boiler was acid-cleaned. Radiographs were taken of all SHII field welds, 32 of which were subsequently replaced.
12/13-18	Added economizer steam vent line to drum above water line to control drum level swings and improve drum level stability. Modified drum level trip logic.
12/19-23	Load at 30-45 MWe on coal. Reliable ash cooler service. Bed pressure taps erratic. Tripped on low underbed air flow to combustor A.
12/30-31	Unit restarted at 45 MWe gross. Trip on coal feed imbalance between combustors. Control logic corrected.

1988

Date	Description
1/1/88	Trip due to high I.D. fan inlet suction pressure caused by too many baghouse compartments out of service due to frozen baghouse limit switches. Delayed restart due to lack of propane supply.

1/4-11	Longest continuous run at 45 MWe (161 hours). Good ash cooler performance; erratic limestone feed. Air heater PA to SA cross-leakage. SA fan trip.
1/12-16	Unit Restarted. Irregular fluidization and circulation indicated by bed pressure drop swings; bed inventory was increased to stabilize circulation. Unit trip due to low PA flow after control was switched to manual.
1/17-23	Visually observed bed material backsifting into windbox. Began investigation of primary air to secondary air cross-leakage in air heater. Controlled shutdown to repair leaking safety valves.
1/27-2/2	Three element drum level and boiler master control placed in service. Load raised to 82 MWe (highest to date). SA fan trip temporarily removed from MFT logic due to cross-leakage in air heater.
2/3-8	Load decreased from 76 to 50 MWe due to SA fan trip. Controlled shutdown due to gearbox failure in coal reclaim conveyor C.
2/9-12	Shutdown due to water leak in A side distributor plate floor tube caused by metal failure due to differential expansion between windbox and distributor plate floor header. Repairs required removal of some windbox refractory. A small leak was also repaired on the SHIII inlet header.
2/13-16	Tube leak developed on B side distributor plate outside of windbox and was repaired.
2/17-26	Load at 96 MWe. Attempts to increase PA fan speed past maximum cause trip. Load raised to 106 MWe on 2/22. Unit 1 drain line ruptures and reduces load to 83 MWe until repaired. Load reduced due to high silica level in feed water.
2/27-3/10	SA fan trip due to faulty silicon controlled rectifier on variable speed drive; unit shut down. Excessive bed material inventory delays restart. Loose refractory brick and abraded pieces were found in the ash coolers and bed material was found in the loop seal coal feeder air duct.
3/11-18	Sizeable bed pressure drop fluctuations due to cyclic loop seal flow. Problems experienced with bottom ash cyclone separator on top of the bottom ash storage silo. Boiler trip on low PA flow due to excess bed inventory in B combustor caused by a

loop seal flush. Unit shut down to remove bed material and inspect loop seals. Refractory pieces found in B loop seal. Aeration taps in vertical portion of loop seal were found bent down and were replaced. To stabilize solids recycle flow, new air nozzles were installed in the loop seal floors and four additional aeration pipes were added to each loop seal.

3/19-31	Loop seals continue to surge. Boiler trip on drum level due to operator error on 3/21. Solids recirculation was stable with both high-pressure blowers for loop seal air in service, although one is redundant. Full load operation for 96 hours with fans at maximum, O_2 at 3.5% and bed temperatures at 1675-1725 °F. After reducing load because of deteriorating feed water quality and SA fan trips, plant tripped due to a failure of unit 4 excitor transformer. I.D. fan coupling failed during cool down and bed material removal.
4/17-5/7	Unit load at 100 MWe gross. Tripped unit due to excursion on coal feeders B and C. Unit restarted to 100 MWe immediately. Coal feeder control cards replaced after another uncontrolled excursion of B and C feeders. Stack certification completed. Controlled shutdown.
5/7-17	Outage to reinstall six steam separators. They did not improve drum level stability; moisture carryover restricted steam production. Installed 50 redesigned bubble caps on distributor plate to reduce backsifting. Start-up was difficult; problems included two drum level MFT's, two ID fan trips, and several start-up burner trips from low propane gas pressure. Bottom ash removal problems were experienced. Attempts to restart were unsuccessful after an SA fan trip.
5/18-29	Outage to replace SA fan control cards and repair leaking bonnet on SH spray manual block valve. Attempting to increase limestone feed particle size. Load brought to 110 MWe. Problems with coal reclaiming system. Unit 3 condensate forwarding pump failed and was shut down and load was reduced. Tripped 5/29 from low ID fan inlet pressure.
5/30-6/2	Plant restarted and high ash coal fed. Limestone pulverizer slowed to increase feed particle size. Indications of air heater cross-leakage at 70 MWe. Refractory pieces blocking ash coolers. Load

lowered due to high bed pressures. Drum level MFT at low load with propane assistance.

6/3-6 Outage for inspection of ash coolers, combustion chambers and loop seals. Ash-handling system supplier on site to review problems with bottom ash transport system. Refractory pieces found in both loop seals. Some distributor caps missing in both combustors.

6/7-18 Restarted unit and went to full load. Dry run acceptance test with low sulfur design coal A completed on June 10. Developed electrohydraulic control (EHC) fluid leak on unit 4; controlled plant shutdown. Restarted unit in preparation of acceptance test with high ash (30%) coal. Load reduced due to high PA transformer temperatures and bed pressures. Two pieces of refractory removed from 4D ash cooler inlet. Ash-handling system supplier was called in again to review bottom ash transport problems. MFT from ID fan trip due to lightning storm.

6/19-21 Plant down due to low EHC pressure on unit 4. Unit restarted on 6/21 and tripped again due to lightning strike. During restart, plant tripped three times due to drum level instability and then tripped due to high back pressure on unit 4 after getting on-line. The unit was then restarted.

6/22-27 Load was raised to 110 MWe and testing with high sulfur (2.2%) coal was attempted. Problems occurred with limestone feeders at high feed rate. Load was reduced due to leaking flange on unit 2 deaerator, high PA transformer temperature, and high bed pressures. SO_2 monitors in cyclone were erratic; temporarily substituted stack SO_2 monitor to control operation. Returned to 18% ash coal and went to full load. Unit 1 condensate forwarding pump failed and load was reduced to 82 MWe. MFT due to low drum level.

6/28-30 Unit restarted; work continued on ash removal problem. Unit 1 condensate pump repaired. Boiler operated at 32% MCR firing coal only.

7/1-6 Preparation for acceptance tests with design coal A in progress when high exhaust back pressure on unit 4 forced load reduction to 80 MWe. Certification tests on stack monitors (CO_2, NO_x, SO_2) completed. Load was increased to 100% MCR on 7/6, unit was stabilized, and isokinetic samples taken at stack inlet to establish compliance with state particulate emissions. Measured emissions of the four tests were between 0.022 and 0.027 $lb/10^6$ Btu, satisfying the state requirement of 0.03 $lb/10^6$ Btu.

7/7-11 Acceptance tests on design coal A completed. Sixteen hours into the test period and 9 hours into the solids sampling interval, coal feeder 4A tripped, however, sufficient samples were obtained prior to the termination of the test. Load was increased to 116.4 MWe to establish equipment and design limitations on the plant. Load was ramped between 925 klb/hr and 750 klb/hr steam flow, with the maximum rate of change limited by turbine control settings to 8.4 klb/min (1 MWe/min). This was improved to 1.5 MWe/min in July 11. Stack emissions were also verified at 750 klb/hr load.

7/12-21 Turbine testing conducted with unit 4 governor valves 100% open and 117 MWe gross plant output. Bed temperature reduction schemes (adjusting PA/SA ratio and ash cooler/classifier air flows) were attempted. Pressure data was taken on the PA fan inlet, economizer, and air heater outlets as part of the investigation of fan capacity. Plant shut down to inspect PA fan and to plug distributor plate air nozzles with missing bubble caps (2 missing on A side and 5 missing on B side). Unit restarted 7/18 after repair of a leak on the B side ash reinjection line. Two MFT's on high drum level occurred during start-up, as well as a large difference in temperatures between combustors. The A and B combustor average temperatures at the 20 inch level were 1068 °F and 1500 °F, respectively. The boiler tripped on high drum level while the temperature difference was being addressed. The unit was shut down to repair a leak on the 4A boiler feed pump outboard seal and to repair the 4B boiler feed pump recirculation valve. 4B coal feeders were calibrated and badly eroded lock hopper gate and equalizing valves on the fly ash separator were repaired during the outage.

7/22-31 In start-up on 7/22, the uninterruptable power system (UPS) failed, was bypassed, and start-up was resumed. A frequency card on the system was later replaced. Start-up was delayed by several drum level MFT's, an electrohydraulic fluid leak, a sticky throttle valve, and problems with latching the turbine. After start-up on 7/26, load was held at 35 MWe due to high silica in the feed water. An MFT occurred due to an SA fan trip later in the day. Load adjustments were made to accommodate problems with high silica, high back pressure on unit 3, the coal reclaim system, fly ash unloader, and bottom ash bag filters. A thunderstorm initiated a PA fan trip and MFT on 7/31.

8/1-10 A problem with the demineralizer train persisted through August 9. The resin was cleansed of sulfate deposits with hydrochloric acid. A larger feeder motor was installed on the 4B limestone feeder during the outage. During the outage, too much bed material had drained into the windbox through nozzles with missing bubble caps; these had to be plugged before restarting on 8/9. Four were from the A side and six were from the B side, and all were from nozzles located in front of the loopseal entrance or ash cooler inlets.

8/11-23 Unit 4 on-line at 8:00, but tripped as a result of an ID fan trip. Restart was delayed by several drum level MFT's and several instances of suspected loss of generator 4A excitation which also caused trips. The propane (start-up fuel) inventory was also exhausted. An outage was declared to upgrade the bottom ash transport system and replace over 4300 retaining washers on the distributor plate, loop seal, and ash cooler bubble caps. Inspection of the cyclones, loop seals and combustion chambers revealed refractory damage and accumulation of refractory pieces in the bottom of the loop seals, between the distributor plate bubble caps, and in the ash coolers/classifiers.

8/24-9/15 Refractory inspections were conducted and revealed many areas in poor condition. Inspection also revealed erosion at the protective weld overlay on the water walls just above the refractory interface and on side wall tubes closest to the front wall. Work during the outage included: replacement of carbon steel bubble cap retaining washers with stainless steel; modifications to bottom ash transport system; repair or replacement of damaged cyclone, loop seal and combustor refractory; installation of a new transport pipe on the windbox to loop seal reinjection line; grinding of rough spots on the weld overlay at the interface between the water walls and lower combustor refractory; repair of damaged demineralizer train; relocation of one SO_2 analyzer from the cyclone outlet to the air heater inlet; repair of PA duct turning vanes; work on propane vaporizer system; radiographic inspection of convection pass field welds; inspection for erosion of upper furnace walls and SHII.

9/16-30	Restart commenced 9/16; two high drum level trips occurred. Unit back on line at 35 MWe 9/18. On 9/19, a water-wall tube leak developed on the B side southeast bottom corner of the loop seal wall box on the outside of the boiler. The plant was shut down for repair and restarted on 9/21. An MFT occurred on 9/23 as the result of failure of the instrument air compressor. On 9/24, the boiler tripped from an air to fuel ratio imbalance. The same type of trip occurred again on 9/27. On 9/28, the unit was restarted following a vaporizer trip, a coal feeder trip, three low drum level trips, and repair of a steam lead on the unit 4 throttle valve flange.
10/1-6	An MFT occurred due to loss of power on an input/output module on the DCS. Restart delayed by a low drum level MFT and difficulty raising bed temperatures due to low quality coal. Coal and propane fires were shut down to conserve and replenish propane inventories. Restart on 10/3 following propane vaporizer trip. Load was increased to 110 MWe in preparation for acceptance tests after tube leaks on unit 2 condenser were repaired and a broken bag was replaced in compartment 2S. Five additional bags in the same compartment were then replaced before an MFT due to an ID fan trip, which was caused by a system ground fault initiated by a local thunderstorm.
10/7-15	Second series of acceptance tests was started. A series of tests was started on the baghouses to check draft losses. Verification of compliance with emissions regulations was conducted at 75% and 35% loads. A series of fan tests were conducted on 10/11-12. A bad eccentric weight bearing on the 4B limestone feeder motor was replaced after causing a feeder trip.
10/16-18	A bed material leak developed on the southwest corner of the 4A windbox on 10/16; a temporary repair was applied. On 10/17, load was increased to conduct high sulfur coal tests. At 103 MWe unit output, limestone feeder 4B began tripping. Since feeder 4A was only capable of a 3600 lb/hr feed rate, load was reduced to 50 MW to bring the plant back into SO_2 emission compliance. The unit was later brought off line to inspect for

suspected bubble cap loss in the combustors and to repair limestone feeder 4B.

10/19-25 Loose refractory was found in both combustors and loop seals. Eighteen bubble caps were missing in combustor 4A; two were missing in 4B. All air nozzles with missing bubble caps were located in the area in front of the loop seal inlets. Limestone feeder 4B weight bearings were replaced after only 1 week of operation; feeder 4A limestone feeder bearings were also replaced. The unit was restarted on 10/25.

10/26-30 Limestone feeder 4A failed and eccentric weight bearings were replaced sequentially in feeders 4A and 4B and the feeder motor was replaced in feeder 4A. Load was reduced to 70 MWe due to vibration in turbine 2. Shortly after investigation and repair of a leaking union on the boiler 4A feed pump drain line, coal feeder 4F tripped from belt misalignment, 4D tripped from a plugged chute, and 4E tripped from belt misalignment, resulting in an MFT from the loss of all feeders on one combustor. The unit was restarted on 10/28 after two drum level trips. Another leaking union on the boiler feed pump drain line was replaced.

10/31-11/6 High ash tests were being conducted. On 11/1, a very high ash coal (>40%) forced a load reduction to 80 MWe due to falling throttle pressure at maximum primary air flow. At this load, the primary air control dampers came back into control range after being 100% open at maximum PA fan output, but limestone feeder 4B tripped repeatedly and 4A eventually failed. Load was reduced further and limestone feeder 4A eccentric weight bearings were replaced and the weight settings were changed from 100% to 80% to reduce the stress on the bearings. Rotary valve speeds were also increased on feeder 4A. Two more attempts at full-load operation on the high ash coal were made, but difficulties with PA flow, bed material buildup and blockage at the ash classifier inlets required load reductions. The boiler was shut down in a controlled manner to inspect combustion chambers and loop seals.

11/7-30 Inspections revealed small amounts of refractory in the loop seals, combustion chambers and ash classifier inlets, which were all cleared. There was also a 2 to 6 in. buildup of ash on the tube sheet floors on the baghouse compartments. Coal feeders were recalibrated and the boiler was restarted. Water sprays were installed on bottom ash classifiers 4A and 4C and the new process configuration was tuned for further high ash coal tests. On 11/19, a packing failure on the valve to the steam drum level switch head chamber forced a controlled unit shutdown and was repaired. After start-up, an MFT occurred due to an ID fan trip. ID and PA fan watt meter readings taken to confirm calibration. On 11/24, a malfunction of furnace 4A pressure transmitter caused an MFT. After restart, a high sulfur coal test was attempted at 65 MWe with a 2.32% sulfur coal. New sprockets were ordered to increase limestone rotary valve speeds and increase overall feed rate of each feeder to 10,000 lb/hr. Load was reduced due to the loss of another eccentric weight bearing on limestone feeder 4A. A minimum air flow test was conducted on 11/30.

12/1-10 Shaker motors were replaced on limestone feeders 4A and 4B due to failures of both. On 12/2, a PA fan trip from high amperage caused an MFT. Work was done on the circulating water pump to the old cooling tower. High ash tests were resumed but difficulties were encountered with pluggage in the bottom ash drain above the rotary valve, with matching water spray flow rate, with ash classifier temperature, and with high PA fan amps. High stack opacity led to the discovery of 23 ruptured bags in compartment 2S, which were replaced. 25 damaged bags were also replaced in compartment 2P. 16 bags in compartment 4E were damaged by leakage around the IBFM's. These were removed and bags were replaced.

12/11-31 The unit was taken off-line due to failure of the generator 4A excitor collector ring. During the repair outage, maintenance work progressed on unit 2 governor valves and steam seal regulator. Fan tests were conducted to determine the cause of the high PA fan amps at 90 MWe operating levels. The boiler was restarted on 12/20. 21 bags were replaced in compartment 2Q. On 12/26, a faulty pressure switch on the ID fan inlet resulted in MFT. After restart, problems with limestone feeder 4B trips continued. An MFT occurred due to overheating of the variable speed drive (VSD) controls on the SA fan, which was caused by faulty air conditioning in the VSD room. Eccentric weight bearings were replaced on both limestone feeders. Difficulties with PA fan amps continued to cause problems.

2.1.2 Plant Operating Problems

Many of the problems encountered during start-up and the first year of operation were routine in nature, and included equipment trips that occurred before and during the control system fine tuning, minor steam leaks and generator synchronization difficulties. Other miscellaneous minor problems involved feed pump seals, recirculation valves, EH fluid leaks, sticky throttle valves, condenser vacuum, and the coal delivery system. Another group of problems, such as steam line expansion interference, steam leaks at field welds, boiler casing leaks, air heater cross leakage, pluggage of pressure taps, and faulty analyzers, air dampers, and actuators, can be attributed to design or construction inadequacies. Problems associated with the new technology and scale-up uncertainties included backsifting of bed material and poor ash cooler performance. Table 2-1 is a partial summary of unit outages during the period July 1987 through December 1988. The longest outage was that required for repair after the overheat incident in September 1987.

One problem that affected unit operation was the performance of the primary air fan. At full load there was little margin available to control the bed pressures, and hence the bed temperatures. The auxiliary power load for the fans was high, which led to transformer overheating during the second quarter of 1988. In addition, the variable frequency power supply caused several plant trips. These problems limited variation of the PA/SA ratio and adversely biased commercial statistics through excessive horsepower requirements.

Full load operation had been restricted to approximately 105 MWe to allow some margin for control of excess air. The PA fan inlet and outlet duct work was inspected in July, 1988, and no major problems were observed. Air flow tests on the fans were conducted in July, October, and December of 1988, in accordance with the Air Moving Council of America (AMCA), to determine causes for performance shortfalls. After these tests and inspections, the equipment supplier claimed there were major air flow distribution problems in the PA fan inlet boxes. They recommended inlet box modifications followed by additional air flow testing. These modifications produced only limited improvement in PA fan performance.

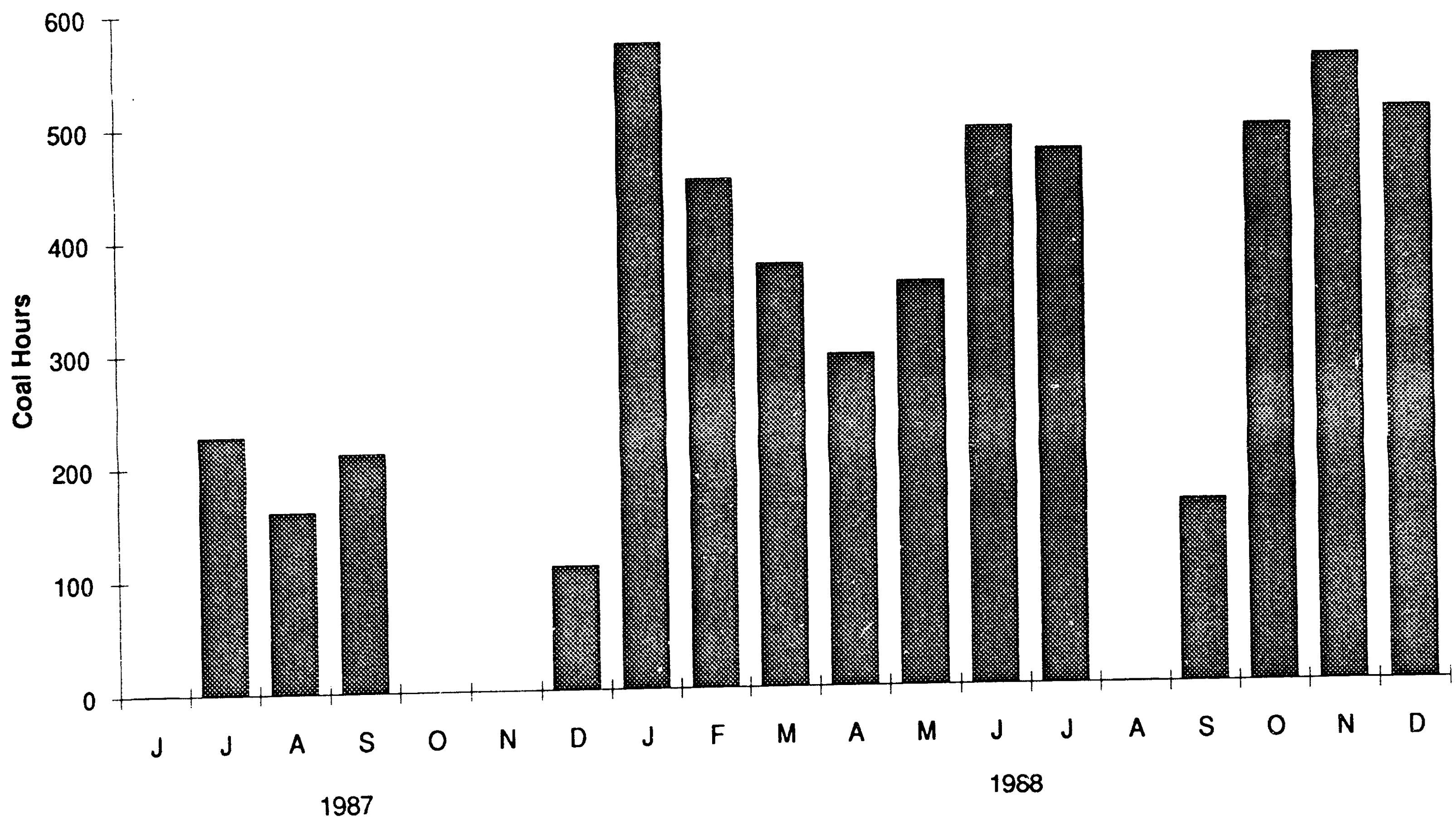
Table 2-1. Outage Summary

START OUTAGE	STOP OUTAGE	CAUSE
12-Jul-87	13-Jul-87	MAINTENANCE OUTAGE
24-Jul-87	3-Aug-87	MAINTENANCE OUTAGE
13-Aug-87	16-Aug-87	OUTAGE TO REPACK AND REPAIR SAFETY VALVES AND ERV
18-Aug-87	26-Aug-87	RESOLVE INTERFERENCE WITH MAIN STEAM DRAIN LINE AND RECIRCULATION LINE
4-Sep-87	16-Sep-87	OUTAGE FOR INSPECTION AND 4B SH II REPAIR
25-Sep-87	26-Sep-87	SHUTDOWN FOR REPAIRS ON 4B WINDBOX AND ASH COOLERS
29-Sep-87	12-Dec-87	REPAIR OUTAGE FROM OVERHEAT INCIDENT
1-Jan-88	2-Jan-88	TRIP DUE TO HIGH ID FAN INLET SUCTION PRESSURE. LOW PROPANE THEN DELAYED RESTART
11-Jan-88	12-Jan-88	SA FAN TRIP DUE TO UNKNOWN CAUSE
21-Jan-88	23-Jan-88	OUTAGE TO REPAIR LEAKING SAFETY VALVES
6-Feb-88	8-Feb-88	OUTAGE TO REPAIR FAILED RECLAIM CONVEYOR GEARBOX
9-Feb-88	13-Feb-88	OUTAGE TO REPAIR COMBUSTOR A DISTRIBUTOR PLATE FLOOR TUBE LEAK
14-Feb-88	16-Feb-88	OUTAGE TO REPAIR COMBUSTOR B DISTRIBUTOR PLATE FLOOR TUBE LEAK
1-Mar-88	4-Mar-88	OUTAGE TO INSPECT COMBUSTION CHAMBERS AND REPAIR SA FAN VARIABLE SPEED DRIVE CONTROLLERS
8-Mar-88	10-Mar-88	OUTAGE TO INSPECT BED AND ASH COOLERS
16-Mar-88	18-Mar-88	UNIT DOWN TO REMOVE BED MATERIAL, INSPECT LOOP SEALS
29-Mar-88	31-Mar-88	START OUTAGE PRIOR TO ACCEPTANCE TESTS
7-May-88	12-May-88	OUTAGE TO REINSTALL SIX STEAM SEPARATORS AND INSTALL 50 REDESIGNED BUBBLE CAPS
18-May-88	23-May-88	OUTAGE TO REPLACE SA FAN CONTROL CARDS AND REPAIR LEAKING BONNET ON SUPERHEAT SPRAY MANUAL BLOCK VALVE
29-May-88	30-May-88	TRIP FROM LOW ID FAN INLET PRESSURE
3-Jun-88	6-Jun-88	OUTAGE TO INSPECT ASH COOLERS, COMBUSTION CHAMBERS AND LOOP SEALS.
11-Jun-88	12-Jun-88	CONTROLLED SHUTDOWN DUE TO EHC FLUID LEAK
18-Jun-88	21-Jun-88	MFT FROM ID FAN TRIP DUE TO LIGHTNING STORM
27-Jun-88	28-Jun-88	DRUM LEVEL MFT DUE TO FAILURE OF UNIT 1 CONDENSATE FORWARDING PUMP
15-Jul-88	18-Jul-88	SHUTDOWN FOR PA FAN AND BUBBLE CAP INSPECTIONS
18-Jul-88	26-Jul-88	MFT FROM HIGH DRUM LEVEL, OUTAGE STARTED TO REPAIR A LEAK ON 4A BFP OUTBOARD SEAL. UPS FAILURE AND OTHER START-UP PROBLEMS DELAYED RESTART

TABLE 2-1. OUTAGE SUMMARY (CONTINUED)

START OUTAGE	STOP OUTAGE	CAUSE
31-Jul-88	9-Aug-88	PA FAN TRIP AND MFT INITIATED BY THUNDERSTORM. PROBLEMS WITH DEMINERALIZER TRAIN DELAYED RESTART UNTIL AUGUST 9
9-Aug-88	11-Aug-88	DURING RESTART ON 8/9, MISSING BUBBLE CAPS ALLOWED EXCESSIVE BED MATERIAL TO ACCUMULATE IN WINDBOX; PLUGGAGE OF 10 PIPE NIPPLES WAS REQUIRED. DURING RESTART ON 8/11, DIFFICULTIES RESULTED IN DEPLETION OF PROPANE INVENTORY. REPAIR OUTAGE DECLARED.
11-Aug-88	16-Sep-88	REPAIR OUTAGE TO UPGRADE BOTTOM ASH TRANSPORT SYSTEM AND TO REPLACE RETAINING WASHERS ON DISTRIBUTOR PLATE, LOOP SEAL AND ASH COOLER BUBBLE CAPS. REFRACTORY INSPECTIONS CONDUCTED
20-Sep-88	21-Sep-88	TUBE LEAK REPAIR SHUTDOWN
23-Sep-88	24-Sep-88	MFT FROM FAILURE OF INSTRUMENT AIR COMPRESSOR
24-Sep-88	25-Sep-88	BOILER TRIP FROM AN AIR/FUEL RATIO IMBALANCE
27-Sep-88	28-Sep-88	BOILER TRIP FROM AN AIR/FUEL RATIO IMBALANCE
1-Oct-88	2-Oct-88	FAILURE OF AN INPUT/OUTPUT MODULE POWER SUPPLY ON THE DCS CAUSED MAIN FUEL TRIP (MFT).
2-Oct-88	3-Oct-88	CONTROLLED SHUTDOWN AS A RESULT OF LOW BED TEMPERATURES FROM HIGH ASH, LOW HHV COAL SUPPLY. UNIT HELD OFF LINE TO RESTORE PROPANE INVENTORY.
6-Oct-88	6-Oct-88	INDUCED DRAFT (ID) FAN TRIP FROM A SYSTEM GROUND FAULT DURING A LIGHTNING STORM.
17-Oct-88	26-Oct-88	CONTROLLED SHUTDOWN RESULTING FROM UNIT BEING OUT OF SO2 COMPLIANCE ON HIGH SULFUR COAL TEST. WENT INTO EXTENDED OUTAGE TO REPLACE MISSING BUBBLE CAPS AND TO WORK ON LIMESTONE FEEDERS.
28-Oct-88	28-Oct-88	TWO OF THREE COAL FEEDERS OUT OF SERVICE ON FURNACE B. BOILER TRIPPED WHEN THIRD COAL FEEDER TRIPPFD ON BELT MISALIGNMENT.
4-Nov-88	10-Nov-88	CONTROLLED SHUTDOWN TO INSPECT COMBUSTORS FOR SUSPECTED REFRACTORY BLOCKAGE IN LOOP SEALS AND ASH CLASSIFIERS.
19-Nov-88	19-Nov-88	CONTROLLED SHUTDOWN TO REPAIR PACKING LEAK ON STEAM DRUM BLOW DOWN VALVE.
20-Nov-88	20-Nov-88	ID FAN THIP DURING DELTA/WYE SWITCH.
24-Nov-88	24-Nov-88	MFT FROM MALFUNCTION OF FURNACE 4A PRESSURE SWITCHES FOR DRAFT CONTROL.
2-Dec-88	3-Dec-88	MFT DUE TO HIGH PRIMARY AIR (PA) FAN AMPS.
11-Dec-88	20-Dec-88	FAILURE OF GENERATOR 4A EXCITOR COLLECTOR RING.
26-Dec-88	26-Dec-88	MFT FROM FAULTY PRESSURE SWITCH ON ID FAN INLET.
27-Dec-88	27-Dec-88	MFT FROM OVERHEAT OF VARIABLE SPEED DRIVE (VSD) CONTROL CARD ON SECONDARY AIR (SA) FAN DUE TO ROOM AIR CONDITIONING PROBLEMS.

Figure 2-1. Nucla CFB Coal Hours
January through December 1988



2.2 OVERHEAT INCIDENT REPORT

The following text is excerpted from Appendix A, EPRI Technical Progress Report for the period November 1986 through December 1987.

"B" Combustor Tube Failure
"A" Combustor Overheat Damage

This is a statement of events intending to summarize plant operations, prior to, during, and after the operating incident of September 29 and 30, 1987.

After a brief shutdown the end of the previous week to remove pluggage from bottom ash discharge line and bed material from the windbox, the unit was started-up smoothly and Unit #4 turbine generator was synchronized at 0700 on September 27th. By 1200 on the 27th, Unit #4 generator was at the 50 MWe level and remained there the balance of the 27th, all of the 28th, and through the first shift on the 29th. During this period of stable boiler operation, the windbox (WB) variable spring support hangers were showing an increase in movement throughout the 29th. Motion of these supports is affected by boiler pressure (thermal expansion of pressure parts) and or by accumulation of solids in the windboxes due to backsifting. Several checks of WB drains did not indicate significant material accumulation at the drains, as had been experienced previously.

The purpose of this run, as with previous runs, was to increase station load to full load while continuing to tune controls throughout the plant. On the 29th Unit #2 was synchronized at 0739 and Unit #3 at 1714. This operation resulted in total generation of 62 MW at 1800 hours. This 62 MW represented 56% of rating. One boiler feed water pump rated at 60% of full load capacity was in service.*

Concern over a 30° - 50° temperature mis-match between the lower combustion chambers existed since the unit start on the 27th. The operator varied the coal feed at 1430 hours to adjust for the temperature difference. All combustion air, fuel and boiler master controls were in manual. Through the balance of the evening, including a shift change, coal feed rates were adjusted and increased overall to account for temperature mismatches and steam pressure changes. No corresponding air flow changes were made. During this period, there was no reliable indication of O_2 in the flue gas.

Total station generation peaked at 67 MWe, or 60% of rating, around 2030 hours.*

At 2236 an MFT (Main Fuel Trip) occurred due to low primary air flow to the "A" combustor. Prior to the MFT, multiple problems occurred which caused the control room operator to use a plant operator to help with the control board. Problems included uneven temperature, loss of throttle pressure, load and firing changes, a stuck auto-extraction valve, drum level swings, a stuck primary air damper, and coal feeder trips. After about ten minutes, the MFT was cleared and coal feeders were restarted. The accumulated unburnt coarse fuel in combustor "A" ignited when primary air flow was increased, resulting in a rise in steam pressure. Drum level swings continued to be a problem because the one boiler feed water pump in service, rated at 60%, was not sufficient to maintain drum level at 61% load and corresponding high drum pressure.

Unit #2 was taken off-line at 2255 and station generation was down to 59 MWe. At 2306 the safety valves lifted and all coal feed was secured by the operator. A low drum level alarm was received at 2308. Since 2200 hours approximately 3300 alarms were acknowledged by the board operator and a portion required action. This was nearly 50 per minute. To assist with this activity a second control room operator was called to the site. Unit #3 was taken off-line at 2310. Station generation* was below 50 MW by 2330 hours. The second boiler feed water pump was started. A second MFT from high furnace pressure along with a fan trip occurred at 2327.*

While the fans were coasting down, a tube leak was discovered in "B" combustor and Unit #4 was taken off-line at 2337. Feed water flow stopped at 2354 when boiler feed pump 4B was shut down. All water reserves in Unit #4 were depleted by this time. All turbine generators and auxiliary systems were secured at this time in preparation for repair of the tube leak.

Decisions were made to start fans and cool the unit down for repair of the tube leak. The induced draft fan was started at 0024 on the 30th of September. Primary air and secondary air fans were started at 0052. By 0055 a rapid rise in "A" combustor temperature was reported. A decision was made to continue fan cool-down. "A" bed temperatures were approaching 2000°F by 0115. Primary air duct hangers failed due to over-expansion of "A" combustor. The induced draft fan was secured at 0211.

Specific data is available to support this report, however, for clarity the intent has been to minimize specific temperatures, pressure levels, etc.

A number of the factors which may have contributed to this incident include windbox air flow distribution, lack of reliable O_2 indication, lack of automatic control, incorrect *air flow indications, overfeeding of coal with no increase in combustion air, operation using a single boiler feed water pump near its design rating, starting the bed cool down process with a fuel rich bed, and continuing to fan the unit down even though temperatures were rapidly increasing.*

** Total generation is from 30 minute averaged data.*

2.3 BOILER ACCEPTANCE TESTS

In June of 1988, a dry run acceptance test was completed at full load with Design Coal A, followed by operability tests with high ash and high sulfur Design Coals B. Characteristics of these coals are shown in Table 1-1. Although the dry run acceptance was successful in establishing operating and sampling procedures, the high ash and high sulfur coal tests were unsuccessful due to capacity limitations with the original bottom ash transport system. Modifications that were made to the bottom ash system to increase transport capacity are discussed in Section 5.

The first acceptance test on Design Coal A was completed on July 7, 1988. During this test, the unit failed to meet its Ca/S requirement at 70% sulfur retention. The guarantee value is 1.5 (excluding calcium in the coal ash), while the actual value for the test was 3.0. There were four reasons that were cited for failure to meet the guaranteed value:

- High combustion chamber temperatures. For the performance period of 16 hours, combustor A and B temperatures averaged 1647 °F and 1707 °F, respectively (as measured approximately 20 inches above the distributor plate around the perimeter of the combustor). These temperatures should have been in the vicinity of 1600 °F.

- Low ash content. The ash content of the coal averaged 16.9 percent versus the value for design A coal of 26.1%. This resulted in a deficiency of calcium and other potential sorbents in the ash.

- Improper limestone sizing, particularly excessive fines fraction. The small particles pass through the hot cyclones and do not recirculate.

- Poor combustion balance between the two chambers. Better matching of air and coal flows may improve performance and reduce mean bed temperatures.

The acceptance test was originally scheduled for 24 hours, with solids sampling covering a 12-hour interval in the middle of this period. Sixteen hours into the test period and 9 hours into the solids sampling interval, coal feeder 4A tripped and caused a significant-enough boiler upset that the run was terminated 8 hours earlier than the 24-hour agreement. However, CUEA and PPC agreed that the two complete isokinetic samples and five sets of solids samples that were taken would suffice.

On July 8, 1988, load was increased to a gross output of 116.4 MWe to establish equipment and design limitations on the plant. In this case, a drop in drum water level suggested a possible limitation with the feed water system. This was subsequently found to be controls related.

The load was ramped between 925 klb/h and 750 klb/h steam flow. Maximum rate of change was limited to approximately 8.4 klb/min (1 MWe/min). This limitation is dictated by turbine control settings which require final tuning by Westinghouse before this rate can be significantly improved. Nearly full load was maintained through July 11 when load was shed at an improved rate of 1.5 MWe/min to approximately 750 klb/h steam flow. This was achieved without final tuning of the turbine controls by Westinghouse.

Stack emissions were also verified at the 750 klb/h load. The Ca/S ratio limit for meeting the SO_2 emission limit of 0.4 lb/10^6 Btu at these partial load points is not stipulated contractually. Emissions were satisfactory at 750 klb/h.

On July 12, turbine testing was completed with the unit 4 governor valves 100% open and gross plant output at 117 MWe. Load was then reduced to 80 MWe to test various schemes for reducing bed temperatures, which were in the range of 1650 °F to 1700 °F at the peak load. At the reduced load, there is enough fan margin for adjusting the primary air to secondary air ratios. Adjustment of the relative air flows appeared to have little affect on bed temperatures. The tests, however, were not conducted in a controlled fashion for a sufficient duration to reach positive conclusions. Ash cooler/classifier air flows were also adjusted between 4 ft/s and 10 ft/s fluidizing velocities to determine if bed particle sizing could be altered enough to influence bed temperature. Again, these tests were inconclusive due to inadequate test duration and controlled process conditions.

Although acceptance tests for Design Coal A were run again at lower operating temperatures, process conditions were as follows:

Boiler performance item	Design Value	Data, 7/7/88
steam flow, lb/hr	925,000	922,600
steam temp, °F	1005	1005.3
dP superheater, psi	150	147
dP economizer, psi	12	14.6
air resistance(PA/SA) in wg.	62/37	61.1/39.9
draft loss, in wg.	16.2	16.76
air heater leakage (air-gas)	0	0
boiler efficiency	88.3	88.8
steam purity	0.1	ok
control range SH %	54-100	ok
PA fan kW	1620	2689
circ. pump, kW	N/A	N/A
sootblower steam demand	2034 lb/h	ok
SA fan kw	400	649
ID fan kw	1400	1961
Ca/S ratio	1.5	3.06
particulate emission, #/MBtu	0.03	0.0245
NOx emission, #/MBtu	0.5	0.37
SO2 emission, #/MBtu	0.4	0.401
#4 Baghouse Performance		
stack gas dust loading:		
grain loading, gr/acf	0.01	0.0075
#/million Btu	0.03	0.0245
dP 4 compartments out, in wg.	7.5	7.3
dP 2 compartments out, in wg.	7.0	6.4
dP all compartments in, in wg.	6.8	5.8
bag life	2 yr. min.	not tested
stack opacity	20%	20%
dT baghouse, °F	15	unreliable data

Notes:
- all data by Colorado-Ute
- Ca/S ratio guaranteed at full load only
- SO2 emission guarantee is without a limit on the Ca/S ratio

The process operating summary, generated by the PMF software, is shown in Table 2-2. This acceptance test run provided a good opportunity to verify the PMF calculating system. The calculations used manually entered data of the average solids data and variables such as fly ash flow rate and CO_2 percentage where the measuring devices were known to be inaccurate. Gas-side mass balances were calculated by the O_2 and total balance methods. (Flue gas flow rate is not measured.) The O_2 method calculates flue gas flow rate by using the oxygen content of the flue gas and the air required for coal burning. The total balance method calculates flue gas flow rate from the input streams and the solid waste streams.

Table 2-2

PROCESS OPERATING SUMMARY REPORT
(Sheet 1 of 8)

TEST : 80707AAT

Start....... 7/ 7/88   8: 0: 0
End......... 7/ 7/88 16: 0: 0
Printed.....08-SEP-1988 11:47:43.00

	Combustor A	Combustor B	Total
Final SH Stm. Flow (klb/hr)			914.63
Final SH Out. Press (Psig)			1508.79
Final SH Out. Temp. (F)			1004.10
Coal Rate Frnt-Wst (klb/hr)	15.20	0.00	
Coal Rate Frnt-Est (klb/hr)	15.82	25.89	
Coal Rate Rear (klb/hr)	17.71	23.12	
Total (klb/hr)	48.73	49.02	97.75
Limestone Rate (klb/hr)	4.51	4.42	8.92
Bed Drain Rate (klb/hr)	2.38	0.93	3.31
Flyash Flow (klb/hr)			23.38
Superficial Velocity (ft/sec)			
Distributor Plate (Inl Air)	10.67	11.51	
Freeboard (Inlet Air)	17.42	18.99	
Dist. Plate (O2 Method)	9.61	10.34	
Freeboard (O2 Method)	16.26	17.72	
Avg Bed Temp. (F) 20"	1652.86	1730.93	
Avg Bed Temp. (F) 40"	1629.67	1695.70	
Avg Bed Temp. (F) 80"	1602.73	1687.89	
Wet Flue Gas Flow - O2 Method (klb/hr)			1041.26
Flue Gas Composition (AH Inlet)			
O2 (V%)			3.89
CO2 (V%)			15.60
CO (PPMV)			59.54
NOX (PPMV)			195.76
SO2 (PPMV)			211.44
PA Underbed Flow (klb/hr)	278.70	280.87	559.57
Sec. Air Flow (klb/hr)	250.04	272.11	522.14
Total Air Flow (klb/hr)			1081.72
SA/PA Ratio	0.90	0.97	0.93
Other Air Flows (klb/hr)			7.10

Table 2-2 (Cont'd)
(Sheet 2 of 8)

TEST : 80707AAT

Start....... 7/ 7/88 8: 0: 0
End......... 7/ 7/88 16: 0: 0
Printed.....08-SEP-1988 11:47:43.00

	Combustor A	Combustor B	Total
PA Fan Out. Press. (in WG)			60.76
SA Fan Out. Press. (in WG)			39.86
PA AH Out. Press. (in WG)	54.07	54.80	
SA AH Out. Press. (in WG)	36.92	36.94	
Windbox Press. (in WG)	48.22	50.20	
Bed Press. Over Grid (in WG)	29.60	18.18	
Grid DP (in WG)	18.62	32.03	
Freeboard Press. (in WG)	-0.48	-0.25	
Cyclone Out. Press. (in WG)			-8.35
SH 1 & 3 Flue Gas DP (in WG)			1.19
Economizer Flue Gas DP (in WG)			1.51
AH DP (in WG)			0.00
Baghouse In. Press. (in WG)			-15.59
ID Fan In. Press. (in WG)			-23.25
Cyclone In. Temp. (F)	1644.63	1735.27	
Cyclone Out. Temp. (F)	1600.77	1692.20	
Loop Seal Solids Temp. (F)	1673.45	1759.77	
AH Gas In. Temp. (F)			538.72
AH Gas Out. Temp. (F)			294.76
Pri. Air AH In. Temp. (F)			140.78
Pri. Air AH Out. Temp. (F)			426.82
Sec. Air AH In. Temp. (F)			123.94
Sec. Air AH Out. Temp. (F)			443.99
Feedwater Flow (klb/hr)			880.81
SH2 Attemp. Flow (klb/hr)			20.36
SH3 Attemp. Flow (klb/hr)			13.46
Drum Press. (Psig)			1682.86
Ambient Temp. (F)			104.35
Baro. Press. (In Hg)			24.51
Rel. Humidity (%)			15.56

Table 2-2 (cont'd)

(Sheet 3 of 8)

TEST : 80707AAT

Start....... 7/ 7/88   8: 0: 0
End......... 7/ 7/88 16: 0: 0
Printed.....11-NOV-1988 10:12:37.00

CHEMICAL PROCESS SUMMARY

	VALUE	UNC*
Ca Utilization % (Sorbent Only).................	23.60	2.23
Ca Utilization % (Coal and Sorbent)............	20.95	1.92
Alkali Utilization % (Coal and Sorbent)........	20.51	1.28
Ca To S (Sorbent Only).........................	3.06	0.23
Ca To S (Coal and Sorbent).....................	3.44	0.25
Alkali To S (Coal and Sorbent).................	3.52	0.25
SO2 Retention %	72.11	1.84
Combustion Efficiency %	98.21	0.72
Carbon Conversion (Loss Method) %	95.90	2.23
Carbon Conversion (I/O Method) %	97.57	0.86

BOILER PERFORMANCE SUMMARY

Boiler Efficiency (Loss Method) %	88.20	0.37
Boiler Efficiency (I/O Method) %	83.65	3.15
Excess Air %	22.24	2.14
Boiler Load %MCR	97.35	3.15

FLUE GAS FLOW RATES AND VELOCITIES

Wet flue gas flow - O2 Method (klbs/hr)	1115.06	36.95
Wet flue gas flow - Total Method (klbs/hr)	1115.80	******
Superficial Velocities (ft/sec)		
Distributor Plate, Comb A (Inlet Air Method)	9.52	0.85
Distributor Plate, Comb B (Inlet Air Method)	10.23	0.93
Freeboard, Comb A (Inlet Air Method)	16.43	1.36
Freeboard, Comb B (Inlet Air Method)	17.96	1.45
Distributor Plate, Comb A (O2 Method)	10.94	1.13
Distributor Plate, Comb B (O2 Method)	11.89	1.26
Freeboard, Comb A (O2 Method)	17.42	1.46
Freeboard, Comb B (O2 Method)	19.04	1.59

* Uncertainty, +/- in same units as variable.

Table 2-2 (cont'd)
(Sheet 4 of 8)

TEST : 80707AAT

Start....... 7/ 7/88   8: 0: 0
End......... 7/ 7/88 16: 0: 0
Printed.....08-SEP-1988 11:47:57.00

INPUTS(klb/hr)	Coal	Sorbent	Air	Total Input
Total	97.75	8.92	1088.82	1195.49
C	60.93	0.99		61.92
H	4.47	0.00	1.07	5.54
O	13.93	3.96	258.34	276.24
N	1.12		829.40	830.52
S	0.79	0.00		0.79
Ca	0.38	3.23		3.61
Mg	0.00	0.05		0.05
Fe	0.00	0.02		0.02

OUTPUTS(klb/hr)	Flue Gas	Fly Ash	Bed Drain	Total Output	% Acc For
Total	1041.26	23.38	3.31	1067.94	89.33
C	60.68	1.40	0.04	62.12	100.32
H	5.41	0.00	0.00	5.41	97.68
O	245.21	2.30	0.36	247.87	89.73
N	730.18			730.18	87.92
S	0.22	0.58	0.11	0.90	114.78
Ca		3.26	0.48	3.74	103.82
Mg		0.12	0.02	0.14	309.94
Fe		0.45	0.04	0.49	3060.39

Table 2-2 (cont'd)
(Sheet 5 of 8)

TEST : 80707AAT

Start....... 7/ 7/88   8: 0: 0
End......... 7/ 7/88 16: 0: 0
Printed.....08-SEP-1988 11:48:01.00

INPUTS(klb/hr)	Coal	Sorbent	Air	Total Input
Total	97.75	8.92	1088.82	1195.49
C	60.93	0.99		61.92
H	4.47	0.00	1.07	5.54
O	13.93	3.96	258.34	276.24
N	1.12		829.40	830.52
S	0.79	0.00		0.79
Ca	0.38	3.23		3.61
Mg	0.00	0.05		0.05
Fe	0.00	0.02		0.02

OUTPUTS(klb/hr)	Flue Gas	Fly Ash	Bed Drain	Total Output	%ACCT FOR
Total	1168.80	23.38	3.31	1195.49	100.00
C	68.40	1.40	0.04	69.84	112.79
H	5.54	0.00	0.00	5.54	100.01
O	271.99	2.30	0.36	274.64	99.42
N	823.12			823.12	99.11
S	0.25	0.58	0.11	0.93	118.33
Ca		3.26	0.48	3.74	103.82
Mg		0.12	0.02	0.14	309.94
Fe		0.45	0.04	0.49	3060.39

Table 2-2 (cont'd)
(Sheet 6 of 8)

TEST : 80707AAT

Start........ 7/ 7/88 8: 0: 0
End.......... 7/ 7/88 16: 0: 0
Printed.....08-SEP-1988 11:48:06.00

	Coal	Sorbent	Fly Ash	Bed Drain Matl
HHV (Btu/lb)	10876.20			
Total Moisture (%)	6.48	0.11		
Air Dry Loss (%)	3.98			
Blk Den (#/cft)	0.00			
Volatiles (%)	29.38			
Fixed C (%)	47.26			
Ash (%)	16.89			
CONSTITUENTS (%)				
C	62.34		5.99	1.16
H	3.84	0.00	0.00	0.00
O	8.50			
N	1.15			
S	0.81	0.00	2.46	3.28
Ca	0.39	36.14	13.94	14.64
Mg	0.00	0.52	0.53	0.64
Fe	0.00	0.18	1.91	1.33
CO2		40.63	0.75	0.19

Table 2-2 (cont'd)
(Sheet 7 of 8)

TEST : 80707AAT

Start........ 7/ 7/88 8: 0: 0
End.......... 7/ 7/88 16: 0: 0
Printed.....08-SEP-1988 11:48:14.00

BOILER EFFICIENCY (%)(LOSSES METHOD)		88.01
	Value(KBtu/hr)	% of total *
CHEMICAL HEAT INPUT OF THE COAL:	1064111.75	98.36
I. CREDITS		
1. Heat credit for sensible heat in entering moist air	13862.19	1.28
2. Sensible heat in entering as-fired coal	96.12	0.01
3. Sensible heat in entering wet sorbent	5.31	0.00
4. Heat credit for sulfation reaction	3824.06	0.35
5. Auxiliary power input	0.00	0.00
6. Sootblowing steam	0.00	0.00
II. LOSSES		
1. Heat loss from unburned coal	20136.29	1.86
2. Heat loss from sensible heat in dry flue gas	52538.57	4.86
3. Heat loss due to moisture in as-fired fuel and sorbent	7280.07	0.67
4. Latent heat loss due to moisture from burning of hydrogen	38564.79	3.56

* Total equals: Chemical input of coal plus credits

Table 2-2 (cont'd)
(Sheet 8 of 8)

TEST : 80707AAT

Start....... 7/ 7/88 8: 0: 0
End......... 7/ 7/88 16: 0: 0
Printed.....08-SEP-1988 11:48:14.00

	Value(KBtu/hr)	% of total *
II. LOSSES (CONT)		
5. Latent heat loss due to moisture in the air	830.90	0.08
6. Heat loss due to calcination of sorbent	5955.92	0.55
7. Heat loss due to formation of CO	234.49	0.02
8. Heat loss due to unburned hydrocarbons in flue gas	0.00	0.00
9. Heat loss due to radiation and convection	2800.00	0.26
10. Heat loss due to sensible heat in flue dust	1020.88	0.09
11. Heat loss due to sensible heat in bed drain	262.79	0.02
12. Heat loss due to sootblower steam	0.00	0.00
SUM OF LOSSES TERMS	129624.71	11.98

* Total equals: Chemical input of coal plus credits

Disregarding bed material, superficial velocities are calculated by the air inlet and O_2 methods, at 20 inches above the air distributor plate and in the freeboard, 93 feet above the distributor plate. The air inlet method uses the volume of air fed to the combustion chambers and the cross-sectional area through which the air passes. The air density is adjusted for the pressure and temperature to calculate the velocity. The O_2 method utilizes the flue gas flow rate calculated by the O_2 method above less the air to calculate the gas flow rate at the two elevations.

Concerning the carbon balance, a value of 15.6% CO_2 in the flue gas was assumed. This assumption affects the carbon mass balance.

Process conditions in the two combustors were different during the run. The differences in process conditions may be caused by errors in the assumed air flow, coal flow, and bed inventory.

The boiler efficiency calculated by the PMF (EPRI "long form") is slightly different than the CUEA-calculated efficiency (CUEA "short form"). This is due to different assumptions made in calculating losses; CUEA's method accounts for five losses, while the EPRI PMF method accounts for 12 losses and 6 credits. These differences are discussed in more detail later in the section.

On October 7, 1988, a repeat of the July 7 Design Coal A boiler performance acceptance test was run. The calcium to sulfur ratio was substantially lower during the second acceptance test than during the first test. The ratio was 1.4 when only the calcium present in the limestone was considered, but rose to 1.7 when the calcium in the coal was also included. Both of these values correspond to an SO_2 retention rate of 72 percent. Factors that may have contributed to the improvement in Ca/S ratio included lower overall combustor temperature, better temperature balance between the two combustors, and change in limestone size distribution as indicated by a larger median size in the second test.

Process conditions during this Design Coal A acceptance test were as follows:

Boiler performance item	Design Value	Data, 10/7/88
steam flow, lb/hr	925,000	959,672
steam temp, °F	1005	1003
air resistance(PA/SA) in wg.	62/37	54.0/37.3
draft loss, in wg.	16.2	
boiler efficiency	88.3	88.55
PA fan kW	1620	
Ca/S ratio	1.5	1.33
Particulate, #/MBtu		
925 Klb flow	0.03	0.018
750	0.03	<0.03
500	0.03	<0.03
350	0.03	<0.03
NOx, #/MBtu		
925	0.5	0.2
750	0.5	0.18
500	0.5	0.17
350	0.5	0.08
SO2, #/MBtu		
925	0.4	0.39
750	0.4	0.28
500	0.4	0.27
350	0.4	0.19
#4 Baghouse Performance		
Grains/cf of gas	0.01	0.0094
dP (2x2), in wg.	7.5	7.1
dP (2x2) soot blow, in wg.	7.5	7.6
dP all compartments in, in wg.	6.8	6.6
stack opacity	20%	6.3-9.4

Notes:
all data by Colorado-Ute
Ca/S ratio guaranteed at full load only
SO2 emission guarantee is without a limit on the Ca/S ratio

Process operating summary reports are shown in Table 2-3. Concerning the two methods of calculation of boiler efficiency that were discussed with the first acceptance test results (CUEA "short form"/EPRI test program "long form"), a comparison of the losses calculated by the two methods is shown in Table 2-4.

Table 2-3

PROCESS OPERATING SUMMARY REPORT

TEST : 81007ADI

Start.......10/ 7/88 13:20: 0
End.........10/ 7/88 21:20: 0
Printed.....14-DEC-1988 10:30:16.00

	Combustor A	Combustor B	Total
Final SH Stm. Flow (klb/hr)			925.67
Final SH Out. Press (Psig)			1505.56
Final SH Out. Temp. (F)			1003.17
Coal Rate Frnt-Wst (klb/hr)	18.86	18.52	
Coal Rate Frnt-Est (klb/hr)	17.94	17.79	
Coal Rate Rear (klb/hr)	17.58	18.05	
Total (klb/hr)	54.39	54.36	108.75
Limestone Rate (klb/hr)	1.80	1.79	3.59
Bed Drain Rate (klb/hr)	2.28	1.51	3.79
Flyash Flow (klb/hr)			23.59
Superficial Velocity (ft/sec)			
Distributor Plate (Inl Air)	11.16	11.38	
Freeboard (Inlet Air)	18.82	18.64	
Dist. Plate (O2 Method)	12.40	12.62	
Freeboard (O2 Method)	19.61	19.42	
Avg Bed Temp. (F) 20"	1641.89	1668.05	
Avg Bed Temp. (F) 40"	1621.27	1626.06	
Avg Bed Temp. (F) 80"	1589.10	1618.93	
Wet Flue Gas Flow - O2 Method (klb/hr)			1221.44
Flue Gas Composition (AH Inlet)			
O2 (V%)			4.24
CO2 (V%)			14.60
CO (PPMV)			66.14
NOX (PPMV)			138.85
SO2 (PPMV)			178.22
PA Underbed Flow (klb/hr)	286.83	286.11	572.93
Sec. Air Flow (klb/hr)	287.35	279.73	567.08
Total Air Flow (klb/hr)			1140.01
SA/PA Ratio	1.00	0.98	0.99
Other Air Flows (klb/hr)			0.50

Table 2-3 (cont'd)

TEST : 81007ADI

Start.......10/ 7/88 13:20: 0
End.........10/ 7/88 21:20: 0
Printed.....14-DEC-1988 10:30:16.00

	Combustor A	Combustor B	Total
PA Fan Out. Press. (in WG)			53.31
SA Fan Out. Press. (in WG)			36.86
PA AH Out. Press. (in WG)	46.25	46.96	
SA AH Out. Press. (in WG)	34.87	34.93	
Windbox Press. (in WG)	43.39	42.95	
Bed Press. Over Grid (in WG)[a]	19.20	15.92	
Freeboard Press. (in WG)	-0.20	-0.67	
Cyclone Out. Press. (in WG)			-6.73
SH 1 & 3 Flue Gas DP (in WG)			1.33
Economizer Flue Gas DP (in WG)			1.88
AH DP (in WG)			NM[b]
Baghouse In. Press. (in WG)			-17.19
ID Fan In. Press. (in WG)			-26.08
Cyclone In. Temp. (F)	1652.70	1660.41	
Cyclone Out. Temp. (F)	1605.24	1617.93	
Loop Seal Solids Temp. (F)	1674.58	1692.75	
AH Gas In. Temp. (F)			515.56
AH Gas Out. Temp. (F)			269.97
Pri. Air AH In. Temp. (F)			126.40
Pri. Air AH Out. Temp. (F)			409.59
Sec. Air AH In. Temp. (F)			108.92
Sec. Air AH Out. Temp. (F)			429.53
Feedwater Flow (klb/hr)			876.49
SH2 Attemp. Flow (klb/hr)			40.36
SH3 Attemp. Flow (klb/hr)			11.82
Drum Press. (Psig)			1667.48
Ambient Temp. (F)			101.64
Baro. Press. (In Hg)			24.70
Rel. Humidity (%)			17.23

(a) Average of three pressure taps located approximately 1 ft above the distributor plate.

(b) Not measured.

Table 2-3 (cont'd)

CHEMICAL ANALYSIS REPORT

TEST : 81007ADI

Start.......10/ 7/88 13:20: 0
End.........10/ 7/88 21:20: 0
Printed.....14-DEC-1988 10:30:30.00

	Coal	Sorbent	Fly Ash	Bed Drain Matl
HHV (Btu/lb)	10480.00			
Total Moisture (%)	5.80	0.06		
Air Dry Loss (%)	NM (a)			
Blk Den (#/cft)	NM			
Volatiles (%)	28.66			
Fixed C (%)	44.10			
Ash (%)	21.42			
CONSTITUENTS (%)				
C	59.99		5.90	0.90
H	3.85	0.00	0.00	0.00
O	7.21			
N	0.97			
S	0.72	0.00	1.91	3.70
Ca	0.36	36.37	8.13	12.60
Mg	0.00	0.53	0.00	0.00
Fe	0.00	0.00	0.00	0.00
CO2		40.96	0.40	0.20

(a) Not measured.

Table 2-3 (Cont'd)

TEST : 81007ADI

Start.......10/ 7/88 13:20: 0
End.........10/ 7/88 21:20: 0
Printed.....14-DEC-1988 10:30:32.00

Mesh	Actual Microns	Percentage Less Than: Coal	Sorbent	Bed Drain
1.500	37500.	100.00	100.00	100.00
1.000	25000.	100.00	100.00	100.00
0.750	19000.	100.00	100.00	100.00
0.500	12500.	100.00	100.00	100.00
0.250	6300.	94.45	100.00	98.70
4	47500.	87.82	100.00	97.27
6	3350.	77.80	100.00	94.93
8	2360.	67.70	100.00	92.53
10	1700.	56.95	100.00	88.70
14	1180.	46.50	92.30	83.80
20	850.	37.55	80.35	76.77
28	600.	30.45	68.98	67.93
48	300.	18.23	49.43	36.67
100	150.	9.95	37.65	3.77
150	106.	7.00	33.48	0.27
200	75.	0.05	30.25	0.03
325	45.	0.00	26.65	0.00
400	38.	0.00	25.03	0.00

	Coal	Sorbent	Bed Drain
Weight Mean	2176.81	444.93	867.65
Surface Mean Vol.	490.15	61.97	367.08
Surface Mean	130.01	20.90	224.38
Volume Mean	202.34	30.02	264.39
Arithmetic Mean	108.36	19.56	200.25
Geometric Mean	100.69	19.27	181.40

Table 2-3 (cont'd)

PERFORMANCE SUMMARY REPORT

TEST : 81007ADI

Start.......10/ 7/88 13:20: 0
End.........10/ 7/88 21:20: 0
Printed.....14-DEC-1988 10:30:23.00

CHEMICAL PROCESS SUMMARY

	VALUE	UNC*
Ca Utilization % (Sorbent Only)................	54.25	3.28
Ca Utilization % (Coal and Sorbent)............	41.74	2.22
Alkali Utilization % (Coal and Sorbent)........	40.99	2.16
Ca To S (Sorbent Only).........................	1.33	0.08
Ca To S (Coal and Sorbent).....................	1.73	0.08
Alkali To S (Coal and Sorbent).................	1.76	0.08
SO2 Retention %	72.17	1.27
Combustion Efficiency %	98.20	0.55
Carbon Conversion (Loss Method) %	102.34	2.46
Carbon Conversion (I/O Method) %	97.86	0.66

BOILER PERFORMANCE SUMMARY

Boiler Efficiency (Loss Method) %	88.25	0.35
Boiler Efficiency (I/O Method) %	85.76	3.14
Excess Air %	26.40	2.39
Boiler Load %MCR	99.55	3.14

FLUE GAS FLOW RATES AND VELOCITIES

Wet flue gas flow - O2 Method (klbs/hr)	1221.44	36.16
Wet flue gas flow - Total Method (klbs/hr)	1225.47	27.68
Superficial Velocities (ft/sec)		
Distributor Plate, Comb A (Inlet Air Method)	11.16	0.98
Distributor Plate, Comb B (Inlet Air Method)	11.38	1.00
Freeboard, Comb A (Inlet Air Method)	18.82	1.48
Freeboard, Comb B (Inlet Air Method)	18.64	1.47
Distributor Plate, Comb A (O2 Method)	12.40	1.22
Distributor Plate, Comb B (O2 Method)	12.62	1.24
Freeboard, Comb A (O2 Method)	19.61	1.58
Freeboard, Comb B (O2 Method)	19.42	1.57

* Uncertainty, +/- in same units as variable.

Table 2-3 (cont'd)

MATERIAL BALANCE REPORT
(Total Balance Method)

TEST : 81007ADI

Start.......10/ 7/88 13:20: 0
End.........10/ 7/88 21:20: 0
Printed.....14-DEC-1988 10:30:28.00

INPUTS(klb/hr)	Coal	Sorbent	Air	Total Input
Total	108.75	3.59	1140.51	1252.85
C	65.23	0.40		65.63
H	4.89	0.00	1.14	6.03
O	13.44	1.61	270.70	285.75
N	1.05		868.68	869.72
S	0.79	0.00		0.79
Ca	0.39	1.31		1.70
Hg	0.00	0.02		0.02
Fe	0.00	0.00		0.00

OUTPUTS(klb/hr)	Flue Gas	Fly Ash	Bed Drain	Total Output	%ACCT FOR
Total	1225.47	23.59	3.79	1252.85	100.00
C	67.33	1.39	0.03	68.76	104.76
H	6.03	0.00	0.00	6.03	100.02
O	279.54	1.51	0.41	281.46	98.50
N	872.82			872.82	100.36
S	0.22	0.45	0.14	0.81	103.10
Ca		1.92	0.48	2.39	140.98
Hg		0.00	0.00	0.00	0.00
Fe		0.00	0.00	0.00	0.00

Table 2-3 (cont'd)

MATERIAL BALANCE REPORT
(02 Method)

TEST : 81007ADI

Start.......10/ 7/88 13:20: 0
End.........10/ 7/88 21:20: 0
Printed.....14-DEC-1988 10:30:26.00

INPUTS(klb/hr)	Coal	Sorbent	Air	Total Input
Total	108.75	3.59	1140.51	1252.85
C	65.23	0.40		65.63
H	4.89	0.00	1.14	6.03
O	13.44	1.61	270.70	285.75
N	1.05		868.68	869.72
S	0.79	0.00		0.79
Ca	0.39	1.31		1.70
Mg	0.00	0.02		0.02
Fe	0.00	0.00		0.00

OUTPUTS(klb/hr)	Flue Gas	Fly Ash	Bed Drain	Total Output	% Acc For
Total	1221.44	23.59	3.79	1248.82	99.68
C	67.14	1.39	0.03	68.56	104.46
H	5.96	0.00	0.00	5.96	98.90
O	278.33	1.51	0.41	280.25	98.08
N	870.26			870.26	100.06
S	0.22	0.45	0.14	0.81	103.02
Ca		1.92	0.48	2.39	140.98
Mg		0.00	0.00	0.00	0.00
Fe		0.00	0.00	0.00	0.00

Table 2-3 (cont'd)

HEAT BALANCE REPORT

TEST : 81007ADI

Start.......10/ 7/88 13:20: 0
End.........10/ 7/88 21:20: 0
Printed.....14-DEC-1988 10:30:34.00

BOILER EFFICIENCY (%)(LOSSES METHOD)		88.25
	Value(KBtu/hr)	% of total *
CHEMICAL HEAT INPUT OF THE COAL:	1140791.13	98.64
I. CREDITS		
1. Heat credit for sensible heat in entering moist air	12120.63	1.05
2. Sensible heat in entering as-fired coal	-241.85	-0.02
3. Sensible heat in entering wet sorbent	-5.25	0.00
4. Heat credit for sulfation reaction	3814.93	0.33
5. Auxiliary power input	0.00	0.00
6. Sootblowing steam	0.00	0.00
II. LOSSES		
1. Heat loss from unburned coal	20272.20	1.75
2. Heat loss from sensible heat in dry flue gas	54708.55	4.73
3. Heat loss due to moisture in as-fired fuel and sorbent	7173.74	0.62
4. Latent heat loss due to moisture from burning of hydrogen	42520.62	3.68

* Total equals: Chemical input of coal plus credits

Table 2-3 (cont'd)

TEST : 81007ADI

Start.......10/ 7/88 13:20: 0
End.........10/ 7/88 21:20: 0
Printed.....14-DEC-1988 10:30:34.00

	Value(KBtu/hr)	% of total *
II. LOSSES (CONT)		
5. Latent heat loss due to moisture in the air	836.16	0.07
6. Heat loss due to calcination of sorbent	2365.02	0.20
7. Heat loss due to formation of CO	307.95	0.03
8. Heat loss due to unburned hydrocarbons in flue gas	0.00	0.00
9. Heat loss due to radiation and convection	6500.00	0.56
10. Heat loss due to sensible heat in flue dust	904.00	0.08
11. Heat loss due to sensible heat in bed drain	245.44	0.02
12. Heat loss due to sootblower steam	0.00	0.00
SUM OF LOSSES TERMS	135833.67	11.75

* Total equals: Chemical input of coal plus credits

Table 2-4. Comparison of Boiler Efficiency Terms

	CUEA	Test Program
Dry gas loss	4.64	4.73
H_2O from H_2 combined	3.8	3.68
Combustibles in refuse	1.79	1.75
Moisture in fuel	0.65	0.62
Moisture in air	0.50	0.07
Radiation/Convection	0.24	0.44
Other		0.33
Total	11.62	11.63
Boiler efficiency	88.38	88.37

Some of the differences between the two methods are:

- The difference in calculation of the flue gas flow rate affects the dry gas loss and the loss due to moisture in the air.

- The CUEA dry gas heat loss is based on a reference temperature of 80 °F. The Test Program uses actual inlet temperature.

- The Test Program method includes the heat credits and losses caused by sulfation and calcination.

- The Test Program radiation and convection losses are based on actual measurements; CUEA uses the value stated in the contract.

Concerning acceptance tests with high ash coal, demonstrations of sustained operability on the high ash coal were initially unsuccessful due to excessive temperatures of bed material discharging from the ash classifiers at full load. The high temperatures were reduced to acceptable operational levels by operating two ash classifiers and the water-cooled screw cooler on each combustion chamber. The two ash classifiers operate in parallel and the water-cooled screw cooler operates in series with either or both of the ash classifiers. According to the original design, under any set of boiler operating conditions, only two of the three ash cooling systems can be in service on each combustion chamber simultaneously. Modifications to the bottom ash cooling system also helped to reduce bed material drain temperatures and improve bottom ash disposal flow rate. However, PA fan limitations terminated the tests during the fourth quarter of 1988.

High sulfur coal testing was also attempted at full load on several occasions through the fourth quarter of 1988. Limitations in limestone feed flow rate and feeder failures prevented the successful completion of these tests. These feeder problems were caused by shaker motor and/or bearing failures on the eccentric shaker weights. A new shaker motor design was later incorporated.

Section 3

COLD-MODE SHAKEDOWN AND CALIBRATION

During the reporting period, the cold-mode shakedown phase of the testing program was begun. The purpose of the cold-mode shakedown and calibration phase is to verify the manufacturer's calibration curves for the various instruments and to develop calibration curves for instruments that did not have calibration information provided. Furthermore, specialized instrumentation and computer programs were developed to support the test program. The solids preparation laboratory was also commissioned and sample preparation procedures were developed.

3.1 INSTRUMENTATION CALIBRATIONS

Calibrations were performed on the following instrument systems:

- Air Flow Instruments
- Coal Flow Weigh Belts
- Limestone Feeders
- Bottom Ash Weigh Bins
- Fly Ash Flow Measurements
- Test Instrumentation

Activities in each of these tasks are discussed below.

3.1.1 Air Flow Calibration

Figure 3-1 shows a schematic of the air system on the Nucla CFB. The primary air fan supplies air to the windbox, two sets of lower injection ports, three in-bed start-up burners, and miscellaneous air flows to one coal feeder, one loop seal expansion joint and one lower injection point for combustors A and B. Air flow to the primary air fan is manually measured at the inlet of the fan by an annubar. Air foils are used to measure the air flow to the windbox (GFT1C & GFT1D), the lower injection ports (GFT1W, GFT1X, GFT1Y, & GFT1Z), and the start-up burners (GFT2I, GFT2J, & GFT2K for combustor A and GFT2L, GFT2M, & GFT2N for combustor B).

The miscellaneous air flows, shown in Figure 3-1, are not measured. The air flows to the loopseal injection point contain rotameters that were never calibrated. The loopseal expansion joint air flow is not measured. Other unmeasured air flows include the vortex finder cooling air, limestone

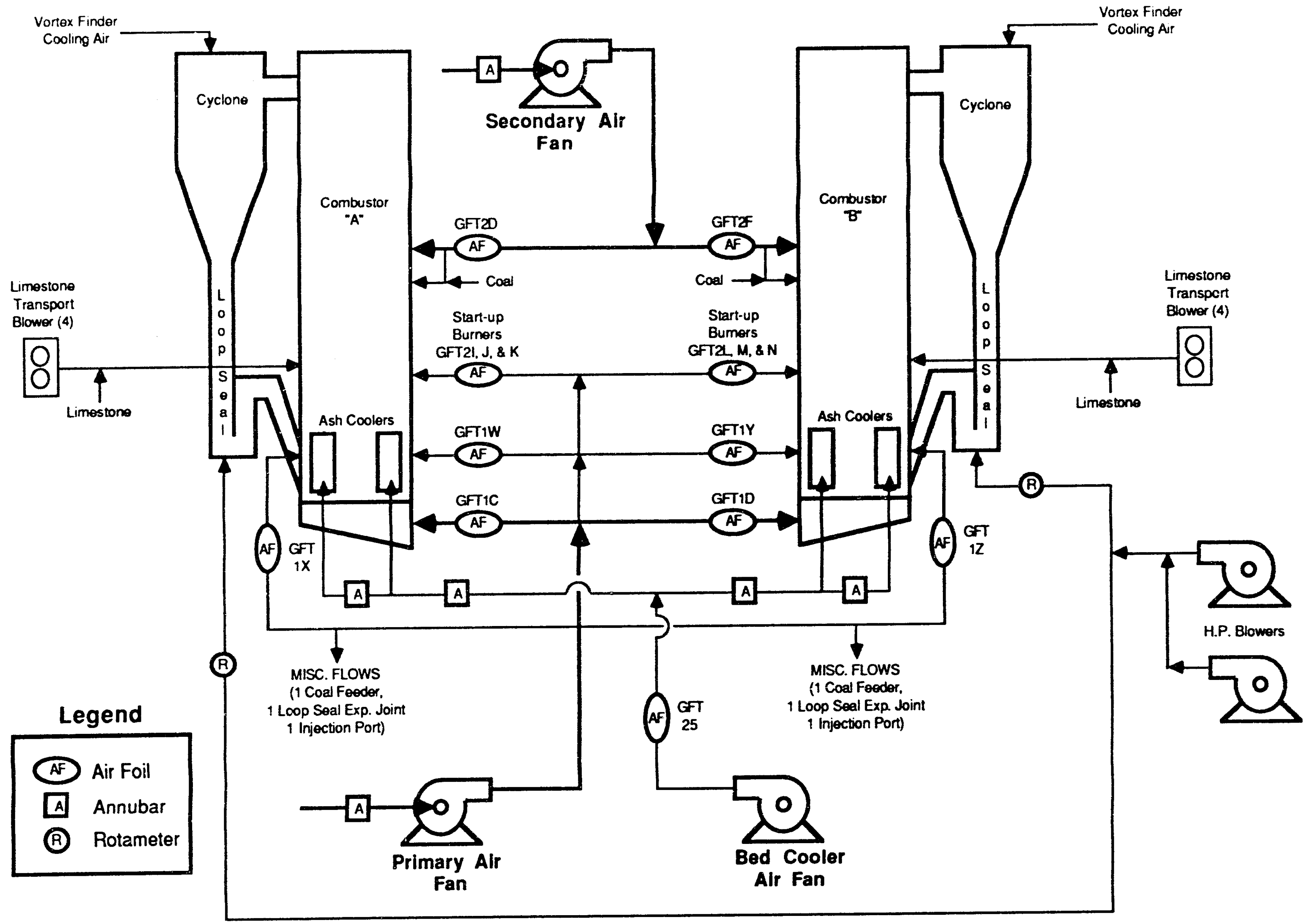


Figure 3-1 Schematic of Air Flow Measurement System at Nucla

transport air, and miscellaneous instrument air flows. Only one of the six start-up burner air foils were calibrated. All of these are the same, therefore it was assumed that they would all have the same calibration.

The secondary air fan provides air to the secondary air injection ports and to the front wall coal feeders. The air flow to the secondary air fan is measured manually at the fan inlet by an annubar. Air foils measure the flow of secondary air to each of the combustors (GFT2D & GFT2F). The air foils measure the secondary air including the coal feeder air. Two 100% high pressure blowers supply aeration air to the loop seals. Rotameters measure the air flow to the loop seals. The bed cooler fan provides cooling air to the four bed ash coolers (two for each combustor). Air foil GFT25 measures the total air to all four bed ash coolers. Annubars measure the air flow to the individual ash coolers.

In addition to the air flow calibrations, an air foil is installed at the outlet of the new baghouse to measure the gas flow to that baghouse. This air foil was also calibrated as part of the air flow calibration program.

Air flow calibrations were performed using a Fechheimer probe traversing the ducts. The Fechheimer probe is a air flow measuring device, similar to a pitot tube, that measures not only the velocity of the gas, but also measures the directional component of the flow. Because of the probe's ability to measure the directional component flow, the Fechheimer is considered more appropriate than a pitot tube for this type of application. Two Fechheimer probes of different lengths were used for the air flow calibrations. Both probes were calibrated at the Babcock & Wilcox Instrument Laboratory prior to use at Nucla.

Air flow measurements were performed by measuring the velocity within the duct at several traverse points upstream of the air foil. Sample locations were installed in the ducts to conform to ASME Performance Test Code 4.4. Most of the traverses were performed at three flow rates in a V-notch load ramp, where the gas flow rate was first increased and then decreased. This flow pattern was used to look for any possible hysteresis in the flow elements.

Calibrations were performed both under hot conditions, when the unit was operating, or cold, when the unit was shut down with just the fans operating. The following flow traverse calibrations were made during the reporting period:

- Hot calibration of combustor A windbox flow (GFT1C) at 50% load during plant operation.

- Hot calibrations of lower injection ports for both combustors (GFT1W, GFT1X, GFT1Y, & GFT1Z) at 50% load during plant operation.

- Cold calibrations were performed for the secondary air airfoils GFT2D & GFT2F, and the combustor windbox flows GFT1C & GFT1D.

- Hot calibrations at 40 and 75 percent load for the secondary air airfoils GFT2D & GFT2F, for the combustor A & B windbox flows GFT1C & GFT1D, and for the lower injection nozzles GFT1W, GFT1X, GFT1Y, & GFT1Z.

- Hot calibration of the bottom ash cooling air airfoil, GFT25, at 40, 27, and 53 klb/hr.

- Hot calibration of the new baghouse outlet duct was performed at 40 and 80 percent load.

- Cold calibration of the bottom ash cooling air airfoil, GFT25, at 50, 75, and 100 percent of design flow in a V-notch load ramp.

- Cold calibration of the primary air ducts to the lower air injection ports (GFT1W, GFT1X, GFT1Y, and GFT1Z) at minimum flow, 100 percent design flow, and halfway between minimum and design load in a V-notch ramp.

- Hot calibration of the air duct to start-up burner 4C. This air foil was considered to be representative of all of the start-up burner airfoils. Traverses were performed at approximately 50,75,100,75, and 50 percent of design air flow, in that order. An additional traverse was performed under cold conditions at 15 percent of design air flow. This flow corresponds to the amount of cooling air passing through the burners under normal operations of the boiler.

Based on these calibration runs, constants within the plant control system and the performance calculation package were changed to correspond to the new calibrations. Adjustments were made to the DCS calculations for secondary air readings from both combustors (GFT2D & GFT2F), the windbox primary air flow to both combustors (GFT1C and GFT1D), and the new baghouse outlet gas flow rate. The bottom ash cooling air flow rate, GFT25, was found to read about 30% higher than the calibrated flow rate. However, this flow was not adjusted in the plant distributed control system (DCS) which provides information to the plant operators because it was not considered critical for operations. All air flow calibration correlations will be used to calculate the flow rate of the air streams in the performance calculation package used by the demonstration program. In addition, the air flow inputs to the performance calculation package will be pressure compensated while those on the DCS will not.

A hand-held anemometer was used to measure the cooling air flow to the two cyclone vortex finders during hot operations with the unit at 55 MW. The air flow to each vortex finder was measured to be approximately 3,550 lb/hr. Air flow into the vortex finder is drawn into the cyclones from the boiler house by the negative pressure in the cyclones. A constant value of 7,100 lb/hr will be used for this flow rate in the performance calculations.

Most of the air flow instruments provided for the Nucla CFB are airfoil sensors. Figure 3-2 shows a schematic of an air foil. The configuration shown is typical of large ducts. In smaller ducts, such as the bottom ash cooling air duct, only the center foil is installed. The present installation at Nucla has a ΔP transmitter installed between the total pressure tap and only one of the static pressure taps. There was concern that the use of only one static pressure tap could introduce an unacceptable measurement error due to maldistribution of air flow between both sides of the central foil.

In order to assess the potential error of this installation, a test was performed on the bottom ash cooling airfoil, GFT25. During this test, a manometer was hooked up between the unused static pressure tap and the total pressure tap. Pressure drop readings were taken at four air flow rates. Air flow rate data were also taken from the DCS. Table 3-1 contains the results of this test. The recorded DCS flow rate was used to back-calculate the ΔP reading across the connected pressure taps. The actual flow rate shown in column 6 is based on the flow traverses that were described above and the ΔP in column 2 (the used tap ΔP). These tests were conducted prior to correcting the DCS constants.

The results in Table 3-1 show that there is some error associated with the use of only one static pressure tap. However, the error appears to be systematic and nearly linear. The air flow calculated from the average ΔP (column 5) is only slightly different than that obtained from the used pressure tap, and is not sufficient to account for differences between the indicated flow and actual flow. Nevertheless, since the error is systematic, the use of only one pressure tap with the new air flow calibrations should not introduce any new errors.

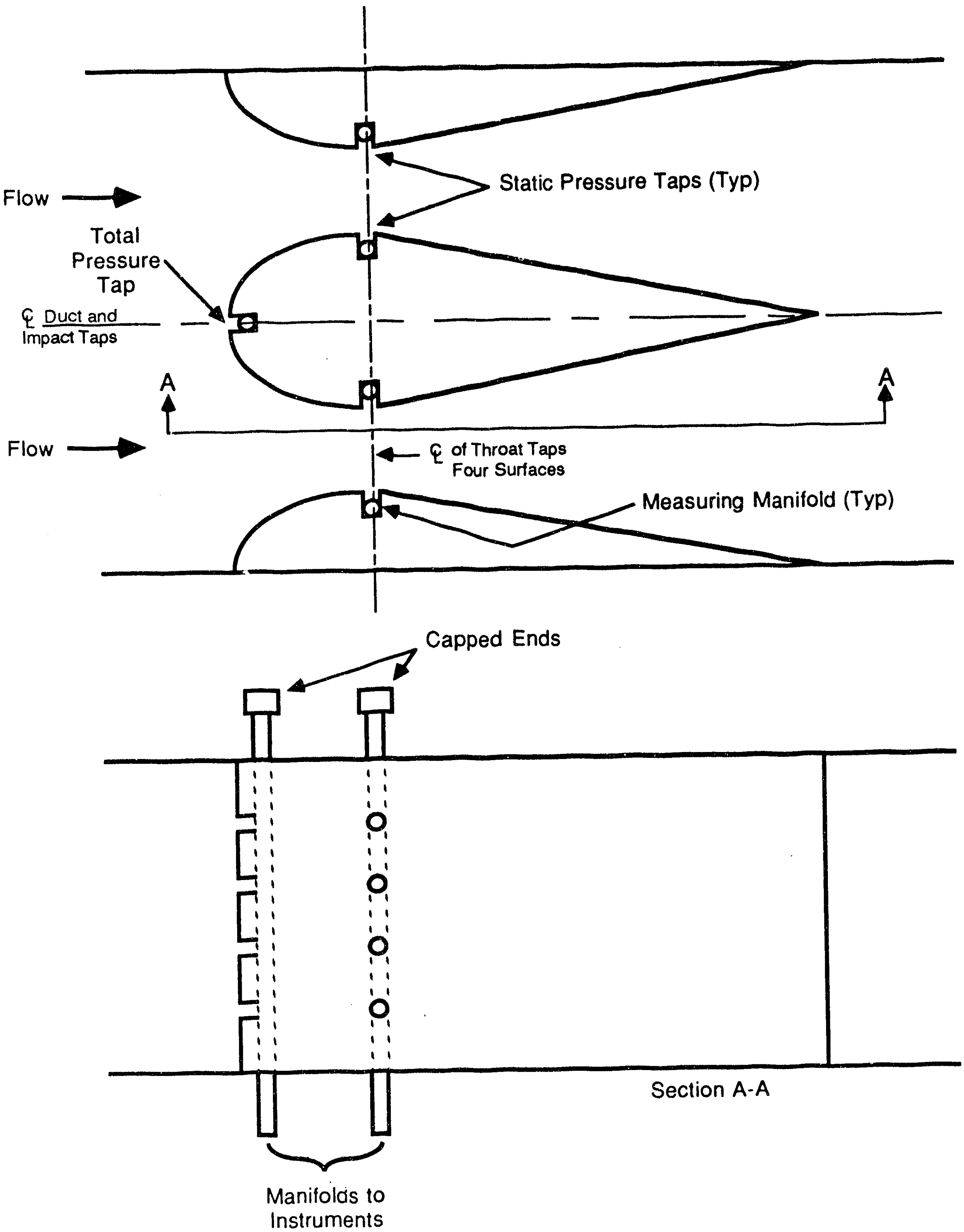


Figure 3-2 Typical Air Foil

Table 3-1

Bottom Ash Cooling Air Flow GFT25
(Airfoil Pressure Differential and Flow Data)

Col. 1 Unused Throat Tap ΔP, in H_2O (Mannometer)	Col. 2 Used[(a)] Throat Tap ΔP, In H_2O	Col. 3 Avg. ΔP In. H_2O	Col. 4 DCS Flow Klb/hr	Col. 5 Air Flow, (from Avg. ΔP) Klb/hr	Col. 6 Actual[(b)] Air Flow Klb/hr
1.31	1.67	1.49	24.1	22.8	20.8
2.70	3.62	3.16	35.6	33.2	29.2
6.90	6.90	6.90	49.1	49.1	43.7
8.65	7.85	8.25	52.4	53.7	46.5

(a) Back calculated from DCS flow rate.
(b) Based on flow traverse correlations and column 2.

3.1.2 Coal Flow Measurements

The coal flow rate is used in several of the performance calculations and is an important input to boiler efficiency and material balances. Analysis of the performance calculations has shown that the coal feed rate should be measured to an accuracy of ±1 percent in order to achieve the desired accuracy of the performance calculations.

The coal feed rate at Nucla is measured using six gravimetric weigh belt feeders. A review of three calibration options available for this type of feeder indicated that calibration using test chains was required to insure this level of accuracy. Subseq'.ently, the demonstration program purchased a calibrated test chain. To facilitate the frequent calibrations required by the test program a large wooden rolling dolly was built to assist installing and removing the test chain from the rear of each coal feeder. Furthermore, a centering device was built to facilitate alignment of the test chain during calibration (see Figure 3-3).

After initial calibration trials, the calibration procedures were modified to the following four step procedure:

- Tare calibration
- Test weight (chain)
- Electronic factoring to the test chain
- Electronic calibration with an applied voltage.

This procedure will be employed monthly during the demonstration program. Drift data from the calibrations of the coal feeders will be used to establish the measurement bias of the coal feeders.

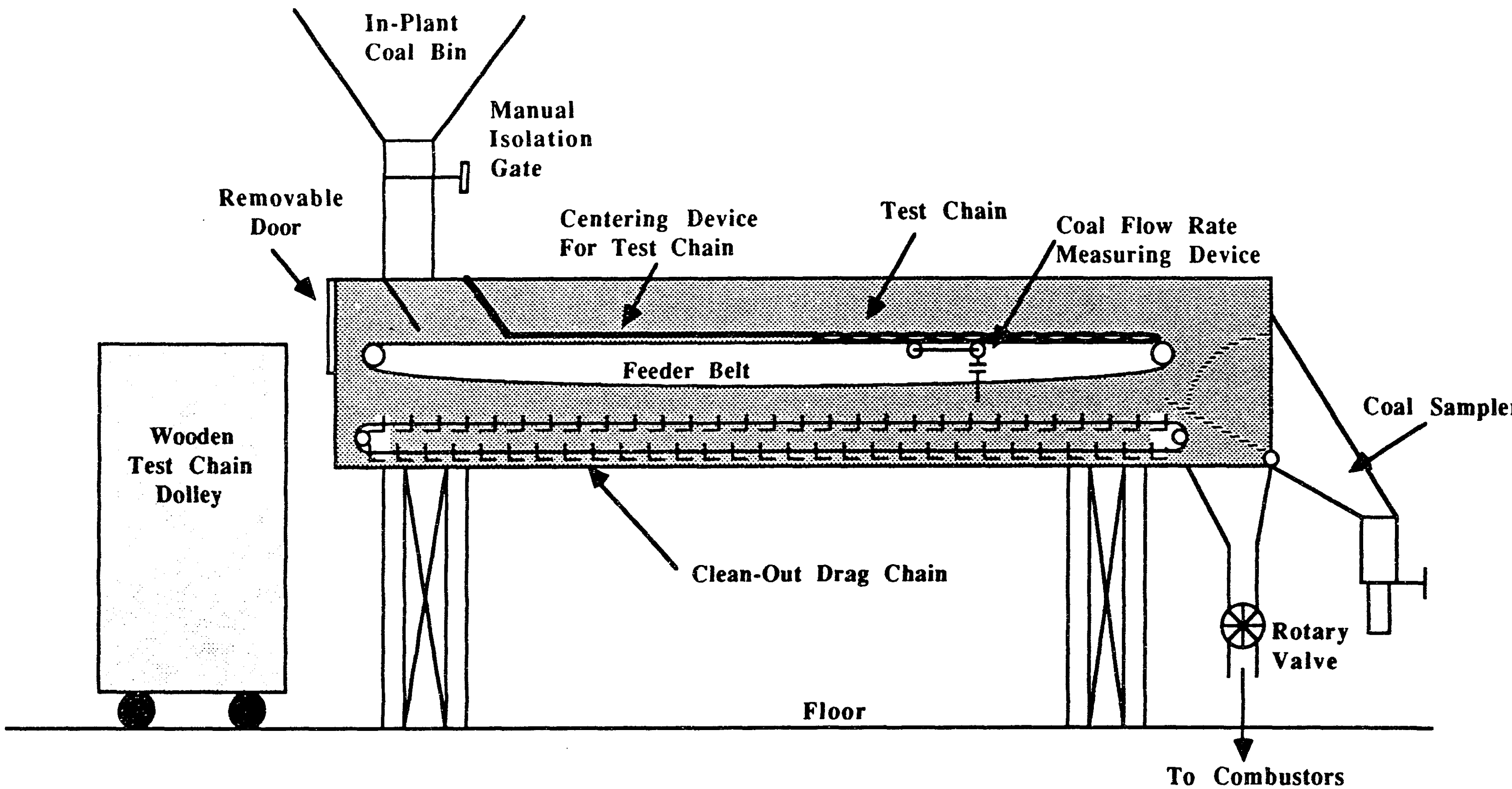


Figure 3-3. Schematic of Coal Feeder and Load Cell Calibration Equipment.

3.1.3 Limestone Feeder Calibration

The limestone feed rate at Nucla is regulated by a variable-speed eccentric shaker that feeds limestone over a vibrating cone through an adjustable gap formed by sector plates. The flow rate is measured by a loss-in-weight system that uses load cells mounted on the hopper above the shaker cone. The weight change from two successive readings is divided by the time between the readings to produce the feed rate.

To calibrate the limestone feeders, weigh chains are hung onto the hoppers and the output signal of the load cells is adjusted to match the weight gain. A length of ship anchor chain was purchased and cut into lengths that could be handled by a technician. These chains were then weighed and tagged. Hangers were also installed onto the four legs of the limestone hoppers to hold the test chains (see Figure 3-4).

After repeated efforts to correct various malfunctions in the weigh system, a final calibration confirmation was performed during June and July, 1988. Table 3-2 shows the results of these calibration runs. The calibrations showed that the limestone feeder for combustor B was more accurate than for combustor A. The average error for A feeder is 16 pounds and for B feeder is 4.5 pounds. When compared to the capacity of the load cells, these errors correspond to a 0.5% error for A feeder and a 0.2% error for B feeder, which is within the accuracy limits required for the demonstration program of ± 1%.

Limestone calibrations will be performed monthly during the demonstration program. Drift errors recorded during these monthly calibrations will be used used to establish the measurement biases for the limestone feeders.

Table 3-2

LIMESTONE WEIGH FEEDER CALIBRATION

A Feeder June 30, 1988

Chains	Weigh Hopper Weight Reading	Actual Weight Added	|Difference|	Error %
0	0 Bouncing*	0	0	-
4	353	374	21	5.6
0	0 Steady*	0	0	-
4	350	374	24	6.4
8	693	705	12	1.7
4	347	366	19	5.2
0	13	0	13	-

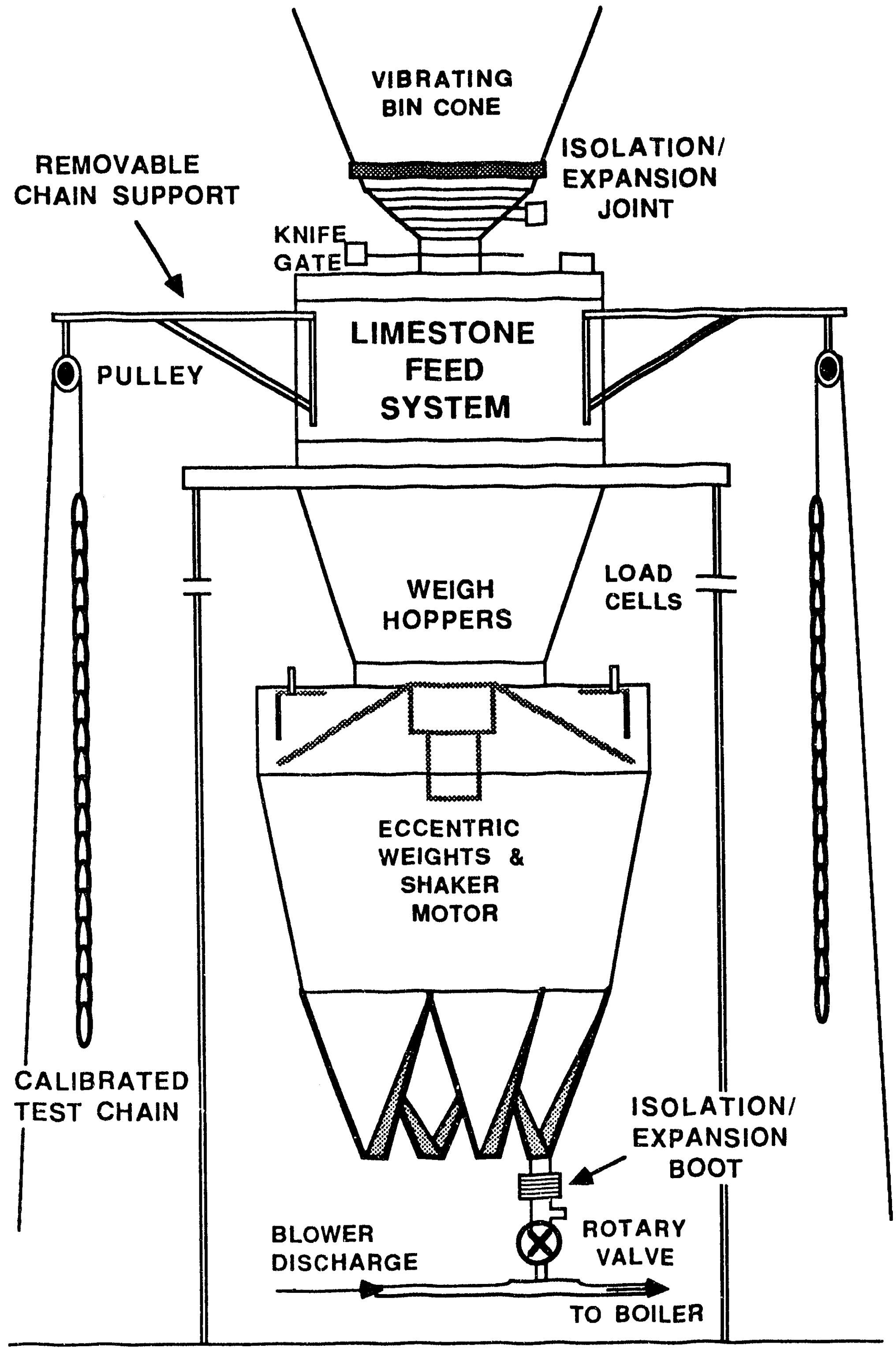


Figure 3-4. Limestone Feeder Load Cell Calibration Hardware.

Table 3-2 (Continued)

LIMESTONE WEIGH FEEDER CALIBRATION

B Feeder July 5, 1988

Chains	Weigh Hopper Weight Reading	Actual Weight Added	|Difference|	Error %
0	0.6	0	0.6	-
4	364	363	1	0.3
0	0 Bouncing*	0	0	-
4	356	363	7	1.9
8	700	705	5	0.7
4	354	363	9	2.5
0	0 Steady*	0	0	-

* Weigh Hopper does not seem to register negative weights.

3.1.4 Bottom Ash Weigh Bin Calibration

The bottom ash flow rate is measured by using a weigh bin that receives bed material from both bed drain coolers on a combustor. The weigh bin fills with bed material to a pre-set weight and then begins an emptying cycle down to a pre set level. The weight of ash is determined starting at the time when the emptying cycle is complete. The weight of the ash added during the fill cycle is measured every 15 minutes until the high level is reached and the emptying cycle begins. The total weight added and the total time between cycles is used to calculate the average bed drain rate for a performance test.

Calibration of the bed drain weigh bin involves checking the accuracy of the load cells in a similar fashion to the limestone feeders. Chains, weighing a total of 1,648 lbs, were added to each hopper when it was filled with three different quantities of bed material (see Figure 3-5). The weight gain on the hopper was recorded, then the chains were removed and the weight recorded again. This process was repeated at least two times at each level of bed material. Table 3-3 shows the results of this calibration procedure. The average error on the weight readings for A hopper was 16 pounds, and the average error on the weight readings for B hopper was 19 pounds. These errors correspond to less than 0.3% of the full scale reading for each hopper.

The bottom ash weigh hopper will be calibrated on a monthly basis during the demonstration program. Drift errors in the weight readings will be used to establish the instrument biases for these two weight measurement devices.

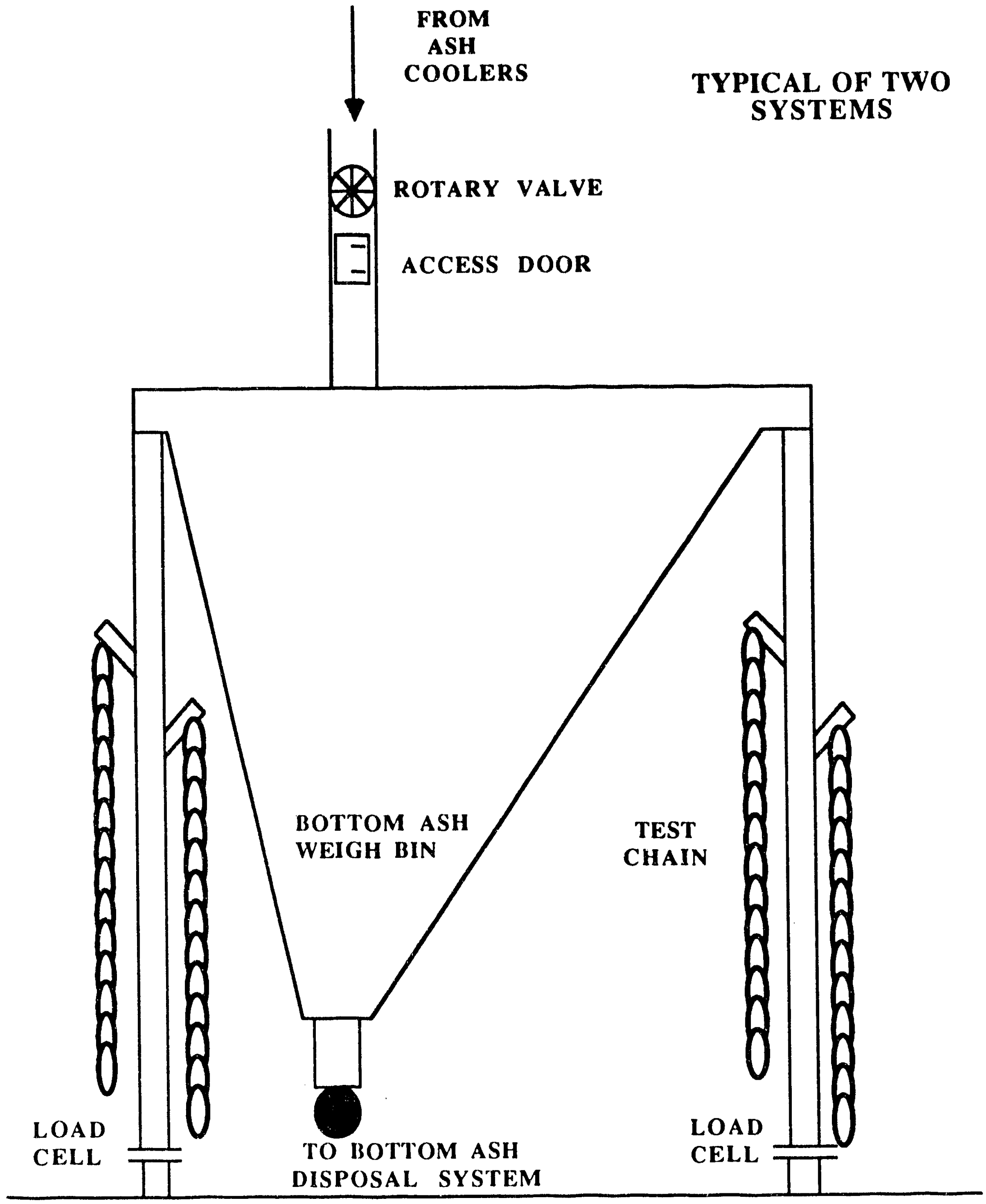


Figure 3-5. Schematic of Calibration Hardware for Bottom Ash Weigh Bin

Table 3-3

BOTTOM ASH HOPPER CALIBRATION DATA

A hopper April 22, 1988

Initial Weight	Weight After Chains Added or Removed	Weight Gain	|Difference|	% Error
480	2110	1630	18	1.09
2110	480	-1630	18	1.09
480	2130	1650	2	0.12
2130	480	-1650	2	0.12
Hopper Filled to 2100 lbs With Bed Material				
2100	3750	1650	2	0.12
3750	2065	-1685	37	2.25
2065	3750	1685	38	2.25
3750	2080	-1670	22	1.33
Hopper Filled to 3620 lbs With Bed Material				
3620	5280	1660	12	0.73
5280	3650	-1630	18	1.09
3650	5300	1650	2	0.12
5300	3650	-1650	2	0.12
Hopper Filled to 5340 lbs With Bed Material				
5304	7010	1670	22	1.33
7010	5340	-1670	22	1.33
5340	7010	1670	22	1.33

B Hopper February 22, 1988

Initial Weight	Weight After Chains Added or Removed	Weight Gain	|Difference|	% Error
-67	1630	1697	49	2.97
1630	-67	-1697	49	2.97
-67	1580	1647	1	0.06
1580	-67	-1647	1	0.06
Hopper Filled to 1550 lbs With Bed Material				
1550	3245	1695	47	2.85
3245	1600	-1645	3	0.18
1600	3260	1660	12	0.73
3260	1610	-1650	2	0.12
Hopper Filled to 3195 lbs With Bed Material				
3195	4895	1700	52	3.16
4895	3230	-1665	17	1.03
3230	4910	1680	32	1.94
4910	3245	1665	17	1.03
Hopper Filled to 4740 lbs With Bed Material				
4740	6390	1650	2	0.12
6390	4740	-1650	2	0.12
4740	6390	1650	2	0.12

3.1.5 Fly Ash Flow Measurement

During the reporting period, the fly ash metering system was modified extensively in an effort to obtain an accurate measurement of the flow rate and a representative sample of fly ash. Figure 3-6 shows a schematic of the fly ash system at Nucla following modifications. The problem with measurement of the flow rate and with the representativeness of the sample stems from the fact that fly ash is collected at 34 separate locations throughout the plant. The air heater and economizer each have two hoppers that collect fly ash. The new baghouse has 12 hoppers and baghouses 1, 2, and 3 each have six hoppers that collect fly ash. Each of these hoppers is equipped with a gate valve that periodically dumps fly ash into a vacuum ash transport system where it is delivered to the fly ash weigh bin. The hoppers are sequentially emptied into the vacuum ash transport system.

Experience has shown that the composition and quantity of ash collected in each of the ash hoppers differs sufficiently, such that none of the hoppers are representative of all of the fly ash. Therefore, a full-cut sampler was installed to continuously sample the fly ash leaving the weigh bin.

The fly ash flow rate meter is a Schenck impact flow meter. This meter measures the flow rate of fly ash that hits a deflector plate as it falls out of the fly ash weigh bin. Numerous attempts to obtain a reliable calibration of the fly ash flow meter failed to produce a reliable and repeatable signal.

In order to overcome the difficulties in obtaining a fly ash flow rate, an alternative method of calculating the flow rate was developed. The calculation involves an inerts balance around the boiler. Inerts are defined as all constituents except CO_2 and SO_3 in the limestone, coal ash, bottom ash, and fly ash. Inerts enter the boiler through the coal stream and the limestone stream.

Inerts In

$$\text{Coal inerts, lb/hr} = \frac{CI}{100} \times \text{coal flow}$$

$$\text{Limestone inerts, lb/hr} = \frac{LI}{100} \times \text{limestone flow}$$

Where: CI = % ash, as-fired coal
$LI = 100 - CO2_l$
$CO2_l$ = % CO_2 in limestone

Inerts leave the boiler via the bed ash stream and the fly ash stream.

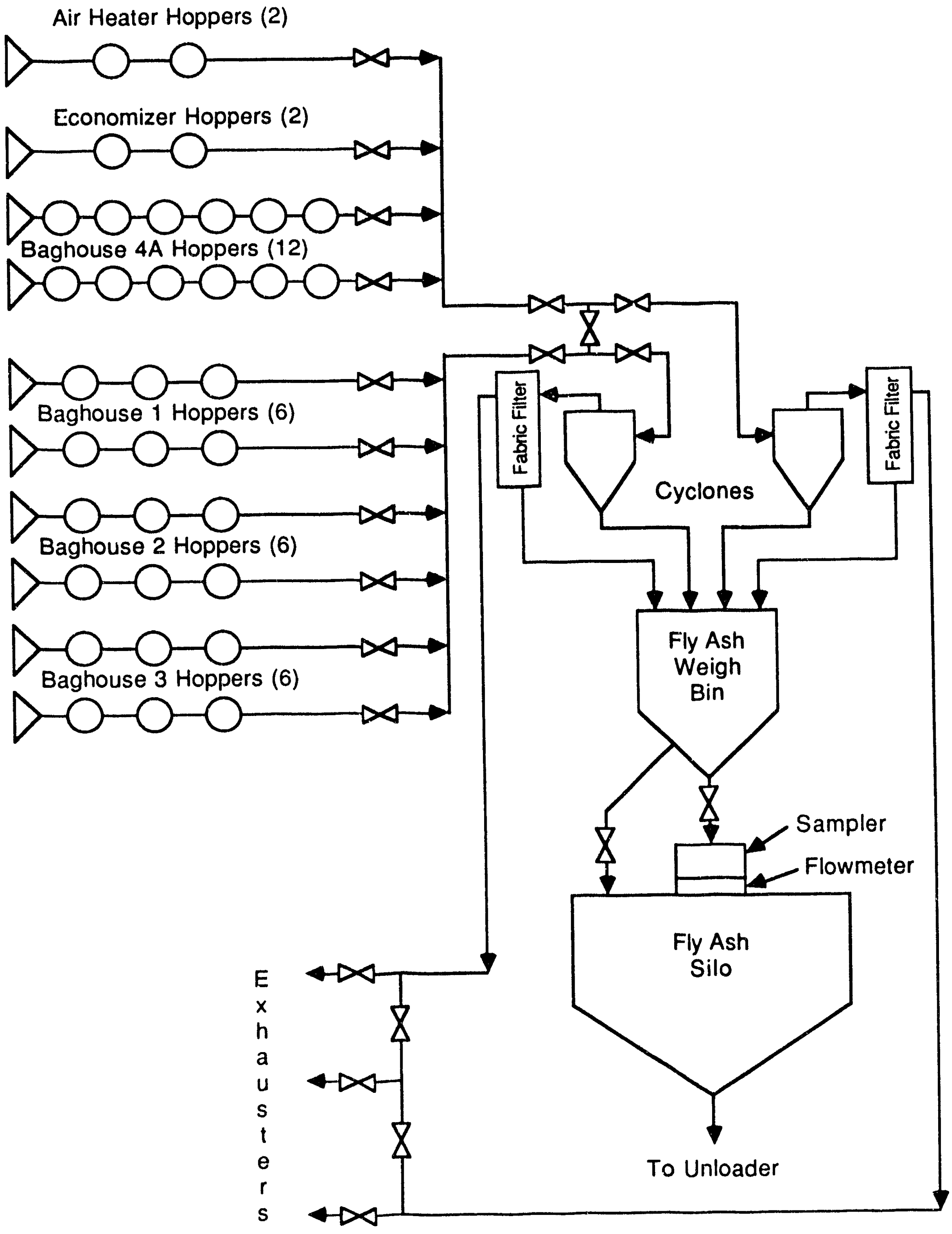


Figure 3-6. Schematic of Revised Fly Ash Collection and Measurement System

Inerts Out

$$\text{Bottom ash inerts, lb/hr} = \frac{BI}{100} \times \text{bottom ash flow}$$

Fly ash inerts, lb/hr = coal inerts + limestone inerts - bottom ash inerts

$$\text{Fly ash flow rate, lb/hr} = 100 \times \frac{\text{fly ash inerts}}{FAI}$$

Where: $BI = 100 - CO2_b - \frac{80}{32} S_b - (C_b - \frac{12}{44} CO2_b)$

$FAI = 100 - CO2_{fa} - \frac{80}{32} S_{fa} - (C_{fa} - \frac{12}{44} CO2_{fa})$

$CO2_{b,fa}$ = % CO_2 in bed ash or fly ash

$S_{b,fa}$ = % Sulfur in bed ash or fly ash

$C_{b,fa}$ = % Carbon in bed ash or fly ash

Note that the carbon in the bed material and fly ash is reported as total carbon and includes carbon contained as CO_2.

This calculation procedure has been incorporated into the performance calculations. The uncertainty analysis performed during the hot mode shakedown tests showed that the above equations gave a satisfactory estimate of the fly ash flow rate with no compromise to the accuracy of the performance calculations.

3.1.6 Test Instrumentation

A detailed list of all of the instrumentation required by the demonstration program was developed during the reporting period. This list included all instrumentation needed for steady-state performance tests and for dynamic load following tests. Included in the list is the required accuracy for each instrument, the calibration schedule for that instrument, the measurement range, and the last calibration date. Appendix A contains a copy of the instrumentation calibration schedule.

In developing the calibration schedule, consideration was given to the contribution of a particular instrument to calculated results uncertainties in the performance calculation package.

The calibration data from the instruments will also provide an estimate of the instrument bias, which is used in the performance calculation software to calculate the final results uncertainties. The instrument drift between calibration periods will be averaged on a sum squared basis to determine the average drift of the instrument. Once sufficient calibrations are performed to verify the average drift, this value will be substituted for the instrument bias that is originally based on manufacturers' specification data.

3.2 SYSTEM COMMISSIONING

As a prelude to the demonstration program, several specialized sampling systems were developed and/or commissioned. Isokinetic sampling probes were needed to measure the baghouse inlet and outlet dust loadings as part of the baghouse monitoring program. Freeboard gas analysis probes were required to sample the flue gas at various points within the combustor as part of the solids and gas mixing test plan. A gas analysis system was required to analyze flue gas for oxygen, carbon dioxide, NO_x, sulfur dioxide, and carbon monoxide at the exit of the control boundary used in the performance calculations to calculate boiler efficiency. Several systems were developed to sample the various solid streams in the plant to insure that representative samples were obtained. A sample preparation laboratory was established to process the samples prior to off-site analysis. Finally, the VAX computer was commissioned and software was developed in support of the demonstration program. This section documents the commissioning of these systems for the demonstration program, and provides details of each system.

3.2.1 Sampling Probes

The demonstration program utilizes three specialized sample systems to test either the solids loading or the chemical composition of the flue gas. These three systems are:

- Isokinetic sampling probes to periodically measure the solids loading in the flue gas.
- Freeboard Gas Analysis System (FGAS) probes to periodically measure the gas composition in the freeboard of the combustor.
- Economizer Exit Gas Analysis System (EGAS) probes to continuously measure the flue gas concentrations at the economizer exit.

During the reporting period all three systems were designed, procured, and placed into service.

3.2.1.1 Isokinetic Sampling Probes

The isokinetic sampling probes were used to measure the dust loading at the inlet and outlet of the baghouse. At the baghouse inlet, the dust loading was expected to be quite high (on the order of 10 to 12 gr/dscf). Two filtration options were evaluated for the isokinetic sampling probes: 1) an in-duct filtration method, and 2) an external filtration method. The in-duct filtration method is simpler to operate and less expensive. However, there was some concern that this type of probe would be subject to plugging due to the high dust loadings. In order to evaluate the applicability of this option, an in-duct filtration probe was obtained on loan from Radian Corporation for trial tests.

The sampling tests have shown that in-duct filtration performs satisfactorily without plugging for a substantial portion of the expected test duration. Accordingly, a complete sampling train was purchased for the demonstration program. The train consisted of the following equipment:

- 1 sampling console
- 1 sample pump
- 1 umbilical cord
- 3 stainless steel condensers
- 1 sample probe
- 2 thimble filter holders
- 1 Gelman filter holder
- 4 nozzles

Figure 3-7 shows a schematic of the isokinetic sampling train.

Two plant technicians are being trained to operate the sampling equipment and to perform the isokinetic sampling. Once training is complete, the sampling team will be subjected to a detailed audit of their procedures and techniques.

3.2.1.2 Freeboard Gas Analysis System (FGAS)

The FGAS probe is designed to sample the gas composition across two traverse planes inside combustor B at elevations 44'6" or 86'6". Gas sampling is possible from near the outside wall to the centerline of the combustion chamber, for a total traverse distance of 10'2". The probes are water-cooled and were originally developed by TVA and EPRI for use in the analysis of a bubbling bed combustor freeboard. The current probe has been modified to incorporate site specific conditions of the Nucla CFB, particularly the higher dust loadings.

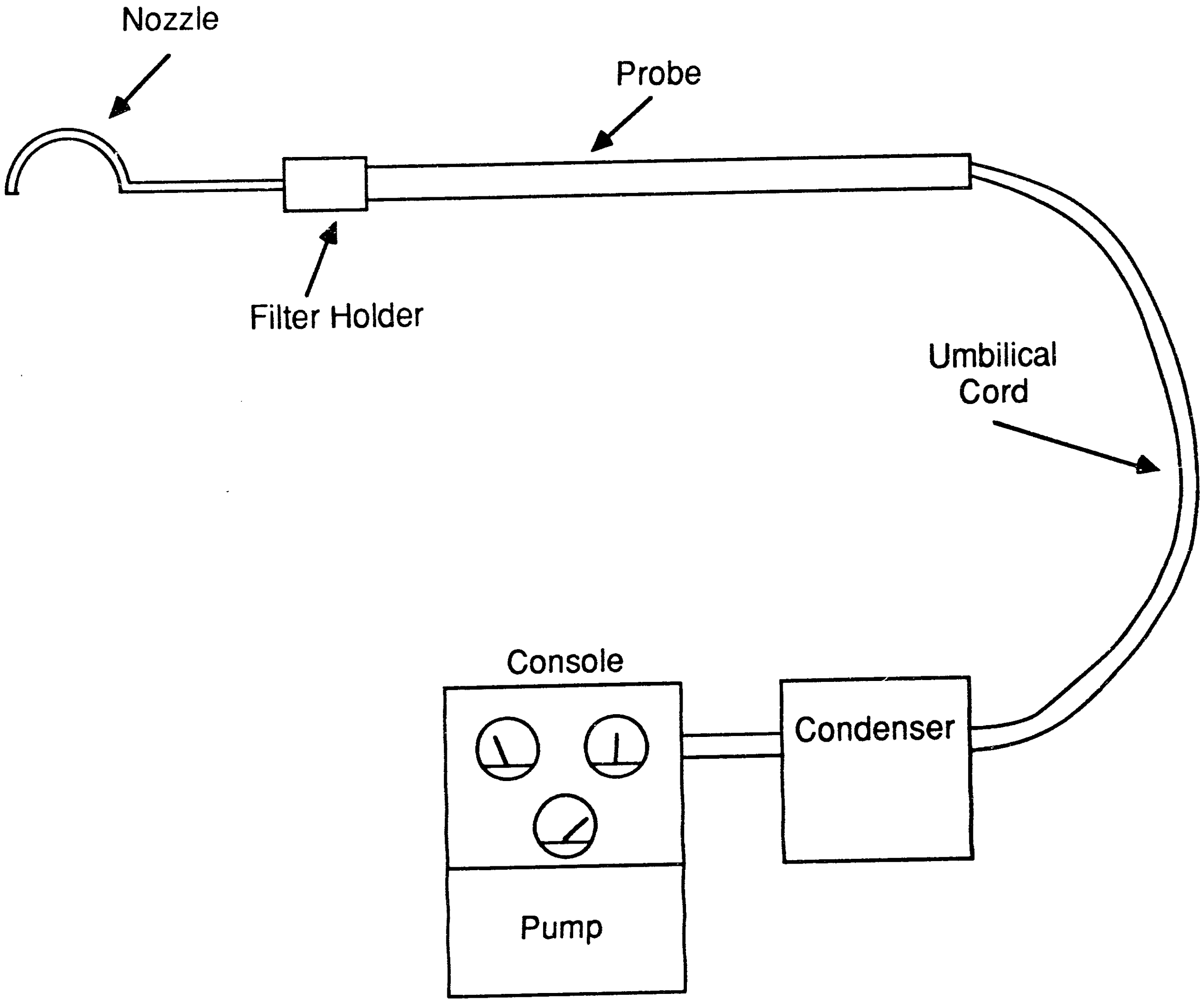


Figure 3-7. Isokinetic Sample Probe

The probe is has a water-cooled outside shell and an electrically heated gas sample tube which is connected to the gas analyzers (described in section 3.2.2) via a heated sample line. Suction is provided by the gas sample pump in the gas analyzer cabinet and pulls the combustion gasses from the combustion chamber. An air aspirated knife gate isolates the penetration through the waterwalls at the two locations.

In operation, the combustion gasses first pass through an unheated quench tube where the gas temperature is reduced to less than 400 °F, the maximum operating temperature of the sample line. The electrically heated sample line then maintains the sample temperature above the acid dew point of the gas (set point is 350 °F) to minimize condensation and corrosion of the sample line. The gas is sampled at a flow rate of approximately 7 liters/min. The sample passes through a cyclone separator and a fabric filter to remove any entrained solids. Both filters are contained within a heated cabinet. The gas sample then passes through another heated sample line to the gas analyzers.

A cooling water flow rate of between five and twenty gpm is required to maintain internal temperatures below 175 °F. Seven thermocouples are included in the system to allow the sampling team to monitor the operating conditions inside the probe. Cooling water passes through the length of the probe and returns to the outlet nozzle before being disposed of in the plant drain system. Water flow control is maintained by a manual control valve on the cooling water inlet line.

Initial use of the FGAS probes met with some difficulty due to plugging of the probe. This was traced to two separate causes. The first was a buildup of particles in the diaphragm valve located in the sample line. This was resolved by moving the valve downstream of the cyclone separator where the particulates are significantly lower. The second problem was caused by blockage of the line by a single large particle. This was solved by adding an orifice at the inlet and by replacing some of the teflon tubing with stainless tubing. With these modifications, the FGAS probe was capable of operating for over two hours without plugging, which is the time needed to complete a traverse.

3.2.1.3 Economizer Exit Gas Analysis System (EGAS)

The economizer exit gas sample is an average of sixteen sample points which are mechanically interconnected in a heated valve averaging enclosure which is located between the two inlet ducts to the tubular air heater at an elevation of 94' (see Figure 3-8). The two inlet ducts to the air heater are divided into eight 2' x 4' grids with a gas sample point

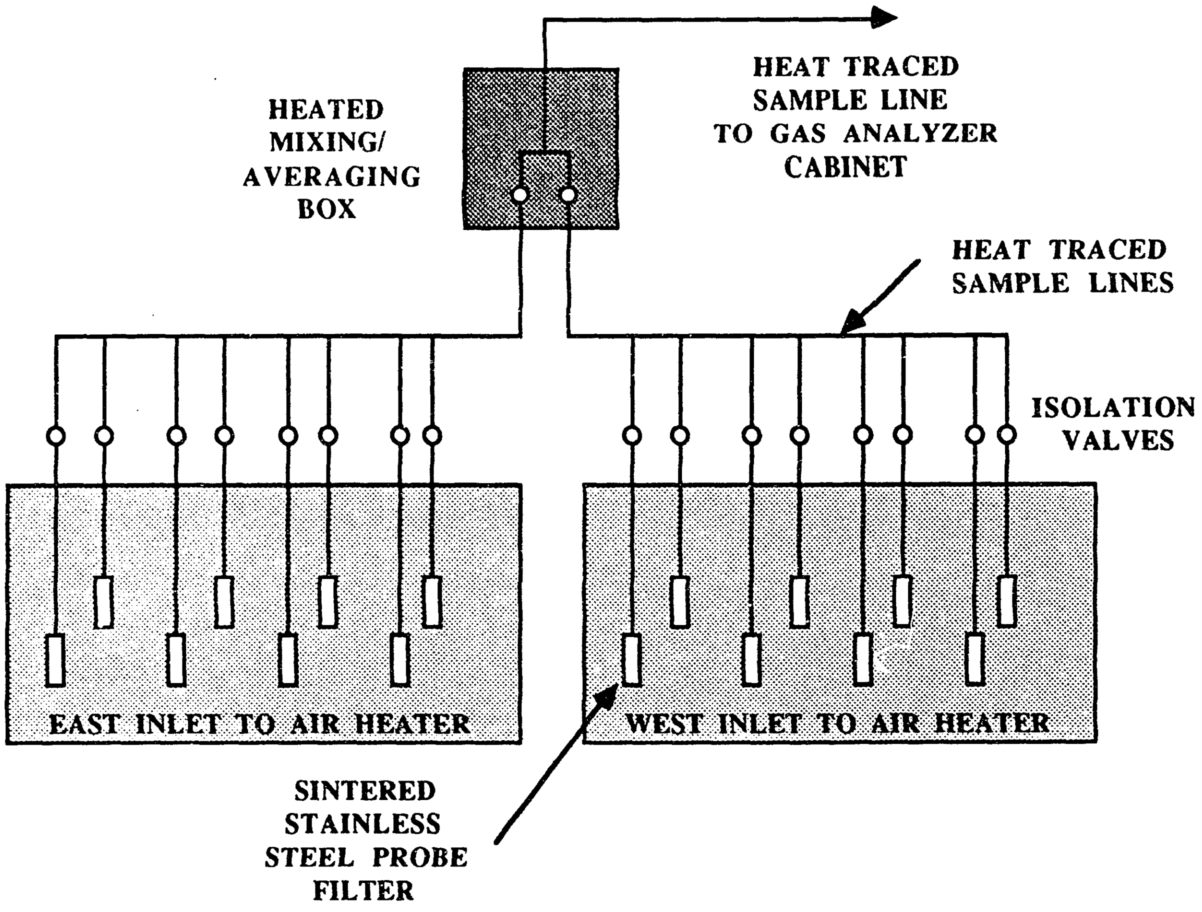


Figure 3-8. Schematic of EGAS Sampling System at Air Heater Inlet

located in the center of each grid. The samples are withdrawn by heated lines that terminate in the sample averaging cabinet. The EGAS averaging cabinet, and all of the sample lines, are heated to prevent acid dew point formation in the sample train. A single heat-traced line carries the gas sample to the gas analyzers.

Gas sample flow rates through each of the 16 probes are equalized by matching the vacuum on each sample line with a Hastelloy needle valve. The system also allows any individual probe, or any combination of probes to be sampled.

Each of the sixteen gas sample points also has a thermocouple installed next to the sample probe. The eight temperatures in each duct are averaged locally in a thermocouple averaging box. The two averages are available as separate values on the DCS. The outlet of the tubular air heater contains eighteen thermocouples arrayed in a similar configuration to the inlet temperature grid. The two average temperatures are also available on the DCS.

3.2.2 Gas Analyzers

The gas analyzer equipment is located at elevation 24' on the turbine deck. The equipment includes a gas conditioning cabinet, and an air conditioned cabinet that contains the gas analyzers and a six pen strip chart recorder. An electrical output signal from each analyzer corresponding to the gas concentration is sent to the DCS. The strip chart recorder also displays the outputs from the analyzers. Other output signals are available for alarms and range settings of the various analyzers. The gas analyzers used in this installation are listed below along with their measurement method. The instruments are listed for the purposes of providing complete information regarding the test program and do not necessarily represent an endorsement of this equipment by CUEA or the DOE.

- Oxygen
  Beckman Industrial Corporation Model 755
  Paramagnetic measurement system.

- Carbon Monoxide and Carbon Dioxide
  Beckman Industrial Corporation Model 864
  Infrared absorption measurement system.

- NO_x
  Beckman Industrial Corporation Model 951A
  Chemiluminescence measurement system.

- Sulfur Dioxide
  Western Research Model 721A
  Energy absorption by a sample cell.

Calibration of the gas analyzers is performed by flowing premixed calibration gasses through the sample system at regular intervals. The calibration gasses are stored in high pressure cylinders and connected to the analyzers by a manifold provided with the equipment. Five gas cylinders are required to store all of the required gas mixtures. Table 3-4 lists the calibration gas mixtures.

3.2.3 Solid Sampling System

For the performance calculations, all of the solid streams entering the boiler and leaving the boiler need to be sampled and analyzed. In order to sample these streams either full-cut or full-cross sampling devices are used. Each of the sampling devices will be discussed below.

Table 3-4. E/FGAS Analyzer Calibration Gasses

Bottle	Gas	Range
1	N_2 for zero reference	N_2 >99.8%
2	Low span O_2, CO, CO_2	O_2 8% CO 400 ppm CO_2 4% Balance N_2
3	High span O_2, CO, CO_2	O_2 20% CO 4000 ppm CO_2 16% Balance N2
4	Low span SO_2, NO_x	SO_2 400 ppm NO_x 400 ppm Balance N_2
5	High span SO_2, NO_x	SO_2 1200 ppm NO_x 800 ppm Balance N_2

The coal is sampled using full cut flow diverters installed on each of the six weigh belt feeders. Initial operation of the full cut diverter sampler had some problems associated with fine accumulation in the sample line and with fine loss due to the dust suppression system. These problems were solved by the addition of close clearance seals on the sample valve, and an air actuated damper on the dust suppression vacuum line to isolate the feeder being sampled.

Limestone is sampled using two thief samplers that withdraw a sample from the limestone weigh bins. The sample point was originally located near the bottom of the weigh bins. However, problems with pressurization of the weigh bins caused severe leakage of air and dust past the thief probes. The sample points were subsequently relocated near the top of the weigh bins.

Bed ash is sampled using thief probes located below each of the four bottom ash coolers. No major problems were experienced with these sample points. The fly ash sampler was described in Section 3.1.5 of this report. The continuous sampler has been found to give a reliable, representative sample of the fly ash.

3.2.4 Sample Preparation Laboratory

In order to measure the performance of a fluidized bed boiler, a number of solid samples need to be taken during the performance tests. These samples include:

- Coal
- Limestone
- Bed ash
- Fly ash

Section 3.2.3 described the manner in which the solid samples are withdrawn from the boiler during the performance tests. In this section, the steps taken to prepare and analyze the solid samples will be discussed.

In order to minimize the cost of the sample laboratory at Nucla, it was decided that most of the chemical analyses required by the performance calculations would be performed at an off-site laboratory. Nevertheless, several steps were needed to insure that a representative sample reached the chemical laboratory. Table 3-5 lists the chemical and physical analyses required by the performance calculations. The sample preparation laboratory at Nucla performs the analyses for:

- Size distribution
- Air dry moisture
- Bulk density
- Particle density
- Sulfur

The remainder of the analyses listed in Table 3-5 are performed by an outside analytical laboratory. Sulfur is also determined by the outside laboratory.

Table 3-5
Chemical and Physical Analyses Required by the Test Program

AS FIRED PROPERTIES	Coal	Sorbent	Fly Ash	Bed Drain
HHV (BTU/lb)	xxxxx.x			
Total Moisture (%)	xx.xx	xx.xx		
Air Dry Loss (%)	xx.xx			
Bulk Density (g/cc)	x.xx			
Volatiles (%)	xx.xx			
Fixed Carbon (%)	xx.xx			
Ash (%)	xx.xx			
Carbon (%)	x.xx		x.xx	x.xx
Hydrogen (%)	x.xx	x.xx	x.xx	x.xx
Oxygen (%)	x.xx			
Nitrogen (%)	x.xx			
Sulfur (%)	x.xx	x.xx	x.xx	x.xx
Calcium (%)	x.xx	x.xx	x.xx	x.xx
Magnesium (%)	x.xx	x.xx	x.xx	x.xx
Iron (%)	x.xx	x.xx	x.xx	x.xx
CO_2 (%)		x.xx	x.xx	x.xx

3.2.4.1 Coal Preparation

Figure 3-9 shows the coal preparation flow sheet. Coal is sampled from the six coal feeders at Nucla. Approximately 5 gallons of coal is sampled from each feeder. All six samples taken at the same time are composited to form one coal sample for the test period. The sample is then riffled down to form a 20 pound analytical sample and a 5 pound physical analysis sample.

The 20 pound analytical sample is crushed to minus 30 mesh. Five pounds of this sample is then allowed to air dry at 40 °C for six hours. Next the air dried analytical sample is riffled and one quart is stored in a sealed, labeled container as an archive sample. The remaining 200-300 grams is pulverized to minus 200 mesh and blended. A small amount of this sample is analyzed in a Leco sulfur analyzer. The remainder of the sample is shipped to the analytical laboratory in a sealed container.

The five pound physical analysis sample is weighed and air dried for 6 hours at 40 °C. The air dried sample is then reweighed and the air dry moisture is determined. Next the sample is riffled to give a 70 gram sample that is analyzed for size distribution and a 300 gram sample that is used for bulk and particle density determinations.

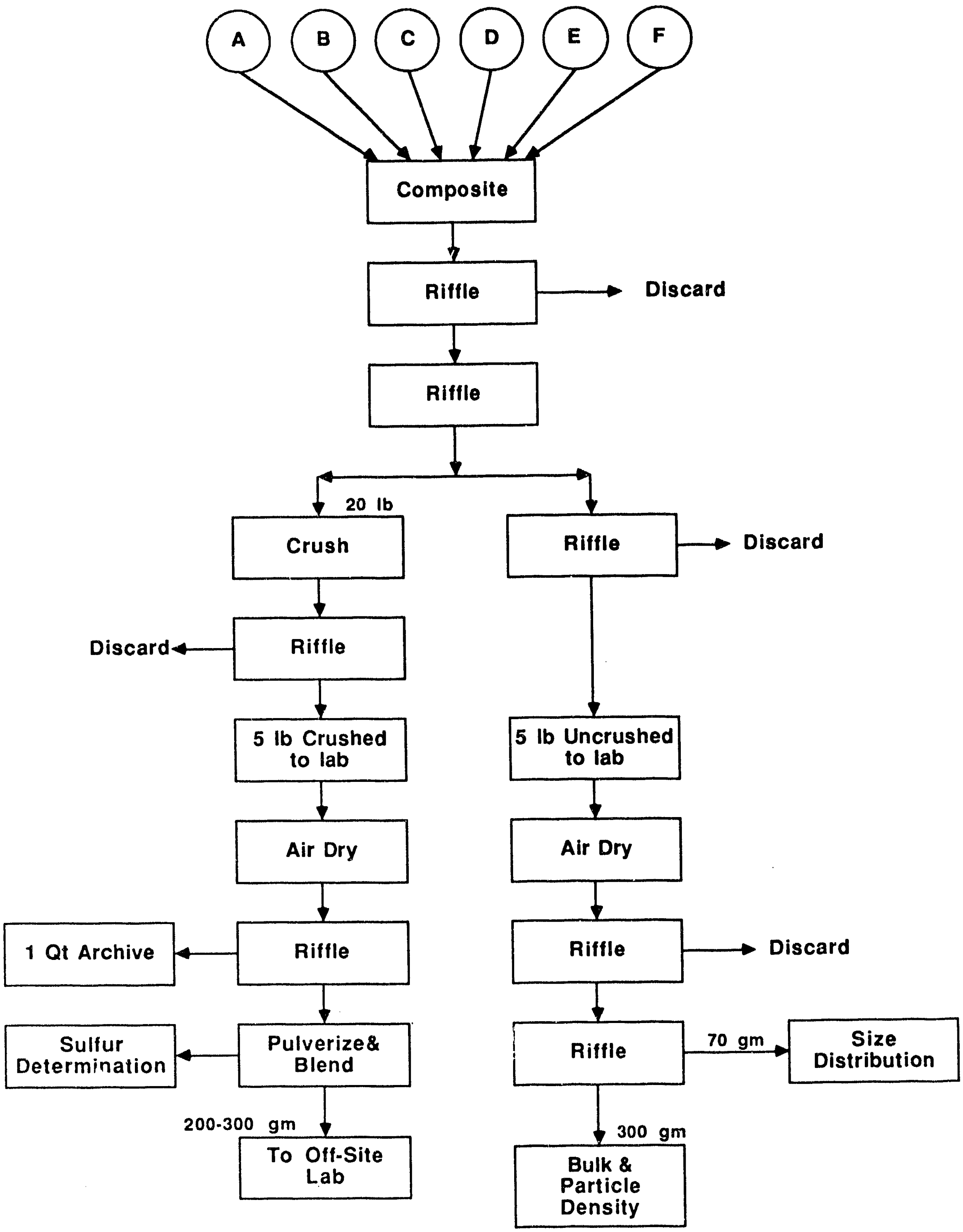


Figure 3-9. Coal Preparation Flow Sheet

3.2.4.2 Limestone Preparation

Figure 3-10 shows the flow sheet for the laboratory preparation of the limestone sample. Approximately five pounds of limestone are withdrawn from each of the two limestone feeders using a thief probe. These two samples are composited to give the limestone gross composite sample for the time period. The ten pound sample is then oven dried to determine the total moisture of the limestone.

Next the limestone sample is passed through a series of riffles to produce a 1 quart archive sample, a 300 gr sample for particle and bulk density determination, a 70 gram sample for size distribution analysis, and a 200 to 300 gram analytical sample. The analytical sample is pulverized to minus 200 mesh, blended, and sent to the outside laboratory for analysis.

3.2.4.3 Bottom Ash Preparation

Figure 3-11 shows the flow sheet for the preparation of the bottom ash sample. Five pound samples are withdrawn from each of the four bed ash discharge points using thief probes. These four samples are composited to form the gross composite bottom ash sample for the sampling period. The gross composite sample is riffled to give about 400 grams of material for the physical analyses. The remainder of the bottom ash sample is crushed to minus 30 mesh. The crushed sample is then riffled to yield a 1 quart archive sample and a 200-300 gram analytical sample. The 200-300 gram analytical sample is pulverized to minus 200 mesh. Some of this material is analyzed in the Leco sulfur analyzer at Nucla, and the rest is sent off site for chemical analysis.

3.2.4.4 Fly Ash Preparation

Figure 3-12 shows the flow sheet for the preparation of the fly ash sample. A single fly ash sample is obtained from the continuous fly ash sampler during a sample time period. This sample is riffled to yield a 1 quart archive sample, a 300 gram sample for bulk and particle density determination, and a 200-300 gram analytical sample. The analytical sample is pulverized to minus 200 mesh. Part of this sample is analyzed in the Leco sulfur analyzer at Nucla. The remainder is sent to the off-site laboratory for chemical analysis.

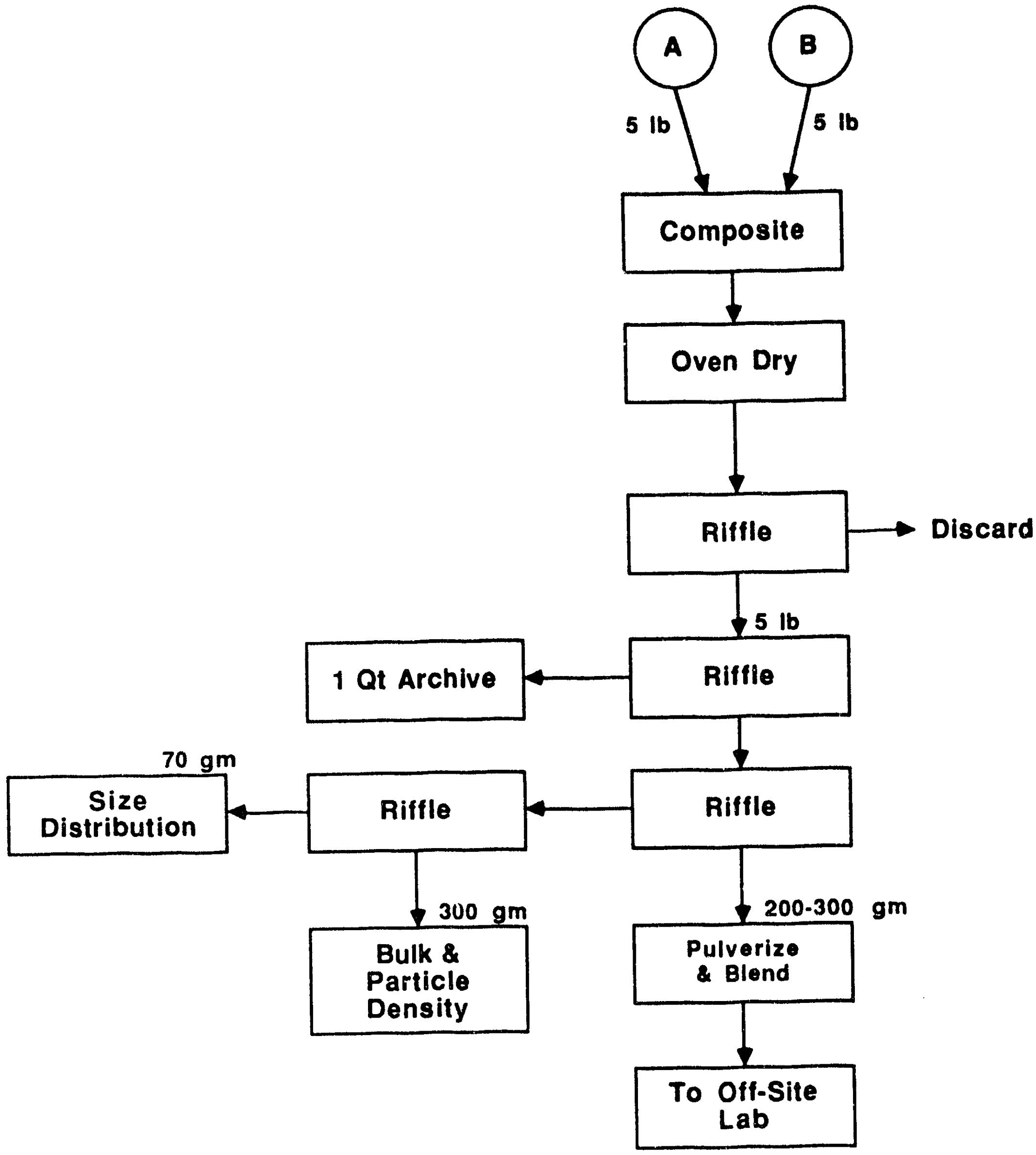


Figure 3-10. Limestone Preparation Flow Sheet

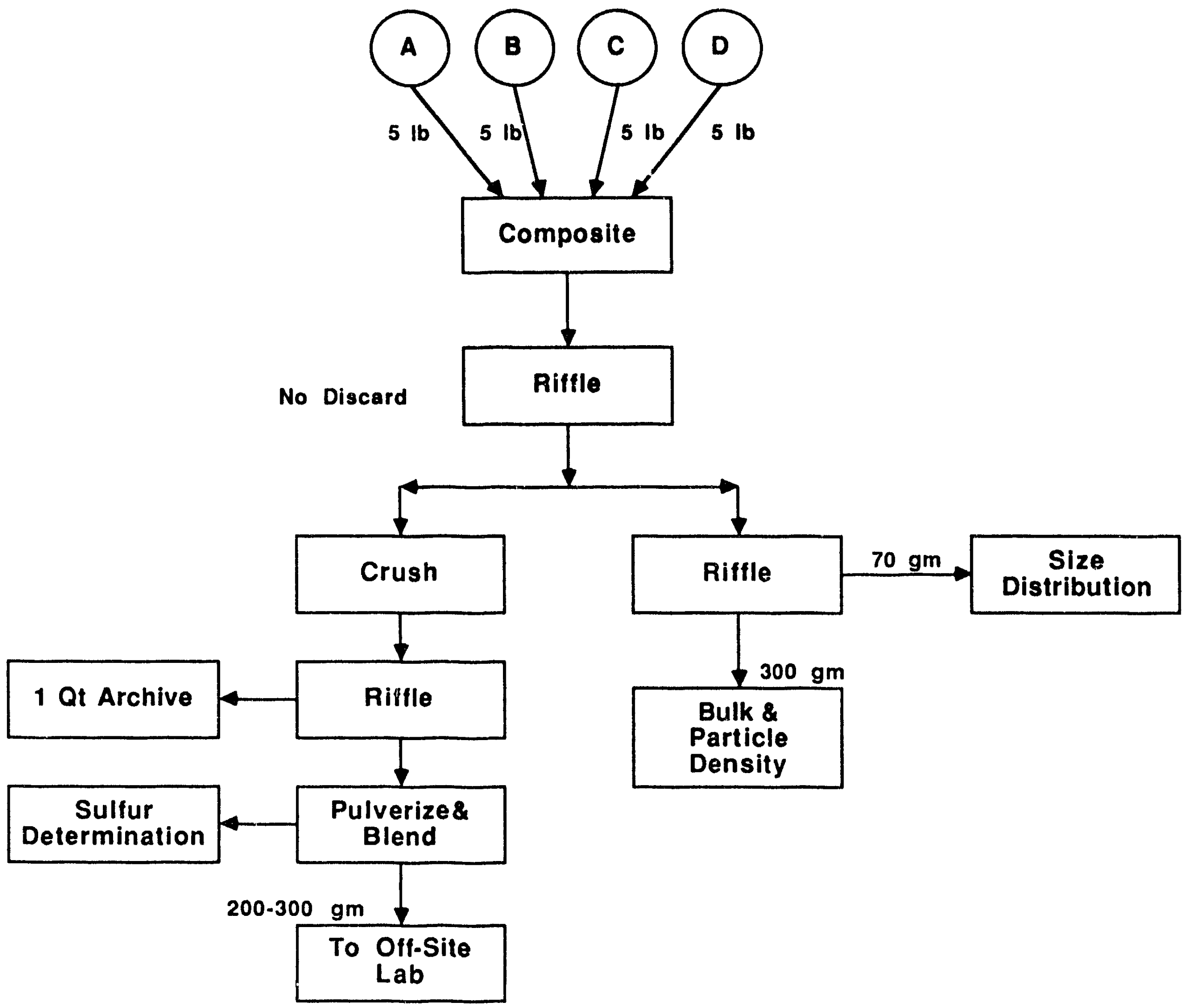


Figure 3-11. Bottom Ash Preparation Flow Sheet

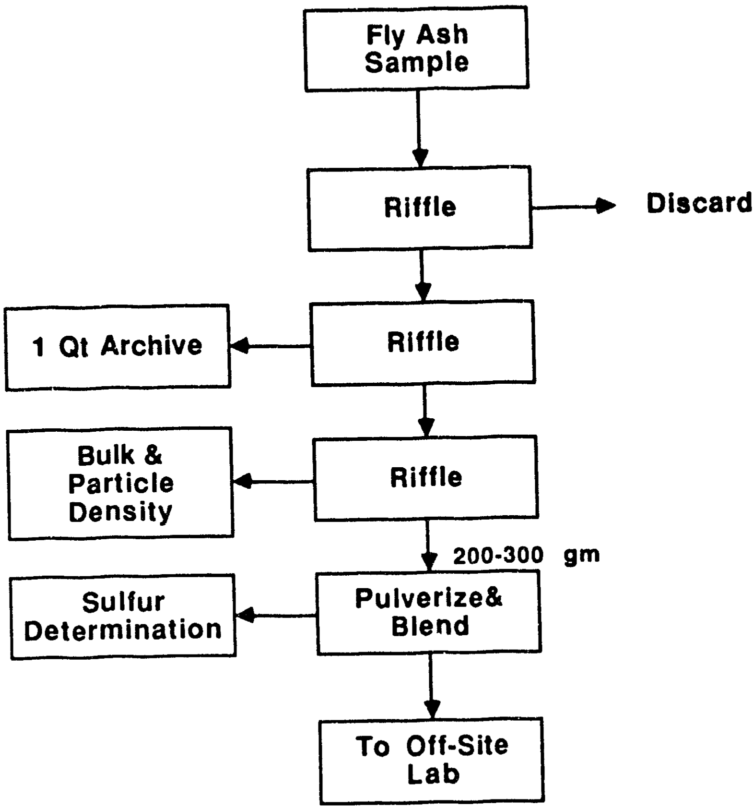


Figure 3-12. Fly Ash Preparation Flow Sheet

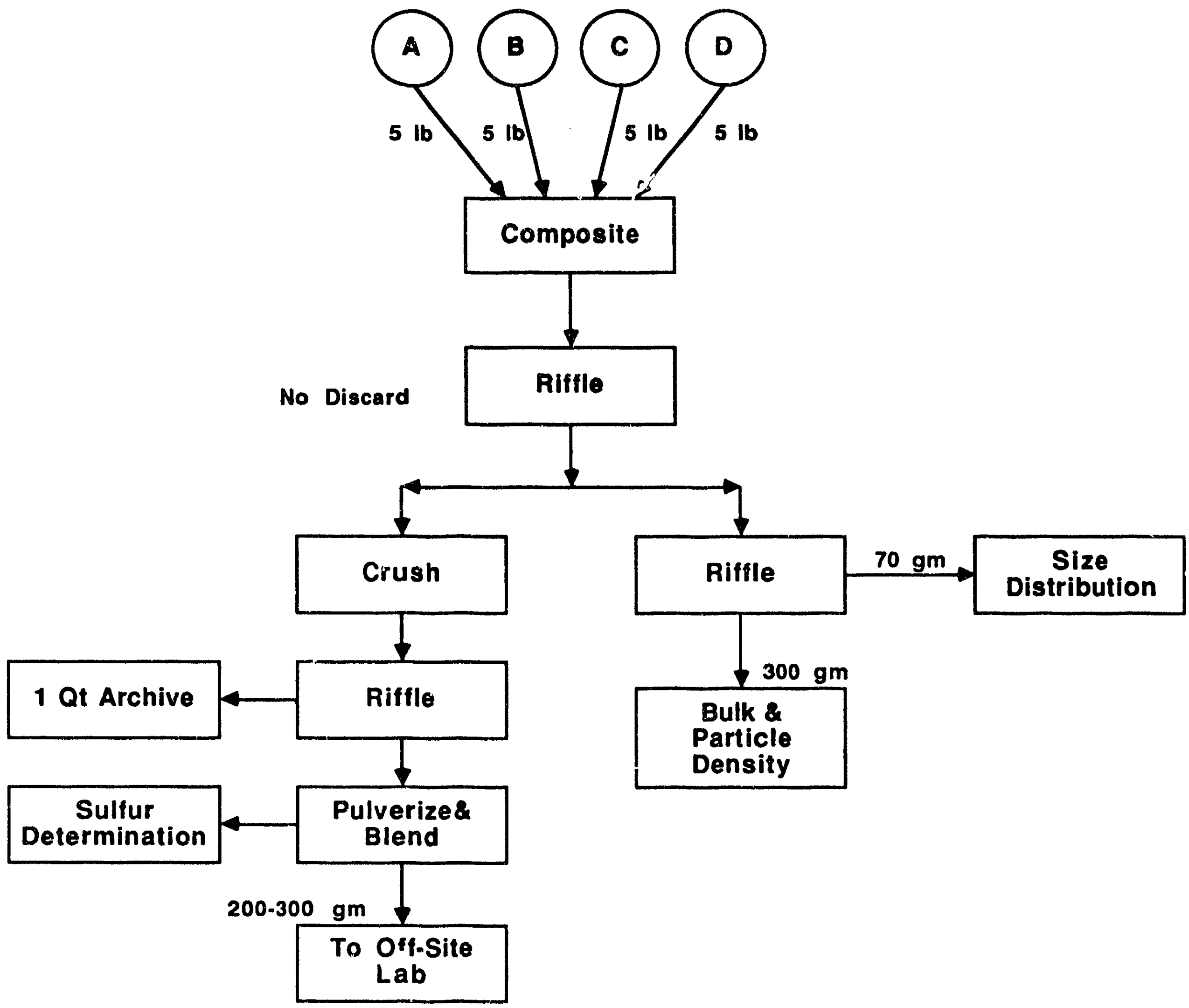


Figure 3-11. Bottom Ash Preparation Flow Sheet

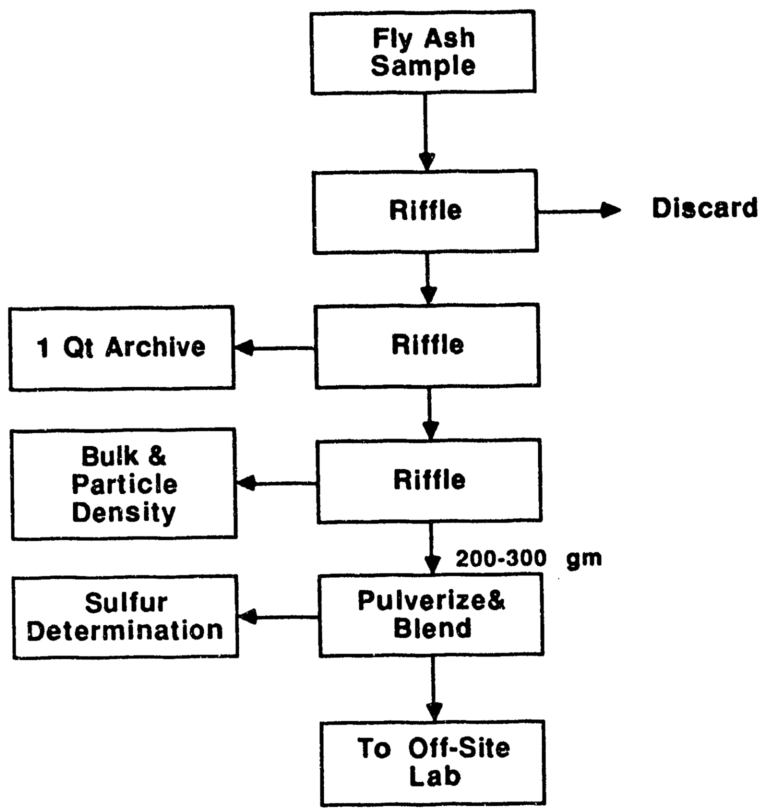


Figure 3-12. Fly Ash Preparation Flow Sheet

3.2.4.5 Quality Control

The Nucla laboratory personnel developed a rigorous program to insure quality control in the preparation and analysis of the solid samples. For each performance test, one of the samples sent to the laboratory will be a duplicate of another sample. In addition, several tests will be conducted to determine the division of analysis variance (See Section 10 on Hot Mode Shakedown). Duplicate samples will also be sent to other laboratories on a round-robbin basis to serve as a check on the outside laboratory's procedures. Careful record keeping is mandatory for quality assurance.

3.2.5 VAX Computer

The data acquisition for the performance tests is performed on a Digital Equipment Corporation (DEC) VAX 8200 computer with four megabytes of random access memory. Performance monitoring software was written by Systems Control, Incorporated. The VAX computer reads plant data directly off the data highway. The software then averages and stores the data for use by the technicians. Software can produce historical trend plots, run the performance calculations and the uncertainty analysis of the performance tests, and other file maintenance procedures from a menu driven master program. A laser printer is attached to the VAX to print the trend plots.

The VAX computer is connected to IBM-PC's and the Macintosh computers via a serial cable. Files can be transferred to or from the VAX using the Kermit protocol.

The historical data storage and retrieval programs of the VAX are far superior to the capabilities of the plant distributed control system. As such the VAX was quite helpful to the test team in evaluating process upsets and trips, as well as assisting in the management of test conditions during the performance tests. Measurement points accessed by the VAX computer are listed in Appendix A along with the calibration information for the transmitters.

3.2.5.1 Performance Calculations

The performance calculations for the test program are carried out on the VAX computer. The algorithms to perform the calculations were developed by EPRI and their contractors. The calculations include an implementation of PTC 4.1, the ASME boiler test code, heat and material balances around the boiler envelope, calculations of Ca/S molar ratio, Calcium utilization, superficial velocities, and particle sizes of the various solid streams. Details of the performance calculations are contained in Appendix B.

The performance calculations were checked extensively by EPRI and their contractors. The VAX calculation results were checked against an Excel spread sheet calculation prepared by EPRI.

Results of the performance calculations are printed out on eight summary sheets. Figures 3-13(a) through 1-13(d) show examples of the eight data summary sheets. These summary sheets contain all of the relevant data obtained during a performance test.

3.2.5.2 <u>Uncertainty Analysis</u>

An uncertainty analysis of the performance calculations will provide information on the measurement uncertainty of the calculated results. This is especially important when comparing performance from two different boilers. ASME PTC 19.1 provides guidelines for determining the measurement uncertainty of the various plant measurements that feed the performance calculation program. PTC 19.1 also provides guidelines for propagating these uncertainties throughout the performance calculations.

The procedure for calculating the uncertainty of the results of a given calculation can be summarized as follows:

1. Determine the average values of the independent parameters ($\overline{P}_i$) that enter into the result (r) of the calculation.
2. Determine the precision index of the average value ($S_{\overline{P}_i}$) for each $\overline{P}_i$.
3. Determine the bias limit for each of the measured parameters ($B_{\overline{P}_i}$).
4. Determine the degrees of freedom associated with each $\overline{P}_i$ ($\nu_{\overline{P}_i}$).
5. Use the perturbation method to determine the bias limit of the result (B_r).
6. Use the perturbation method to determine the precision index of the result (S_r).

PROCESS OPERATING SUMMARY REPORT

TEST : 00418P70

Start....... 4/18/90 9: 0: 0
End......... 4/18/90 15: 0: 0
Printed.....22-AUG-1990 09:06:05.00

	Combustor A	Combustor B	Unit
Gross Plant Output (MWe)			109.73
Final SH Stm. Flow (klb/hr)			916.69
Final SH Out. Press (psig)			1461.55
Final SH Out. Temp. (F)			1000.45
Coal Rate Frnt-Wst (klb/hr)	18.19	19.22	
Coal Rate Frnt-Est (klb/hr)	18.34	18.69	
Coal Rate Rear (klb/hr)	18.77	17.42	
Total (klb/hr)	55.30	55.32	110.62
Limestone Rate (klb/hr)	2.13	5.24	7.37
Bed Drain Rate (klb/hr)	2.64	1.05	3.69
Flyash Flow (klb/hr)			
Calculated			24.09
Superficial Velocity (ft/sec)			
Distributor Plate (Inl Air)	10.91	11.74	
Freeboard (Inlet Air)	16.88	16.88	
Dist. Plate (O2 Method)	10.72	11.52	
Freeboard (O2 Method)	16.51	16.51	
Avg. Bed Temp. (F) 20"	1562.58	1701.62	
Avg. Bed Temp. (F) 66"	1546.09	1689.36	
Avg. Bed Temp. (F) 118"	1543.43	1686.15	
Wet Flue Gas Flow - O2 Method (klb/hr)			1041.97
Flue Gas Composition (AH Inlet)			
O2 (v%)			3.01
CO2 (v%)			15.70
CO (ppmv)			82.60
NOX (ppmv)			144.41
(lbs/10^6 btu)			0.20
SO2 (ppmv)			123.94
(lbs/10^6 btu)			0.24
Total Air Flow (klb/hr)			953.95
Primary Air Flow (klb/hr)			584.84
Sec. Air Flow (klb/hr)			369.11
SA/PA Ratio			0.63

PROCESS OPERATING SUMMARY REPORT

TEST : 00418P70

Start....... 4/18/90 9: 0: 0
End......... 4/18/90 15: 0: 0
Printed.....22-AUG-1990 09:06:05.00

	Combustor A	Combustor B	Unit
PA Fan Out. Press. (in WG)			0.81
SA Fan Out. Press. (in WG)			0.09
PA AH Out. Press. (in WG)	61.78	62.12	
SA AH Out. Press. (in WG)	45.12	45.56	
Windbox Press. (in WG)	52.19	51.17	
Bed Press. 18" Above Grid (in WG)	21.64	19.81	
Freeboard Press. (in WG)	-0.24	-2.10	
Cyclone Out. Press. (in WG)			-10.29
SH 1 & 3 Flue Gas DP (in WG)			1.17
Economizer Flue Gas DP (in WG)			1.46
AH DP (in WG)			6.35
Baghouse In. Press. (in WG)			-15.99
ID Fan In. Press. (in WG)			-25.17
Cyclone In. Temp. (F)	1565.91	1684.27	
Cyclone Out. Temp. (F)	1530.91	1646.59	
Loop Seal Solids Temp. (F)	1549.65	1725.07	
AH Gas In. Temp. (F)	519.33	544.27	
AH Gas Out. Temp. (F)	274.37	281.07	
Pri. Air AH In. Temp. (F)			106.48
Pri. Air AH Out. Temp. (F)	397.53	419.12	
Sec. Air AH In. Temp. (F)			105.24
Sec. Air AH Out. Temp. (F)	438.28	458.29	
Feedwater Flow (klb/hr)			882.52
SH2 Attemp. Flow (klb/hr)			28.19
SH3 Attemp. Flow (klb/hr)			7.18
Drum Press. (Psig)			1639.51
Ambient Temp. (F)			87.29
Baro. Press. (In Hg)			24.52
Rel. Humidity (%)			12.67

Figure 3-13(a). Performance Test Summary Sheets Pages 1 and 2.

------------ PERFORMANCE SUMMARY REPORT ------------

TEST : 00418P70

Start....... 4/18/90 9: 0: 0
End......... 4/18/90 15: 0: 0
Printed.....22-AUG-1990 09:06:14.00

	VALUE	UNC*
CHEMICAL PROCESS SUMMARY		
Ca Utilization % (Sorbent Only)	21.36	1.69
Ca Utilization % (Coal and Sorbent)	18.79	1.68
Alkali Utilization % (Coal and Sorbent)	17.86	1.61
Ca To S (Sorbent Only)	3.66	0.23
Ca To S (Coal and Sorbent)	4.16	0.33
Alkali To S (Coal and Sorbent)	4.37	0.35
SO2 Retention %	78.07	2.09
Combustion Efficiency %	97.56	0.26
BOILER PERFORMANCE SUMMARY		
Boiler Efficiency (Loss Method) %	87.46	0.30
Boiler Efficiency (I/O Method) %	85.36	2.39
Excess Air %	16.39	0.95
Air Heater Effectiveness	0.73	0.01
Boiler Load %MCR	100.40	1.20
Wet flue gas flow - O2 Method (klbs/hr)	1041.97	22.06
MATERIAL BALANCE		
Total balance %	99.79	0.54
Carbon balance %	95.59	6.57
Hydrogen balance %	100.43	0.10
Oxygen balance %	97.63	4.72
Nitrogen balance %	100.97	1.38
Sulfur balance %	85.79	13.09
Calcium balance %	99.50	8.67
UNIT HEAT RATE		
Gross Heat Rate (btu/kwhr)	10276.	153.
Net Heat Rate (btu/kwhr)	11328.	178.

* Uncertainty, +/- in same units as variable.

----- MATERIAL BALANCE REPORT (O2 METHOD) -----

TEST : 00418P70

Start....... 4/18/90 9: 0: 0
End......... 4/18/90 15: 0: 0
Printed.....22-AUG-1990 09:06:16.00

METHOD "A" MEASURED AIR FLOWS

INPUTS(klb/hr)	Coal	Sorbent	Air	Total Input
Total	110.62	7.37	1043.90	1161.89
C	65.13	0.81		65.94
H	4.94	0.00	0.49	5.43
N	1.38		798.85	800.23
O	18.19	3.25	244.56	265.99
S	0.59	0.00		0.59
Ca	0.37	2.69		3.05

OUTPUTS(klb/hr)	Flue Gas	Fly Ash	Bed Drain	Total Output	% Acc For
Total	1041.97	24.09	3.69	1069.74	92.07
C	61.18	1.79	0.06	63.03	95.59
H	5.39	0.02	0.01	5.41	99.64
N	738.51			738.51	92.29
O	237.16	1.76	0.20	239.12	89.90
S	0.13	0.34	0.04	0.50	85.79
Ca		2.73	0.30	3.04	99.50

METHOD "B" CALCULATED AIR FLOW

INPUTS(klb/hr)	Coal	Sorbent	Air	Total Input
Total	110.62	7.37	953.95	1071.94
C	65.13	0.81		65.94
H	4.94	0.00	0.45	5.39
N	1.38		730.02	731.40
O	18.19	3.25	223.48	244.92
S	0.59	0.00		0.59
Ca	0.37	2.69		3.05

OUTPUTS(klb/hr)	Flue Gas	Fly Ash	Bed Drain	Total Output	% Acc For
Total	1041.97	24.09	3.69	1069.74	99.79
C	61.18	1.79	0.06	63.03	95.59
H	5.39	0.02	0.01	5.41	100.43
N	738.51			738.51	100.97
O	237.16	1.76	0.20	239.12	97.63
S	0.13	0.34	0.04	0.50	85.79
Ca		2.73	0.30	3.04	99.50

Figure 3-13(b). Performance Test Summary Sheets Pages 3 and 4.

---------- HEAT BALANCE REPORT ----------

TEST : 00418P70

Start....... 4/18/90 9: 0: 0
End......... 4/18/90 15: 0: 0
Printed.....22-AUG-1990 09:06:23.00

BOILER EFFICIENCY (%)(LOSSES METHOD)		87.46
	Value(KBtu/hr)	% of total *
CHEMICAL HEAT INPUT OF THE COAL:	1128676.13	98.68
I. CREDITS		
1. Heat credit for sensible heat in entering moist air	7128.19	0.62
2. Sensible heat in entering as-fired coal	-346.95	-0.03
3. Sensible heat in entering wet sorbent	38.82	0.00
4. Heat credit for sulfation reaction	3086.96	0.27
5. Bottom ash cooling water input	5183.12	0.45
6. Sootblowing steam	0.00	0.00
II. LOSSES		
1. Heat loss from unburned coal	27269.82	2.38
2. Heat loss from sensible heat in dry flue gas	48421.45	4.23
3. Heat loss due to moisture in as-fired fuel and sorbent	10988.92	0.96
4. Latent heat loss due to moisture from burning of hydrogen	39327.72	3.44

* Total equals: Chemical input of coal plus credits

---------- HEAT BALANCE REPORT ----------

TEST : 00418P70

Start....... 4/18/90 9: 0: 0
End......... 4/18/90 15: 0: 0
Printed.....22-AUG-1990 09:06:23.00

	Value(KBtu/hr)	% of total *
II. LOSSES (CONT)		
5. Latent heat loss due to moisture in the air	366.30	0.03
6. Heat loss due to calcination of sorbent	4768.24	0.42
7. Heat loss due to formation of CO	325.85	0.03
8. Heat loss due to unburned hydrocarbons in flue gas	0.00	0.00
9. Heat loss due to radiation and convection	5000.00	0.44
10. Heat loss due to sensible heat in flue dust	963.07	0.08
11. Heat loss due to sensible heat in bed drain	44.96	0.00
12. Heat loss due to sootblower steam	0.00	0.00
13. Heat loss to bottom ash cooler cooling water	6004.30	0.52
SUM OF LOSSES TERMS	143480.66	12.54

* Total equals: Chemical input of coal plus credits

Figure 3-13(c). Performance Test Summary Sheets Pages 5 and 6.

---------- CHEMICAL ANALYSIS REPORT --------------

TEST : 00418P70

Start....... 4/18/90 9: 0: 0
End......... 4/18/90 15: 0: 0
Printed.....22-AUG-1990 09:06:19.00

	Coal	Sorbent	Fly Ash	Bed Drain Matl
HHV (Btu/lb)	10193.88			
Total Moisture (%)	8.70	0.08		
Air Dry Loss (%)	3.00			
Blk Den (#/cft)	60.80			
Volatiles (%)	31.80			
Fixed C (%)	41.05			
Ash (%)	18.45			
CONSTITUENTS (%)				
C	58.88		7.44	1.69
H	3.49	0.00	0.06	0.18
O	8.71			
N	1.25			
S	0.53	0.00	1.40	1.07
Ca	0.33	36.45	11.35	8.24
Mg	0.06	0.41	0.34	0.40
Fe	0.20	0.18	0.90	1.04
CO2		40.36	0.94	0.68

NOTE: Only constituents used in the Performance Calculations are reported.

---------- PHYSICAL ANALYSIS REPORT --------------

TEST : 00418P70

Start....... 4/18/90 9: 0: 0
End......... 4/18/90 15: 0: 0
Printed.....22-AUG-1990 09:06:21.00

Mesh	Actual Microns	Percentage Less Than: Coal	Sorbent	Bed Drain
1.50	37500	100.00	100.00	100.00
1.00	25000	100.00	100.00	100.00
0.75	19000	100.00	100.00	100.00
0.50	12500	100.00	100.00	100.00
0.25	6300	76.55	100.00	94.75
4	4750	67.15	100.00	88.25
6	3350	58.10	100.00	76.80
8	2360	48.65	100.00	69.05
10	1700	39.45	100.00	62.20
14	1180	31.60	100.00	55.15
20	850	25.55	100.00	47.35
28	600	20.75	87.10	38.85
48	300	12.55	72.00	15.15
100	150	6.75	59.85	3.60
150	106	4.55	54.90	0.55
200	75	4.55	50.65	0.30
325	45	4.55	44.25	0.30
400	38	4.55	41.65	0.30
Median diameter		2480.59	71.09	950.32

Figure 3-13(d). Performance Test Summary Sheets Pages 7 and 8.

7. Calculate the degrees of freedom of the result (ν_r).

8. Find the Student's t factor (t) corresponding to n_r.

9. Calculate the total uncertainty of the result by the root-sum-square method (U_{rRSS}).

A more detailed description of this procedure is given in Appendix C.

Section 4

COAL AND LIMESTONE PREPARATION AND HANDLING

This section summarizes the operating experiences of the coal and limestone preparation and feed systems during the start-up period through 1988. The coal preparation and feed system has operated without major incident during the period. The limestone preparation and feed system has experienced problems due to erratic feed rate signals, feed shaker motor failures, vent system blockage, and rotary valve clearances. The performance of these systems is discussed below.

4.1 SYSTEM DESCRIPTIONS

4.1.1 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 4-1 and is designed from existing and new equipment.

Raw run-of-mine coal is delivered from local coal mines to the plant by truck and is weighed and then dumped into an unloading hopper. 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 A and B. 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

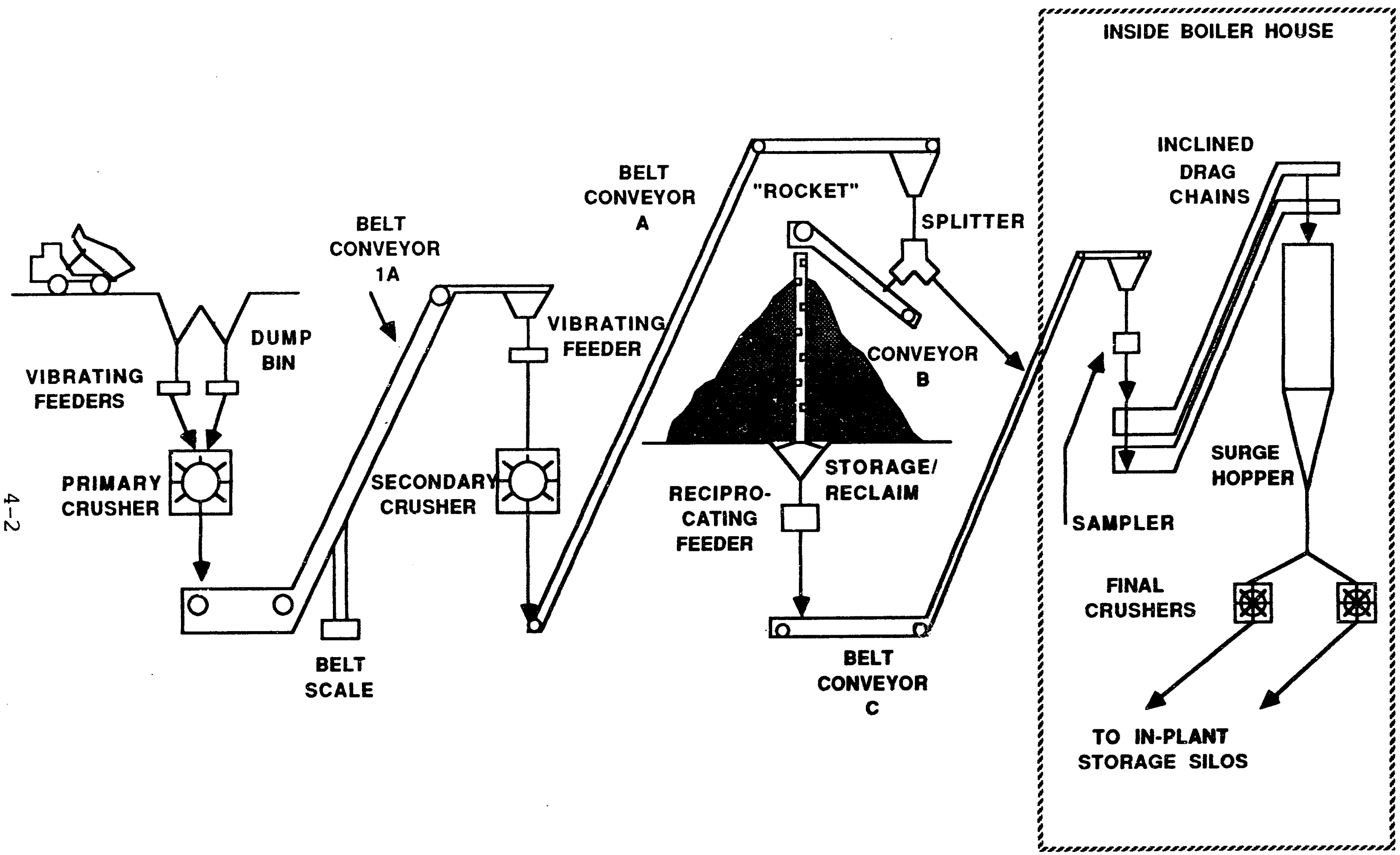


Figure 4-1. Schematic of Coal Preparation System.

conveyor C at the base of these inclined conveyors. In the event of equipment problems, an 18 ton surge hopper has been installed just above the final crushers (at the discharge of the inclined conveyors) with capacity to store all coal on conveyor C (see Figure 4-2).

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 on 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. This 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 4-3).

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 conveyor is used to transfer coal from each of two gravimetric feeders situated along the front walls, around the side walls of each combustor, and to the loop seal coal feed points.

4.1.2 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 4-4 and 4-5.

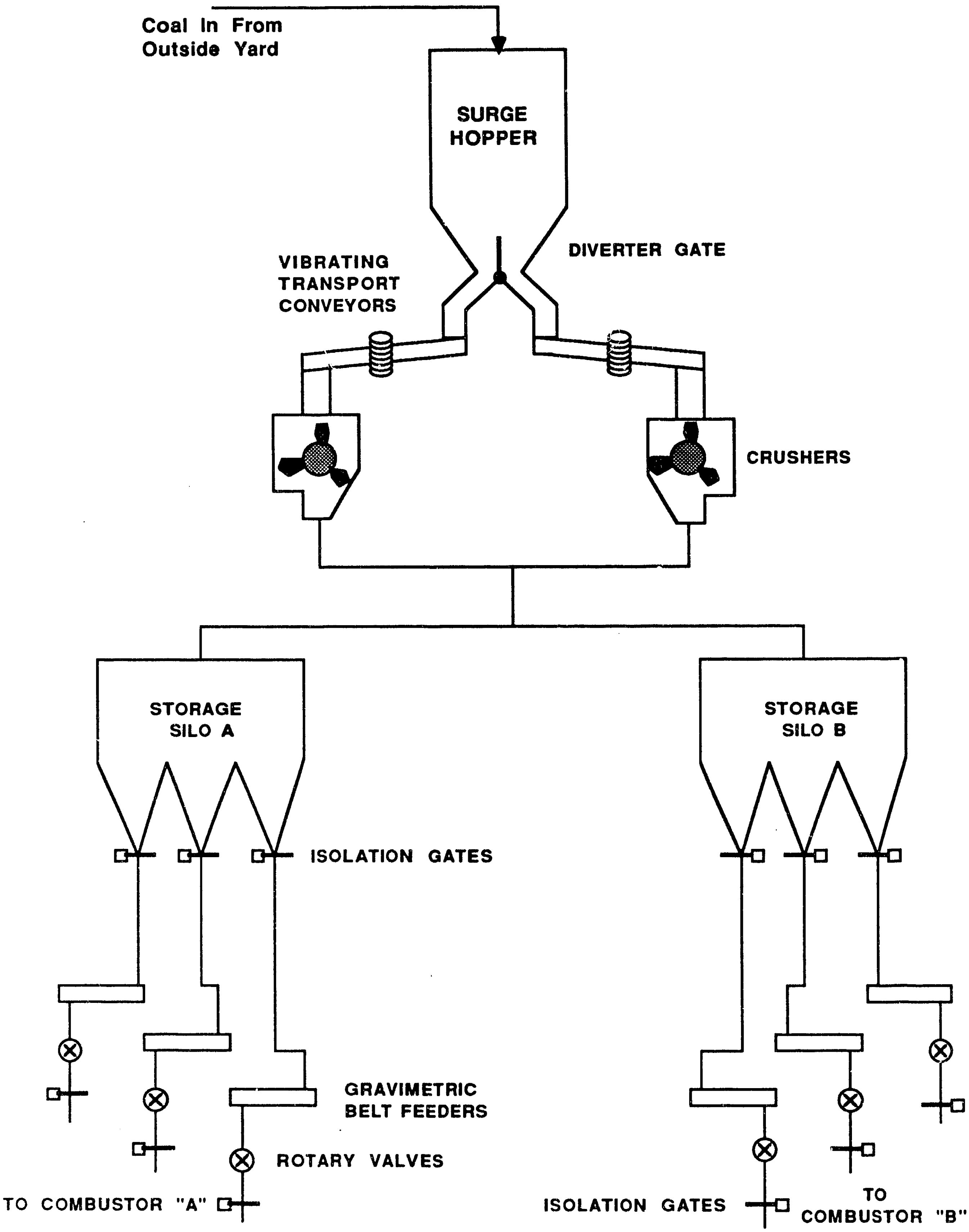


Figure 4-2. Schematic of Coal Feed System.

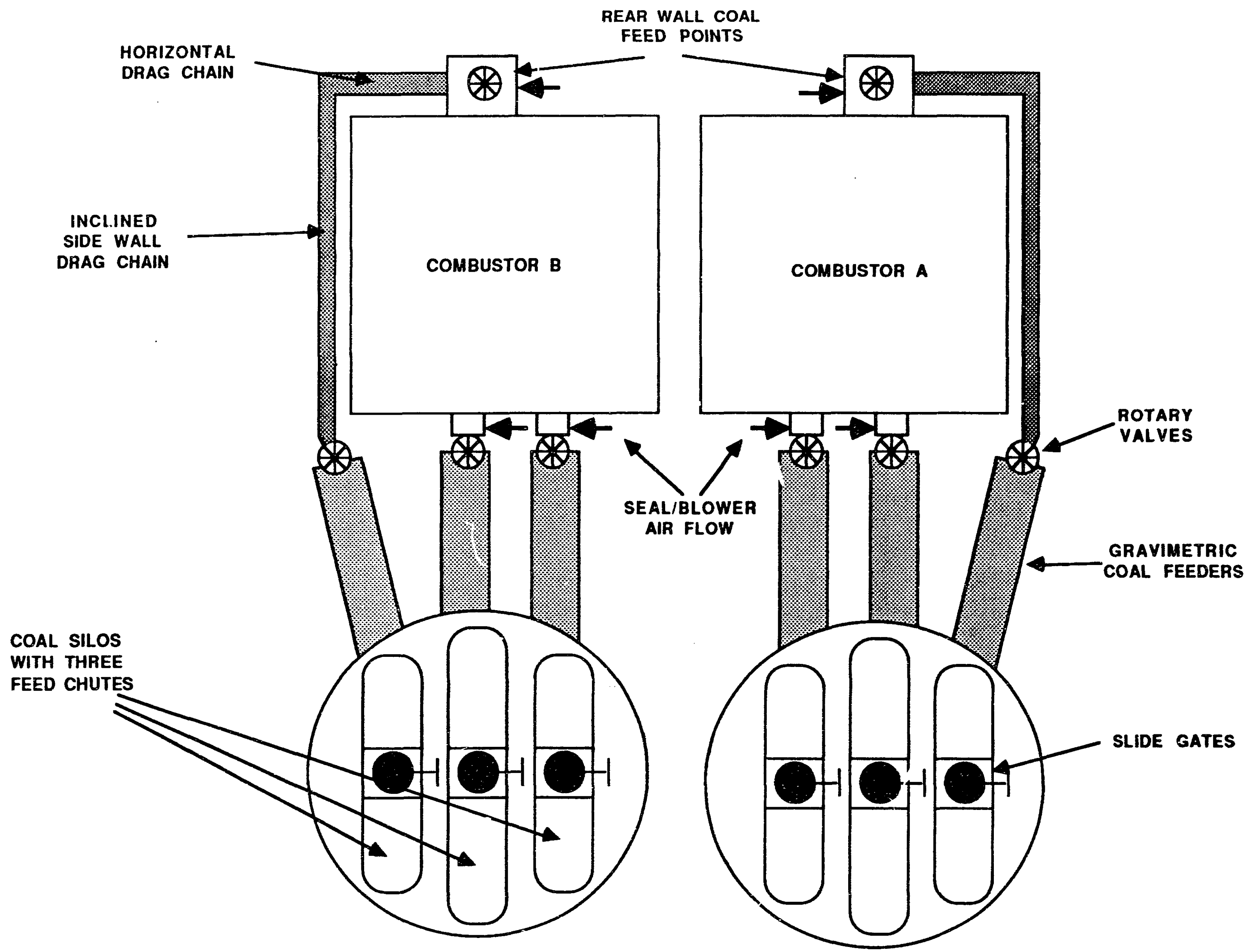


Figure 4-3. Plan View of Combustor Coal Feed Configuration.

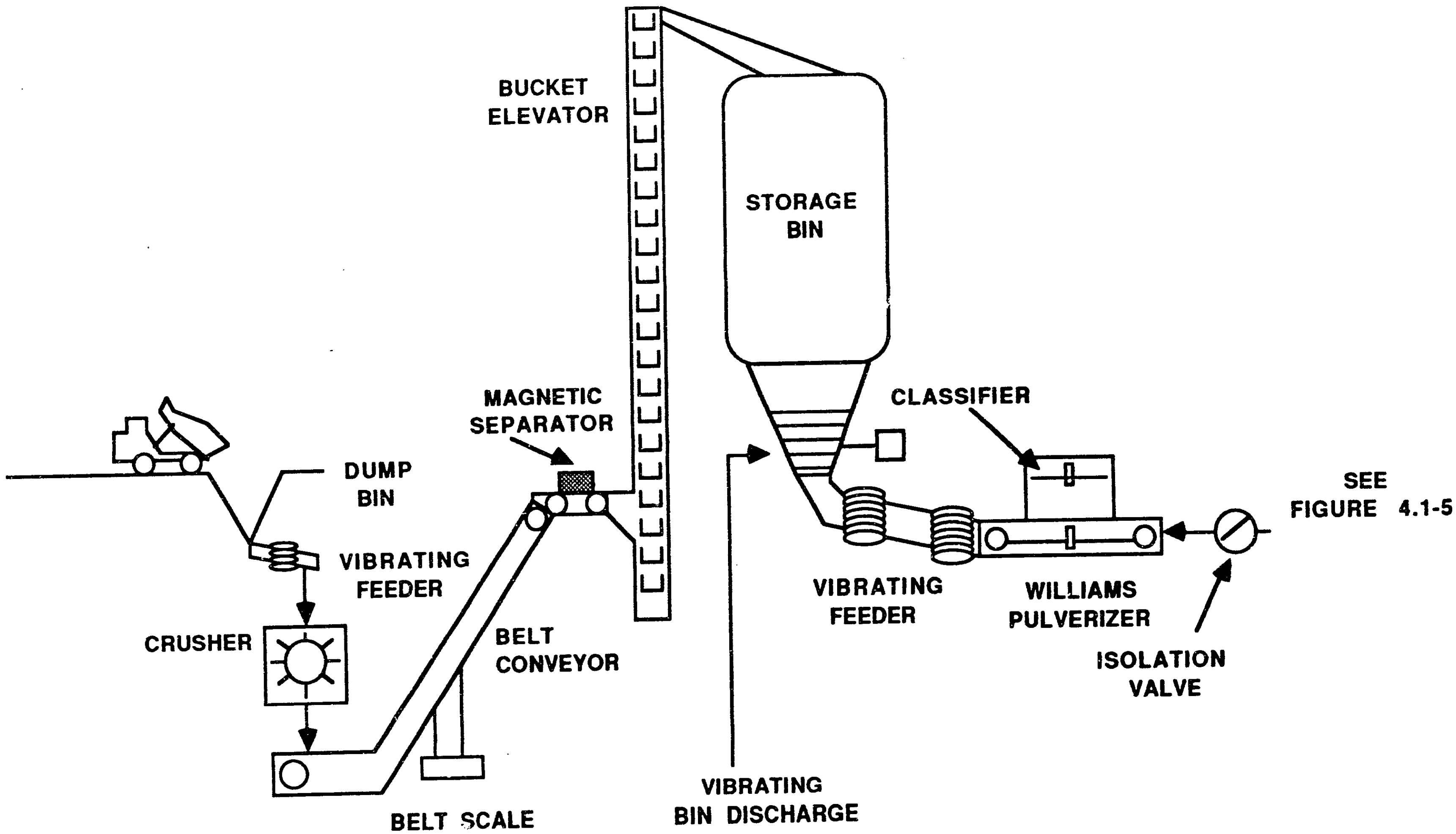


Figure 4-4. Partial Schematic of Limestone Preparation System

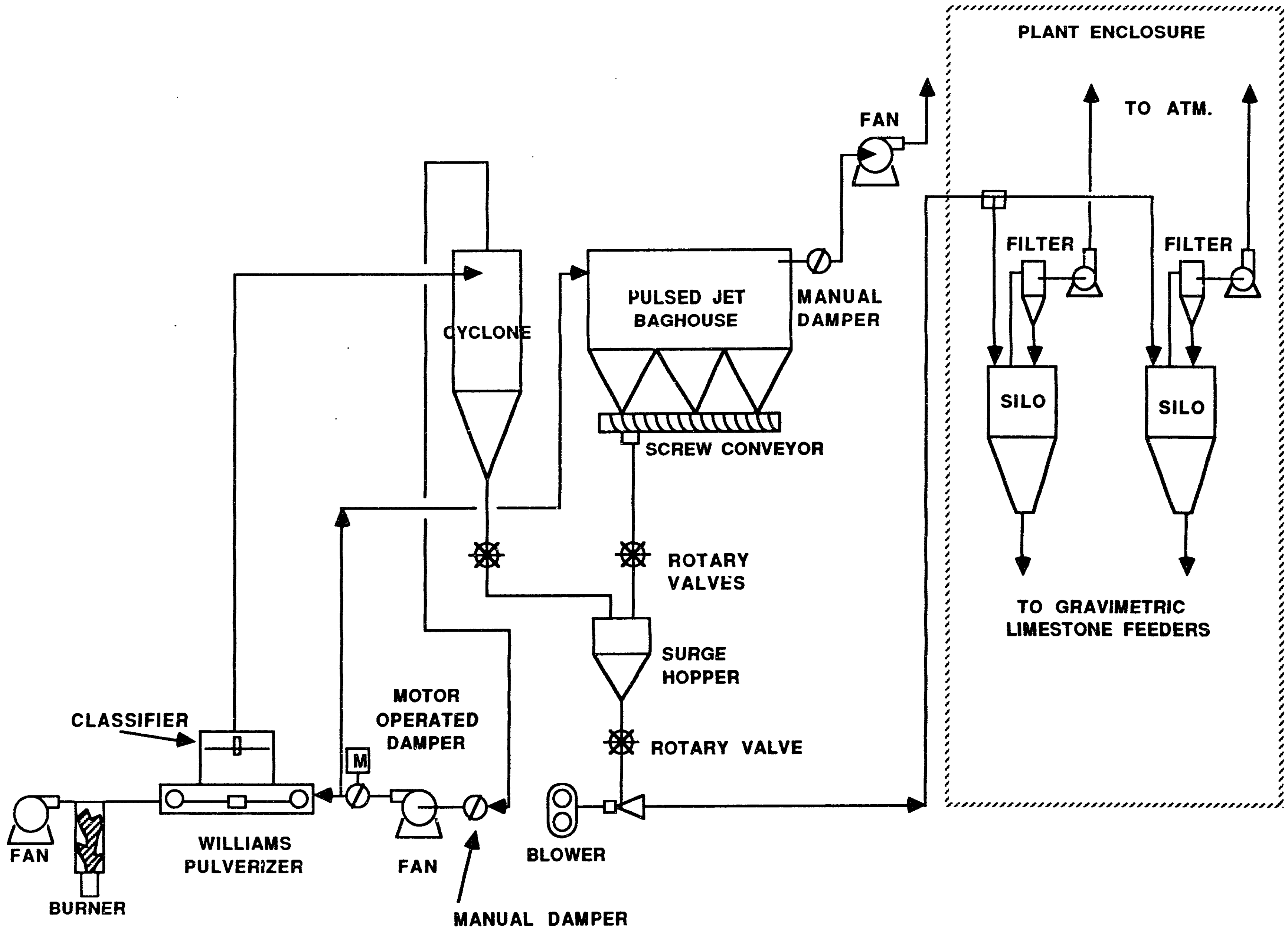


Figure 4-5. Schematic of Limestone Preparation System.

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 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 4-4, 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 a fan and burner system. The separated limestone in the cyclone drops through a rotary feeder into a surge hopper (see Figure 4-5).

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. The fabric filter discharges collected limestone via a screw feeder and rotary valve to the surge hopper where it 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 a 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 4-6, and is filled by the storage silo at a preset weight. The load cell output is electronically

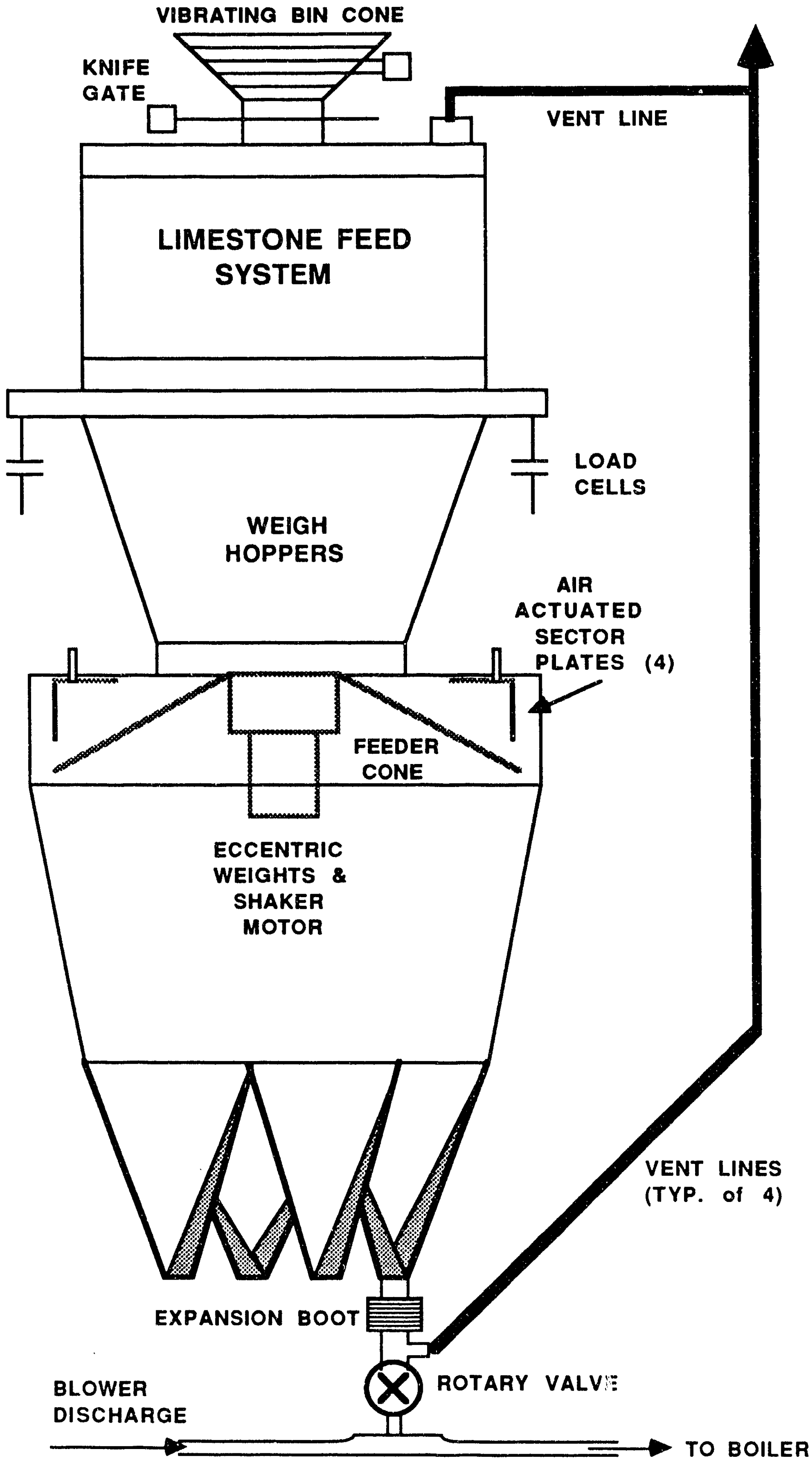


Figure 4-6. Schematic of Limestone Feed System (typical of two).

monitored over a period of time to obtain an integrated rate of limestone feed. Each feeder is automatically adjusted in direct relation to combustion chamber coal flow and trimmed base 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 relation 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.

Each of the four feed lines on each limestone feed system transport 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 4-7.

4.2 COAL PREPARATION FEED SYSTEM OPERATING EXPERIENCE

The coal preparation and feed system operated in a reliable manner without major incident during the reporting period. Most problems were maintenance related such as gear box failures on "C" conveyor, broken drag chain links, tramp material in rotary valves, and worn front wall coal chutes. Other minor problems are listed below.

- Pluggage has occurred on occasion at the diverter gate on the outlet of the in-plant storage silo. This occurs typically with a high ash/clay/moisture feed stock.

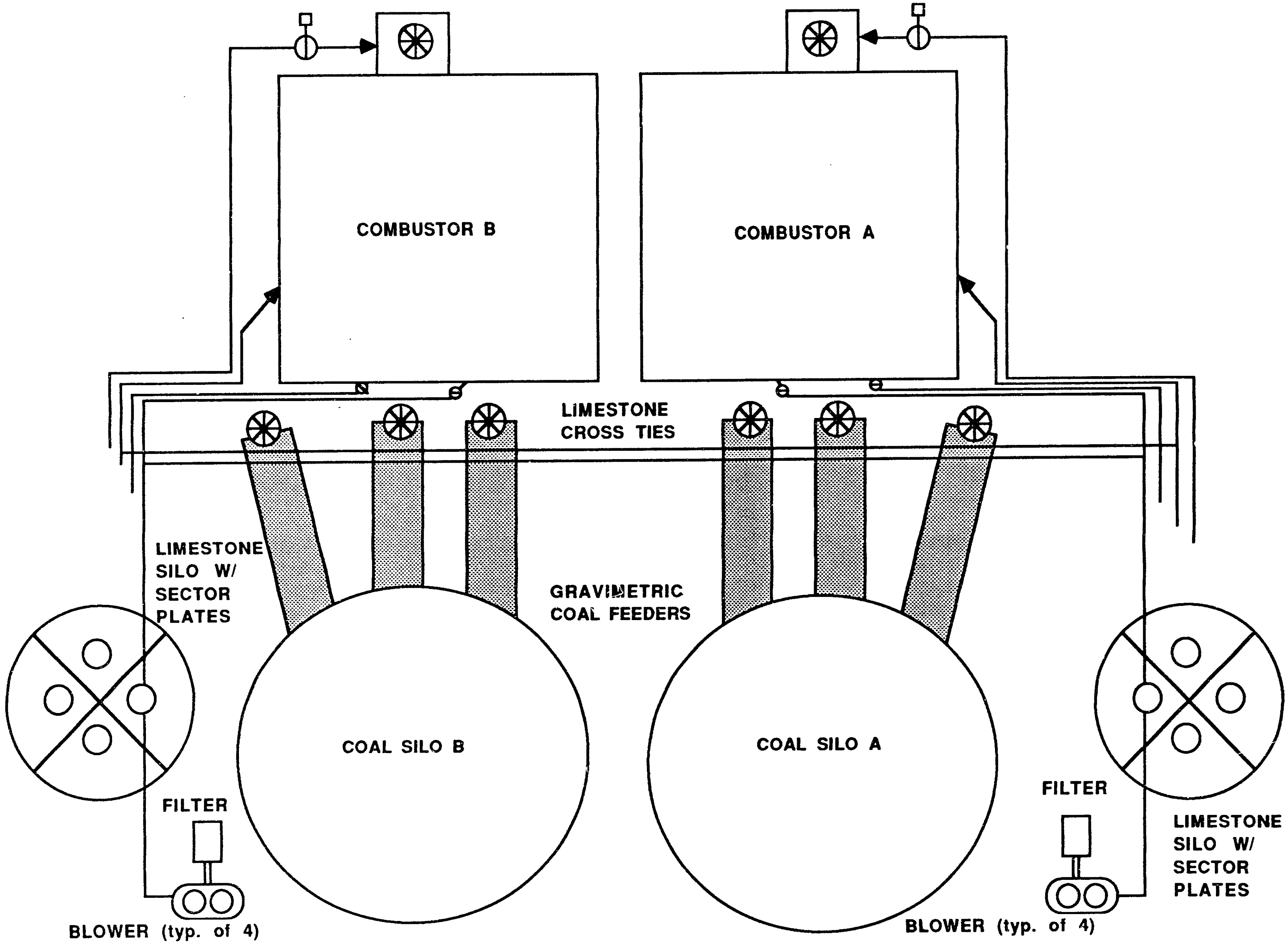


Figure 4-7. Plan View of Limestone Feed Configuration.

- The structural supports failed on the vibrating conveyors downstream of the surge hopper inside the plant. The problem was with the length of the cable used to suspend the vibrating feeders. This length was shortened and no further failures occurred.

- The horizontal drag chains used to feed the in-plant coal silos exceeded guaranteed noise levels during initial run-in. To correct this problem, teflon sheets were added to the bottom of the drag chains. This reduced noise levels and acceptability remains under review at the conclusion of this reporting period.

- Several coal feeder trips and one unit trip 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.

4.3 LIMESTONE SYSTEM OPERATING EXPERIENCE

The limestone preparation system has performed well during the reporting period, although the system has proven to be fairly inflexible towards changes in product size. The feed system located inside the plant has not performed well during the period as the result of unstable feed rate signals rotary valve wear, and shaker motor and bearing failures. These are discussed in more detail below.

Sieve analysis of limestone size prior to the first acceptance test in July 1988 indicated a median particle size in the range of 100 microns, which is below the design value of 150 microns. To increase the sizing, the manufacturer recommended the following three possible changes to the system operation.

1. Increase the air flow through the pulverizer to increase the mean particle size that is transported to the cyclone separator.

2. Reduce the classifier speed and/or remove classifier blades to decrease the fraction of pulverized limestone that is returned to the pulverizer.

3. Reduce the speed of the pulverizer.

The damper to the inlet of the transport fan shown in Figure 4-5 was already set to its maximum open position, thereby providing maximum possible air flow. Therefore, no increases in limestone particle size were possible from step 1.

Subsequently, the classifier speed was reduced, classifier blades were removed, and finally, the classifier "fan" was shut completely off. None of these changes produced noticeable increases in limestone size.

Implementation of step 3 involved changing the shieve size on the pulverizer to reduce its speed. Following two changes in shieve size in May 1988, an increase in the mean particle size was measured by sieve analysis of the product. During June 1988, adjustments were made to the classifier speed to fine tune the final sizing prior to acceptance testing in July 1988. The final median particle size at the conclusion of these adjustments was approximately 180 micron.

On two occasions during this reporting period, the motor operated damper at the outlet of the transport fan closed during system shutdown and did not reopen when the system was restarted. When this occurred, hot undiluted air and gas from the burner (for reducing product moisture content) passed directly into the baghouse and destroyed a significant number of bags on both occasions. Since changes to the operating logic, no additional failures have occurred. The balance of system preparation continued to operate reliably during the reporting period.

The feed system located inside the plant suffered numerous problems during the reporting period and restricted unit load on occasion so as to maintain SO_2 emissions compliance. Problems associated with this equipment are discussed below.

1. During initial operation of both systems, the feed rate signal was extremely "noisy". The nearly instantaneous variability of the signal made it difficult to place the system in "auto", whereby the feed rate is automatically set for a given load and is then trimmed by the plants SO_2 analyzers. The feed rate signal was also of concern to the test program since the uncertainty in the average feed rate over a time period was outside the accuracy required for comparative testing.

   To correct the problem, the manufacturer tuned the limestone feeder control system on several occasions. This eventually resulted in an acceptable feed rate signal, except during periods when limestone from the outside preparation system was being transported into the in-plant storage silos. This is discussed in item 2 below.

2. The vent lines from the limestone feeders shown in Figure 4-6 connect to the fill space in the top of the in-plant storage silo. This allows blow-by and leakage on the limestone feed system to be filtered in the same manner as the transport air from the outside preparation system. During transport of limestone into the in-plant storage silos, the transport air and/or limestone appears to interfere with the vent system from the feeders, which are both common to the upper silo fill area. When this occurs, the feed rate signal becomes extremely erratic. Operators then place the system in "manual" and operate the feeder at a fixed rate until the in-plant storage silos are full. Limestone transport from the preparation system is then shut down and the limestone feed system is placed back into "auto". In an attempt to correct this problem, a check valve was installed on the vent line from the feeder to the upper storage hopper. This should prevent interference between the transport system and limestone feeder vent system. Some improvement was noted but the system will need additional modifications in 1989 to eliminate the problem.

3. On several occasions, the expansion joints on the limestone feeders shown in Figure 4-6 failed. When this occurs, the rubber boot around the expansion joint fails and substantial quantities of limestone are discharged into the plant. This is believed to be related to item 2 above and to excessive leakage of high pressure transport air past the rotary valves. To address this problem, clearances between the rotor and housing on the rotary valves were tightened to decrease the leakage. Some improvement was noted in combination with modifications in step 2 above.

4. The shaft seals on the rotary valves were the source of significant fugitive limestone dust emissions inside the plant. This occurred on a continuous basis during normal operation of the limestone feeders. To correct the problem, new seals were installed on several occasions. This eliminates the leakage until the shaft seals begin to wear. The leakage is exacerbated by problems listed in items 2 and 3 above.

5. The shaker motor and eccentric weights shown in Figure 4-6 are attached to the underside of the shaker cone inside the lower transport hopper. By increasing the motor speed, the shaker cone vibration increases and this, in turn, increases the flow of limestone from the weigh bin to the transport hopper. Throughout the third and fourth quarters of 1988, both the eccentric weight bearings and the shaker motors failed on numerous occasions.

During this period, the unit was operating for extended time intervals at full load with the limestone feeders experiencing the maximum service to date. To address this problem, larger shaker motors were installed and the weight settings on the eccentric weights were reduced from 100% to 80% to reduce the stress on the bearings. These changes were made during the fourth quarter of 1988. Although no additional motor or bearing failures were reported, limestone feeder motor trips continued at feed rates of 8000 lb/h during testing on high ash and high sulfur coals. Each feeder is rated at 12,000 lb/h. To increase the feed rate and reduce the incidence of tripping, new sprockets were installed on the rotary valves to increase their speed and feed rate. This also will reduce the level in the transport hopper which should improve shaker motor and bearing performance.

At the conclusion of 1988, limestone feeder performance remained a major area of concern to the plant. Demonstrated, reliable performance of this system was required at feed rates of 12,000 lb/h in order to complete acceptance testing on high sulfur design "B" coal during 1989. Although changes to the system in 1988 mentioned above improved overall performance, the system remained a high maintenance area and suffered numerous trips. On occasions, these trips or related problems forced load reductions on the unit in order to maintain emissions compliance. Many of the problems listed above appear to be interrelated. However, the absence of instrumentation of the the feed system makes it extremely difficult to trouble-shoot. During 1989, the boiler vendor will continue to monitor and improve system performance in order to demonstrate stable, reliable operation at 12,000 lb/h feed rates required for high sulfur coal acceptance tests.

Section 5

ASH HANDLING SYSTEM PERFORMANCE AND OPERATING EXPERIENCE

This section summarizes the operating experiences of the fly ash and bottom ash disposal systems during the start-up period through 1988. 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 has required relatively high maintenance due to erosion and high pressure drop on the transport system baghouse. The bottom ash disposal system required a major modification during the reporting period to increase system capacity. The performance of these systems is discussed below.

5.1 SYSTEM DESCRIPTIONS

5.1.1 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 filling facility and the reinjection equipment. A schematic of the system is shown in Figures 5-1 and 5-2.

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, are 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 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.

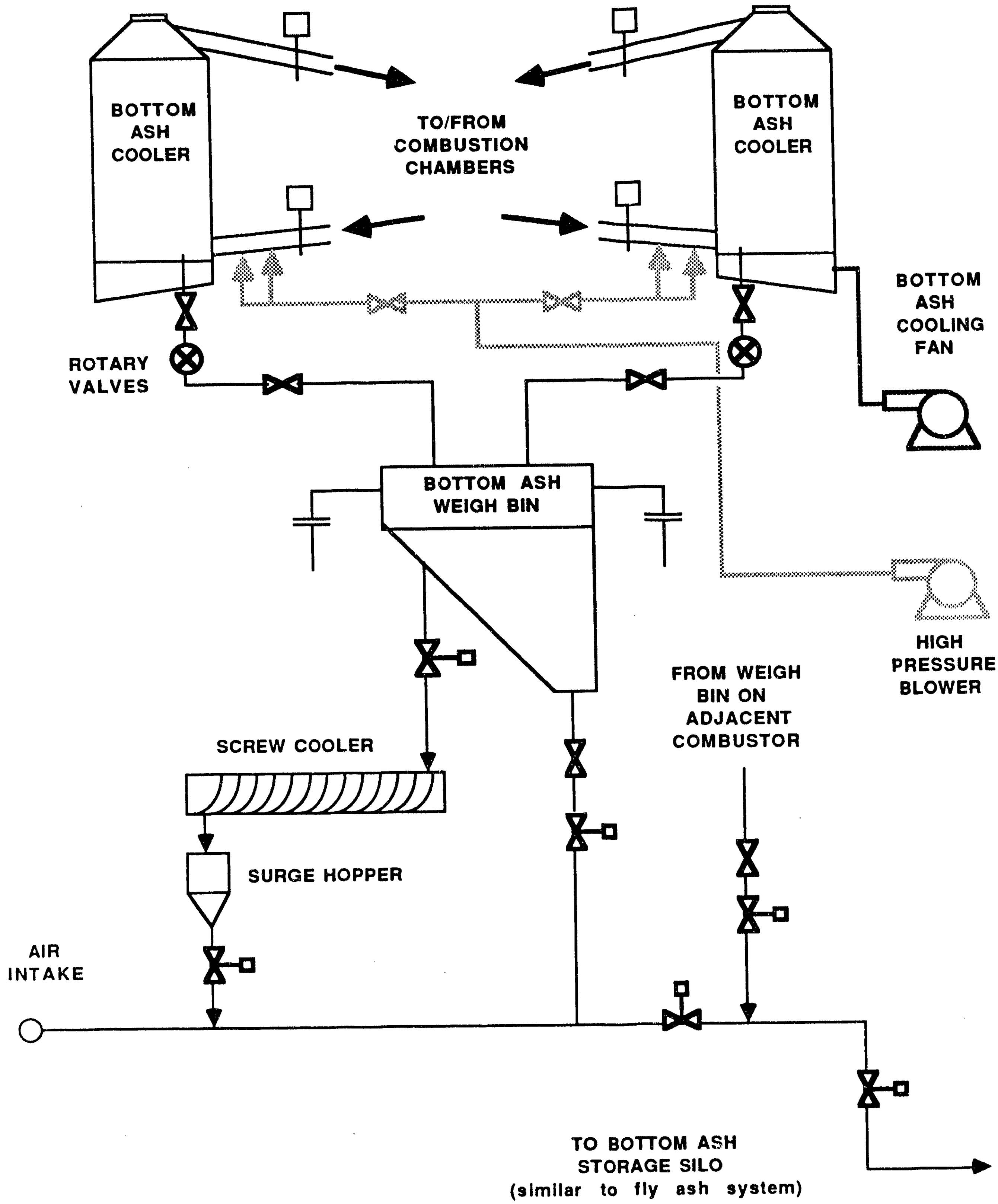


Figure 5-1. Schematic of Bottom Ash Removal System (typical of two).

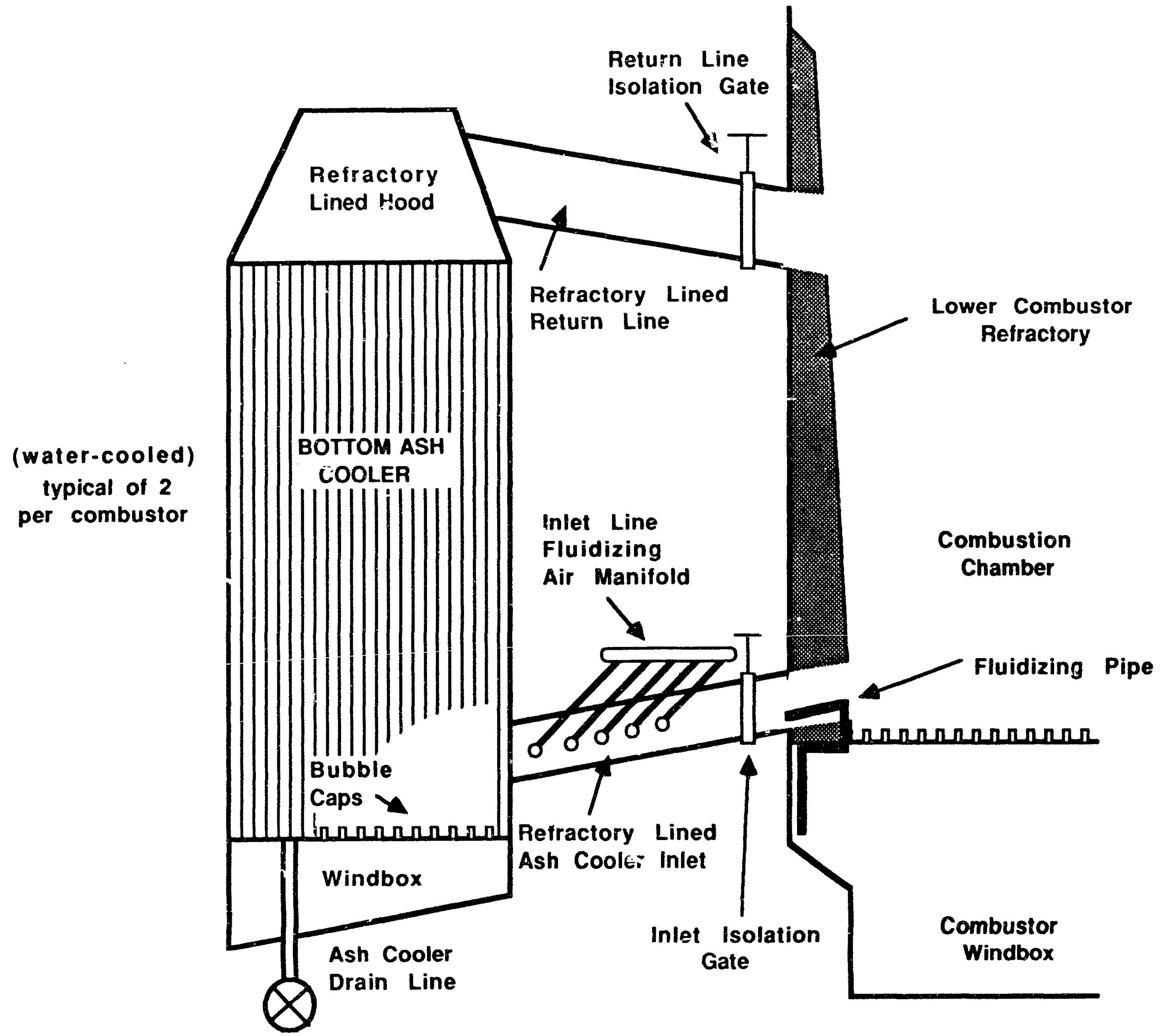


Figure 5-2. Bottom Ash Cooler Arrangement.

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. 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 coolers 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.

5.1.2 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 and air heater enclosures, and on the old and new baghouse hoppers. Fly ash is transported to a 720 ton capacity storage silo before being discharging via a condition 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 truck loading facility. The system is shown schematically in Figure 5-3.

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.

5.2 BOTTOM ASH DISPOSAL SYSTEM OPERATING EXPERIENCE

The bottom ash handling system has undergone several changes during this reporting period in order to pass acceptance tests on high ash coal. The changes include the amendment to the ash coolers to classifiers, modification to the ash cooler discharge lines, and modifications to increase ash handling capacity.

Concerning amendment of the ash cooler to classifier, control logics were altered to regulate the total air flow rate to each cooler in order to maintain the classifying velocity at a preset value. In the original control scheme, the air flow rate was held constant to each cooler and classifying velocity fluctuated with ash cooler operating pressures and temperatures. This arrangement was prone to excess temperatures in the ash coolers and clinkering on several occasions. The modified design uses motor-actuated butterfly dampers and annubars on each ash cooler air line. Classifying velocity in the ash coolers is determined based on the air flow rate measured by the annubars, the cooler cross-sectional area, and the temperature and pressure in the ash cooler. Flow is then modulated to maintain a constant velocity. This modification has reduced the incidence of high ash cooler operating temperatures and also allows the sizing of the drain and ash cooler return solids to be varied. This is accomplished by changing the fluidizing velocity set-point.

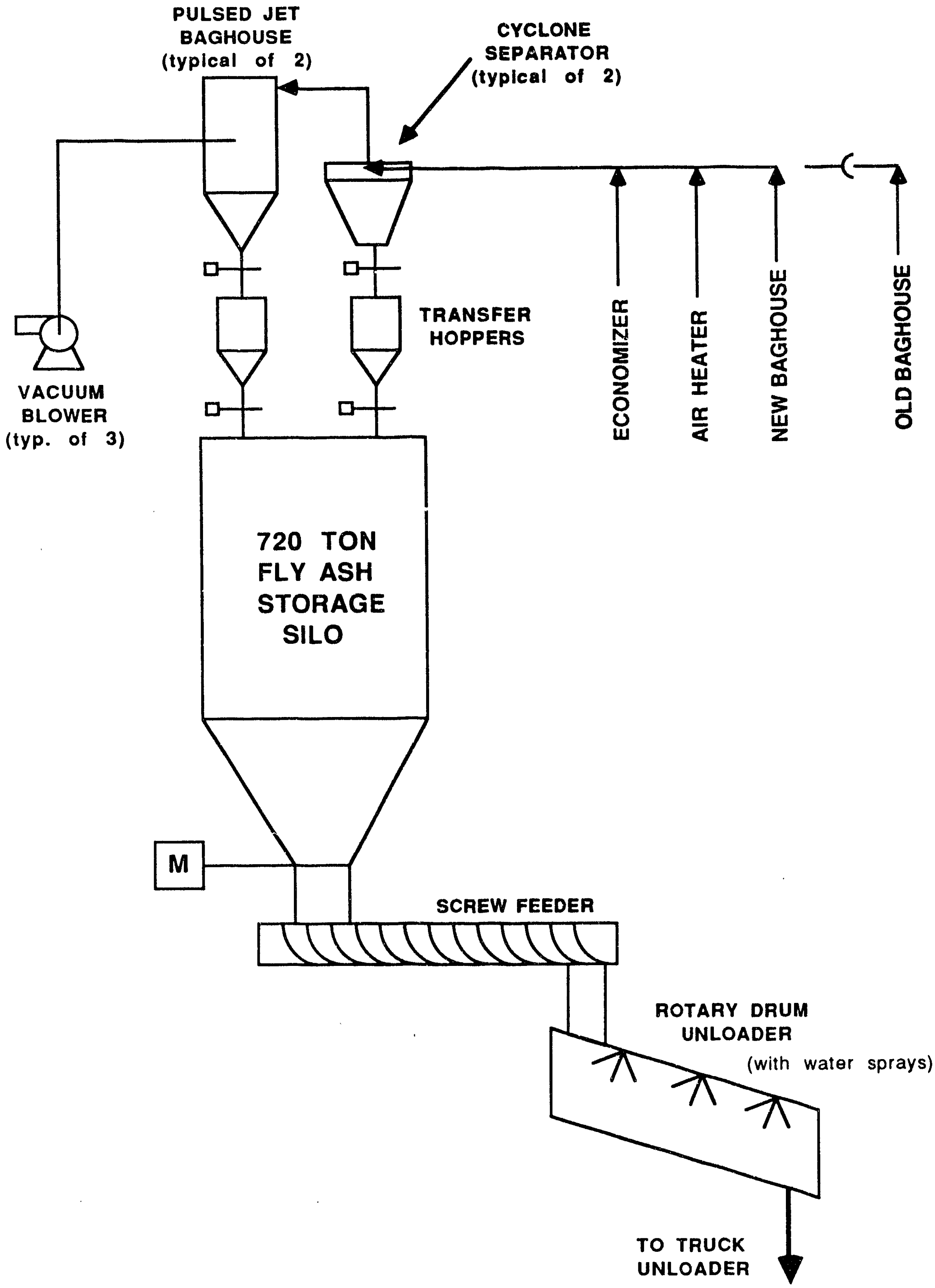


Figure 5-3. Schematic of Fly Ash Disposal System.

During this modification, refractory brick was added around the perimeter of the air distributor on each ash cooler to decrease the area by approximately 35%. This provided an increase in ash cooler fluidizing velocities. It also resulted in the decrease of approximately 20% of the cooling tube surface area. Throughout this reporting period, this has operated reliably with no adverse affects from the loss of heat transfer surface area.

Because the refractory thickness in the lower combustion chambers was increased during construction to increase air distributor fluidizing velocities, a section of the ash cooler drain line from the combustion chambers to the ash cooler was left unfluidized. This is shown in Figure 5-2 and comprises approximately the first 1.5 feet of drain closest to the combustion chamber. This unfluidized section was believed to be the source of most drain blockages. To circumvent the problem, a fluidizing pipe was installed as shown in the figure. The pipe is directed through the windbox and air distributor floor and is mounted flush with the bottom of the drain line. A series of holes drilled on the top side of the pipe provides the fluidizing air flow.

Also during the period, a minor modification was made to the ash cooler drain line from the ash cooler to the surge hopper. This region was prone to pluggage and clinkering during early start-up (prior to the logic change to ash classifiers) and removal of this material was difficult. An access port was installed above the rotary valve to allow for inspection and removal of this material.

During trial runs on high ash coal at full-load in preparation for the high ash coal acceptance tests, the bottom ash transport system from the weigh hoppers to the storage silo displayed capacity limitations of 8 tons/h. The design capacity of this system is 20 tons/h. After a thorough review by the bottom ash transport vendor, major changes to the system were made. These included modifying/simplifying the piping layout, increasing pipe size, increasing transport flow from 3800 to 5000 ft^3/min, and adding water sprays at the transport exhauster inlets to increase the volumetric flow.

Changes in piping layout and pipe size with the revised system were necessary to reduce friction losses in the ash transport line and to increase ash handling capacity. The piping arrangement within the ash pit was improved to form a single conveying line instead of two parallel lines to each combustion chamber, as shown in Figure 5-4. This eliminated the purge time and increased time for conveyance. For ease of maintenance and reduced friction loss, the number of bends was reduced and 90° elbows were replace by more gradual bends. The size of the conveying line from the plant building to the

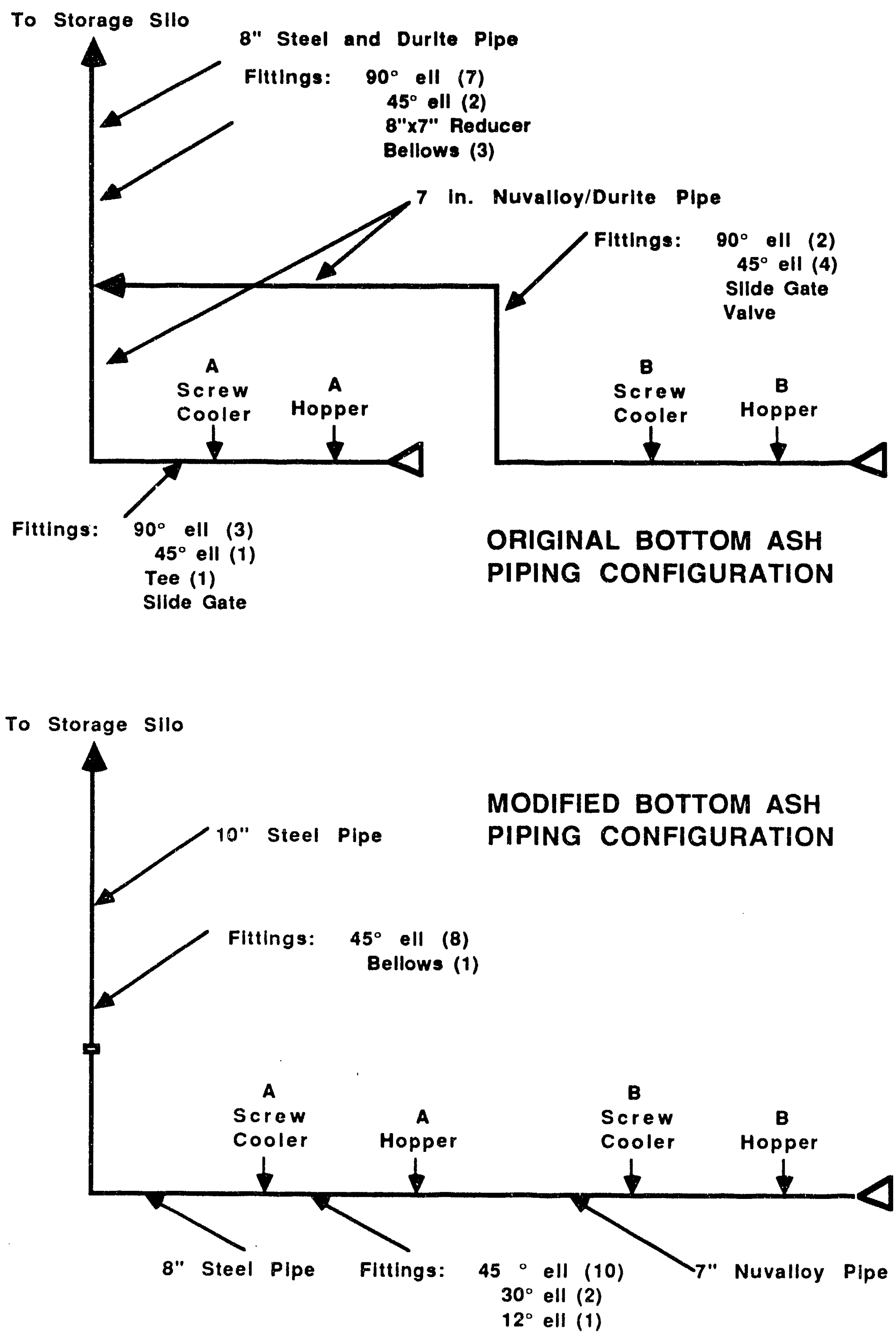


Figure 5-4. Bottom Ash Piping Modification.

top of the bottom ash silo was increased from 8" to 10" to reduce pressure drop at the higher conveying volume. Also, the air line from the separator to the exhausters was enlarged for the same purpose. All of these modifications are expected to reduce the friction loss by approximately 50 percent.

To increase volumetric capacity, the sheaves on the exhauster drive motor were replaced to increase the operating speed from 1500 to 1750 rpm. Also, to increase mass flow rate and efficiency, water sprays were added at the transport exhausters. The water injection provided a better seal and also lowered the temperature resulting in a higher vacuum.

The conveyor pickup velocity had been designed for 3800 ft^3/min after taking into account the actual sizing of the bottom ash generated at the Nucla unit. Of particular concern was the fraction of large size material not present during the pilot plant test burn. The higher flow velocities in the modified design should provide a better motive force for moving this material.

Also during these modifications, the outlet of the surge/weigh hopper to the screw cooler was modified. As shown in Figure 5-5, the original design caused bed material to back up into the drain line and eventually trip the rotary valve. This line was lowered, as shown in the figure, and corrected the problem.

During 1989, acceptance tests are planned on high ash and high sulfur design "B" coals. During these tests, the 20 ton/h system capacity of the ash coolers and bottom ash disposal system will be tested. There are no other significant problems or modifications to report during this period.

5.3 FLY ASH DISPOSAL SYSTEM OPERATING EXPERIENCE

The fly ash disposal system has demonstrated capacity during early testing on high ash and high sulfur coals, but the equipment comprising this system has been a source of relatively high maintenance. Problems have included erosion of solids separation equipment, high pressure drop across the transport system due to baghouse filter pluggage, and fly ash leakage around the shaft of the screw feeder at the discharge of the fly ash storage silo. These problems have resulted in high maintenance requirements through the first 1.5 years of operation, but have not caused anything but temporary reductions in unit load.

Erosion has occurred mainly on the inlet target area of the cyclone separator, around the dump valves on each side of the transfer hoppers, on bends located in the transport line and on the three-way valves located in the vent system. Through

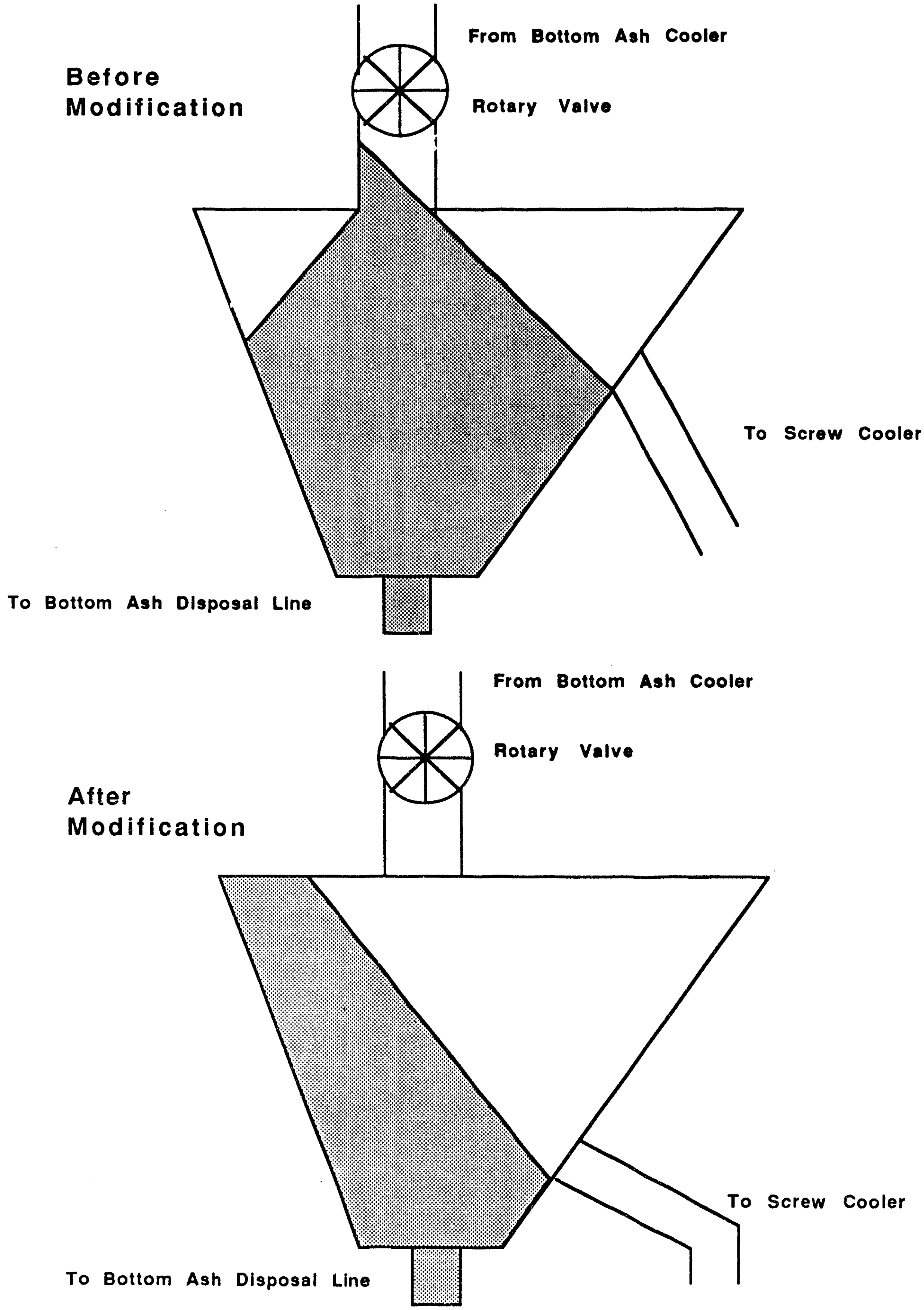


Figure 5-5. Modifications to Bottom Ash Weigh Hopper.

1988, these problem areas have been repaired/replaced with similar materials.

With high ash loads during full-load operation on high ash coal, the bag filters have plugged on numerous occasions on the pulsed-jet baghouse separator. Typically, the transport blowers are shut down and baghouse is allowed to timed through several cleaning cycles before being put back into service. Bags have been changed on this system once during this reporting period.

Leakage of fly ash around the screw feeder shaft seals at the base of the fly ash storage silo has required high maintenance. Although shaft seals have been replaced on several occasions, fugitive dust emissions continue to be a periodic problem.

Section 6

BAGHOUSE OPERATION AND PERFORMANCE

6.1 BAGHOUSE MONITORING PLAN

Table 6-1 gives design information on the three existing baghouses, numbers 1, 2, and 3, and the new baghouse, number 4. Figure 6-1 shows the general arrangement of the baghouses at Nucla. A detailed baghouse monitoring plan was developed by Southern Research Institute (SoRI), a contractor to EPRI. The baghouse monitoring plan was issued in draft form on October 1, 1987 and was included in the overall detailed test plan document. The following discussion summarizes the baghouse monitoring plan.

The baghouse monitoring plan focuses on the effects of particulates on the baghouse operability and performance. Baghouse particulates, both physical properties and loading, and bag material will be monitored along with operating conditions in an effort to develop guidelines for atmospheric fluidized bed combustion (AFBC) baghouse specifications. These specifications may include bag type, cleaning method, and air/cloth ratio.

Instrumentation on the new baghouse, number 4, includes tube sheet ΔP transmitters, an overall baghouse ΔP transmitter, a gas flow measurement airfoil, as well as individual baghouse flow monitor (IBFM) sensors installed on six bags in compartment E. Instrumentation installed on baghouses 1, 2, and 3 include tube sheet ΔP transmitters, overall baghouse ΔP transmitters, and six IBFM sensors installed in baghouse 2 in each compartment P and Q.

Compartment Q of baghouse 2 has an experimental bag material, which is identical to the material used in every other compartment of the baghouses, only the bags were manufactured with the warp-in configuration, rather than the warp-out. This means that the texturized side of the fabric is facing the clean side of the gas stream. This configuration is referred to as having a 25% exposed surface texturization. The bags in the remainder of the compartments of all the baghouses have the normal 75% exposed surface texturization. Previous testing, with reverse-gas cleaning, conducted by EPRI at the Arapahoe Test Facility indicated that a lower surface texturization could result in lower residual dust cake weights without compromising drag or emissions for pulverized coal fly ash. The IBFM sensors will be used to compare the performance of the experimental bags in compartment Q with the bags in compartment P.

Table 6-1

Design Information on Colorado-Ute Nucla Station Baghouses

Unit	Baghouse 4A	Baghouse 1, 2, 3
Baghouse manufacturer	Research-Cottrell	Wheelabrator-Frye
Number of compartments	12	6
Bags per compartment	180	112
Bag size	8 in. x 22 ft	8 in. x 22 ft
Bag manufacturer and model number	Fabric Filters # 504	Fabric Filters # 504
Bag description	3x1 twill, warp out, 10% Teflon B	3x1 twill, warp out, 10% Teflon B
Bag cleaning method	Shake/deflate	Shake/deflate
Bag cleaning initiation	Pressure drop, batch clean, up to 360 s delay between compartments	Pressure drop, batch clean, up to 360 s delay between compartments
Baghouse cleaning setpoint	6 in. wc.	7 in. wc.
Deflation air/cloth ratio	0.3 acfm/sq ft	0.3 acfm/sq ft
Shake frequency	3 Hz.	3 Hz.
Shake amplitude	1 in.	1 in.
Cleaning sequence	Null (25 s), deflate (45 s), shake (5 s, 15 s after deflate starts), null (15 s)	Null (25 s), deflate (45 s), shake (5 s, 15 s after deflate starts), null (15 s)
Bag tension	60 lb	60 lb
Design filtering air/cloth ratio,	2.24 acfm/sq ft (gross)	2.24 acfm.sq ft (gross)
based on all 30 compartments and	2.50 acfm/sq ft (net)	2.50 acfm/sq ft (net)
full load flow of 214,000 acfm	2.76 acfm/sq ft (net-net)	2.76 acfm/sq ft (net-net)
Cloth area per bag	44.31 sq ft	44.31 sq ft
Cloth area per compartment	7,967 sq ft	4,963 sq ft
Cloth area per baghouse	95,712 sq ft	29,778 sq ft
Compartment isolation available	Yes	Yes
Purge system available	Yes	No
Baghouse bapass available	Yes	No
High inlet temp. bypass	320 °F	320 °F
Low inlet temp. bypass	180 °F	180 °F
High pressure drop bypass	9 in. wc.	9 in. wc.
Hopper size per compartment	230 cu. ft.	98 cu. ft.

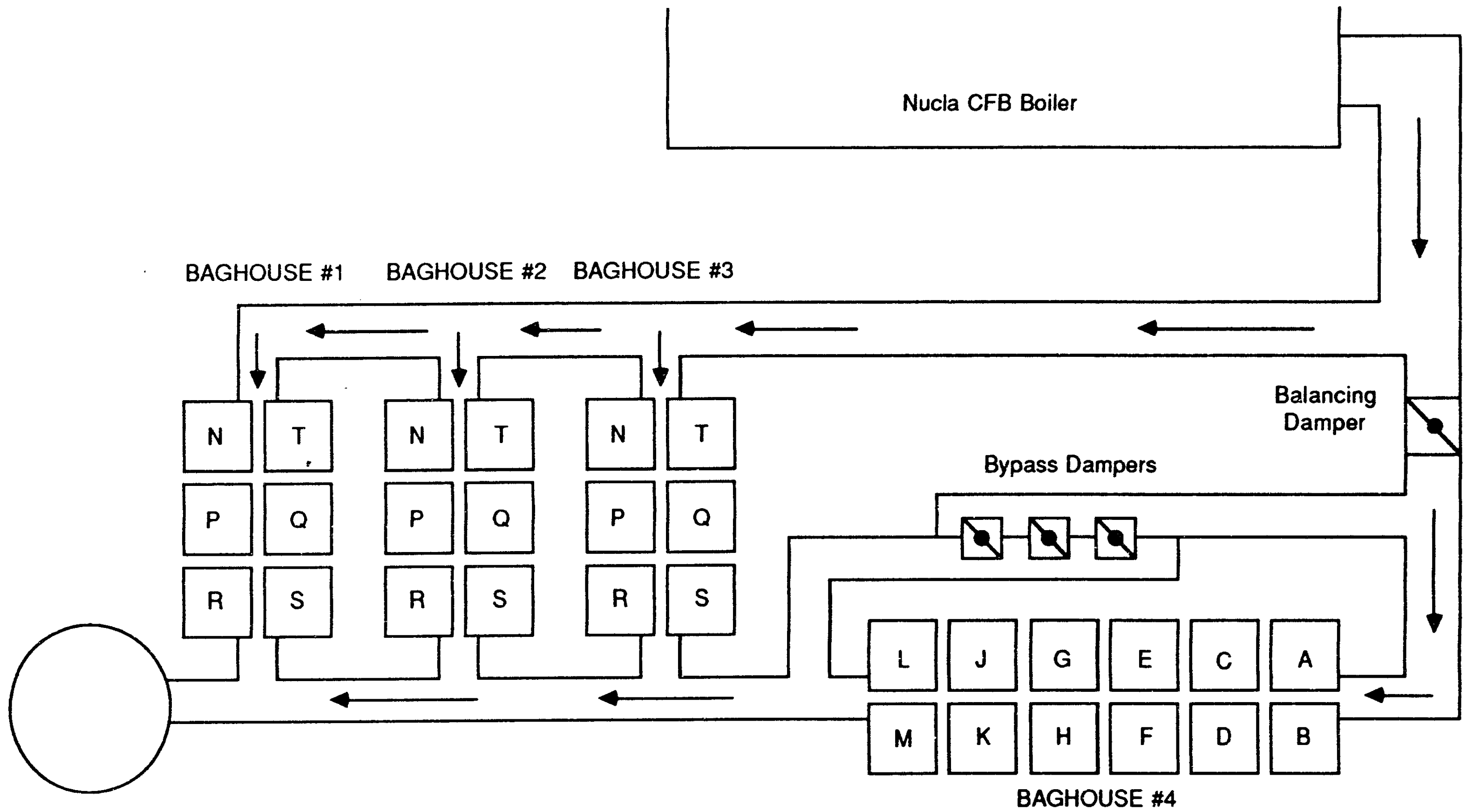


Figure 6-1. General Arrangement of the Baghouses at Nucla

Measurements associated with the baghouse monitoring plan include routine measurements of the baghouse and tube sheet ΔP's for all baghouses during all performance test periods. Pressure drop and drag (pressure drop divided by air/cloth ratio) will be plotted versus the air/cloth ratio for comparison with other baghouses. Operating history of the baghouses will also be maintained to determine bag life and any unusual maintenance occurrences. Periodic inlet and outlet particulate loading measurements will be taken to evaluate the collection efficiency of the baghouses. Size distributions will also be obtained during these periodic tests to determine the fractional collection efficiency. Samples of baghouse ash will be tested for physical properties relevant to baghouse performance. In addition, whole bags will be removed periodically for inspection and tested for residual dust cake and residual drag. Weigh measurements of individual bags will also be performed to determine the amount of residual dust cake adhering to the bag material in compartment P and Q of baghouse 2 and compartment E of baghouse 4.

A more complete description of the baghouse monitoring plan can be found in the Colorado-Ute Test Plan document issued by EPRI.

6.2 INITIAL RESULTS

No performance tests were conducted during the reporting period. Therefore there was no actual baghouse test data to report. Most of the activities regarding the baghouses involved installation of special monitors and calibration of the available instrumentation in preparation for the performance tests. Several times during the reporting period SoRI visited the site. During each visit, data was obtained to allow calculation of preliminary results of drag, baghouse ΔP and air/cloth ratio. However, due to the uncalibrated nature of the instrumentation used, this data is suspect, and is only presented here as an example of the types of measurements that will be made.

The airfoil measuring the flue gas flow rate to baghouse 4 was calibrated during the first quarter of 1988. Traverses with the Fechheimer probe indicated a flow rate of 745 Klb/hr versus an indicated flow rate of 695 Klb/hr on the Westinghouse control system. Examination of the differential pressure transmitter on the airfoil revealed that it had been installed at a low point for the tubing, making it susceptible to accumulation of condensate. After relocating the transmitter and tubing, and ensuring that all of the sensor lines were clear, the airfoil calibration was again checked. This time the Fechheimer probe indicated a flow rate of 735 Klb/hr while the Westinghouse control system showed a flow rate of 733 Klb/hr. Following this, calibration traverses were performed at 40% load and 80% load. Corrections to the DCS calculated flow rate were made to conform to the results of the calibration runs.

On March 26, 1988 data was obtained from a steady-state operating period at full load. The baghouse temperature differential was found to be in the range of 20 to 25 °F after correction for a suspected error in the single-point temperature measurement at the outlet of the baghouse. During the gas flow traverses with the Fechheimer probe, it was discovered that the single point outlet temperature measurement on the Westinghouse system read approximately 50 °F too low. The single-point inlet temperature to the baghouse was checked by plant operators, and is believed to be correct. During this time period, the baghouse flange-to-flange pressure drop averaged 5.7 in.wg. and the air/cloth ratio was calculated to be 2.54 acfm/ft^2. The average tube sheet pressure drop during this time was 4.5 in.wg., and the average drag was found to be 1.8 in.wg./(ft/min).

During the October 7, 1988 performance test conducted by CUEA the baghouse performance guarantees were met. These guarantees include baghouse pressure drop with:

- All compartments in service.
- One and two compartments out of service.
- Two compartments out of service during soot blowing.

Opacity guarantees are also included under these conditions.

6.3 IBFM SENSORS

The IBFM monitors were installed in compartments P and Q of baghouse 2 and in compartment E of baghouse 4 during the week of April 11, 1988. Figures 6-2 and 6-3 show the location of the IBFM monitors in baghouse 2, compartments P and Q, and baghouse 4, compartment E, respectively. In compartments P and Q of baghouse 2, thimble locations D4, D8, D12, E2, E6, and E10 were chosen in which to install the IBFM sensors. In baghouse 4 the IBFM sensors were installed in thimble locations F5, F9, F10, G3, G7, and G11 of compartment E.

The IBFM sensor is essentially a flow orifice that is installed at the inlet to an individual bag. Installation of the sensor involves removing the bag, installing silicon gasket material between the tube sheet and the sensor below the thimble, installing the sensor into the thimble and attaching it to the tube sheet with all-thread bolts, and reinstalling the bag. The sensor has two pressure taps which are connected to a differential pressure transmitter located outside of the baghouse. Copper tubing is connected to the

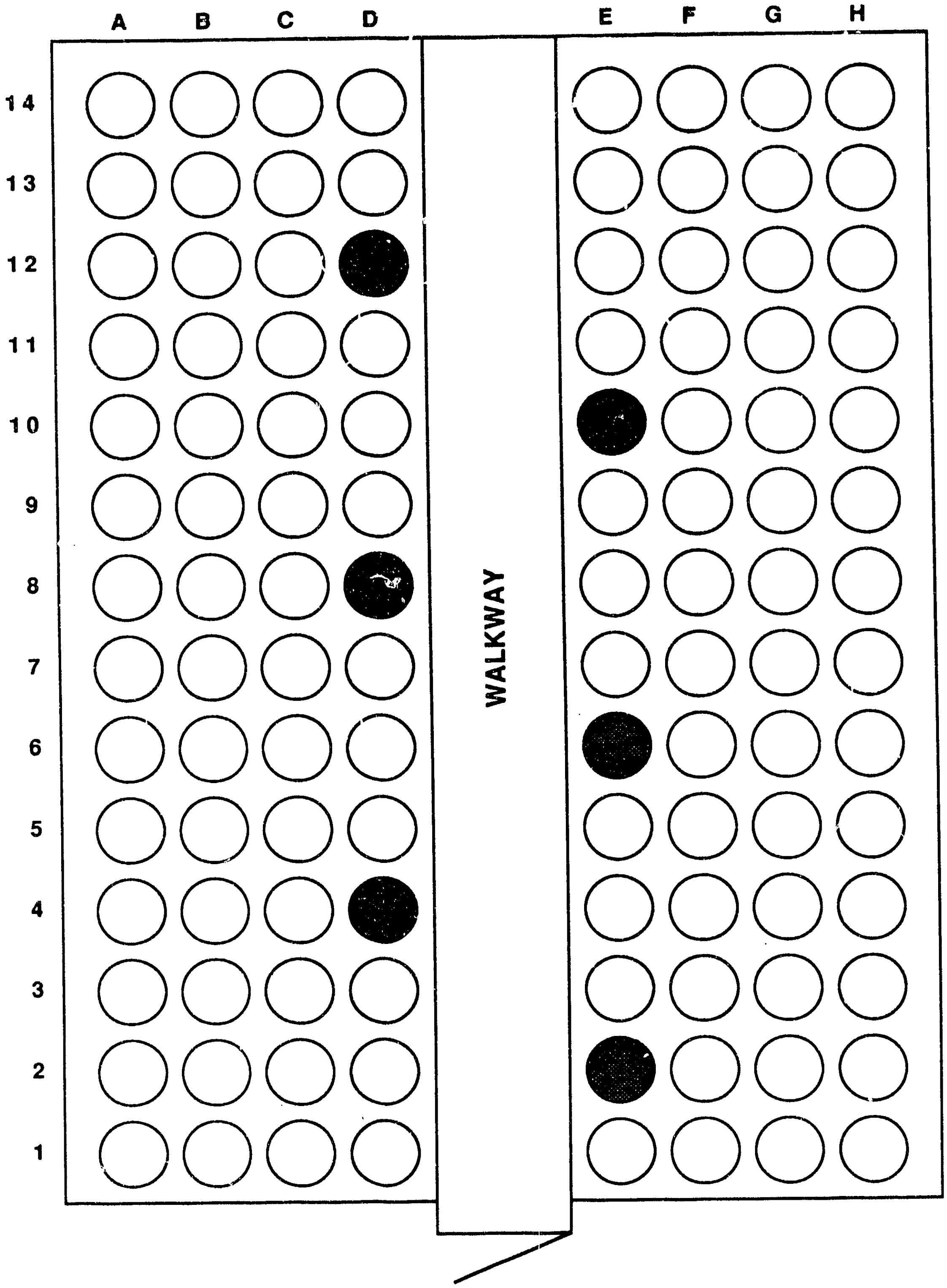


Figure 6-2. Location of IBFM ensors in Baghouse 2
Compartments P and Q.

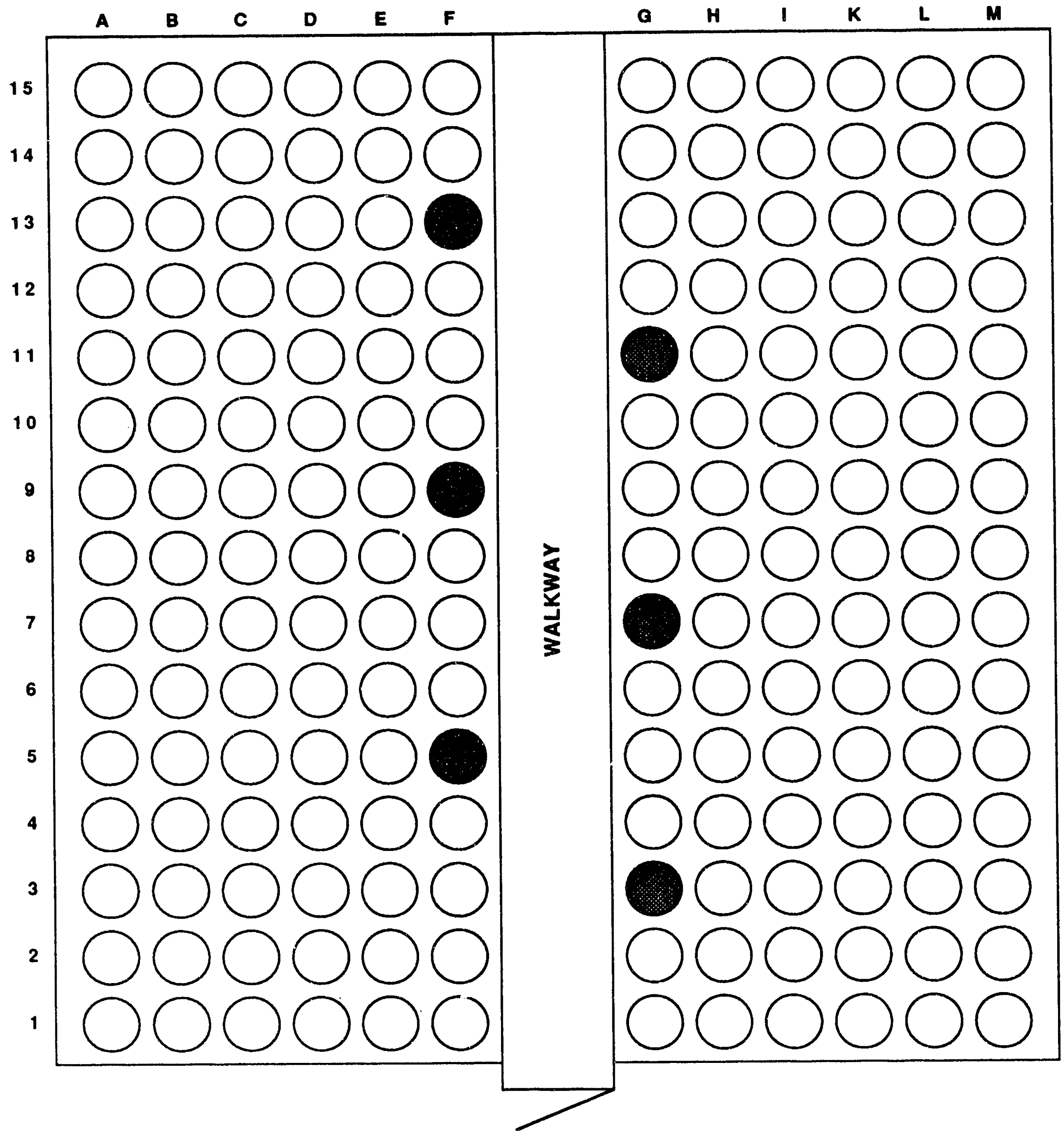


Figure 6-3. Location of IBFM Sensors in Baghouse 4A
Compartment E

pressure taps on the sensors and to bulkhead fittings installed in the baghouse wall. Vinyl tubing was used to connect the bulkhead fittings to differential pressure transmitters located outside of the baghouse. A thermocouple was also installed in each compartment and tied to the copper tubing approximately one-third of the way into the baghouse.

During the installation of the sensors, it was observed that compartments P and Q of baghouse 2 had approximately 2 inches of fly ash laying on the clean side of the tube sheet and approximately 1/4 inch of fly ash coating the clean side of the bags. However, no obvious bag failures were found. In baghouse 4 compartment E there was a fine layer of fly ash coating the entire compartment.

Installation of the IBFM sensors was quite difficult. In compartment E of baghouse 4, the thimbles are beveled at the tube sheet. As a result of this beveling, the flat surface where the sensor could be properly seated was 8-3/4 inches in diameter rather than the 8 inch diameter of the thimble as expected. The sensors are 8-1/2 inches in diameter. Initially, the sensors were installed with the silicon gasket filling the gap between the sensor and the tube sheet. In compartments P and Q of baghouse 2 reinstallation of the bags was difficult due to the short length of the bags. One bag in compartment Q (D4) had to be cut in order to complete the installation. Final connection of the sensors to the differential pressure transmitters was not completed during this week due to a shortage of vinyl tubing.

During the week of June 15 1988, representatives of SoRI returned to complete the installation of the probes. The remaining pressure transmitters were connected. Compartment E of baghouse 4 was removed from service to inspect the sensors. A small pile of fly ash surrounding one of the six sensors indicated a possible leak (location G7). The sensor was removed from this location and it was found that the gasket material had developed a small leak. Since no additional gasket material was available, the bag was replaced without a sensor. Thus baghouse 4 compartment E will have only five IBFM sensors.

During the fourth quarter of 1988, all five remaining IBFM sensor gaskets in baghouses 4 compartment E were found to have failed. Accordingly all of the sensors in this baghouse were removed until a more secure installation could be obtained. Details of these failures are given in Section 6.4 with the discussion of bag failures, which follows.

6.4 BAG FAILURES

During the initial installation of the IBFM monitors, evidence of fly ash on the clean side of the baghouse was found in compartments P and Q of baghouse 2 and, to a lesser extent, in compartment E of baghouse 4. At that time, no broken bags were found. Compartments B, F, and H in baghouse 4 were also inspected and found to have fly ash on the clean side. Most of this leakage appeared to be due to improper installation of the bags.

On August 12, 1988 during the outage period, an inspection of baghouse 4 was made. All 12 compartments were inspected by the test team. The bags were found to be in good condition. No rips or tears were found, and each bag was securely attached to the tube sheet. On a few bags, loose stitching in some small areas was noted, but this was not believed to be a problem since the bags were double stitched. A layer of fly ash was found in all of the compartments. The depth of fly ash measured between 2 and 6 inches. It is suspected that fly ash may be leaking around the snap-ring bag attachment at the base of the bag.

During the fourth quarter of 1988, serious bag failures began appearing. A total of 123 bags in five compartments had to be replaced due to tears in the bag material. Three bags were replaced in compartment 1-T (baghouse 1 compartment T). Twenty six bags were replaced in compartment 2-P, 17 in compartment 2-Q, and 61 in compartment 2-S. Several bags in compartment 2-S were replaced more than once. Sixteen bags were replaced in compartment 4-E.

Figure 6-4 shows the location of the torn bags in compartment 1-T. The failed bags were torn 1 to 2 feet from their top connection. This is the only compartment where tears were found at the tops of the bags. Most of the other bag failures occurred in the lower 2 feet of the bag.

Figures 6-5, 6-6, and 6-7 show the bags that failed in compartments 2-P, 2-Q, and 2-S. By far, the most bag failures were found in baghouse number 2, with the most being in compartment 2-S. Several bags in compartment 2-S were replaced more than once, indicating a severe failure mechanism. The bags failed between 1 and 2 feet above the bottom connection of each bag. The bag material in the area of the tears appeared to be threadbare.

Figure 6-8 shows the bag failures found in compartment 4-E. Five of the bags that failed were mounted on the IBFM sensors, and had torn 1 to 2 inches above the bottom band clamp connections. These tears appeared to have been the result of rubbing between the bags and the top of the IBFM sensors during the shake operation. Bag degradation was probably accelerated by roughened IBFM sensor top surfaces in

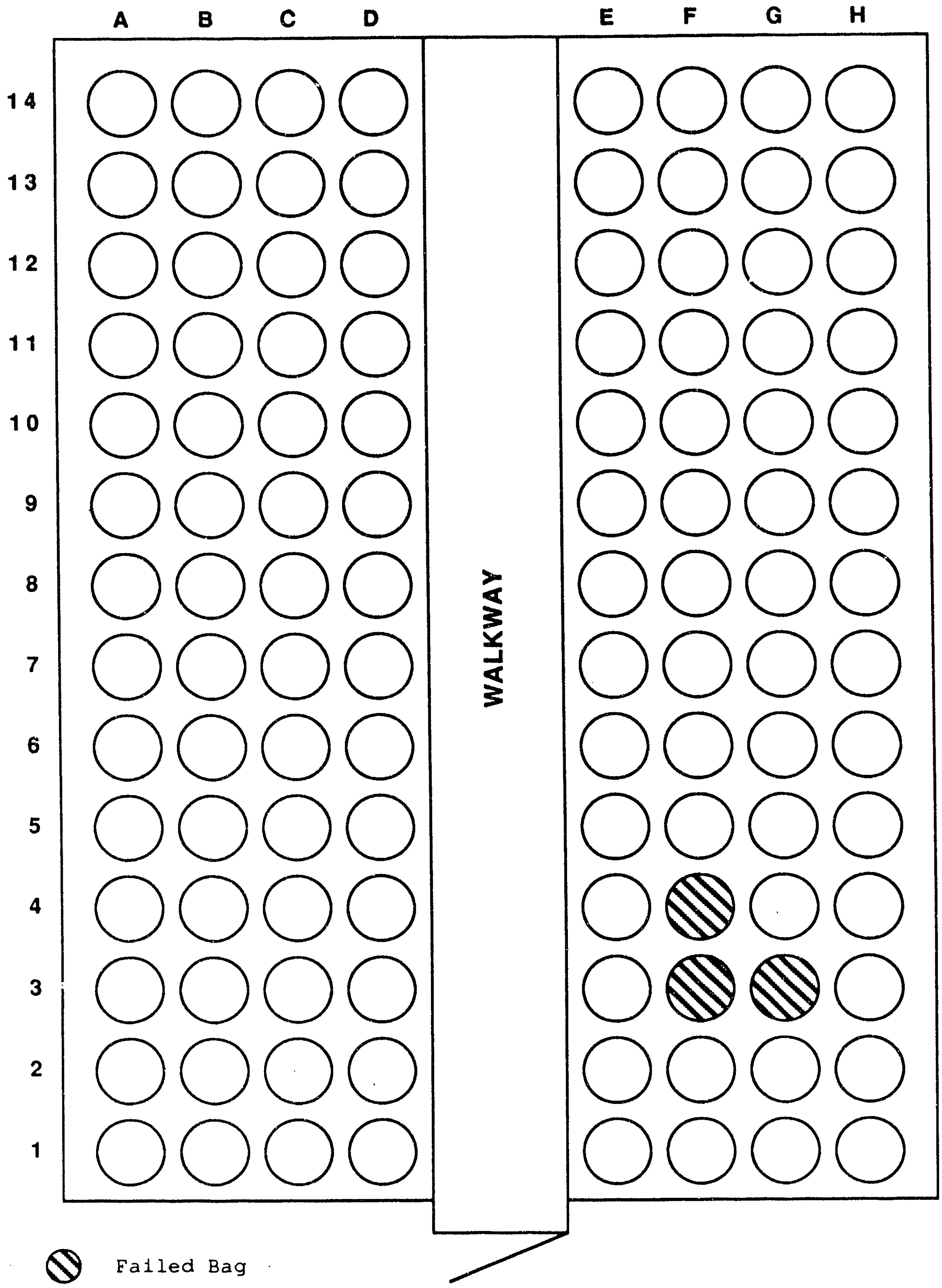


Figure 6-4. Location of Failed Bags in Compartment 1-T.

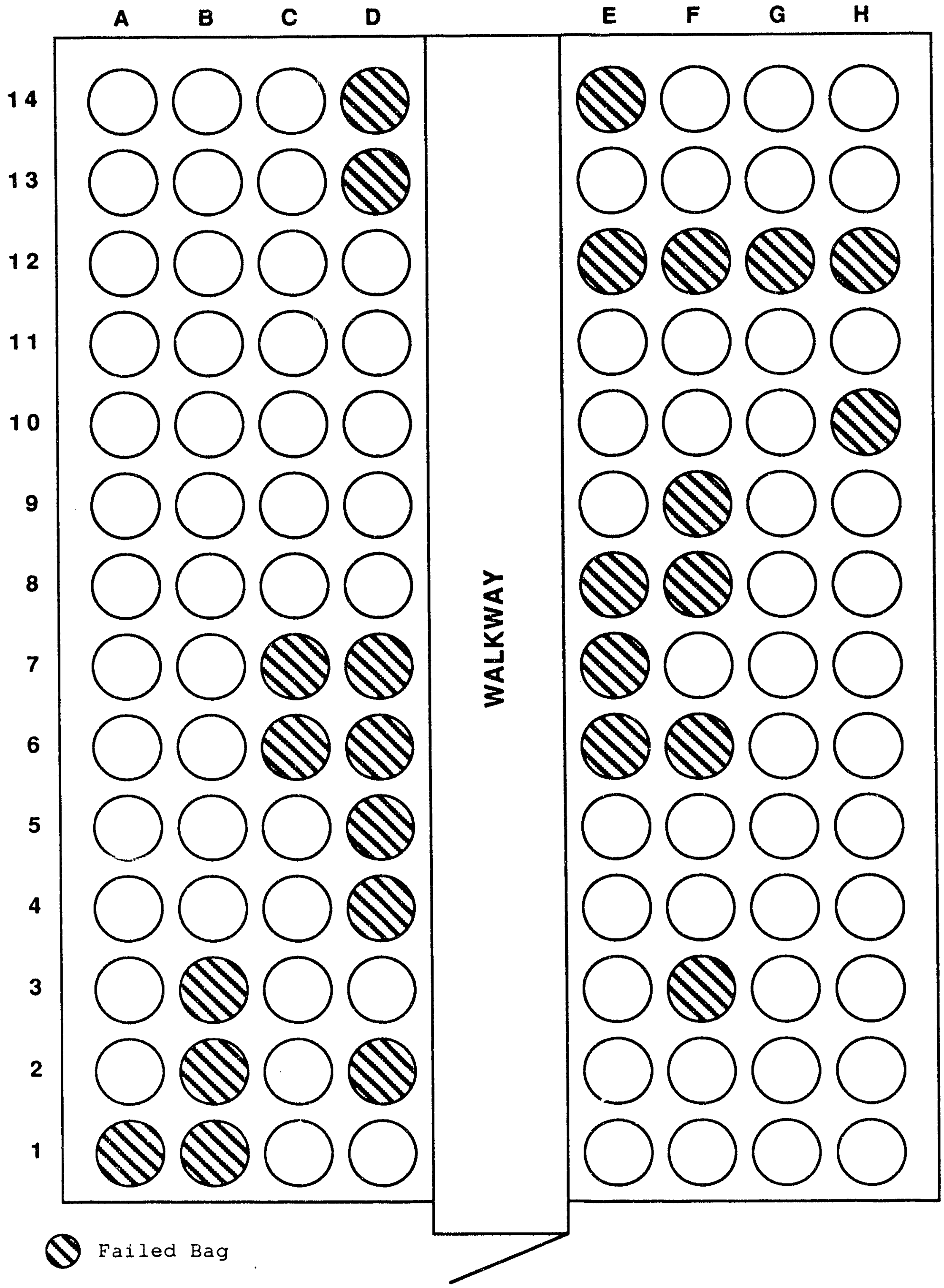


Figure 6-5. Location of Failed Bags in Compartment 2-P.

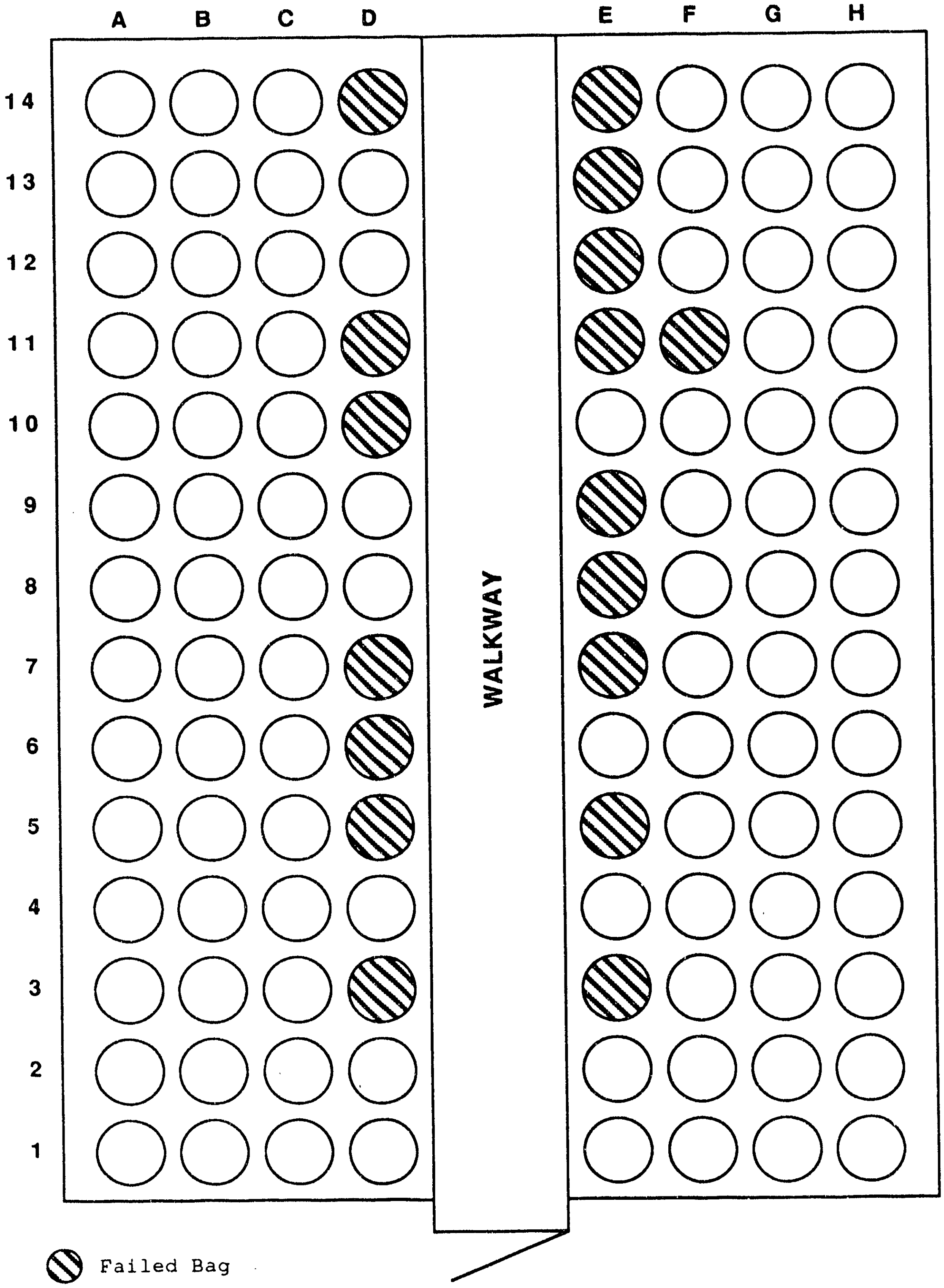


Figure 6-6. Location of Failed Bags in Compartment 2-Q.

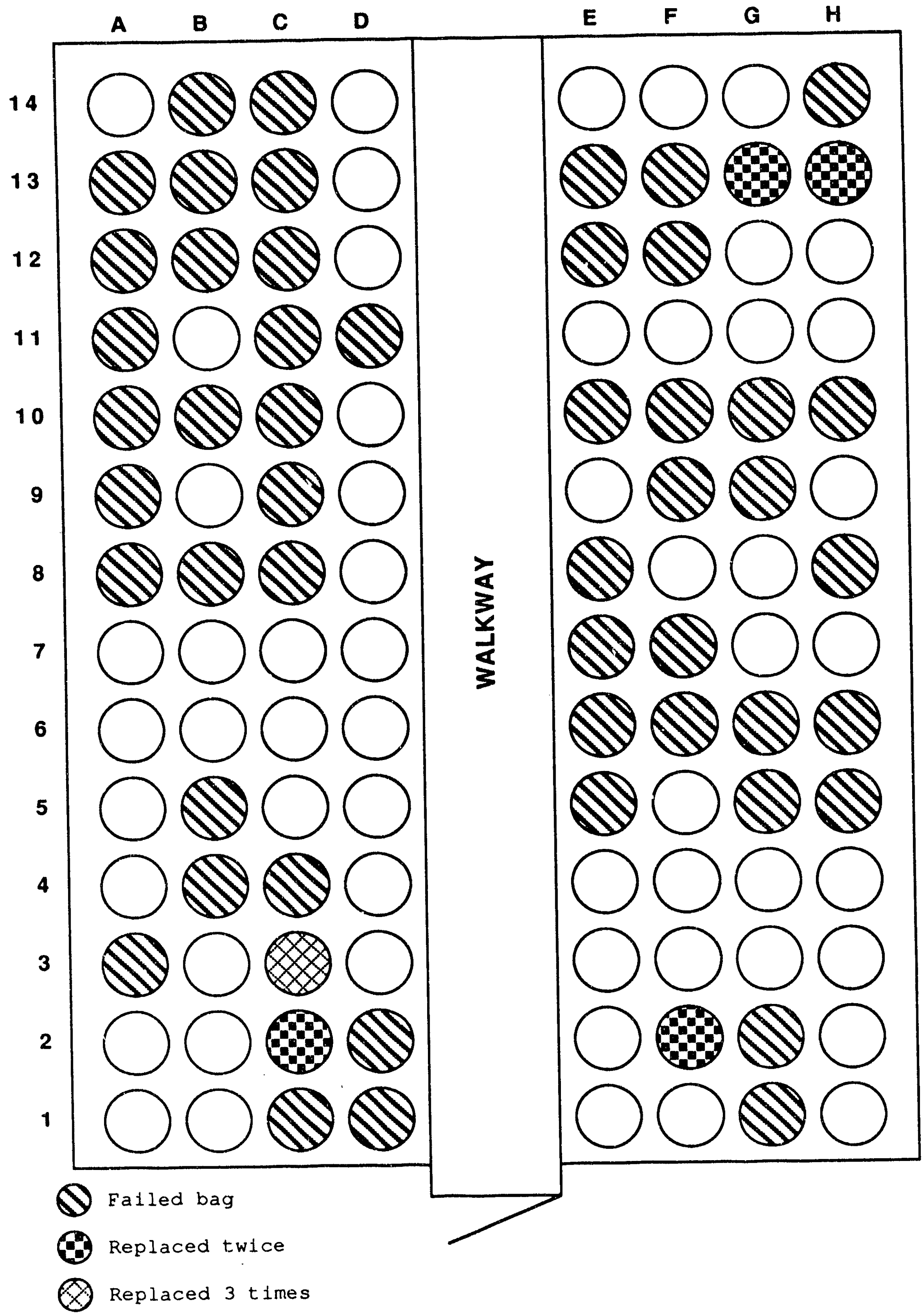


Figure 6-7. Location of Failed Bags in Compartment 2-S.

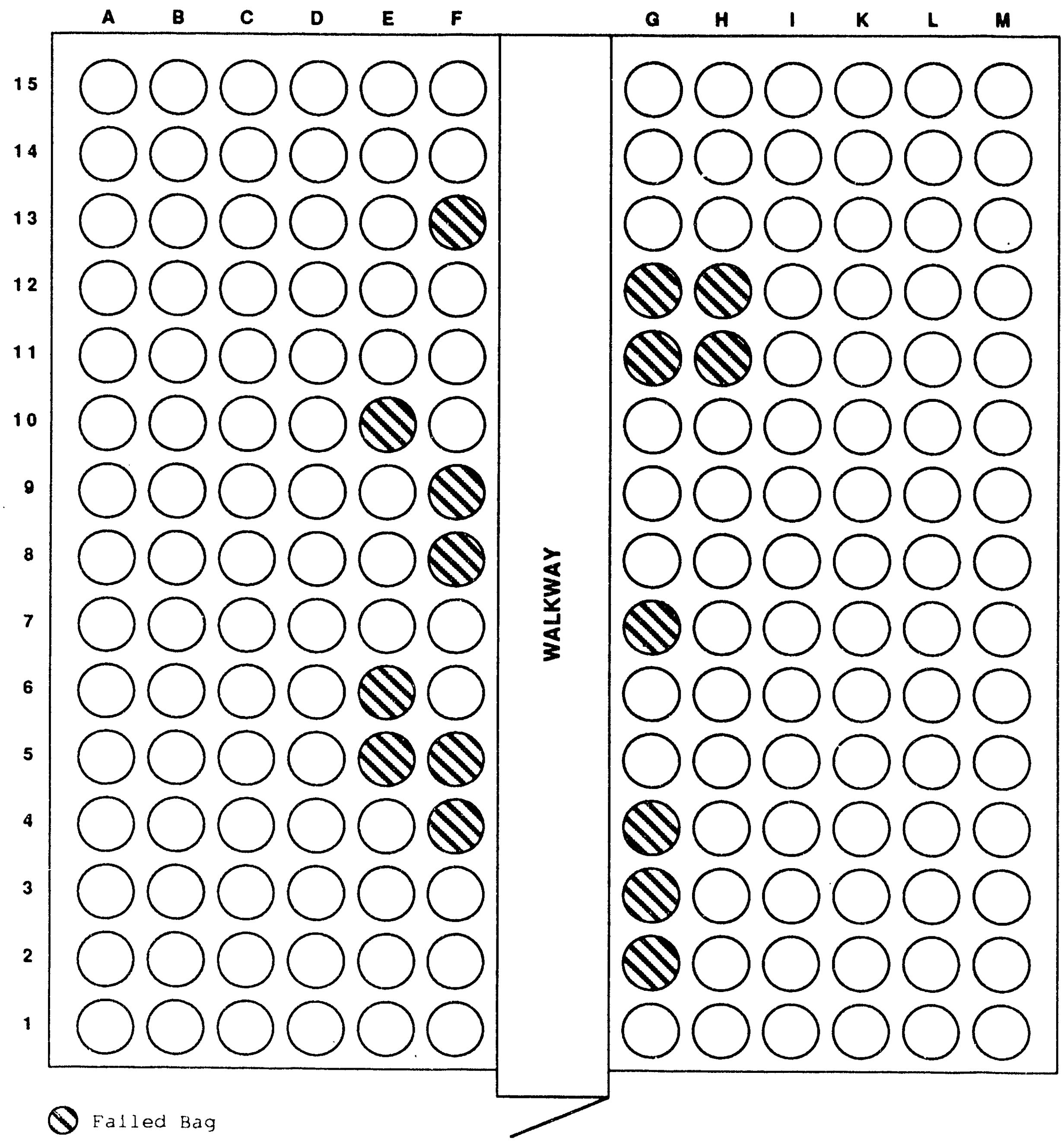


Figure 6-8. Location of Failed Bags in Compartment 4-E.

the weld attachment area. The 11 other bags replaced in this compartment, which were adjacent to one of these five bags with IBFM sensors, were torn approximately 2 inches above the bottom connection on each bag. Gas impingement from leaking IBFM gaskets may have caused these failures. All five IBFM sensor gaskets were found to have failed. These sensors were removed until better installation mounts could be developed.

At the request of SoRI, three failed bags from compartment 4-E, two failed bags from compartment 2-S, and an unused bag were sent to Grubb Filtration Testing Services, Inc. Results of this analysis were not available in the reporting period and will be reported in the 1989 Annual Report.

SoRI has been kept informed about the premature bag failures and has speculated that excessive cleaning, due to over inflation during the deflate cycle, is a primary cause of the bag failures not associated with the IBFM sensors. SoRI also stated that the practice of shaking the bags during the deflation cycle may be compounding the bag wear by putting additional stresses on the bag material. Recommendations were made to change the baghouse cleaning cycle logic to shake the bags after the deflation cycle and measuring the deflation air pressure drop for each baghouse compartment. These suggestions will be carried out early in 1989.

Section 7

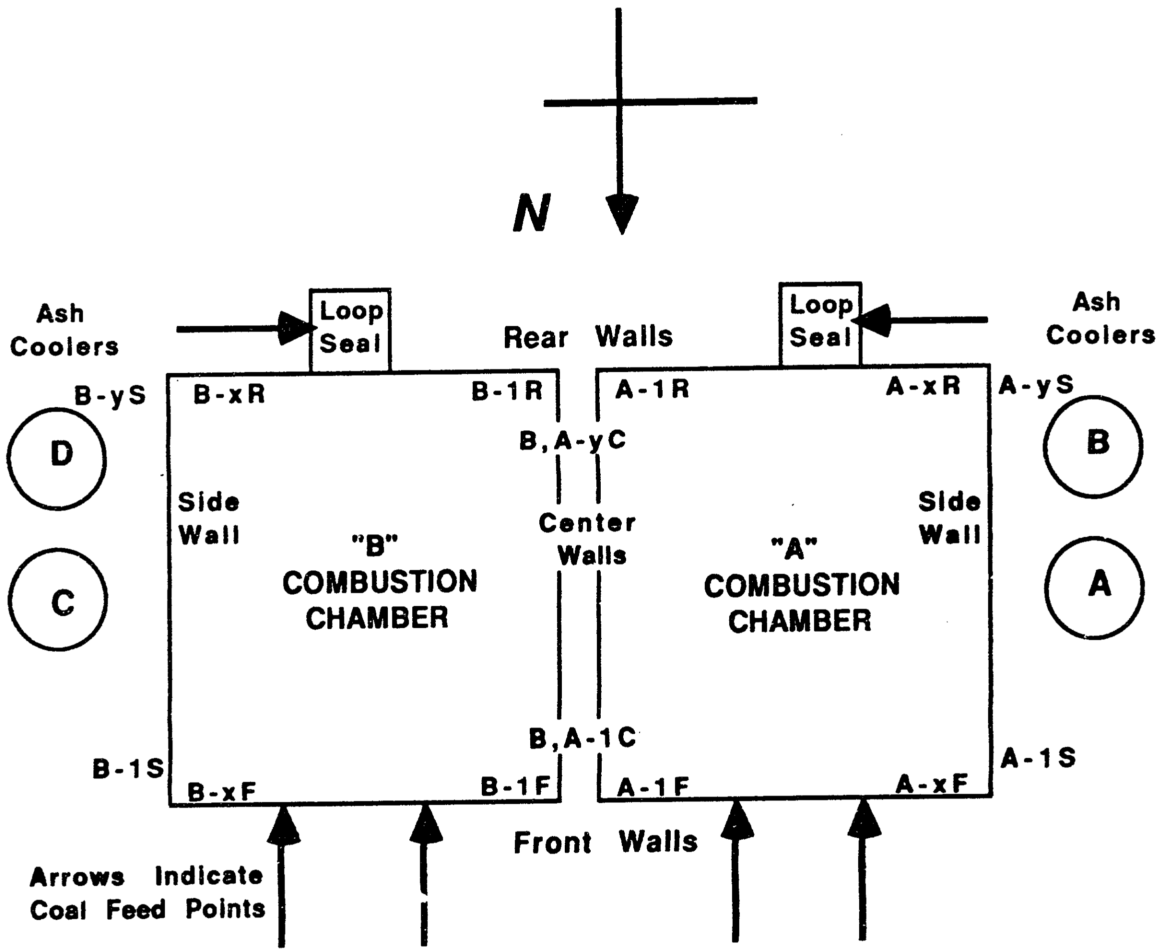
MATERIALS MONITORING PLAN

The test plan for materials monitoring at Nucla is based on periodic inspections of CFB-related boiler components over the normal course of unit operation. Inspections include photographic surveys, tube wall thickness measurements, and inspection reports of CFB-related materials components. A baseline inspection plan was developed and implemented prior to first coal firing in February/March 1987. This plan concentrated primarily on fireside metal and refractory components. Tube thickness measurements were taken after 600 coal burning hours during repairs from the overheat incident in November 1987, and after 3600 coal burning hours in August 1988. These three inspections are discussed in this report along with an expanded version of the original inspection plan. The latter was developed to assist in standardizing inspection reporting for the duration of the test program. At the conclusion of 1988, the unit operated on coal for a total of 5426 total hours since initial coal firing in June 1987.

7.1 BASELINE PLAN

The baseline inspection plan consisted of a photographic survey of boiler pressure and refractory parts along with ultrasonic thickness measurements of select water-wall and superheater tubes. The intent of the latter was to obtain a statistical determination of nominal tube wall thicknesses. Tube measurements were taken by the on-site test team on February 20, 1987 in combustor A and on March 3, 1987 in combustor B. Tube preparation consisted of hard-wire brushing the measurement point and application of an acoustic gel to the area prior to measurement. A Krautkramer-Branson DM-2 UT measurement meter was used with a 0.25 inch diameter probe head. The tube numbering convention adopted for these measurements and those for the remainder of the Phase I and II test programs is shown in Figures 7-1 and 7-2.

The exact measurement locations on water-wall and superheater tubes were not punch-marked because of concerns over creating potential erosion sites. As a result, measurements were taken to acquire a statistical representation of tube wall thicknesses. Water-wall tube measurements were taken approximately 6 inches above the lower combustor refractory interface (just above the weld overlay). Fifteen thickness measurements were taken on each wall of both combustion chambers. Superheater II tube measurements were taken on



EXAMPLE: B-66F is tube number 66 on the Front wall of the "B" combustor.

Figure 7-1. Waterwall Tube Numbering Scheme at Nucla.

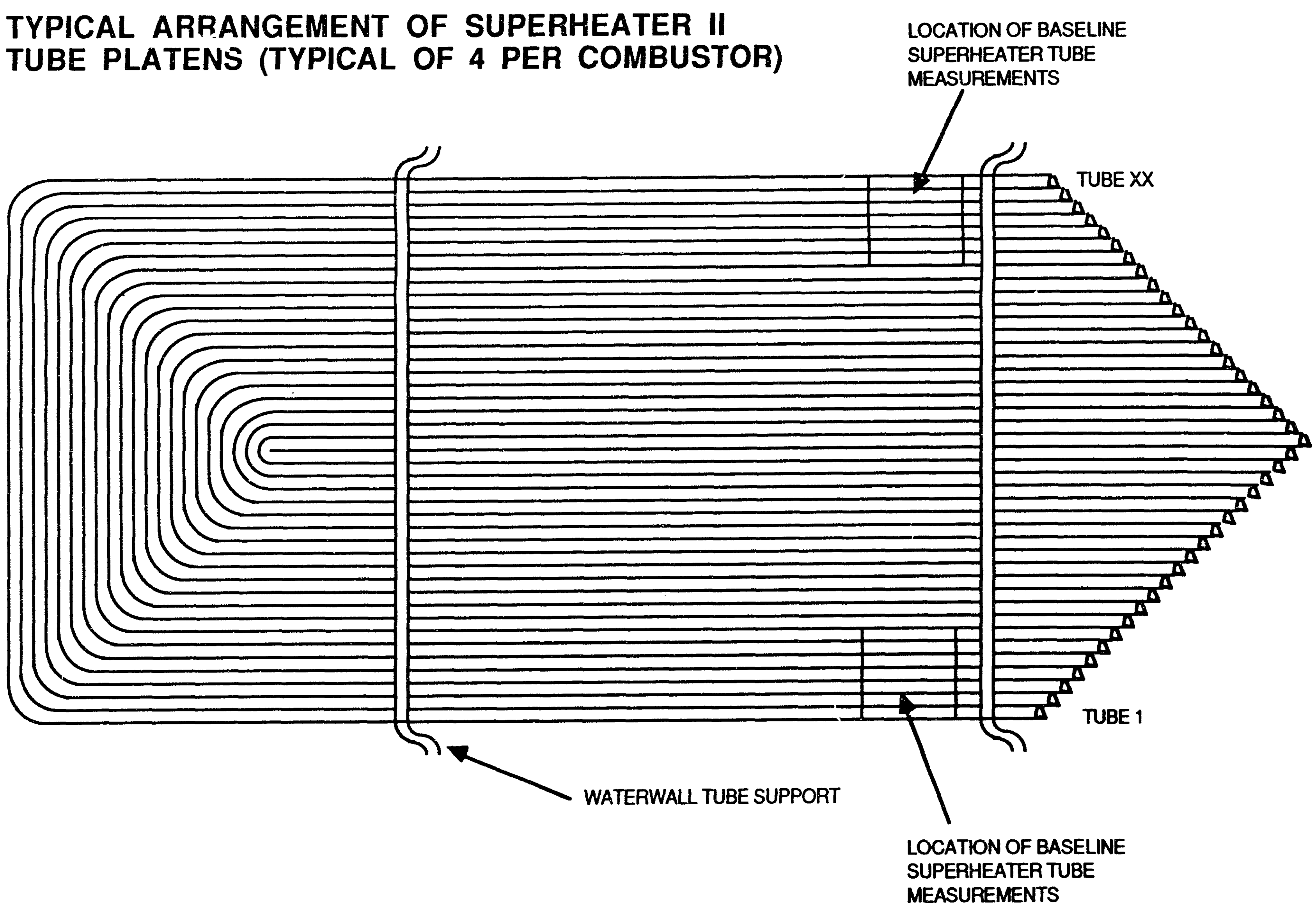


Figure 7-2. Location of Baseline Superheater II Tube Measurements.

select tubes on the side walls of both combustion chambers, as shown in Figure 7-2. Superheater tubes on the remaining two walls in each combustion chamber were not measured due to time constraints in the unit start-up schedule. The results of all measurements are shown in Table 7-1.

Data from these baseline measurements indicated that water-wall tube thickness measurements averaged 15 to 20% above the minimum wall thickness (MWT). The average of all 120 measurements was 0.258", which is 17% above MWT. The average of all superheater II tube measurements on inlet tubes 1 through 10 was 0.194", which is 18% above MWT. The inlet tubes comprise numbers 1 through 32 on each of the four superheater panels. The outlet or return tubes number 33 through 64. Measurements taken on tubes 60 through 64 averaged wall thicknesses of 0.252", which is 15% over MWT. Note that the return tubes are designed with a greater tube wall thickness to withstand the higher temperatures on the outlet flow path.

In addition to the tube thickness measurements on water-wall and superheater tubes, an extensive photographic survey was completed comprising approximately 220 baseline photographs. These included a survey of the lower combustor refractory, refractory/water-wall interface, and superheater II tubes. Close-up photographs were taken of all refractory port openings in the lower combustion chambers and of all superheater tube supports in the upper combustion chambers. No photographs were taken in the windboxes, cyclones, or backpass during the baseline inspection due to access and time constraints.

A detailed inspection plan for future outages was also developed by a panel of fluidized bed materials experts from EPRI and other organizations. In addition to photographs and inspection reports, this plan included a total of 1680 ultrasonic thickness measurements per combustor on an annual basis. The intent of these thickness measurements was to monitor generalized tube erosion. The locations of these measurements are summarized below.

1. Water-Wall Tubes at the Lower Refractory Interface - every third tube should be measured around the perimeter of both combustion chambers 6" and 12" above the refractory interface. Measurements should be taken on the front face of the tube and at 45° on each side of the front face. This results in a total of 728 measurements per combustor or 1456 total measurements.

Table 7-1. Baseline Waterwall and Superheater Tube Thickness Measurements

Waterwall Tubes: SA210-A1, 2.5 inch OD, 0.220 MWT

A-SIDE WALL TUBE	MEAS.	A-FRONT WALL TUBE	MEAS.	A-CENTER WALL TUBE	MEAS.	A-REAR WALL TUBE	MEAS.	B-SIDE WALL TUBE	MEAS.	B-FRONT WALL TUBE	MEAS.	B-CENTER WALL TUBE	MEAS.	B-REAR WALL TUBE	MEAS.
A-16S	0.256	A-15F	0.262	A-39C	0.262	A-16R	0.248	B-49S	0.249	B-18F	0.258	B-41C	0.275	B-63R	0.259
A-17S	0.258	A-16F	0.254	A-40C	0.263	A-17R	0.256	B-50S	0.262	B-19F	0.266	B-42C	0.27	B-64R	0.272
A-18S	0.245	A-17F	0.266	A-41C	0.264	A-18R	0.24	B-51S	0.258	B-20F	0.258	B-43C	0.25	B-65R	0.258
A-19S	0.258	A-18F	0.261	A-42C	0.258	A-19R	0.272	B-52S	0.238	B-21F	0.256	B-44C	0.262	B-66R	0.262
A-20S	0.252	A-19F	0.266	A-43C	0.259	A-20R	0.26	B-53S	0.254	B-22F	0.247	B-45C	0.26	B-67R	0.267
A-21S	0.244	A-20F	0.258	A-44C	0.268	A-21R	0.248	B-54S	0.266	B-23F	0.244	B-46C	0.271	B-68R	0.262
A-22S	0.259	A-21F	0.256	A-45C	0.253	A-22R	0.247	B-55S	0.249	B-24F	0.258	B-47C	0.26	B-69R	0.256
A-23S	0.263	A-22F	0.256	A-46C	0.268	A-23R	0.255	B-56S	0.274	B-25F	0.254	B-48C	0.266	B-70R	0.276
A-24S	0.249	A-23F	0.268	A-47C	0.268	A-24R	0.27	B-57S	0.246	B-26F	0.243	B-49C	0.246	B-71R	0.267
A-25S	0.263	A-24F	0.254	A-48C	0.272	A-25R	0.248	B-58S	0.254	B-27F	0.263	B-50C	0.251	B-72R	0.256
A-26S	0.256	A-25F	0.26	A-49C	0.26	A-26R	0.254	B-59S	0.26	B-28F	0.262	B-51C	0.251	B-73R	0.257
A-27S	0.258	A-26F	0.262	A-50C	0.253	A-27R	0.257	B-60S	0.258	B-29F	0.254	B-52C	0.252	B-74R	0.256
A-28S	0.26	A-27F	0.268	A-51C	0.262	A-28R	0.262	B-61S	0.264	B-30F	0.264	B-53C	0.244	B-75R	0.261
A-29S	0.246	A-28F	0.26	A-52C	0.258	A-29R	0.26	B-62S	0.263	B-31F	0.237	B-54C	0.238	B-76R	0.275
A-30S	0.259	A-29F	0.254	A-53C	0.257	A-30R	0.25	B-63S	0.249	B-32F	0.271	B-55C	0.252	B-77R	0.265
AVGS	0.255		0.26		0.262		0.255		0.256		0.256		0.257		0.263

SUPERHEATER II TUBES: SA213-T11, 1.5 inch OD, 0.165 inch MWT

B SIDE WALL TUBE	MEAS.	B SIDE WALL TUBE	MEAS.	B SIDE WALL TUBE	MEAS.	B SIDE WALL TUBE	MEAS.	B SIDE WALL TUBE	MEAS.	B SIDE WALL TUBE	MEAS.	B SIDE WALL TUBE	MEAS.	A SIDE WALL TUBE	MEAS.
W-64S	0.254	X-64S	0.244	Y-64S	0.254	W-11S	0.194	X-5S	0.196	Y-5S	0.195	Z-5S	0.19	X-12S	0.194
W-63S	0.247	X-63S	0.242	Y-63S	0.251	W-1-S	0.194	X-4S	0.191	Y-4S	0.193	Z-4S	0.192	X-11S	0.198
W-62S	0.247	X-62S	0.252	Y-62S	0.262	W-9S	0.198	X-3S	0.198	Y-3S	0.19	Z-3S	0.19	X-10S	0.188
W-61S	0.253	X-61S	0.258	Y-61S	0.257	W-8S	0.192	X-2S	0.192	Y-2S	0.188	Z-2S	0.199	X-9S	0.21
W-60S	0.249	X-60S	0.256	Y-60S	0.248	W-7S	0.194	X-1S	0.201	Y-1S	0.197	Z-1S	0.197	X-8S	0.204
						W-6S	0.199							X-7S	0.204
						W-5S	0.19							X-6S	0.208
						W-4S	0.192							X-5S	0.208
						W-3S	0.192							X-4S	0.206
						W-2S	0.2								
						W-1S	N/A								
AVGS	0.25		0.25		0.254		0.195		0.196		0.193		0.194		0.202

2. Freeboard Water-Wall Tubes - Thickness measurements should be taken on every 10th tube around the perimeter of both combustion chambers at 40' and 80' elevations. Measurements should be taken on the front face of the tube and at 45° on each side of the front face. This results in a total of 240 measurements per combustor or 480 total thickness measurements.

3. Water-Wall Port Openings on Combustion Chamber B- Thickness measurements should be taken around each of the ports located at 40' and 80' elevations. Measurements should include four tubes on each side of the opening 9" and 18" above and below the opening. This results in a total of 80 measurements on combustor B only.

4. Superheater II Tubes - Measurements should be taken every three feet around each of the three walls on tube 1, tube 32, and tube 64 of each panel. This results in a total of 480 measurements per combustor or 960 total measurements.

5. Upper Combustor Water-Wall Support Tubes - Every water-wall support tube for the secondary superheaters should be measured in both combustion chambers on each of the four panels. Measurements should be taken on the bottom, middle, and top of each tube on each panel. This results in a total of 120 measurements per combustion chamber or 240 total measurements.

6. Convection Pass - Measurements should be taken across the top of the final superheater tube bundle on eight equally spaced tubes at four different depths. This results in a total of 32 tube measurements per combustor of 64 total measurements.

7. Convection Cage - No measurements were recommended on the steam-cooled convection cage enclosure.

7.2 INSPECTION FOLLOWING 600 OPERATING HOURS

On September 29, 1987 following approximately 600 unit hours of operation on coal, the boiler experienced an overheat incident that resulted in a 10 week repair outage. The major areas of damage included water-wall warpage in both combustion chambers, warpage of the upper buckstays primarily along the center walls and combustion chamber A, expansion joint damage on the loop seals and air heater inlet, and failure of the windbox hanger rods.

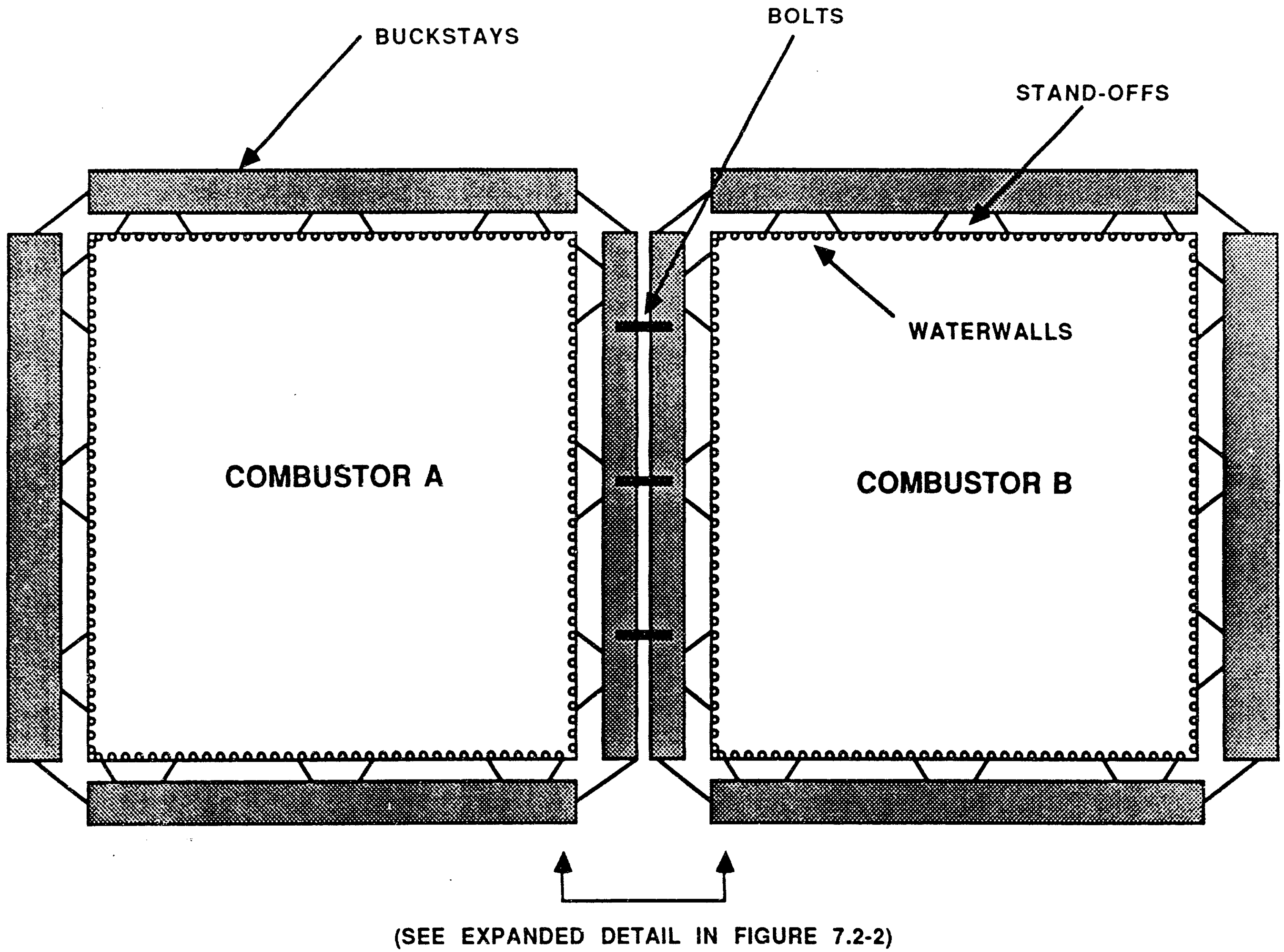
Of primary concern was the warpage of water walls in both combustion chambers. During the overheat incident, the combustor A expanded downward relative to combustor B. This was caused by high combustion chamber temperatures due to unburned coal and lack of coolant in the upper combustor water walls. The incident report from this event is presented in Section 2.2 of this report.

Figure 7-3 shows a plan view of the buckstay arrangement for the two combustion chambers, which is typical of 10 elevations. These buckstays are designed to maintain the cross-sectional dimensions of the combustion chambers during normal operation and in the event of an explosion or implosion inside the chambers. The bolts shown in the figure tie the center wall buckstays together. As shown in Figure 7-4, as combustor A expanded downward relative to combustor B, the buckstays along the center walls rotated. Since the buckstays at a particular elevation act as a ring around each chamber, distortion of the center wall buckstays affected the alignment of the remaining buckstays. In effect, the rings formed by the buckstays around the combustion chamber became tilted. This, in turn, caused the warpage of the water walls since the two are attached at several points on a given elevation via stand-offs.

The warpage was more severe on combustor A, occurring on all four walls with a vertical frequency corresponding to the placement of the outside buckstay rings. Warpage on combustor B was confined to the center wall and consisted of one or two large radius bows in the water walls.

During the 10 week repair outage, the upper six buckstay rings were replaced/straightened and the water-wall bows were corrected on both chambers to within ±1.5" from centerline. Aptech Engineering Services out of Sunnyvale, California was contracted for a metallurgical examination of water-wall and superheater components in both combustion chambers following the overheat incident. In their conditions assessment report, Aptech concluded that because of the slow cool-down following the overheat incident, metal components were effectively annealed without damage or loss of tube life.

Huntington Testing Inc. out of Huntington, West Virginia was contracted to perform tube thickness measurements on water-wall tubes in both combustion chambers, particularly around areas that were subjected to warpage. In total, approximately 2200 thickness measurements were taken in combustor A and 1100 in combustor B. In addition, a total of 78 water-wall tube thickness measurements were taken by the test team in each combustion chamber at 6" and 10" elevations above the lower combustor refractory. These data are summarized in Section 7.3 along with tube thickness measurements taken after 3600 hours of unit operation on coal.



NOTE: BUCKSTAY ARRANGEMENT TYPICAL OF 10 ELEVATIONS.

Figure 7-3. Schematic of Combustor Buckstay Arrangement.

7.3 INSPECTION FOLLOWING 3600 OPERATING HOURS

In August 1988, an extensive outage was required to replace bubble cap retainer washers, upgrade the bottom ash transport system, and complete refractory patchwork. This effort involved approximately 2100 manhours to complete. During this outage, the test team completed the following fireside tube thickness measurements:

1. On water-wall tubes approximately 6" and 10" above the refractory interface in the lower combustion chambers.

2. On the top of the weld overlay that extends approximately 3" above the lower combustor refractory.

3. On the water-cooled superheater hanger tubes at the outlet of the cyclones in the upper convection cage plenum.

4. On the top rows of the final superheater III tube bank.

5. On the top rows of economizer tubes.

6. On the steam-cooled convection cage floor tubes just downstream of the termination point of the cyclone outlet refractory on the north side of the convection pass.

Of these measurements, only the water-wall tubes at the refractory interface had been previously taken. The remaining measurements were compared to nominal thicknesses for new tubes and were used as a baseline for future measurements.

7.3.1 Water-Wall Tube Measurements

Table 7-2 summarizes water-wall tube thickness measurements taken after 600 hours and 3600 hours of unit operation on coal. The numbering system used in this table was presented in Figure 7-1. A total of 154 tube thickness measurements were taken in both combustion chambers approximately 6" to 10" above the lower combustor refractory. The end tubes along each wall and every fifth tube were measured. The difference between the thickness measurements is also shown in the table. No generalized erosion pattern is evident from these data. The small changes in wall thicknesses indicated in the table are within the accuracy limitations of the UT measurement device. In addition, exact tube measurement locations were not permanently marked for either measurement sequence to avoid the creation of possible erosion sites.

Although there was no evidence of generalized water-wall erosion at the refractory interface following 3600 hours of unit operation on coal, there were visible signs of localized

Table 7-2. Summary of Waterwall Tube Thickness Measurements.

"A" SIDE WALL

TUBE	600 HR	3600 HR	DELTA
A-1S	0.262	0.267	0.005
A-5S	0.264	0.264	0
A-10S	0.268	0.258	-0.01
A-15S	0.266	0.256	-0.01
A-20S	0.263	0.256	-0.007
A-25S	0.271	0.272	0.001
A-30S	0.264	0.266	0.002
A-35S	0.269	0.27	0.001
A-40S	0.264	0.261	-0.003
A-45S	0.266	0.264	-0.004
A-51S	0.263	0.258	-0.005
A-56S	0.261	0.257	-0.004
A-61S	0.258	0.258	0
A-66S	0.265	0.263	-0.002
A-71S	0.269	0.26	-0.009
A-76S	0.265	0.265	0
A-81S	0.269	0.27	0.001
A-86S	0.265	0.269	0.004
A-90S	0.277	0.26	-0.017
A-94S	0.254	0.251	-0.003
AVG	0.265	0.262	-0.003

"A" FRONT WALL

TUBE	600 HR	3600 HR	DELTA
A-1F	0.26	0.263	0.003
A-5F	0.272	0.26	-0.012
A-10F	0.265	0.256	-0.009
A-15F	0.266	0.262	-0.006
A-20F	0.262	0.26	-0.002
A-25F	0.279	0.261	-0.018
A-30F	0.262	0.262	0
A-35F	0.264	0.244	-0.02
A-40F	0.263	0.263	0
A-45F	0.272	0.256	-0.016
A-50F	0.254	0.27	0.016
A-55F	0.262	0.261	-0.001
A-60F	0.251	0.265	0.014
A-65F	0.248	0.269	0.021
A-70F	0.27	0.261	-0.009
A-75F	0.264	0.261	-0.003
A-80F	0.255	0.264	0.009
A-85F	0.253	0.255	0.002
A-88F	0.264	0.268	0.004
	0.263	0.261	-0.001

"A" CENTER WALL

TUBE	600 HR	3600 HR	DELTA
A-1C	0.264	0.273	0.009
A-5C	0.263	0.259	-0.004
A-10C	0.254	0.259	0.005
A-15C	0.254	0.26	0.006
A-20C	0.253	0.254	0.001
A-25C	0.258	0.259	0.001
A-30C	0.261	0.266	0.005
A-35C	0.269	0.272	0.003
A-40C	0.263	0.259	-0.004
A-45C	0.245	0.248	0.003
A-50C	0.245	0.249	0.004
A-55C	0.246	0.252	0.006
A-60C	0.232	0.234	0.002
A-65C	0.254	0.256	0.002
A-70C	0.266	0.27	0.004
A-75C	0.24	0.233	-0.007
A-80C	0.26	0.26	0
A-85C	0.271	0.277	0.006
A-90C	0.257	0.258	0.001
A-94C	0.263	0.268	0.005
	0.256	0.258	0.002

"A" REAR WALL

TUBE	600 HR	3600 HR	DELTA
A-1R	0.257	0.255	-0.002
A-5R	0.259	0.262	0.003
A-10R	0.266	0.263	-0.003
A-15R	0.267	0.255	-0.012
A-20R	0.266	0.263	-0.003
A-25R	0.25	0.256	0.006
A-30R	0.25	0.256	0.006
A-35R	0.266	0.271	0.005
A-40R	0.258	0.261	0.003
A-45R	0.273	0.266	-0.007
A-50R	0.261	0.245	-0.016
A-55R	0.261	0.253	-0.008
A-60R	0.265	0.256	-0.009
A-65R	0.264	0.26	-0.004
A-70R	0.274	0.272	-0.002
A-75R	0.28	0.277	-0.003
A-80R	0.273	0.266	-0.007
A-85R	0.277	0.275	-0.002
A-86R	0.261	0.263	0.002
	0.265	0.262	-0.003

"B" SIDE WALL

TUBE	600 HR	3600 HR	DELTA
B-1S	0.257	0.258	0.001
B-5S	0.264	0.264	0
B-10S	0.268	0.269	0.001
B-15S	0.255	0.258	0.003
B-20S	0.272	0.264	-0.008
B-25S	0.25	0.258	0.008
B-30S	0.258	0.266	0.008
B-35S	0.262	0.26	-0.002
B-40S	0.249	0.253	0.004
B-45S	0.256	0.259	0.003
B-50S	0.26	0.263	0.003
B-56S	0.261	0.265	0.004
B-61S	0.263	0.26	-0.003
B-66S	0.253	0.256	0.003
B-71S	0.267	0.272	0.005
B-76S	0.266	0.272	0.006
B-81S	0.255	0.254	-0.001
B-86S	0.261	0.263	0.002
B-91S	0.254	0.255	0.001
B-94S	0.253	0.249	-0.004
AVG	0.259	0.261	0.002

"B" FRONT WALL

TUBE	600 HR	3600 HR	DELTA
B-1F	0.259	0.265	0.006
B-5F	0.255	0.268	0.013
B-10F	0.256	0.264	0.008
B-15F	0.265	0.267	0.002
B-20F	0.254	0.258	0.004
B-25F	0.257	0.258	0.001
B-30F	0.256	0.259	0.003
B-35F	0.266	0.268	0.002
B-40F	0.26	0.259	-0.001
B-45F	0.256	0.259	0.003
B-50F	0.251	0.254	0.003
B-55F	0.254	0.254	0
B-60F	0.264	0.261	-0.003
B-65F	0.266	0.264	-0.002
B-70F	0.262	0.265	0.003
B-75F	0.257	0.26	0.003
B-80F	0.254	0.26	0.006
B-85F	0.256	0.257	0.001
B-88F	0.278	0.278	0
	0.259	0.262	0.003

"B" CENTER WALL

TUBE	600 HR	3600 HR	DELTA
B-1C	0.259	0.27	0.011
B-5C	0.251	0.264	0.013
B-10C	0.252	0.258	0.006
B-15C	0.262	0.262	0
B-20C	0.249	0.25	0.001
B-25C	0.253	0.255	0.002
B-30C	0.256	0.261	0.005
B-35C	0.256	0.259	0.003
B-40C	0.255	0.27	0.015
B-55C	0.251	0.254	0.003
B-60C	0.26	0.264	0.004
B-65C	0.265	0.27	0.005
B-70C	0.258	0.263	0.005
B-75C	0.25	0.26	0.01
B-80C	0.255	0.256	0.001
B-85C	0.27	0.272	0.002
B-90C	0.26	0.264	0.004
B-94C	0.26	0.263	0.003
	0.257	0.262	0.005

"B" REAR WALL

TUBE	600 HR	3600 HR	DELTA
B-1R	0.246	0.248	0.002
B-5R	0.248	0.251	0.003
B-10R	0.267	0.272	0.005
B-15R	0.273	0.278	0.005
B-20R	0.257	0.26	0.003
B-25R	0.262	0.268	0.006
B-30R	0.254	0.253	-0.001
B-35R	0.26	0.268	0.008
B-40R	0.263	0.258	-0.005
B-45R	0.254	0.262	0.008
B-50R	0.254	0.256	0.002
B-55R	0.256	0.253	-0.003
B-60R	0.263	0.262	-0.001
B-65R	0.251	0.246	-0.005
B-70R	0.272	0.268	-0.004
B-75R	0.26	0.259	-0.001
B-80R	0.266	0.265	-0.001
B-85R	0.266	0.27	0.004
B-88R	0.267	0.267	0
	0.26	0.261	0.001

erosion in the weld overlay. This proprietary abrasion resistant material is applied to the first 3" of tube length above the refractory interface and serves as a sacrificial armour over the base tube. The general erosion pattern is a narrow, vertical groove that appears to be exacerbated by discontinuities in the membrane between adjacent water-wall tubes. This type of localized erosion was more severe on the north half of the east wall on combustor A and on the north half of the east and west walls on combustor B. Figure 7-5 shows a typical example of this type of erosion.

In locations where the "grooving" pattern was wide enough to insert the 1/4" probe head of the UT measurement device, tube wall thickness measurements were taken. In addition, thickness measurements were taken on portions of the tube away from the eroded area that included both the base tube wall thickness plus a smooth section of overlay. Measurements were also taken on the base tube just above the weld overlay. Data from nine tubes are summarized in Table 7-3 and provide some indication of the depth of the eroded area.

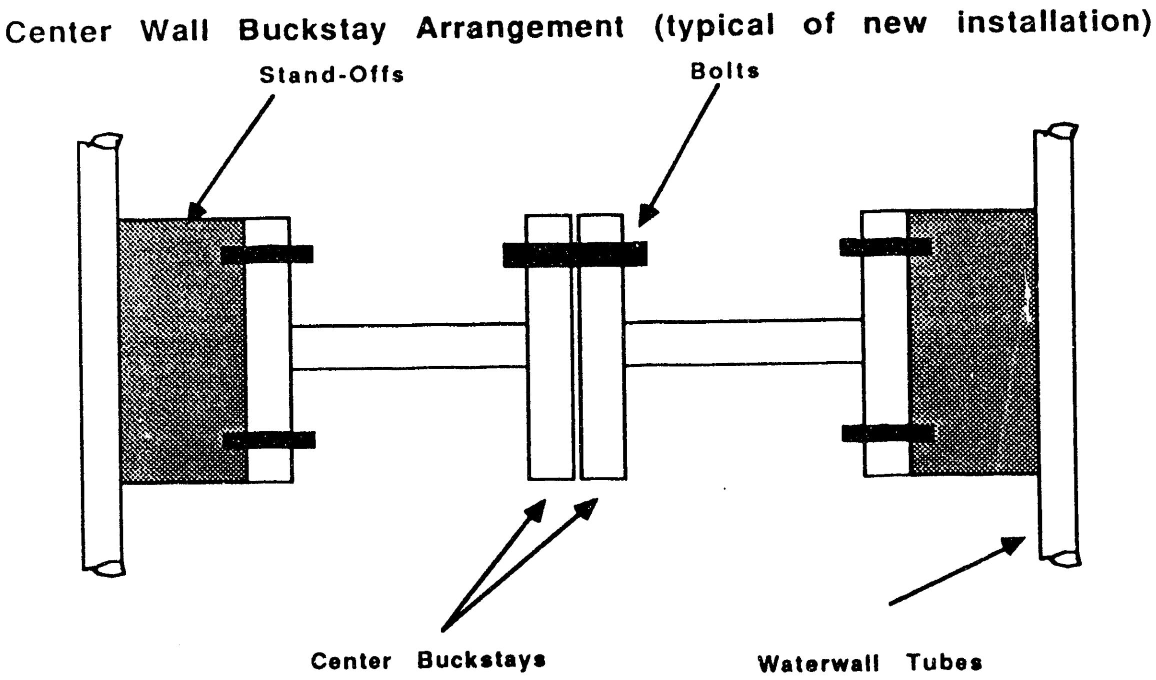
7.3.2 Water-Cooled Superheater Hanger Tubes

Tube thickness measurements were taken on four water-cooled hanger tubes at the cyclone outlets following 3600 hours of operation on coal. The location of these measurements are shown in Figures 7-6 and 7-7. As shown in Table 7-4, thickness measurements were taken on the tube centerline facing the gas flow, and at plus and minus 30° from centerline at five locations on each tube. No generalized erosion pattern was evident from these readings and there were no visual signs of localized or generalized erosion.

Tube thickness measurements were not taken during the inspection following 3600 hours on the upper water-wall tubes or the superheater II tubes. Measurements at these locations are planned during the next major outage in 1989.

7.3.3 Steam-Cooled Convection Cage Floor Tubes

Tube thickness measurements were taken on the convection cage floor tubes at locations shown in Figures 7-6 and 7-7. These floor tubes are located at the cyclone outlet just downstream of where the cyclone refractory terminates. Originally, this area was deemed as a possible high erosion area due to the proximity of the tubes to the cyclone outlet. At each location, readings were taken on the centerline of the tube (facing straight up), and at ± 30° from centerline. No erosion pattern is evident from the data presented in Table 7-5.



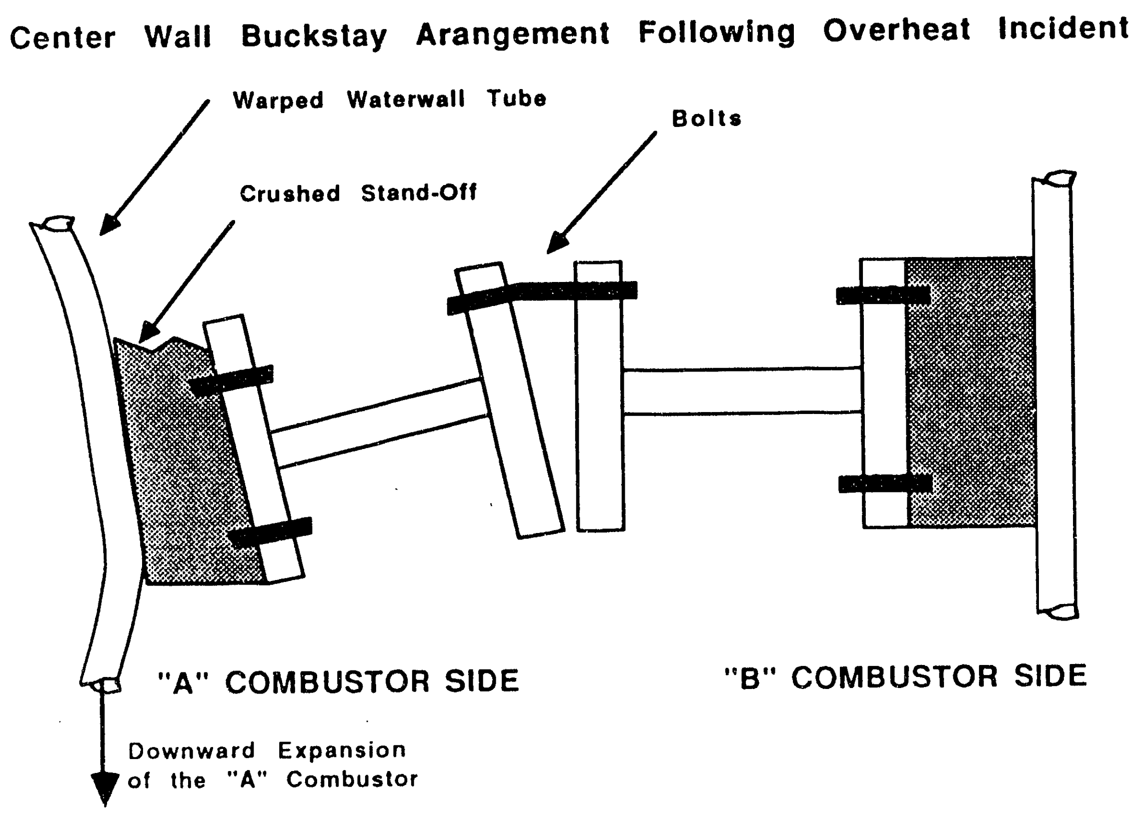


Figure 7-4. Center Wall Buckstay Arrangement.

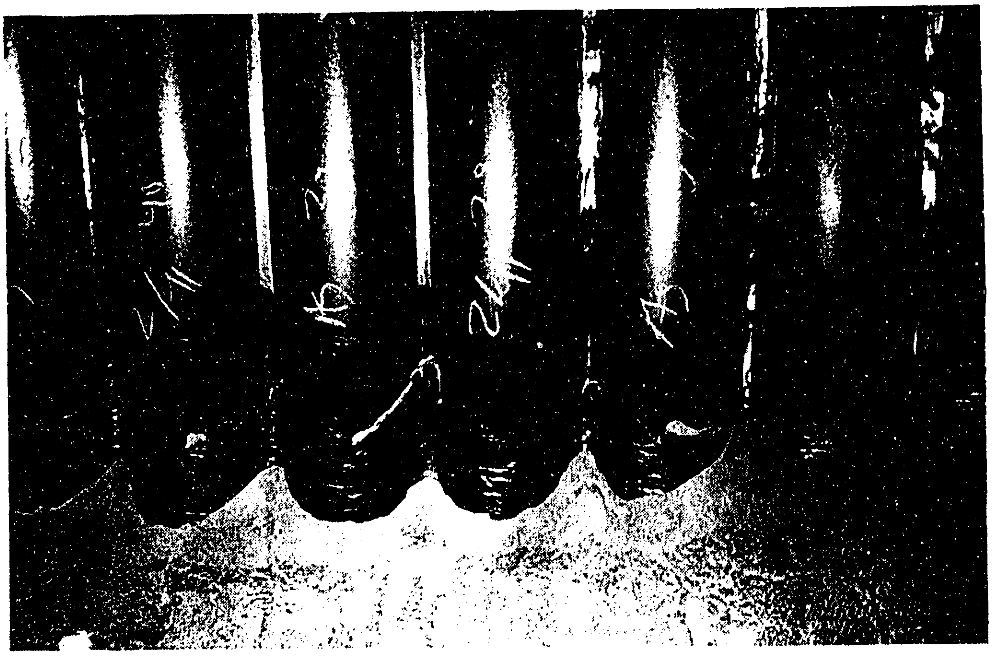


Figure 7-5. Erosion of Weld Overlay in Combustor A.

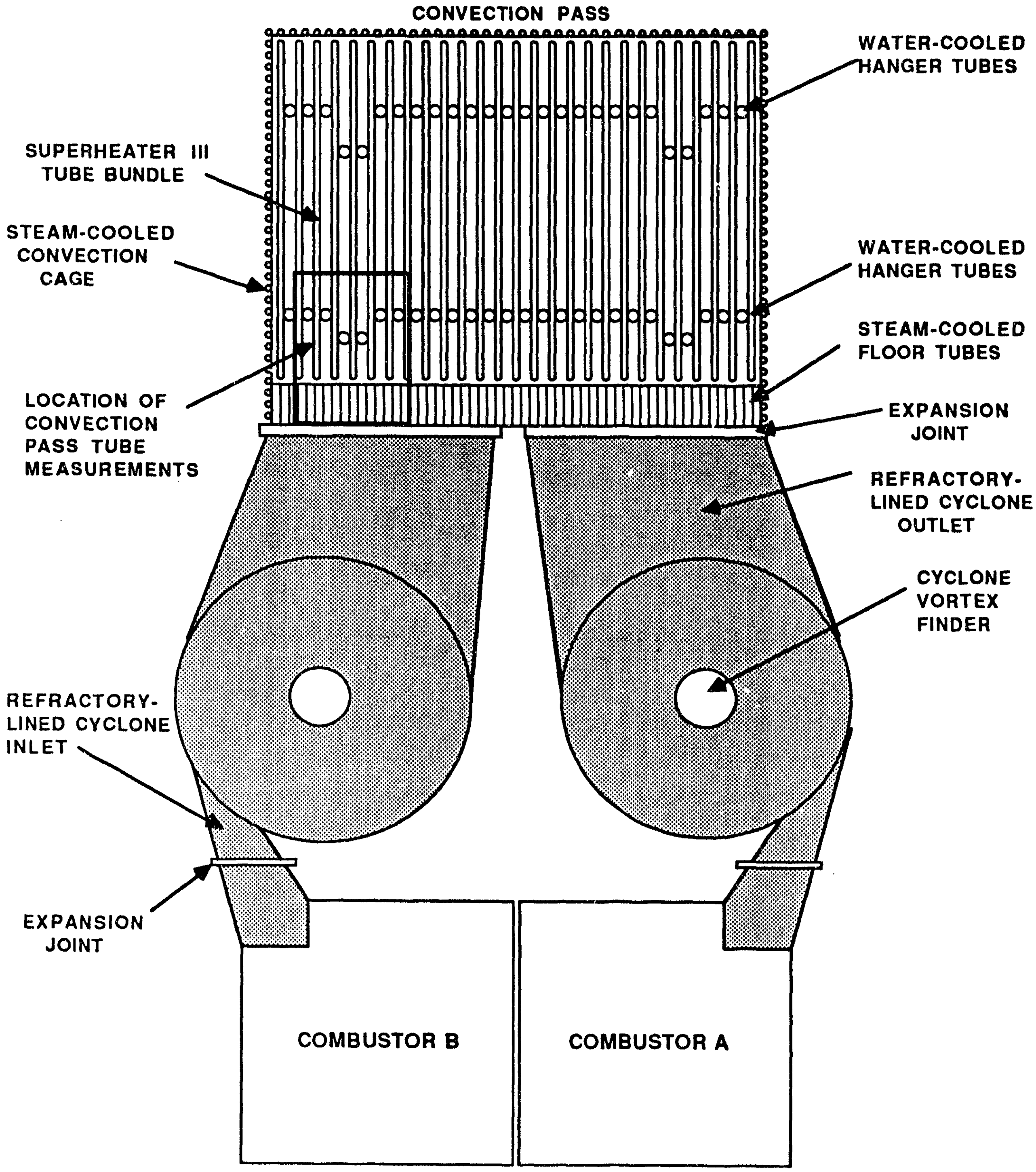


Figure 7-6. Location of Convection Pass Tube Measurements.

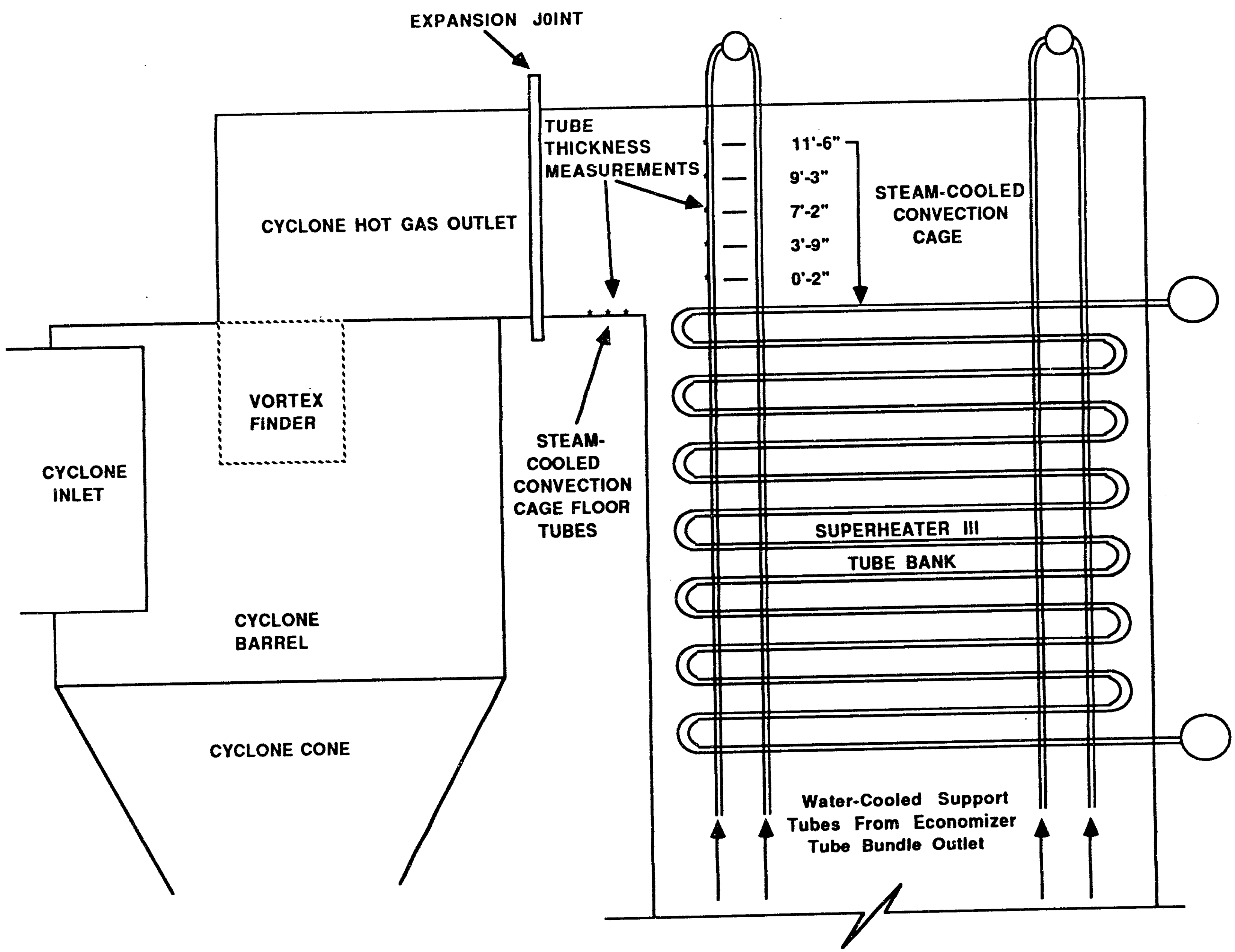


Figure 7-7. Location of Convection Pass Tube Thickness Measurements.

Table 7-3. Tube Thickness Measurements for Localized Erosion Following 3600 Unit Hours of Operation on Coal (Water-Wall/Refractory Interface)

Tube Number	Tube Wall + Overlay Thickness in Eroded Area	Tube Wall + Overlay Thickness- Non-eroded Area	Tube Wall Thickness Above Overlay
A-23C	0.255	0.299	0.260
A-25C	0.250	0.310	0.257
A-28C	0.272	0.302	0.269
A-38C	0.258	0.301	0.252
B-9S	0.268	0.300	0.261
B-11S	0.260	0.314	0.256
B-12S	0.248	0.283	0.258
B-18S	0.264	0.293	0.252
B-19S	0.258	0.296	0.245

Table 7-4. Water-Cooled Hanger Tube Thickness Measurements Following 3600 Hours of Unit Operation on Coal.

Tube	Location on Tube	Thickness @ -30 off Centerline	Thickness @ Centerline	Thickness @ +30° off Centerline
AW	1	0.276	0.266	0.264
AW	2	0.281	0.274	0.272
AW	3	0.281	0.282	0.278
AW	4	0.283	0.277	0.286
AW	5	0.275	0.272	0.284
AE	1	0.284	0.283	0.285
AE	2	0.280	0.288	0.284
AE	3	0.282	0.292	0.283
AE	4	0.286	0.296	0.288
AE	5	0.279	0.274	0.283
BW	1	0.272	0.261	0.274
BW	2	0.262	0.275	0.279
BW	3	0.276	0.268	0.283
BW	4	0.278	0.277	0.276
BW	5	0.273	0.278	0.284
BE	1	0.282	0.268	0.266
BE	2	0.272	0.273	0.285
BE	3	0.268	0.266	0.277
BE	4	0.270	0.270	0.271
BE	5	0.269	0.278	0.283
Averages		**0.276**	**0.276**	**0.279**

Tube Legend:
AW = A Combustor West   BW = B Combustor West
AE = A Combustor East   BE = B Combustor East

Table 7-5. Convection Cage Floor Tube Thickness Measurements at Cyclone Outlet Following 3600 Hours of Unit Operation on Coal.

Tube	Location on Tube	Thickness @ -30° off Centerline	Thickness @ Centerline	Thickness @ +30° off Centerline
AW	1	0.190	0.186	0.186
AW	2	0.182	0.183	0.182
AW	3	0.182	0.181	0.184
AE	1	0.193	0.186	0.190
AE	2	0.185	0.184	0.184
AE	3	0.181	0.180	0.182
BW	1	0.180	0.180	0.182
BW	2	0.169	0.166	0.175
BW	3	0.182	0.181	0.171
BE	1	0.188	0.183	0.184
BE	2	0.176	0.169	0.183
BE	3	0.187	0.178	0.182
Averages		**0.181**	**0.178**	**0.180**

Tube Legend:
AW = A Combustor West
AE = A Combustor East
BW = B Combustor West
BE = B Combustor East

7.4.4 Superheater III Tube Measurements

Tube wall thickness measurements were taken on four tubes on the top of the superheater III tube bundle following 3600 hours of unit operation on coal. The location of these measurements are indicated in Figures 7-6 and 7-7. Measurements were made on the centerline of each tube (facing the gas stream) and at ±30° off centerline. As shown in Table 7-6, no general signs of erosion were apparent.

Table 7-6. Tube Wall Thickness Measurements on Select Top Row Tubes on Superheater III After 3600 Hours of Unit Operation on Coal.

Tube	Location on Tube	Thickness @ -30° off Centerline	Thickness @ Centerline	Thickness @ +30° off Centerline
AW	1	0.184	0.184	0.190
AW	2	0.188	0.191	0.192
AE	1	0.184	0.188	0.192
AE	2	0.186	0.192	0.193
BW	1	0.195	0.190	0.178
BW	2	0.181	0.182	0.173
BE	1	0.193	0.186	0.197
BE	2	0.186	0.183	0.183
Average		**0.187**	**0.187**	**0.187**

Tube Legend:
AW = A Combustor West
AE = A Combustor East
BW = B Combustor West
BE = B Combustor East

7.3.5 Economizer Tubes Measurements

Tube thickness measurements were taken on 10 out of 155 top row tubes on the economizer tube bundle. Measurements were on the centerline of the tube facing the hot gas stream. The numbering system for data summarized in Table 7-7 below are for tubes sequentially numbered from east to west. No generalized erosion was evident from these data and there were no visual signs of generalized or localized erosion.

Table 7-7. Economizer Tube Thickness Measurements on Top Rows of the Bundle After 3600 Unit Hours of Operation on Coal.

Tube Number	Measured Thickness
1	0.182
20	0.187
40	0.181
60	0.190
80	0.182
100	0.194
110	0.189
120	0.180
140	0.180
155	0.184
Averages	**0.185**

7.4 NON-PRESSURE PARTS INSPECTION

A general inspection was made by the test team of refractory condition during the outage following 3600 unit hours of operation on coal. These inspections included refractory in the windboxes, lower combustion chambers, cyclones, and cyclone downcomers. The boiler vendor also completed a detailed inspection on August 24, 1988 which included core samples from the cyclones. In general, the condition of refractory, particularly in the conical sections of the cyclones, appeared worse than during previous outages. Refractory patchwork completed during an April 1988 outage inspection had worked loose in many areas and failed due to inadequate anchoring.

In addition, during the outage, the retaining washers were replaced on all bubble caps located on the air distributor plates in the lower combustors and in the ash coolers and loop seals. This is explained below along with other observations from the inspection outage.

7.4.1 Windboxes Refractory

Random cracking was observed in the insulating refractory layer downstream of the duct burners. Some loss of refractory and radial cracking was observed along the sidewalls of the windboxes around the windbox pipe stiffeners. No major rework was required during this outage.

7.4.2 Lower Combustor Refractory

- On the rear wall of combustion chamber A around the recycle return line, the abrasion resistant refractory had shifted approximately 2" out into the combustion chamber at the cold joint. This region was broken away during the outage and replaced with "blue ram" plastic refractory.

- Similar refractory movement was observed around the expansion joint on combustion chamber B near the recycle return line. Refractory had moved approximately 3" at the cold joint exposing a water-wall tube behind the crack.

- Some refractory cracking and spalling was observed around the lower secondary air ports with some exposure of refractory anchors. These areas were also patched with "blue ram" plastic refractory during the outage

- Separation of refractory from the water walls was observed at some locations around the perimeter of the combustors at the water-wall/refractory interface. No corrective action was taken during this outage.

7.4.3 Cyclone Refractory

- Two areas of erosion and spalling were found in the combustor A cyclone where the outer abrasion resistant layer had separated from the underlying soft, thermal layer. These loose refractory pieces generally drop down into the bottom of the loop seals and can disrupt recycle flow during unit operation. These areas were patched with "blue ram" refractory.

- Some localized areas of refractory breakage and spalling was evident in the combustor B cyclone and some minor repairs were completed during the outage.

7.4.4 Downcomers and Loop Seal Refractory

Spalled sections of abrasion resistant refractory from the cyclones were found in the loop seals during the outage inspection. Refractory breakage was apparent around the loop seal archway on the combustor B cyclone side.

7.4.5 Air Distributor Bubble Caps

In the original installation, carbon steel retaining washers were inadvertently used to secure the bubble caps to pipe nipples that extend up through the air distributor floor. The design specification for these washers was stainless steel. These washers had failed in many areas around the perimeter of the combustion chambers and in the region in front of the loop seal return. Due to the high frequency of washer failure and bubble cap retention during unit operation, the decision was made to replace all carbon steel retaining washers with stainless steel. Because of damage to the pipe nipples during removal of the carbon steel retaining washer and replacement with the stainless steel type, new washers were placed on top of the existing carbon steel washers on about 25 % of the nipples and the bubble cap was tack-welded as shown in Figure 7-8. Over 4300 bubble caps were replaced during this outage requiring an estimated 800 manhours of effort.

7.5 FUTURE INSPECTION PLAN

The original intent of the materials test area was to focus on fireside boiler tube erosion. During the fourth quarter of 1988, in light of operating problems through this time, the focus of the plan was expanded to include all CFB hot-side boiler components from the windboxes to the air heater inlet. The revised inspection plan was developed to standardize inspections and reporting during all future outages. This plan is expected to expand during the course of the test program as operating hours accumulate on the unit. The

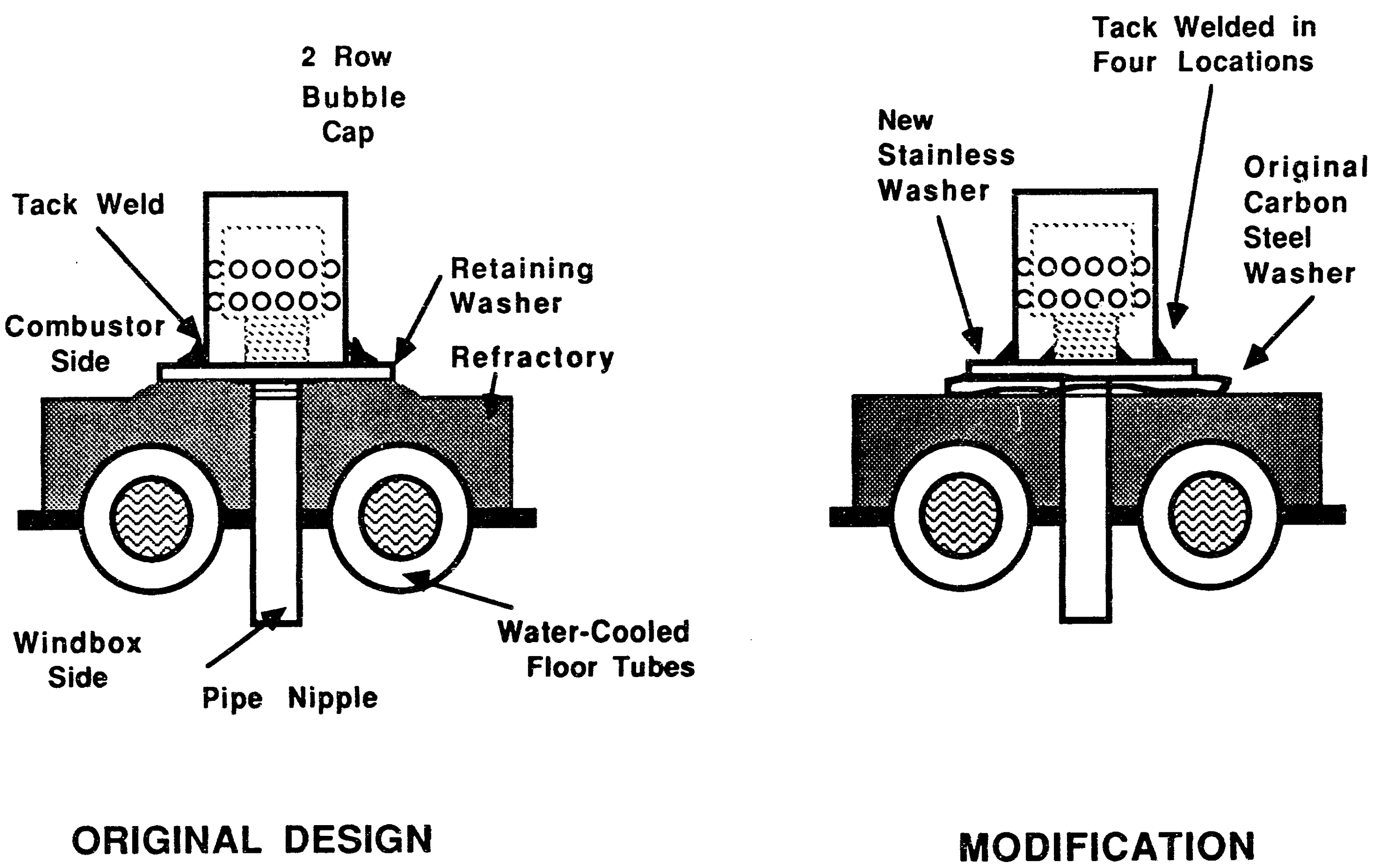


Figure 7-8. Schematic of Bubble Cap Construction and Modification.

general plan is presented below and includes all areas of the original plan.

Windboxes

- Characterize duct burner refractory condition
- Characterize condition of reinjection piping (scaling, deformation)
- Characterize condition of structural members (scaling, deformation, bolt condition)
- Characterize condition of weld seams and duct plate (cracking, buckling)
- Characterize condition of in-duct start-up burners.

Furnaces

- Refractory
  - Characterize general condition
  - Characterize spalled areas
  - Characterize condition in corners
  - Characterize condition of control joints
  - Characterize condition of openings (SA ports, loop seal discharge, coal feed ports, limestone feed ports, thermowells)
  - Characterize condition of water-wall/refractory interface.

- Air Distribution Grid
  - Determine number and location of failed bubble caps
  - Evaluate condition of existing nozzles (erosion, plugged holes)

- Water-Wall Tubes
  - Perform general inspection noting any anomalous conditions (i.e., scale build-up, erosion patterns, or corrosion)
  - Characterize erosion losses of base material and/or weld overlay
  - Obtain tube wall thickness measurements at previously defined matrix locations

Cyclones

- Cyclone Inlets, Outlets, and Cone Section
  - Conduct general inspection of refractory in all areas (cracks, spalling, control joints)
- Loop Seals
  - Characterize condition of refractory (cracks, spalling, control joints)
  - Characterize condition of expansion joints
  - Characterize condition of air nozzles (bent, broken, plugged, missing)
  - Characterize condition of coal feed ports

Convection Pass

- Conduct general inspection of tube surfaces in convection pass cage and between tube banks
- Conduct tube wall thickness measurement according to previous matrix
- Inspect tube-to-tube clips and tube bank supports

Bottom Ash Coolers

- Perform general internal inspection
- Characterize condition of air nozzles (number and location of missing/plugged nozzles)

Section 8

PLANT COMMERCIAL PERFORMANCE STATISTICS

This section presents plant commercial performance statistics from March 1988 through December 1988. Table 8-1 contains monthly operating availabilities, capacity factors, heat rates and averages of each for each month from March 1988 through December 1988. Figure 8-1 is a plot of the monthly operating availabilities from April through December, 1988. Figure 8-2 is a plot of monthly capacity factors from March through December, 1988. Figure 8-3 is a plot of net plant heat rate from April through December, 1988. Tables 8-2 through 8-11 present monthly commercial performance statistics from March through December. Section 8.1 defines the plant commercial performance statistics presented.

Table 8-1. Nucla CFB Plant Commercial Performance Statistics

Month (1988)	Operating Availability, (%)	Capacity Factor (%)	Heat Rate (Btu/Nkwh)
March	N/A	34.1	N/A
April	42.3	26.6	12277
May	49.8	36	11488
June	70.7	46	11877
July	65.2	51.8	N/A
August	0.5	0.1	N/A
September	23.5	12.6	12427
October	68.1	47.6	12168
November	78.9	48.5	11673
December	81.6	46.1	12301
Average	53.4	34.9	12030

Figure 8-1. Nucla CFB Operating Availability
April 1988 through December 1988

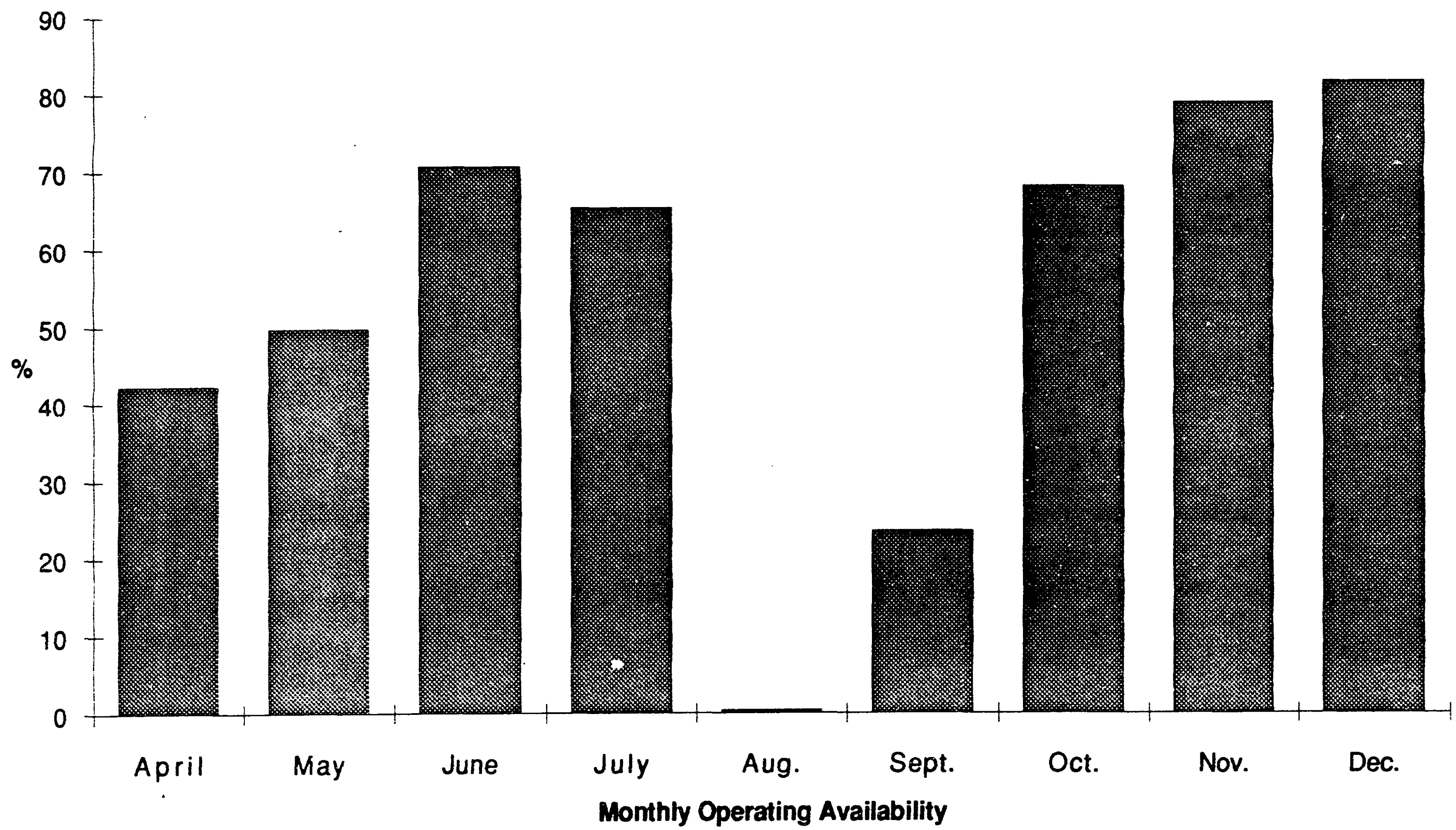


Figure 8-2. Nucla CFB Capacity Factor
March 1988 through December 1988

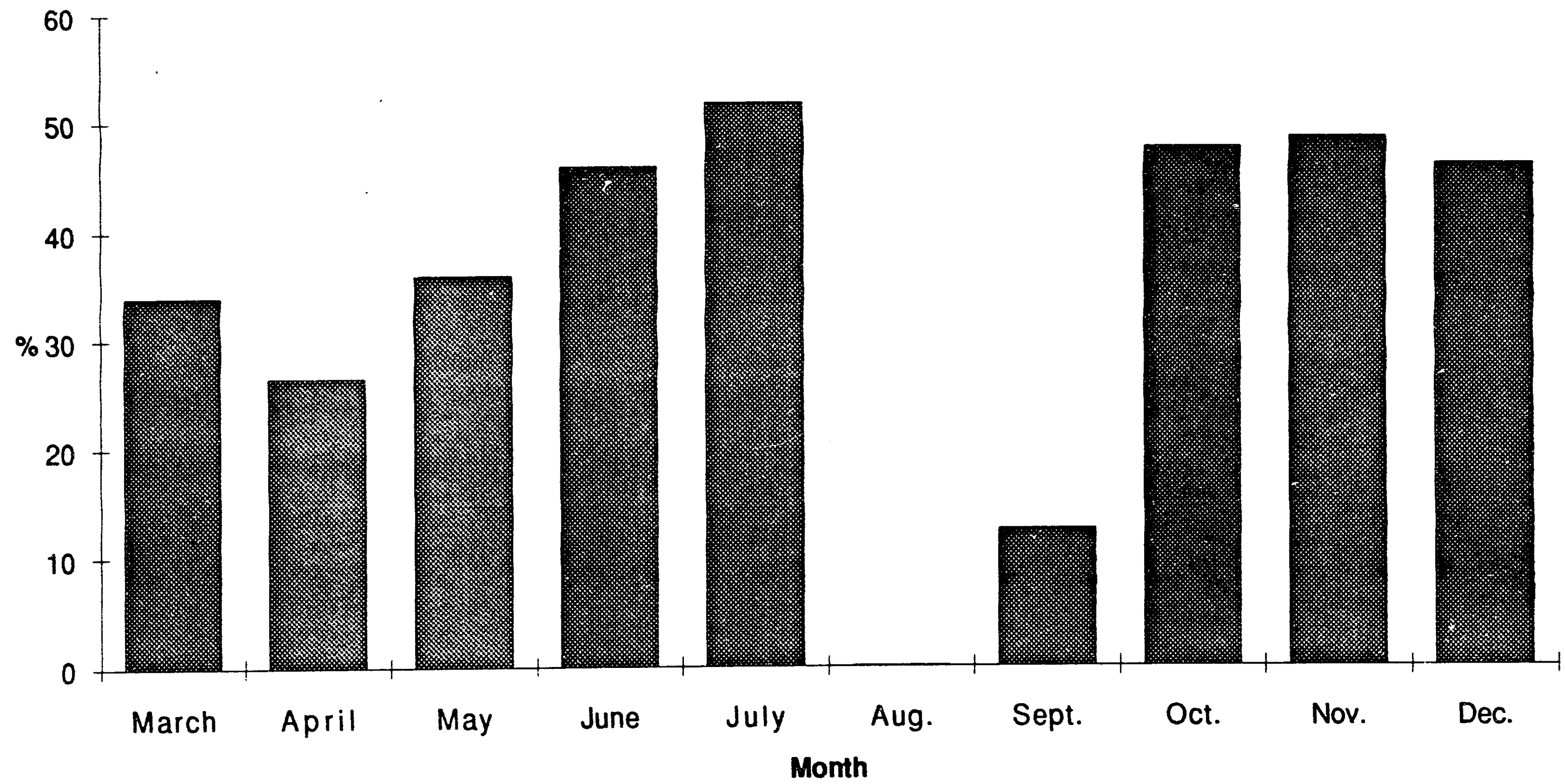
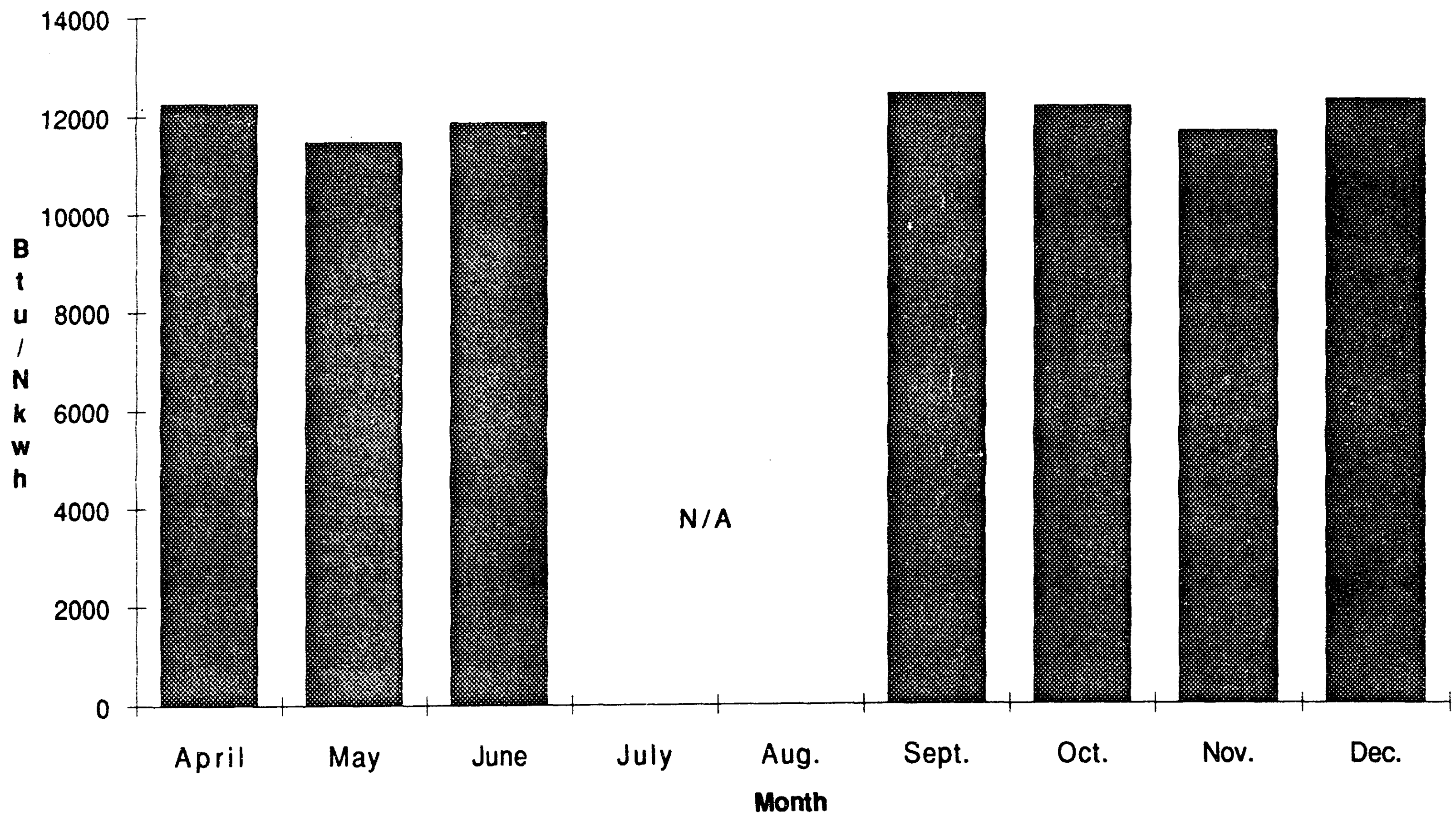


Figure 8-3. Nucla CFB Net Plant Heat Rate
April 1988 through December 1988



8.1 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 the beginning of this section. 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 8 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 8 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 8 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 8 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.

Table 8-2
PLANT COMMERCIAL PERFORMANCE STATISTICS
March 1988

POWER OUTPUTS AND CONSUMPTIONS

Gross generation:	27884.73	mwhrs
Net generation:	23694.20	mwhrs
Aux power use:	4190.526	mwhrs
percent:	15.02803	

CAPACITY FACTOR

Capacity factor:	34.07225	%

MAJOR EQUIPMENT USAGES

Boiler feed pumps:	924363.1	kwhrs
Primary air fan:	1089524.	kwhrs
Secondary air fan:	142424.8	kwhrs
Induced draft fan:	613464.8	kwhrs
High pressure blowers:	67546.22	kwhrs
Bottom ash cooler fan:	95490.55	kwhrs

INDIVIDUAL UNIT OUTPUTS

UNIT	OUTPUT (mwhrs)	AVE LOAD (mw)	HOURS
1	2083.921	10.79752	193
2	2085.708	10.53388	198
3	1952.370	10.55335	185
4	21762.73	56.38012	386

MATERIAL CONSUMPTIONS

Total coal flow:	14605.74	tons
Total Limestone flow:	858.38012	tons

GAS CONSUMPTIONS

Total flow:	7095.410	kscf

OPERATING HOURS

In service:	386
Coal hours:	376
On Standby:	--------
Scheduled outage:	--------
Unscheduled outage:	--------

STARTUPS

Attempted:	7
Successful:	4

Table 8-3
PLANT COMMERICAL PERFORMANCE STATISTICS
April 1988

	CURRENT MONTH	YEAR TO DATE	TWELVE MONTHS	LIFE TO DATE
PRODUCTION				
GENERATION				
GROSS, MWh	21,640	114,149	118,597	118,597
NET, MWh	19,159	100,487	104,075	104,075
STATION SERVICE				
MWh	2,481	13,662	14,522	14,522
PERCENT OF GROSS	11.5	12.0	12.2	12.2
MAX. NET CAPACITY, MW	100	100	100	100
UNIT OPERATION				
PERIOD HOURS	719.00	2,903.00	8,040.00	8,040.00
SERVICE HOURS	303.93	1,739.05	4,790.32	4,790.82
SCHEDULED OUTAGES				
NET GEN. LOSS, MWh	0	14,223	14,223	14,223
HOURS	0.00	142.23	142.23	142.23
FORCED OUTAGES				
NET GEN. LOSS, MWh	41,507	102,172	310,695	310,695
HOURS	415.07	1,021.72	3,106.95	3,106.95
SCHEDULED CURTAILMENTS				
NET GEN. LOSS, MWh	0	0	0	2,850
HOURS	0.00	0.00	0.00	100.00
FORCED CURTAILMENTS				
NET GEN. LOSS, MWh	4,888	66,165	66,165	66,165
HOURS	228.73	1,128.02	1,128.02	1,128.02
FACTORS (NET)				
AVAILABILITY, %	42.3	59.9	59.6	59.6
EQUIV. AVAILABILITY, %	35.5	37.1	51.4	51.4
CAPACITY, %	26.6	34.6	12.9	12.9
PERFORMANCE DATA				
UNIT HEAT RATE				
GROSS, Btu/kWh	10,869.0	11,088.8	12,192.4	12,192.4
NET, Btu/kWh	12,276.6	12,596.4	13,893.7	13,893.7

NOTE: GENERATION IS IN MWh; CAPACITY IS IN MW

Table 8-4
PLANT COMMERICAL PERFORMANCE STATISTICS
May 1988

	CURRENT MONTH	YEAR TO DATE	TWELVE MONTHS	LIFE TO DATE
PRODUCTION				
GENERATION				
GROSS, MWh	29,959	144,108	148,556	143,556
NET, MWh	26,789	127,275	130,864	130,864
STATION SERVICE				
MWh	3,170	16,832	17,692	17,692
PERCENT OF GROSS	10.6	11.7	11.9	11.9
MAX. NET CAPACITY, MW	100	100	100	100
UNIT OPERATION				
PERIOD HOURS	744.00	3,647.00	8,784.00	8,734.00
SERVICE HOURS	370.33	2,109.38	5,161.15	5,161.15
SCHEDULED OUTAGES				
NET GEN. LOSS, MWh	14,795	29,018	29,018	29,018
HOURS	147.95	290.18	290.18	290.18
FORCED OUTAGES				
NET GEN. LOSS, MWh	22,572	124,743	33,267	333,267
HOURS	225.72	1,247.43	3,332.67	3,332.67
SCHEDULED CURTAILMENTS				
NET GEN. LOSS, MWh	1,802	1,802	1,802	1,802
HOURS	60.48	60.48	60.48	60.48
FORCED CURTAILMENTS				
NET GEN. LOSS, MWh	2,556	68,721	68,721	68,721
HOURS	184.07	1,312.08	1,312.08	1,312.08
FACTORS (NET)				
AVAILABILITY, %	49.8	57.8	58.8	58.8
EQUIV. AVAILABILITY, %	43.9	38.5	50.7	50.7
CAPACITY, %	36.0	34.9	14.9	14.9
PERFORMANCE DATA				
UNIT HEAT RATE				
GROSS, Btu/kWh	10,272.6	10,919.1	11,805.2	11,305.2
NET, Btu/kWh	11,488.3	12,363.2	13,401.3	13,401.3

NOTE: GENERATION IS IN MWh; CAPACITY IS IN MW

Table 8-5
PLANT COMMERICAL PERFORMANCE STATISTICS
June 1988

	CURRENT MONTH	YEAR TO DATE	TWELVE MONTHS	LIFE TO DATE
PRODUCTION				
GENERATION				
GROSS, MWh	37,441	181,549	185,997	185,997
NET, MWh	33,126	160,401	163,990	160,990
STATION SERVICE				
MWh	4,315	21,148	22,008	22,008
PERCENT OF GROSS	11.5	11.6	11.8	11.8
MAX. NET CAPACITY, MW	100	100	100	100
UNIT OPERATION				
PERIOD HOURS	720.00	4,367.00	8,784.00	9,504.00
SERVICE HOURS	508.92	2,618.30	4,950.07	5,670.07
SCHEDULED OUTAGES				
NET GEN. LOSS, MWh	0	25,018	29,018	29,018
HOURS	0.00	250.18	290.18	290.18
FORCED OUTAGES				
NET GEN. LOSS, MWh	21,108	145,852	354.375	354.375
HOURS	211.08	1,458.52	3,543.75	3,543.75
SCHEDULED CURTAILMENTS				
NET GEN. LOSS, MWh	0	1,802	1,802	1,802
HOURS	0.00	60.48	60.48	60.48
FORCED CURTAILMENTS				
NET GEN. LOSS, MWh	11,350	80,071	80,071	80,071
HOURS	408.72	1,720.80	1,720.80	1,720.80
FACTORS (NET)				
AVAILABILITY, %	70.7	60.0	56.4	59.7
EQUIV. AVAILABILITY, %	54.9	41.2	47.0	51.0
CAPACITY, %	46.0	36.7	18.7	17.3
PERFORMANCE DATA				
UNIT HEAT RATE				
GROSS, Btu/kWh	10,507.7	10,834.3	11,544.0	11,544.0
NET, Btu/kWh	11,876.5	12,262.7	13,093.3	13,093.3

NOTE: GENERATION IS IN MWh; CAPACITY IS IN MW

Table 8-6
PLANT COMMERICAL PERFORMANCE STATISTICS
July 1988

1. Plant Outputs and Consumptions

• Gross generation:	41705	mWhr
• Net generation:		
- Period	37042	mWhr
- On line	37500	mWhr
• Aux power use:		
- Period	4663	mWhr
- On line	4205	mWhr
• Aux power use (in %):		
- Period	11.18	%
- On line	10.08	%

2. Operating Hours

• Period hours:	744
• In Service:	485
• Coal hours:	470
• On standby:	0
• Scheduled outage:	0
• Unscheduled outage:	259

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	46642	10.50	442
2	4848	11.04	439
3	3865	9.86	392
4	28,250	59.06	480

4. Operating Availability

• Percent:	65.19	%

5. Capacity Factor

• Percent:	51.84	%

6. Major Equipment Usages

• Boiler feed pumps:	1,091,100	kWhr
• Primary air fan:	1,077,400	kWhr
• Secondary air fan:	283,500	kWhr
• Induced draft fan:	665,600	kWhr
• High pressure blowers:	63,000	kWhr
• Bottom ash cooler fan:	84,900	kWhr

7. Material Consumptions

• Total coal flow:	20,491	tons
• Total limestone flow:	2,087	tons
• Total warm-up gas (propane) flow:	2,514.142	kscf

* This report includes hand-calculated performance statistics for the 160 hr period between 7/22/88, 1700 hrs, and 7/29/88, 0900 hrs, when the VAX computer was out of services

Table 8-7
PLANT COMMERICAL PERFORMANCE STATISTICS
August 1988

1. Plant Outputs and Consumptions

• Gross generation:	50	mWhrs
• Net generation:		
- Period	904	mWhrs
- On line	38	mWhrs
• Aux power use:		
- Period	954	mWhrs
- On line	12	mWhrs
• Aux power use (in %):		
- Period	1,908.00	%
- On line	23.40	%

2. Operating Hours

• Period hours:	744	hrs
• In Service:	4	hrs
• Coal hours:	1.4	hrs
• On standby:	0	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	740	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	0	0.00	0
2	0	0.00	0
3	0	0.00	0
4	50	12.5	4

4. Operating Availability

• Percent:	0.54	%

5. Capacity Factor

• Percent:	0.06	%

6. Major Equipment Usages

• Boiler feed pumps:	41,500	kWhr
• Primary air fan:	172,600	kWhr
• Secondary air fan:	30,100	kWhr
• Induced draft fan:	48,500	kWhr
• High pressure blowers:	13,200	kWhr
• Bottom ash cooler fan:	8,500	kWhr

9. Material Consumptions

• Total coal flow:	5.25	tons
• Total limestone flow:	.58	tons
• Total warm-up gas (propane) flow:	2,276.594	kscf

Table 8-8
PLANT COMMERICAL PERFORMANCE STATISTICS
September 1988

1. Plant Outputs and Consumptions

• Gross generation:	9,978	mWhrs
• Net generation:		
- Period	7,900	mWhrs
- On line	8,819	mWhrs
• Aux power use:		
- Period	2,078	mWhrs
- On line	1,159	mWhrs
• Aux power use (in %):		
- Period	20.83	%
- On line	11.62	%

2. Operating Hours

• Period hours:	720	hrs
• In Service:	169	hrs
• Coal hours:	161	hrs
• On standby:	0	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	551	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	759	10.12	75
2	660	8.80	75
3	980	10.32	95
4	7,580	44.85	169

4. Operating Availability

• Percent:	23.47	%

5. Capacity Factor

• Percent:	12.60	%

6. Major Equipment Usages

• Boiler feed pumps:	413,300	kWhr
• Primary air fan:	428,300	kWhr
• Secondary air fan:	74,00	kWhr
• Induced draft fan:	190,200	kWhr
• High pressure blowers:	34,700	kWhr
• Bottom ash cooler fan:	38,900	kWhr

7. Material Consumptions

• Total coal flow:	4,527	tons
• Total limestone flow:	405	tons
• Total warm-up gas (propane) flow:	7,436	kscf

Table 8-9
PLANT COMMERICAL PERFORMANCE STATISTICS
October 1988

1. Plant Outputs and Consumptions

• Gross generation:	38,974	mWhr
• Net generation:		
- Period	34,310	mWhr
- On line	34,755	mWhr
• Aux power use:		
- Period	4,663	mWhr
- On line	4,219	mWhr
• Aux power use (in %):		
- Period	12.0	%
- On line	10.8	%

2. Operating Hours

• Period hours:	744	hrs
• In Service:	507	hrs
• Coal hours:	492	hrs
• On standby:	0	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	237	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	3,783	8.8	430
2	4,067	10.0	405
3	3,602	8.1	444
4	27,521	54.3	507
Unit Total	38,874	76.9	507

4. Operating Availability :	68.1	%
5. Equivalent Availability:	63.1	%
6. Capacity Factor:	47.6	%
7. Average Heat Rate for Period :	12168.1	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	1,119	mWhr
• Primary air fan:	1,067	mWhr
• Secondary air fan:	222	mWhr
• Induced draft fan:	572	mWhr
• High pressure blowers:	70	mWhr
• Bottom ash cooler fan:	81	mWhr

9. Material Consumptions

• Total coal flow:	20,320	tons
• Total limestone flow:	849	tons
• Total warm-up gas (propane) flow:	4,632	kscf
• Avg higher heating value of propane gas:	2,516	btu/scf

10. Average Coal Analysis

• Higher heating value:	10218	btu/lb
• Sulfur:	0.8	%
• Ash:	23.7	%
• Moisture:	4.9	%

11. Solid waste to disposal (wet):	7482	tons

Table 8-10
PLANT COMMERICAL PERFORMANCE STATISTICS
November 1988

1. Plant Outputs and Consumptions

• Gross generation:	38,414	mWhrs
• Net generation:		
- Period	33,659	mWhrs
- On line	34,040	mWhrs
• Aux power use:		
- Period	4,756	mWhrs
- On line	4,374	mWhrs
• Aux power use (in %):		
- Period	12.4	%
- On line	11.4	%

2. Operating Hours

• Period hours:	720	hrs
• In Service:	568	hrs
• Coal hours:	496	hrs
• On standby:	0	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	152	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	3,533	7.2	492
2	3,311	8.5	391
3	3,750	7.7	485
4	27,819	49.0	568
Unit Total	38414	67.6	568

4. Operating Availability:	78.9	%
5. Equivalent Availability:	71.5	%
6. Capacity Factor:	48.5	%
7. Average Heat Rate for Period:	11673.4	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	1,249	mWhrs
• Primary air fan:	1,061	mWhrs
• Secondary air fan:	187	mWhrs
• Induced draft fan:	487	mWhrs
• High pressure blowers:	81	mWhrs
• Bottom ash cooler fan:	84	mWhrs

9. Material Consumptions

• Total coal flow:	20,732	tons
• Total limestone flow:	1,237	tons
• Total warm-up gas (propane) flow:	3,902	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis:

• Higher heating value:	9,424	btu/lb
• Sulfur:	0.9	%
• Ash:	26.5	%
• Moisture:	6.1	%

11. Solid waste to disposal (wet):	9,798	tons

Table 8-11
PLANT COMMERICAL PERFORMANCE STATISTICS
December 1988

1. Plant Outputs and Consumptions

• Gross generation:	37,744	mWhrs
• Net generation:		
- Period	33056	mWhrs
- On line	33537	mWhrs
• Aux power use:		
- Period	4687	mWhrs
- On line	4207	mWhrs
• Aux power use (in %):		
- Period	12.4	%
- On line	11.1	%

2. Operating Hours

• Period hours:	744	hrs
• In Service:	522	hrs
• Coal hours:	505	hrs
• On standby:	85	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	137	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	3,618	8.6	419
2	2,880	8.5	339
3	4,104	8.9	460
4	27,142	52.0	522
Unit Total	37,744	72.2	522

4. Operating Availability:	81.6	hrs
5. Equivalent Availability:	71.3	hrs
6. Capacity Factor:	46.1	hrs
7. Average Heat Rate for Period:	12,304.1	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	1,167	mWhrs
• Primary air fan:	1,039	mWhrs
• Secondary air fan:	157	mWhrs
• Induced draft fan:	516	mWhrs
• High pressure blowers:	53	mWhrs
• Bottom ash cooler fan:	76	mWhrs

9. Material Consumptions

• Total coal flow:	20,895	tons
• Total limestone flow:	1,425	tons
• Total warm-up gas (propane) flow:	5,050	kscf
• Avg higher heating value of propane gas	2516	btu/scf

10. Average Coal Analysis

• Higher heating value:	9,717	btu/lb
• Sulfur:	1.0	%
• Ash:	18.2	%
• Moisture:	9.9	%

11. Solid waste to disposal (wet):	8,181	tons

Section 9

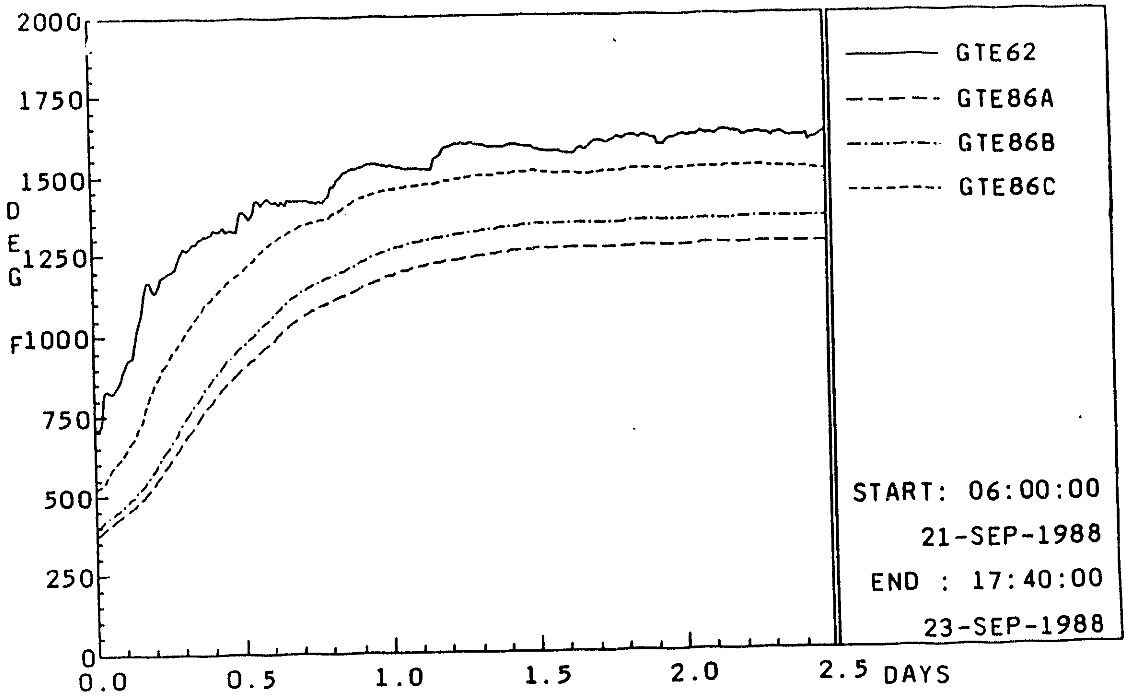
START-UP, HOT AND COLD RESTARTS

The purpose of this section is to investigate the response characteristics of the CFB boiler and its auxiliary systems during start-up and restart after various time periods of unit shutdown. The ultimate intent is to define rate limiting factors that are related to CFB technology or balance-of-plant equipment. The Test Plan called for the analysis of data from cold, hot, and warm restarts during the normal operation of the plant. During this reporting period, the on-site test team refined software required to analyze this type of data as part of cold-mode shakedown activities. In addition, during the start-up phase of the plant and through acceptance testing on design "A" coal in July and October 1988, the start-up and restart procedures were in a period of refinement. Therefore, only limited analysis was completed during the fourth quarter of 1988 from two cold start-ups. These data are presented below.

9.1 OBJECTIVES AND APPROACH

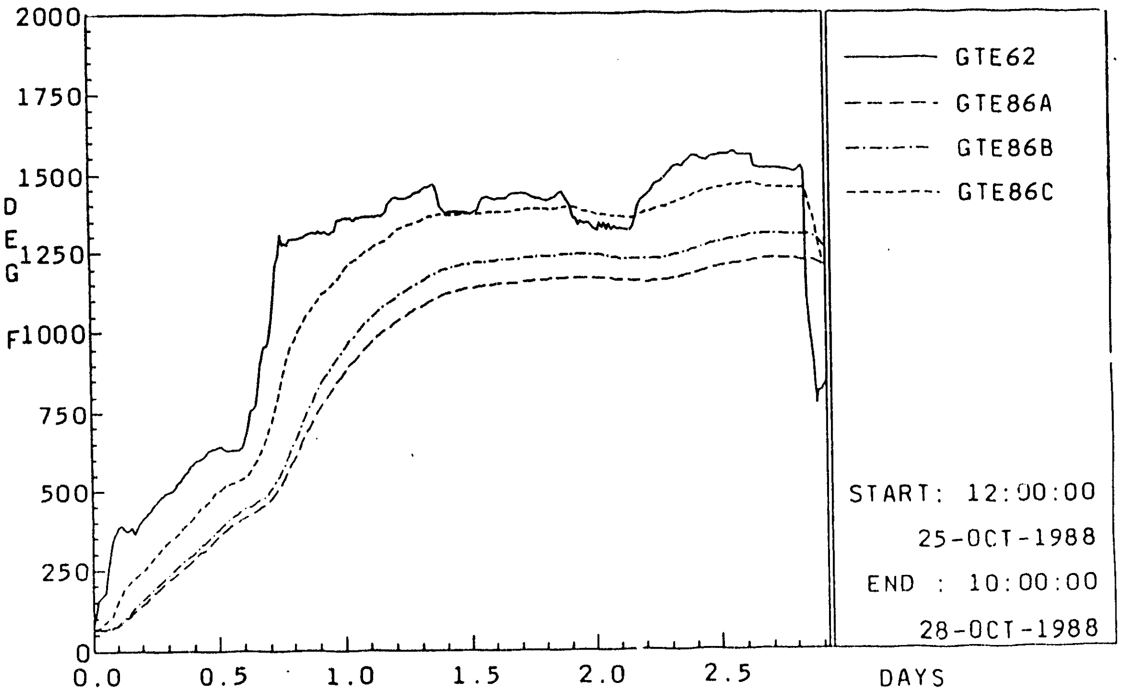
Ultimately, it is the plant owner's objective during start-ups and restarts to raise steam conditions and put energy onto the grid as quickly as possible using start-up procedures that maximize safety and equipment life. With this perspective, the following objectives were defined in the Detailed Test Plan:

- Times to full power operation, starting from cold conditions and from various intervals of unit downtime.
- The component of the boiler system that limits the rate at which it can be restarted.
- Characteristics of the boiler or its auxiliary components that limit the capability to match the steam turbine conditions.
- Start-up fuel (propane) requirements.
- Potential improvements in the start-up procedures that may lead to operational and economic advantages.



GTE62-CYCLONE 4B GAS INLET TEMP GTE86A-CYCLONE 4B LOWER REFACTORY T
GTE86B-CYCLONE 4B LOWER REFACTORY T GTE86C-CYCLONE 4B LOWER REFACTORY T

Figure 9-1. Refractory Temperatures in Lower Cyclones During Cold Start-up on September 21, 1988.



GTE62-CYCLONE 4B GAS INLET TEMP GTE86A-CYCLONE 4B LOWER REFACTORY T
GTE86B-CYCLONE 4B LOWER REFACTORY T GTE86C-CYCLONE 4B LOWER REFACTORY T

Figure 9-2. Refractory Temperatures in Lower Cyclones During Cold Start-up on October 25, 1988.

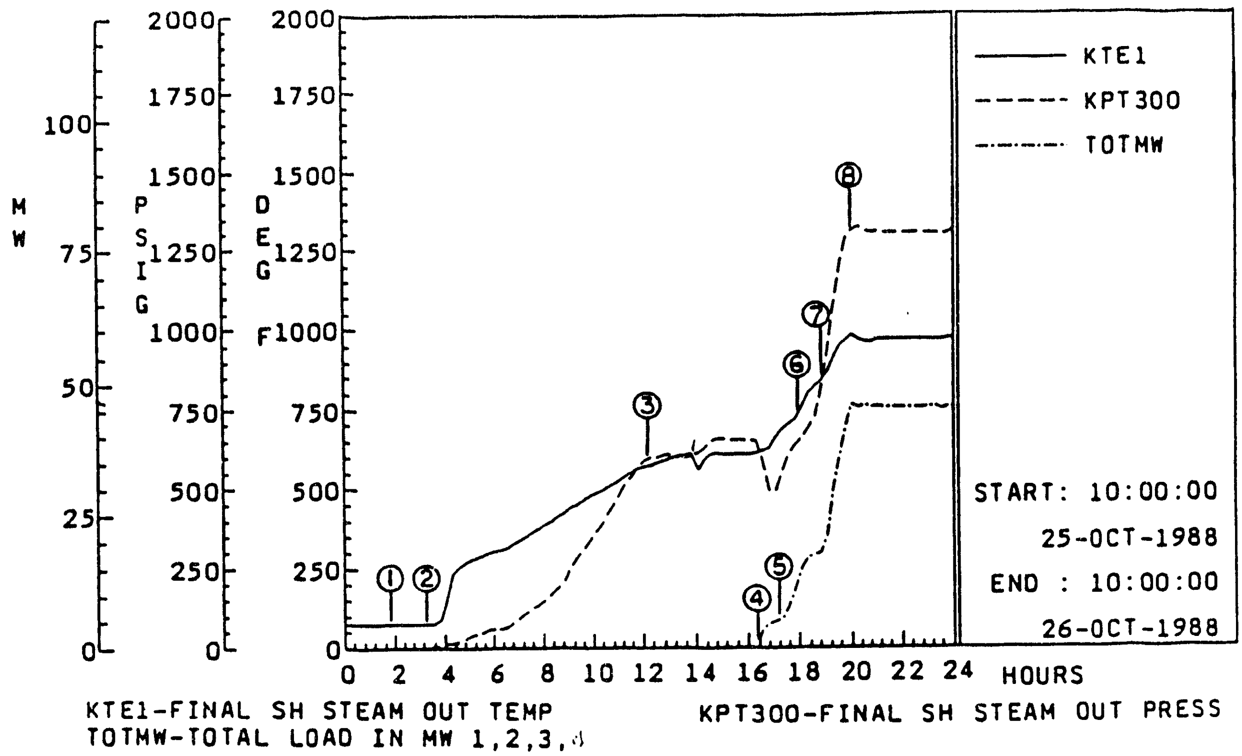


Figure 9-3. Final Steam Conditions and Unit Output from Cold Start-up on October 25, 1988.

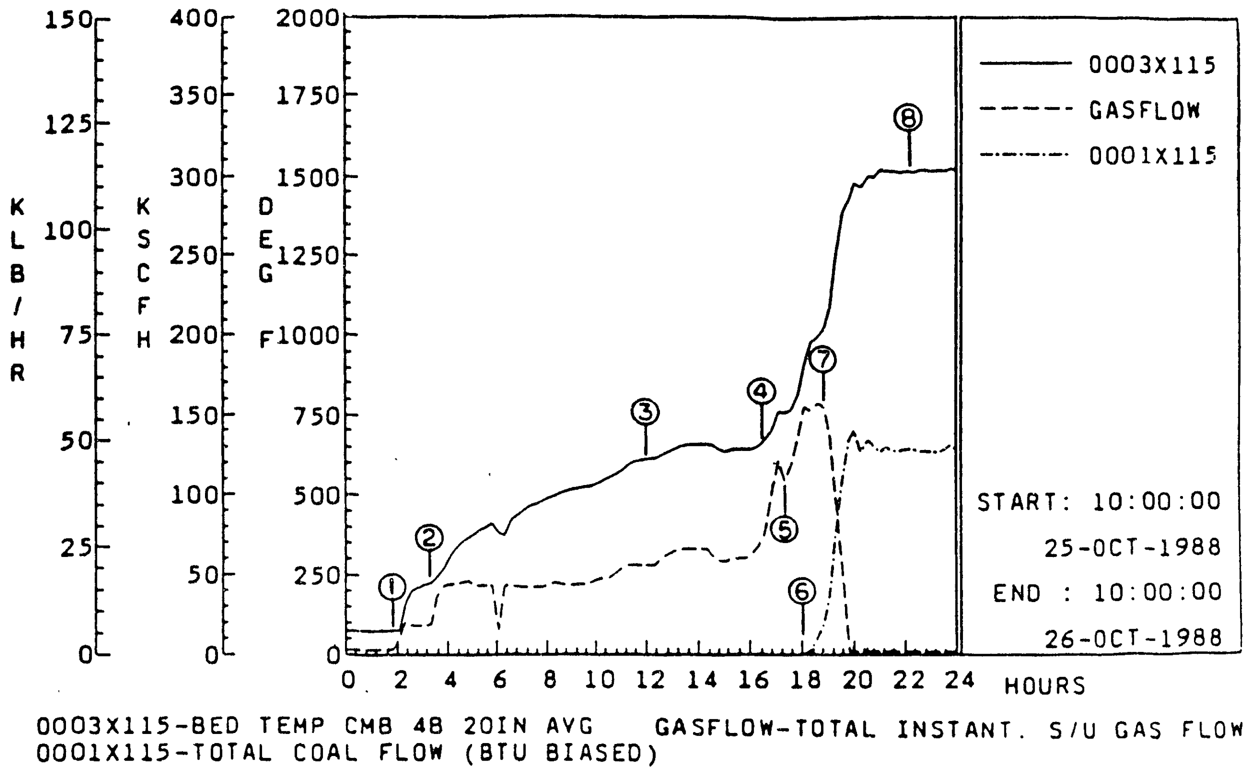


Figure 9-4. Bed Temperatures, Gas Flows, and Coal Flow from Cold Start-up on October 25, 1988.

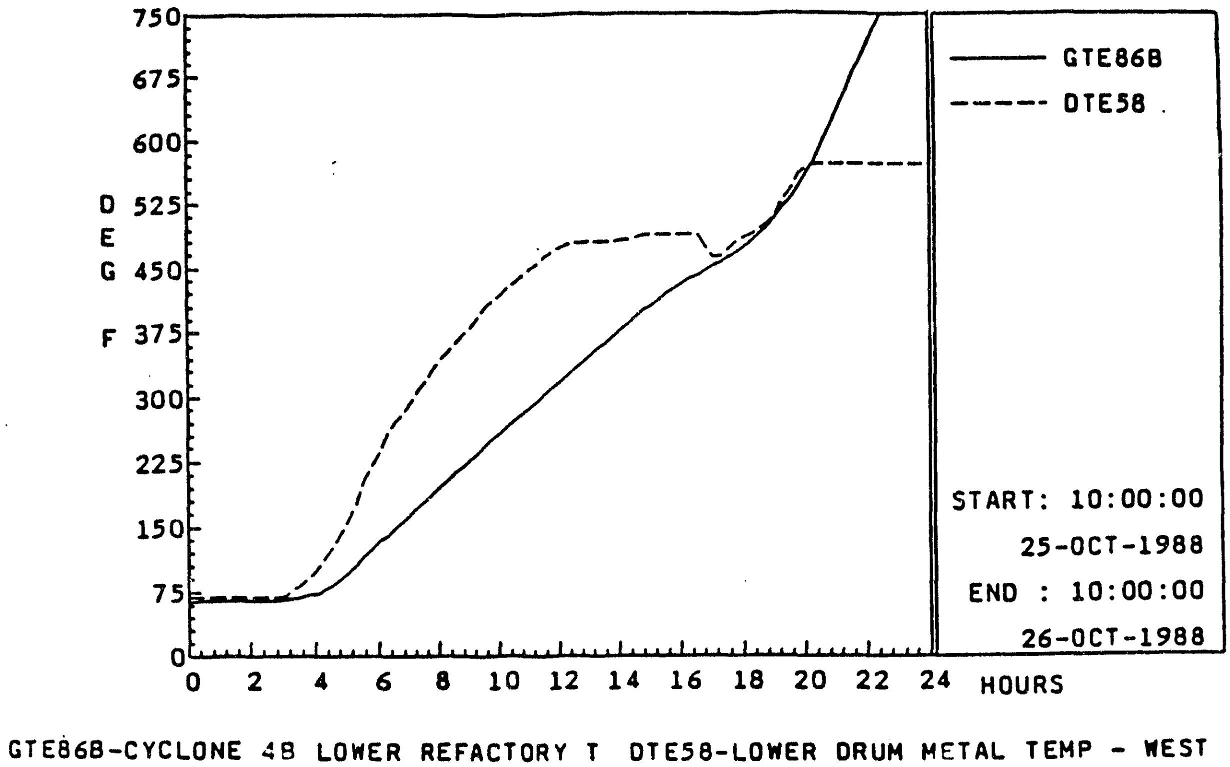


Figure 9-5. Refractory and Drum Metal Temperatures from Cold Start-up on October 25, 1988.

Based on the analysis of data from various normal plant start-ups, a revised set of start-up procedures will be drafted during the course of the test program. These procedures will be designed to minimize start-up and restart times and total gas consumption within safe operating practices and without sacrificing useful equipment life.

9.2 DATA FROM COLD START-UPS

Data from two cold start-ups on September 21 and October 25, 1988 were collected, analyzed, and are presented below. Since the primary test program emphasis during this reporting period was on completion of the cold-mode shakedown test plan in preparation for detailed hot-mode testing, the presentation and analysis of start-up data during this period is limited. More extensive analysis of start-up data is planned in the second quarter of 1989 following the completion of hot-mode testing.

One trend plot is shown for the September 21, 1988 cold start-up and four trend plots are presented for the start-up on October 25, 1988. Figures 9-1 and 9-2 show refractory temperatures in the conical section of the combustor B cyclone over a 2.5 day period following both cold start-ups. The intent of these figures is to indicate the maximum rate of change of refractory temperature during the start-up period. The maximum rate of increase of refractory temperature for the September 21 cold start was 63 °F/hour, and the maximum rate for the October 25 cold start was 73 °F/hour. These rates are under the limits set by the boiler manufacturer. Their specification states that refractory temperatures should not exceed 90 to 100 °F/hour from cold conditions until 600 °F temperatures are reached. From this point, refractory can be warmed at about 130 °F/hour. When the temperature has reached 1100 °F, the refractory no longer limits the warm-up speed.

From this initial data, it appears that rate limitations for increases in refractory temperature are not restrictions to cold start-up rates. This does not guarantee refractory performance, which depends on many other factors such as the quality of installation, thickness, anchoring technique, CFB solids characteristics, etc. In addition, refractory temperatures at the surface (closest to the hot gas) may show rates of temperature increase larger than the bulk temperatures displayed in Figures 9-1 and 9-2. This may contribute to spalling and surface breakage of refractory as has been evident in the cyclones during this reporting period.

Figures 9-3, 9-4, and 9-5 show final steam conditions, total load, drum metal temperatures, bed temperatures, coal flow, and start-up gas flow for the cold start-up on October 25,

1988. The numbering sequence on these figures corresponds to the following:

1. Duct burners are started and run for 2 hours to warm the lower portion of the combustion chambers, including the windbox. The drum level during this period is quite erratic.

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

3. Drum pressure reaches approximately 600 psig for 100 °F of superheat at a temperature of approximately 600 °F. The turbine is rolled and the heat soak period is initiated (minimum of 3 hours).

4. Following completion of the turbine heat soak, the turbine speed is raised to 3600 rpm, the generator is synchronized, and load is increased to a minimum stable level of 5 MWe for 1 hour.

5. Start-up burner firing rates are increased and load is raised to approximately 20-25 MWe.

6. At this point, bed temperatures have achieved 950 °F required for the initiation of coal feed. Coal flow is initiated and load is increased.

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

8. Unit load is held at 45 MWe to stabilize and prepare the old turbines for service. Bed temperatures at this point are approximately 1500 °F.

For this cold start-up, approximately 14 hours were required from the time duct burners were first fired and minimum load was established. Figure 9-5 shows that the rate of increase in lower drum metal temperatures exceeds that of the cyclone lower refractory temperatures. In this case, the maximum rate of change in drum metal temperatures is 85 °F/hour, which is below the 100 °F/hour limitation.

Following the completion of hot-mode testing in the first quarter of 1989, more detailed analysis of cold, warm, and hot restarts will be completed. This will include comparisons of start-up times and start-up fuel (propane) consumption. Ultimately, revised start-up procedures will be prepared to optimize the start-up and restart schedule.

Section 10

HOT-MODE SHAKEDOWN

The majority of the hot-mode shakedown activities were conducted in 1989. This section, that describes activities conducted in 1988, includes ash homogeneity, radiation and convection heat losses, isokinetic operations and gas stratification tests.

10.1 ASH HOMOGENEITY

The fly ash homogeneity issue concerns a method, or methods, to sample fly ash from the air heater and economizer hoppers, the four baghouses, and the fly ash transport air baghouses to obtain a representative sample. The issue was resolved by purchasing a continuous solids sampler and by combining all fly ash streams (see Figure 10-1). This system was installed in 1989.

These modifications combine all ash streams into one stream which then passes over a flow meter and past the sampler regardless of the specific phase of ash pulling sequence or point of ash disengagement from transport air involved. In the original system design, a thief probe in the discharge chute was used to gather representative ash samples by grab sampling from the mechanical separator on the fly ash silo. This ash also passed over the fly ash flow meter.

The sampler and a new fly ash feeder valve (shown in Figure 10-1) replaced an existing knife gate and rotary valve at the bottom of the fly ash weigh bin. The fly ash transport air baghouse discharge piping was rerouted to the fly ash weigh bin. The weigh bin, located above the Schenck fly ash flow meter, now receives all fly ash streams. Fly ash passes through the feeder valve, the sampler, and the Schenck flow meter during testing for weighing and sampling. Bypasses around the weighing and sampling equipment were also provided to facilitate maintenance of the equipment during operations.

The sampler is an automatic, chute-mounted, full-cut sampler. It is programmable for sample frequency, and adjustable for sample quantity per cut. Approximately 21 pounds of sample can be taken in 8 hours or less.

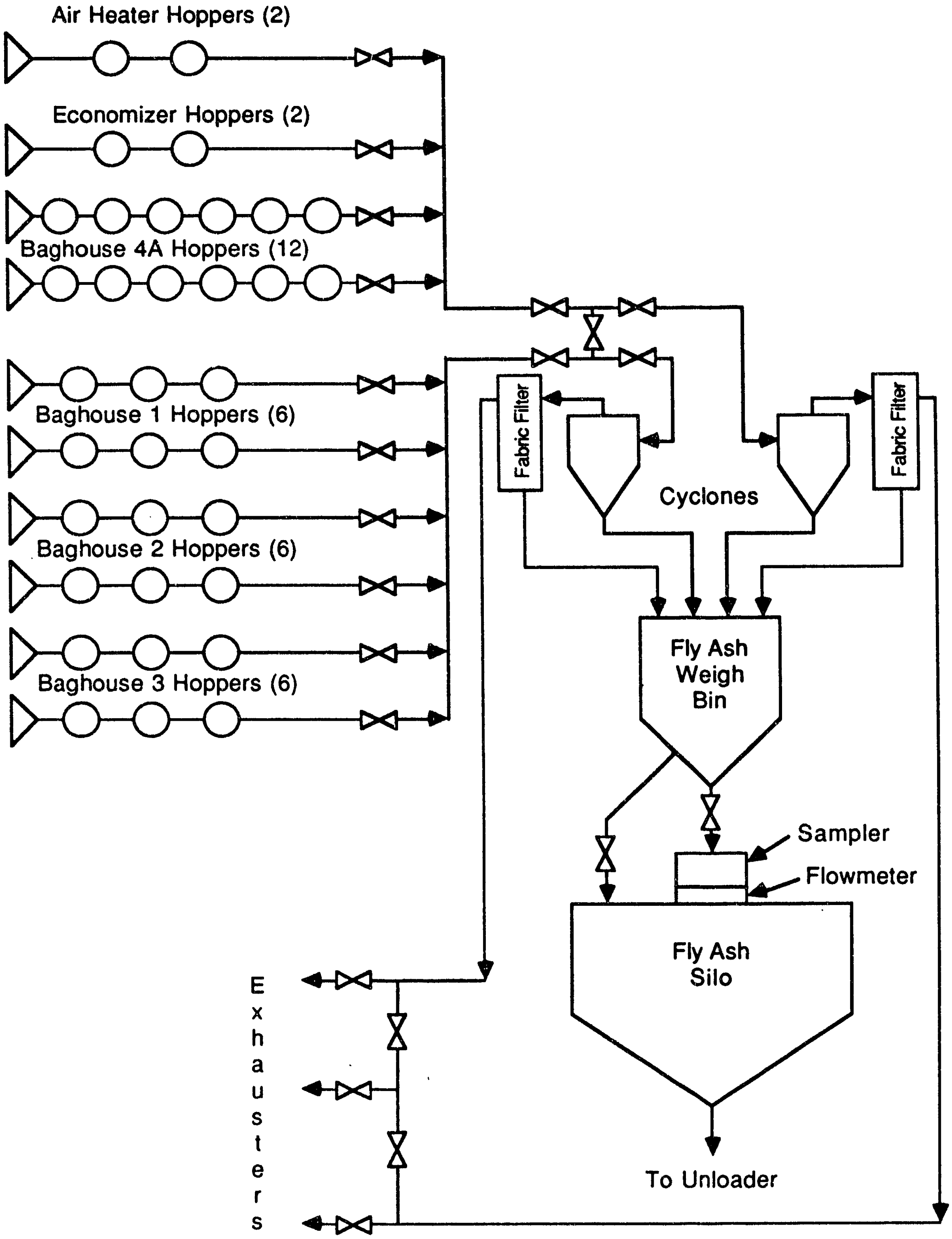


Figure 10-1. Schematic of Revised Fly Ash Collection and Measurement System

10.2 RADIATION AND CONVECTION HEAT LOSSES

The radiation and convection heat loss must be quantified to calculate boiler efficiency using the heat loss method. The design of the CFB boiler at Nucla differs from that of more traditional fossil-fired plants (e.g., refractory lined cyclones and solids recycle duct work with high surface temperatures and relatively large surface areas). To assess the magnitude of heat loss from boiler-related surfaces, the test team developed and refined a methodology for estimating the heat loss based on measurements of surface and ambient temperatures. In the fourth quarter of 1988, the heat loss calculation procedure underwent a final revision. Two temperature and ambient condition surveys were made with the unit running at full load and associated heat loss calculations were performed.

A description of the physical characteristics of the plant that are relevant to the heat loss calculation, the methodology, technical premises and formulation used, and the results obtained are presented below.

10.2.1 Plant Description

The Nucla CFB boiler consists of two combustion chambers with adjacent center walls, a hot cyclone and loop seal return leg for each combustion chamber, a single convection section, and a tubular air heater. The combustion chambers are of water-wall construction above the distributor plates. The walls are insulated with 4 inch thick blocks of mineral wool. Knurled, corrugated aluminum sheets are used for lagging on the outside surface. The center walls of the combustors are adjacent to one another, and the dead space between them is isolated from ambient conditions in the plant by insulation and lagging.

The loop seals, cyclones, and cyclone inlet/outlet ducts are refractory-lined with air cooled, uninsulated outside surfaces. The refractory is nominally 1 foot thick. The outside surfaces are rolled steel, smooth and painted with a dull, non-metallic finish. The walls of the convection pass are insulated with 4 inch blocks of mineral wool, and lagged with knurled, corrugated aluminum sheet.

The air heater is split into two sections separated by 2 feet of open space. The flue gas passes through the tube side of the air heater, while the combustion air passes through the shell side. The air heater is covered with 4 inch thick board insulation and is lagged with corrugated, knurled aluminum sheet.

The primary and secondary air ducts are insulated with 3 inch thick blocks of mineral wool and have corrugated, knurled, aluminum sheet lagging over most of the surface. Some of the air distribution ducts near the boiler are uncorrugated.

The entire boiler is enclosed in a building constructed of wide flange beams, with walls made of fiberglass-reinforced plastic panels. Induced drafts from heated vertical surfaces on the boiler walls are not impeded by the open gratings that are provided for personnel access.

The outside edge of the buckstays extend 20 inches from the lagging surface on the walls of the combustion chambers and 12 inches from the convection section walls. The buckstays are horizontal wide flange beams spaced at 8 foot intervals up the furnace walls and 5 foot intervals on the convection pass walls. The buckstays affect the convection heat transfer process by interfering with the smooth flow of the induced draft up the boiler exterior walls.

Also contributing to an upward movement of air is the location of the inlets to the forced draft fans at the top of the boiler building. The primary and secondary fans draw a total of 1,000,000 lb/hr of air with the unit running at full load. This ventilation scheme works in conjunction with three combination supply and exhaust fans mounted on the boiler room roof. These fans are intended to operate as exhaust fans in warm weather increasing the ventilation air flow up past the boiler in warm weather. In cold weather, these fans are intended to operate as supply fans, introducing unheated outdoor air to the boiler draft fans. The overall ventilation scheme would provide 15 air changes per hour of boiler room air for summer ventilation and less than one air change per hour for winter ventilation.

10.2.2 Methodology

10.2.2.1 <u>Selection of Temperature Measurement Locations</u>

In order to represent the heat loss from the boiler, the surface area was subdivided by major boiler component, yielding seven areas:

- Combustors
- Cyclones and Loop Seals
- Convection Pass
- Air Heater
- Primary Air Duct
- Secondary Air Duct
- Drum and Piping

These surfaces were then subdivided on the basis of surface covering. For example, the primary air duct work is divided into two surface areas, one area covered with corrugated lagging, the other covered with uncorrugated lagging. Further subdivision was based on observations of surface and ambient temperatures. When these temperatures varied substantially over an area, the surface was subdivided to minimize the variation in temperature. This process led to the definition of 39 area subdivisions.

Engineering judgement was exercised in selecting temperature measurement locations that would accurately represent the heat loss characteristics of an area. As a result of this process, a total of 312 measurement locations were selected to represent the 39 area subdivisions. The number of points selected to represent a given area was dependent upon the size of the area, access, and the temperature variation over the surface. For areas where some temperature variation is evident, the measurement points were selected to be representative of the average heat loss characteristics.

10.2.2.2 Surface/Ambient Temperature Measurements

Surface and ambient temperatures are measured and recorded at 312 locations by a crew of three people in approximately six hours. A surface probe contact thermocouple is used for surface temperature measurements, and an air cage thermocouple is used for ambient temperature measurements. Both thermocouples are type "K" and are attached to a two-foot long metal rod. Air temperatures are measured one foot away from the surface probe measurement. Both thermocouples are connected to a hand held thermometer with a digital liquid crystal display readout. The surface probe contact thermocouple is also used to measure the temperature of each of the boiler building's four walls and roof.

10.2.2.3 Data Reduction/Heat Loss Analysis

After a temperature survey has been completed, the surface and ambient temperatures for each of the 312 measurement locations are entered into a spreadsheet program. The surface temperatures for the four walls and roof of the building are also entered.

Average surface and ambient temperatures for each area subdivision are calculated by the program. Convection heat fluxes are calculated based on these average surface and ambient temperatures. Radiation heat fluxes are calculated based on the average surface temperature and the temperature of the boiler building surface facing the component surface. The surface areas for each of the components are included in the spreadsheet program.

10.2.3 Technical Premises

In calculating the radiation and convection heat losses based on surface and ambient temperature measurements, some simplifying assumptions were made. They are as follows:

- All lagged surfaces are considered to be rough plate aluminum with an emissivity of 0.09. All painted surfaces are assigned an emissivity of 0.9.
- The number and location of temperature survey points selected are such that the average heat flux for each subdivision is representative.
- The heat lost through the buckstays, hangers, and other structural steel is considered to be negligible. Surface areas were not calculated for these components and no temperature measurements were made.
- The formula used for calculating convection heat loss is that for vertical plates, since a high percentage of the surface area of the boiler consists of vertical walls.
- Radiation heat transfer between boiler surfaces and structural surfaces other than the boiler building roof and walls is not considered. All radiation heat loss is assumed to be to the boiler building roof and walls.
- The temperature of a boiler building wall or roof is assumed to be constant and represented by the measured temperature.

10.2.4 Formulation

To determine the convection heat loss, the average surface temperature and average ambient air temperature for each of the 39 boiler areas are used in the following equation:

$$QC_i = 0.19 * A_i * CF_i * (TS_i - TA_i)^{4/3} \tag{1}$$

The corrugation factor is used to account for the larger heat transfer surface area associated with corrugated surfaces. A corrugation factor of 1.25 was used. The factor for uncorrugated surfaces is 1.0.

The equation used for calculating radiation heat loss from each of the boiler surfaces is as follows:

$$QR_{ij} = 1.714 * 10^{-9} * ES_i * EB_j * PA_{ij} * (TS_i{}^4 - TB^4{}_j) \tag{2}$$

The total radiation heat loss for boiler area "i" will then be:

$$QR_i = \sum_{j=1}^{5} QR_{ij} \qquad (3)$$

The total radiation and convection heat loss for the boiler is then calculated by summing the radiation and convection losses from each of the 39 boiler surface areas:

$$L_b = \sum_{i=1}^{39} (QR_i + QC_i) \qquad (4)$$

10.2.5 Nomenclature

A_i - ft^2: Projected surface area of "i".
CF_i - Dimensionless: Corrugation factor for area "i".
EB_j - Dimensionless: Emissivity of boiler building surface "j".
ES_i - Dimensionless: Emissivity of surface of area "i".
L_b - Btu/h: Total rate of heat loss due to surface radiation and free convection.
PA_{ij} - ft^2: Projected area of boiler area "i" facing boiler building surface "j".
QC_i - Btu/h: Convection heat loss from area "i".
QR_i - Btu/h: Heat loss rate due to surface radiation for area "i".
QR_{ij} - Btu/h: Radiation heat loss from boiler area "i" to boiler building surface "j".
TA_i - degrees F: Average ambient air temperature surrounding area "i".
TB_j - degrees F: Temperature of boiler building surface "j".
TS_i - degrees F: Average surface temperature of area "i".

10.2.6 Results

Two temperature surveys of the Nucla CFB boiler have been conducted with the unit operating at full load. The radiation and convection heat losses calculated were $4.9*10^6$Btu/h (.44 percent of the total coal firing heat release) for the first survey, and $5.1*10^6$Btu/h (.50 percent of the total coal firing heat release) for the second survey. The actual unit load for the first survey was 110 MWe, and 101 MWe for the second survey. Tables 10-1 and 10-2 show the heat loss, percent of total area, percent of average heat flux, and the average surface and ambient air temperatures associated with the seven components.

Table 10-1

RADIATION AND CONVECTION HEAT LOSS RESULTS - FIRST SURVEY

Component	% of Total Heat Loss	% of Total Area	% of Average Heat Flux
Cyclones & Loop Seals	33.5	14.1	237
Combustors	27.4	20.5	134
Drum & Piping	12.0	15.4	78
Primary Air Ducts	9.3	18.3	51
Air Heater	7.7	16.0	48
Convection Pass	6.8	9.8	69
Secondary Air Ducts	3.3	6.1	53
Average Heat Flux: 50 $Btu/hr/ft^2$			

Table 10-2

RADIATION AND CONVECTION HEAT LOSS RESULTS - SECOND SURVEY

Component	% of Total Heat Loss	% of Total Area	% of Average Heat Flux
Cyclones & Loop Seals	32.8	14.1	233
Combustors	27.6	20.4	135
Drum & Piping	14.6	15.4	95
Primary Air Ducts	9.2	18.2	50
Air Heater	6.2	15.9	39
Convection Pass	6.6	9.8	67
Secondary Air Ducts	2.9	6.1	47
Average Heat Flux: 52 $Btu/hr/ft^2$			

10.2.7 Conclusions

The results of the first two boiler surface temperature surveys at the Nucla CFB indicate radiation and convection heat losses of 0.44% and 0.50% of the total fuel heat input. The outside air temperature was approximately 50 °F for the first survey and 30 °F for the second survey, with the unit operating at full load. It should be noted that the large, uncooled surface of the cyclones and loop seals is responsible for slightly more than one-third of the heat lost from the boiler surface, while comprising less than one-sixth of the total area.

It is expected that the heat loss will be somewhat dependent upon outdoor ambient temperature, and relatively independent of unit load. Throughout the test program additional temperature surveys will be run in order to correlate radiation and convection heat loss to outdoor ambient temperatures and unit load.

10.3 ISOKINETIC OPERATIONS

Isokinetic sampling was used to provide information for the baghouse performance monitoring test area and as a backup for the automatic fly ash sampler. After testing its viability, in-duct filtration was chosen as the sampling configuration as it is simpler and less expensive to use than filtration after the duct.

One initial problem that occurred during practice runs was that some dust was lost out of the filter. This problem is the result of the increased sample amount which must be collected if the probe is to be used to collect a fly ash sample for chemical analysis. The required sample size for this application is much larger than was anticipated at the time the probe was specified. Because of the large sample quantity, material can fall out of the in-duct filter when it is oriented in its normal position with the dirty side of the filter facing downward. In most other applications, the dust typically becomes embedded and retained in the filter, and there is no loss of material. When large quantities of dust are required for sample analysis, loose material will collect in the filter and then fall back out when the sample flow stops. This problem was solved by making minor modifications in the probe in order to change the orientation of the filter.

Personnel were trained to operate the sampling equipment and perform isokinetic sampling in October, 1988, and a detailed audit of procedures and techniques was performed in December, 1988. The auditor reviewed all aspects of the sampling process from pre-sampling preparation to the calculation of results.

To demonstrate repeatability of the sampling method, the sampling team performed two separate sampling runs back-to-back while the unit was at a stable load. The results of these two tests are shown in Table 10-3 below.

Table 10-3. Verification of Isokinetic Accuracy

Item	Test 1	Test 2
Traverse location	air heater exit	air heater exit
Flue gas moisture	7.3%	7.27%
Velocity, ft/s	34.43	33.69
Volumetric flow, ft^3/min	149,874	147,268
Particulate loading, gr/dscf	10.44	10.31
Particulate mass flow, lb/hr	13.412	13,645
Percent isokinetic	100.5	100.6

10.4 GAS STRATIFICATION TESTS

EGAS gas analyzer grid traverses were conducted on October 14 and November 15 after leak checks and corrections. The purpose of these tests was to detect any stratification in the duct.

The traverses were done during a steady-state operating period as indicated by the total megawatt and main steam flow trend plots displayed in the control room during the tests. The data are shown in Tables 10-4 and 10-5. There appeared to be very little stratification in the duct. Variation in the SO_2 readings appeared to be due to fluctuations in the limestone feed rate.

Table 10-4. EGAS Traverse Data at 61.5 MW

Probe #	% O2	ppm CO	% CO2	ppm SO2(Lo)	ppm SO2(Hi)	ppm NOx
All 16	4.9	70	14.6	100	92	132
1	4.7	70	14.8	110	101	129
2	4.6	68	14.7	124	117	131
3	4.65	66	14.6	115	108	131
4	4.6	65	14.6	125	117	130
5	4.7	66	14.4	110	100	131
6	4.65	65	14.4	115	110	129
7	4.8	67	14.4	90	81	131
8	4.6	66	14.5	110	100	128
9	4.55	70	14.7	103	96	130
10	4.45	69	14.8	105	100	128
11	4.6	70	14.9	99	90	127
12	4.45	68	14.8	98	91	129
13	4.55	69	14.7	103	94	130
14	4.6	69	14.9	90	79	129
15	4.65	68	14.7	89	80	131
16	4.6	68	14.5	84	75	130
Mean	4.6	67.75	14.65	104.37	96.18	129.62
Std Dev	0.08	1.73	0.17	12.3	13.09	1.25
All 16	4.8	70	14.3	102	104	120

Table 10-5. EGAS Traverse Data at 39.5 MW

Probe #	% O2	ppm CO	% CO2	ppm SO2(Lo)	ppm SO2(Hi)	ppm NOx
All 16	10.2	144	9	65	73	28
5	10.2	170	8.9	97	99	25
6	10.3	175	8.9	109	110	24
7	10.2	181	9	102	103	26
8	10.2	215	9.1	102	103	25
3	10.2	226	9.15	105	103	24
4	10.1	211	9.15	112	110	24
1	10.3	222	8.9	113	111	26
2	10.15	215	9.15	97	96	26
9	10.4	188	9.1	66	68	30
10	10.1	133	9.3	63	64	31
11	10.4	137	9.05	63	64	30
12	10.0	126	9.4	51	53	31
13	10.3	135	9	69	68	30
14	10.15	134	9.3	63	64	29
15	10.1	130	9.2	61	61	30
16	10.1	130	9.2	61	61	30
Mean	10.2	170.5	9.11	83.37	83.62	27.56
Std Dev	0.11	38.42	0.14	22.64	22.00	2.75
All 16	10.15	167	9.2	93	91	26

Section 11

RELIABILITY MONITORING

The reliability monitoring plan for the Nucla CFB was conceived by the Electric Power Research Institute (EPRI) 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 North American Electricity Reliability Council/Generation Availability Data System (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.

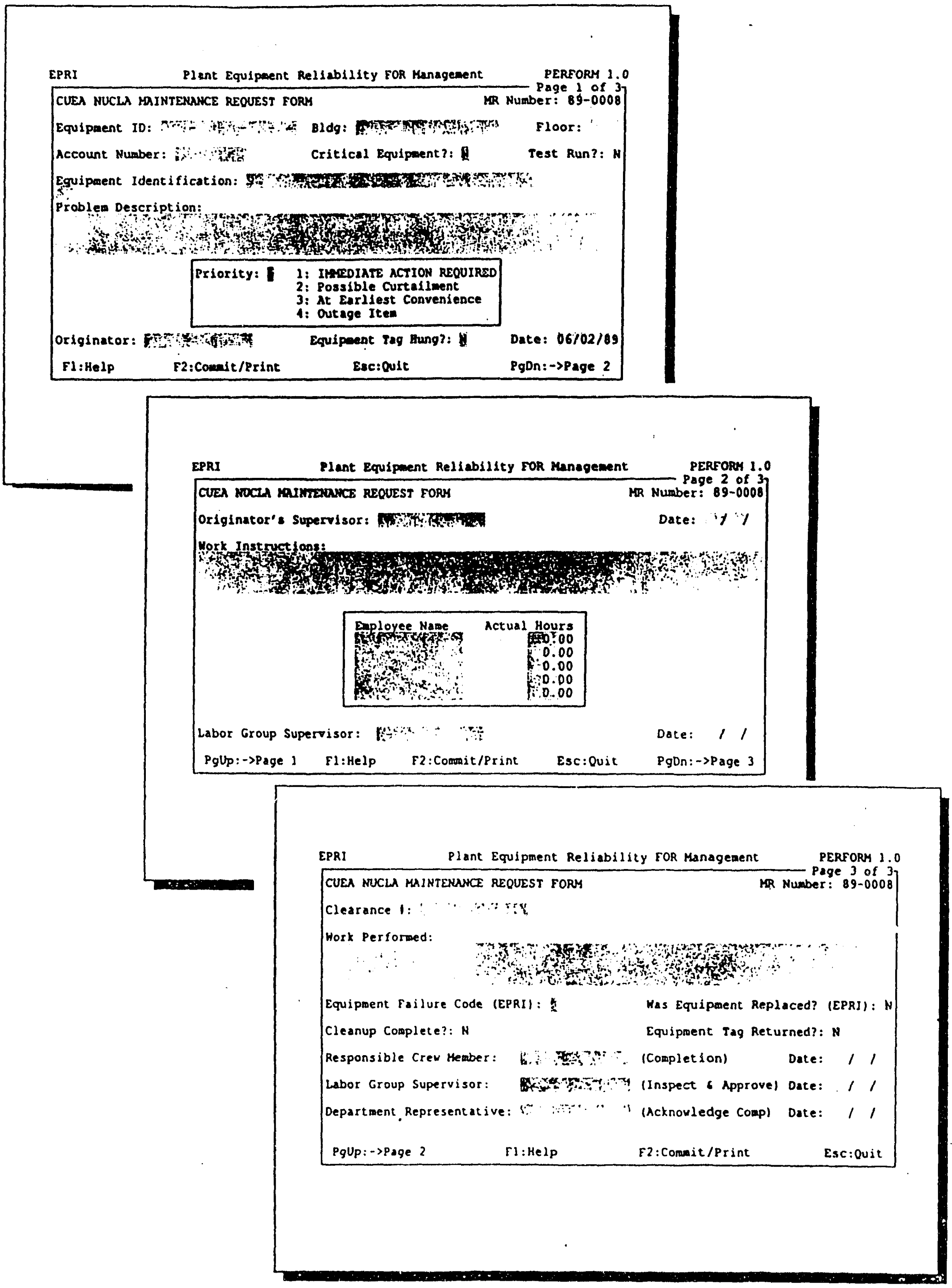
Accomplishing this plan required three steps. First, uniform codes, established by EPRI, were given to plant equipment components on three utility AFBC's under construction or in start-up: Northern States Power's 125 MWe Black Dog Bubbling Bed AFBC, TVA's 160 MWe Bubbling Bed AFBC, and Colorado-Ute Electric 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.

The first step was completed during the cold-mode shakedown period of the Demonstration Program at Nucla. 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 shown in Table 11.1. For 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 used at the other demonstration plants.

To accomplish the second step at Nucla, 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 used at the Nucla CFB during the fourth quarter of 1988 to generate maintenance work requests. The three PERFORM software set-up sheets to be completed by the plant maintenance staff in order to generate an MWR are shown in Figure 11-1.

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 were 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.


EPRI Plant Equipment Reliability FOR Management PERFORM 1.0
Page 1 of 3
CUEA NUCLA MAINTENANCE REQUEST FORM MR Number: 89-0008
Equipment ID: [redacted] Bldg: [redacted] Floor:
Account Number: [redacted] Critical Equipment?: [redacted] Test Run?: N
Equipment Identification: [redacted]
Problem Description:
[redacted]
Priority: [redacted] 1: IMMEDIATE ACTION REQUIRED
2: Possible Curtailment
3: At Earliest Convenience
4: Outage Item
Originator: [redacted] Equipment Tag Hung?: [redacted] Date: 06/02/89
F1:Help F2:Commit/Print Esc:Quit PgDn:->Page 2

EPRI Plant Equipment Reliability FOR Management PERFORM 1.0
Page 2 of 3
CUEA NUCLA MAINTENANCE REQUEST FORM MR Number: 89-0008
Originator's Supervisor: [redacted] Date: / /
Work Instructions:
[redacted]

Employee Name	Actual Hours
[redacted]	[redacted]
[redacted]	0.00
[redacted]	0.00
[redacted]	0.00
[redacted]	0.00

Labor Group Supervisor: [redacted] Date: / /
PgUp:->Page 1 F1:Help F2:Commit/Print Esc:Quit PgDn:->Page 3

EPRI Plant Equipment Reliability FOR Management PERFORM 1.0
Page 3 of 3
CUEA NUCLA MAINTENANCE REQUEST FORM MR Number: 89-0008
Clearance #: [redacted]
Work Performed:
[redacted]
Equipment Failure Code (EPRI): [redacted] Was Equipment Replaced? (EPRI): N
Cleanup Complete?: N Equipment Tag Returned?: N
Responsible Crew Member: [redacted] (Completion) Date: / /
Labor Group Supervisor: [redacted] (Inspect & Approve) Date: / /
Department Representative: [redacted] (Acknowledge Comp) Date: / /
PgUp:->Page 2 F1:Help F2:Commit/Print Esc:Quit

Figure 11-1. PERFORM Reliability Monitoring Set-Up Sheets Required for Generating MWR's.

During the third and fourth quarters of 1988, the Lotus Symphony software was debugged and the PERFORM software package was loaded onto a site personal computer for trial. The test team loaded all equipment maintenance data into the program for September 1988 as a trial run for the PERFORM software. Comments regarding data entry, data sorting, and printing capabilities were forwarded to EPRI's software contractor. Once these comments are incorporated into an updated version of the software, all maintenance work request data will be entered into the PERFORM software for the fourth quarter of 1988. Run time data will also be collected for this period and forwarded to EPRI for analysis. This information will allow the following analyses to be completed:

1. Relative comparisons can be made between plant equipment areas. Equipment with the highest failure rates and/or maintenance requirements can be identified.

2. The effect of equipment upgrades on overall plant and component reliability can be assessed by comparing quarterly or annual "frequency of failure" charts and plant operating data.

3. Data can be used as a planning tool for maintenance outages. Equipment areas with the highest frequency of maintenance repair can be identified.

4. Mean times to failure (MTTF) and mean times to repair (MTTR) can be calculated for the different equipment categories once a sufficient database has been developed. This information can then be used in computer models to predict overall reliability of new plants with various design configurations.

5. Prospective owners and designers of a plant can use the database as a means of selecting equipment components which provide a high level of overall equipment reliability and availability.

Table 11-1. Reliability Monitoring Database (page 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

Table 11-1 cont. Reliability Monitoring Database (page 2).

CUEA No.		EPRI No.			Description	TAG No.
002601516001002	C	02149201	05	02	RECYCLE LOOP SEAL 4B FLUID SYS	GPT4
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

Table 11-1 cont. Reliability Monitoring Database (page 3).

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
002900500001001 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

Table 11-1 cont. Reliability Monitoring Database (page 4).

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

Table 11-1 cont. Reliability Monitoring Database (page 5).

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

Table 11-1 cont. Reliability Monitoring Database (page 6).

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

Table 11-1 cont. Reliability Monitoring Database (page 7).

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
002605503850014	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	TPT39
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	TSEA52A
002604505280001	C		02145123	01	01	BOTTOM ASH EXHAUSTER 4A	TSEA52A
002604505851001	C		02145123	02	01	BOTTOM ASH EXHAUSTER 4A MTR	TSEB52A
002604505280002	C		02145123	01	02	BOTTOM ASH EXHAUSTER 4B	TSEB52A
002604505851002	C		02145123	02	02	BOTTOM ASH EXHAUSTER 4B MTR	VPT50
002600112252001	C4		02142329	12	04	TURBINE OIL COOLER U4	VPT50
002600112330001	C4		02142329	15	04	TURBINE OIL FILTER U4	VZS1A
002600112850001	C4		02142329	10	04	TURB OIL AUX LUBE PMP MTR U4	VZS1A
002600112509001	C4		02142329	09	04	TURBINE OIL AUX LUBE PMP U4	WZS1
002604003851002	C4		02148109	02	02	CONDENSER CIRC PMP 4A MTR	WZS1
002604003500002	C4		02148109	01	02	CONDENSER CIRC PUMP 4A	WZS1,2
002604001001001	N		02148425	01	04	COOLING TOWER #4A	WZS2
002604003851001	C4		02148109	02	01	CONDENSER CIRC PMP 4B MTR	WZS2
002604003500001	C4		02148109	01	01	CONDENSER CIRC PUMP 4B	WZS61
002504003851001	C4		02148109	02	01	CONDENSER CIRC PMP 1 MTR	WZS61
002504003499001	C4		02148109	01	01	CONDENSER CIRC PUMP 1	WZS61,62,63
002504001001001	C3		02148425	01	01	COOLING TOWER EXISTING	WZS62
002504003851002	C4		02148109	02	02	CONDENSER CIRC PMP 2 MTR	WZS62
002504003499002	C4		02148109	01	02	CONDENSER CIRC PUMP 2	WZS63
002504003851003	C4		02148109	02	03	CONDENSER CIRC PMP 3 MTR	WZS63
002504003499003	C4		02148109	01	03	CONDENSER CIRC PUMP 3	XFT300
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	

Table 11-1 cont. Reliability Monitoring Database (page 8).

CUEA No.			EPRI No.			Description	TAG No.
002604506545004	C2		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	

Table 11-1 cont. Reliability Monitoring Database (page 9).

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

Appendix A

INSTRUMENT CALIBRATION DATA

INSTRUMENT CALIBRATION DATA

LOCATION DESCRIPTION	TAG NUM	UNITS REQ'D	HIWAY UNITS	BOT BAR	TOP BAR	PERF CALC	USED IN PERFORMANCE CALCULATION NUMBER 1	2	3	4	5	6	7	8	9	A	B	C	D	E	SO2 EMN RTE	NOX EMN RTE	AUX PWR	SEC 11 TST	SEC 12 TST	SEC 13 TST	SEC 6 TST	SEC 9 TST	USED FOR COMP PNT	CALIB RANGE LOW	CALIB RANGE HIGH	CALIB UNITS	ELMNT TYPE	XMTTR TYPE	LAST CAL DATE	CAL INTVL (DAYS)	NEXT CAL DATE	COEFF NEEDS CHKD/CHNGD	REMARKS
RELATIVE HUMIDITY	CAT301	%		0	100	X													D											0	100	%	CAPACITOR		10/13/87	NR	-		WTHRTRNCS MODEL 1500
REL. HUM. VOLTS TO CURRENT MODULE	CAT301-VCM	VDC		0	5	X													D											0	5	VDC	-	E/I	10/13/87				MODEL 1630 CHANNEL 1 OR 2
AMBIENT AIR PRESS	CPT302	PSIA	IN HG	21	31	X													D	E												IN WG		AP-5		180			
AMBIENT TEMP	CTE300	DEGF		-40	120	X													D											-40	120	DEGF	100ΩPLAT		10/13/87			X	WTHRTRNCS MODEL 1420A
AMB. TMP. VOLTS TO CURRENT MODULE	CTE300-VCM	VDC		0	5	X													D											0	5	VDC	-	E/I	10/13/87		-		MODEL 1630 CHANNEL 1 OR 2
DRUM LEVEL	DLT1PC		IN	-10	10																																		
WEST BOILER DRUM PRESS	DPT50		PSIG	0	1800																							X		0	1500	PSIG	STATIC TAP	GP-9	1/27/87	180			
STEAM TEMP @ SH I OUTLET(SB STM SOURCE)	DTE52	DEGF		500	1000	X	1	2																								DEGF	E	-		NR	-		
STEAM TEMP @ SH I OUTLET(SB STM SOURCE)	DTE53	DEGF		500	1000	X	1	2																								DEGF	E	-		NR	-		
BOILER DRUM UPPER METAL TEMP	DTE57	DEGF		500	1000																							X				DEGF	K	-		NR	-		
BOILER DRUM LOWER METAL TEMP	DTE58	DEGF		500	1000																							X				DEGF	K	-		NR	-		
BOILER DRUM UPPER METAL TEMP	DTE59	DEGF		500	1000																							X				DEGF	K	-		NR	-		
DRUM METAL TEMPERATURE	DTE60																																						
BOILER DRUM LOWER METAL TEMP	DTE64	DEGF		500	1000																							X				DEGF	K	-		NR	-		
MAIN STEAM FLOW	EFI1	KLB/HR		0	1000	X	1																					X		-	-	-	-	-	-	-	-		CLC FRM KPT2,KTE1
SH II SPRAY EAST FLOW	EFT10	KLB/HR		0	18	X	1																							0	20.7	IN WC	ANF	DP-3	4/7/87	180	10/4/87		ANNUBAR
FEEDWATER FLOW RATE	EFT3	KLB/HR		0	1000																								X										
BOILER FEEDWATER FLOW - TEMP COMP	EFT3TC	KLB/HR		0	1000	X	1																					X		0	100	IN WC	FE	2051D		180			EFT3,ETE3
COMB 4A SH II SPRAY FLOW	EFT7	KLB/HR		0	40	X	1																							0	14.7	IN WC	ANF	DP-3	3/25/87	180	9/21/87		ANNUBAR
COMB 4B SH II SPRAY FLOW	EFT8	KLB/HR		0	40	X	1																							0	14.7	IN WC	ANF	DP-3	3/25/87	180	9/21/87		ANNUBAR
SH III SPRAY WEST FLOW	EFT9	KLB/HR		0	18	X	1																							0	20.7	IN WC	ANF	DP-3	4/7/87	180	10/4/87		ANNUBAR
ECON FEEDWATER INLET PRESS	EPT3	PSIA	PSIG	0	2200	X	1																							0	2200	PSIG	STATIC TAP	GP-9	8/11/88	180	2/7/87		
BFP DISCH HDR PRESS (SPRAY SOURCE)	EPT51	PSIA	PSIG	0	2200	X	1																							0	2200	PSIG	STATIC TAP	GP-8	9/16/87	180	3/14/88		
FINISH SUPERHEATER III A INLET STM TEMP	ETE10A		DEGF	500	1000																																		
FINISH SUPERHEATER III A OUTLET STM TEMP	ETE10B		DEGF	500	1500																																		
ECON FEEDWATER INLET TEMP	ETE3	DEGF		0	600	X	1																					X	X			DEGF	E	-		NR	-		
BFP DISCH HDR TEMP (SPRAY SOURCE)	ETE52	DEGF		0	600	X	1																									DEGF	E	-		NR	-		
RADIANT SUPERHEATER II A INLET TEMP	ETE7A		DEGF	700	1000																																		
RADIANT SUPERHEATER II A OUTLET STM TEMP	ETE7B		DEGF	700	1000																																		
RADIANT SUPERHEATER II B INLET TEMP	ETE8A		DEGF	700	1000																																		
RADIANT SUPERHEATER II B OUTLET STM TEMP	ETE8B		DEGF	700	1000																																		
FINISH SUPERHEATER III B INLET STM TEMP	ETE9A		DEGF	500	1000																																		
FINISH SUPERHEATER III B OUTLET STM TEMP	ETE9B		DEGF	500	1500																																		
BFP 4A WATTS	EWM300	KW		0	3000																		X				X	X											
BFP 4B WATTS	EWM301	KW		0	3000																		X																
GAS ANALYZER SO2 (LOW RANGE)	GAT313	PPM		0	500	X			3				7	8			B				X			X			X	X		0	500	PPM	UV ABSRPT	-					KVB
GAS ANALYZER NOx	GAT314	PPM		0	10000	X								8			B					X		X			X	X		0	1000	PPM	CHEMLUMN	-					KVB
GAS ANALYZER CO	GAT315	PPM		0	5000	X		2		4	5			8			B							X			X	X		0	5000	PPM	NDIR	-					KVB
GAS ANALYZER O2	GAT316	%		0	50	X						6	7	8			B							X			X	X		0	21	%	PARAMAG	-					KVB
GAS ANALYZER SO2 (HIGH RANGE)	GAT317	PPM		0	1500	X			3				7	8			B							X			X	X		0	1500	PPM	UV ABSRPT	-					KVB
GAS ANALYZER CO2	GAT318	%		0	20	X				4				8			B							X			X	X		0	20	%	NDIR	-					KVB
STACK OPACITY	GAT54																																						
LOOP SEAL 4B dP	GDPT311	IN WC		0	100																					X				0	100	IN WC	STATIC TAP	DP4	6/10/87	180	12/7/87		
DRAFT LOSS ACROSS PRIM & FINISH SUPERHEATER	GDPT70		IN WC	0	4																																		
DRAFT LOSS ACROSS ECONOMIZER	GDPT71		IN WC	0	4																																		
DRAFT LOSS ACROSS AIR HEATER GAS SIDE	GDPT75		IN WC	0	5																																		
PA FLOW RATE CMB 4A	GFT1C	KLB/HR		0	340																								X										
COMB 4A PRI AIR FLW (UNDERBED) - TEMP COMP	GFT1CTC	KLB/HR		0	500	X											B			E										0	5.98	IN WC	AIRFOIL	DP3	7/16/87	180	1/12/88		CLC FROM GFT1C,GTE1A,GTE1B
PA FLOW RATE CMB 4B	GFT1D	KLB/HR		0	340																								X										
COMB 4B PRI AIR FLW (UNDERBED) - TEMP COMP	GFT1DTC	KLB/HR		0	500	X											B			E										0	5.98	IN WC	AIRFOIL	DP3	6/15/87	180	12/12/87		CLC FROM GFT1D,GTE1C,GTE1D
LOWER LEVEL INJ AIR 4A REAR	GFT1W	KLB/HR																											X										
4A LOWER INJ PRI AIR FLOW - TEMP COMP	GFT1WTC	KLB/HR	KLB	0	150															E										0	6.99	IN WC	AIRFOIL	DP3	6/15/87	180	12/12/87		CLC FROM GFT1W,GTE1A,GTE1B
LOWER LEVEL INJ AIR 4A FRONT	GFT1X	KLB/HR																											X										
4A LOWER INJ PRI AIR FLOW - TEMP COMP	GFT1XTC	KLB/HR	KLB	0	150												B			E										0	6.99	IN WC	AIRFOIL	DP3	6/15/87	180	12/12/87		CLC FROM GFT1X,GTE1A,GTE1B
LOWER LEVEL INJ AIR 4B REAR	GFT1Y	KLB/HR																											X										
4B LOWER INJ PRI AIR FLOW - TEMP COMP	GFT1YTC	KLB/HR	KLB	0	150												B			E										0	6.99	IN WC	AIRFOIL	DP3	6/15/87	180	12/12/87		CLC FROM GFT1Y,GTE1C,GTE1D
LOWER LEVEL INJ AIR 4B FRONT	GFT1Z	KLB/HR																											X										
4B LOWER INJ PRI AIR FLOW - TEMP COMP	GFT1ZTC	KLB/HR	KLB	0	150												B			E										0	6.99	IN WC	AIRFOIL	DP3	6/15/87	180	12/12/87		CLC FROM GFT1Z,GTE1C,GTE1D
BTM ASH CLR AIR FLOW	GFT25	KLB/HR		0	102	X	1	2									B			E										0	6	IN WC	AIRFOIL	DP2	9/26/87	180	3/24/88		
SA FLOW RATE CMB 4A	GFT2D	KLB/HR		0	137																								X										

DATE 4/26/88

INSTRUMENT CALIBRATION DATA

LOCATION DESCRIPTION	TAG NUM	UNITS REQ'D	HIWAY UNITS	BOT BAR	TOP BAR	PERF CALC	USED IN PERFORMANCE CALCULATION NUMBER: 1	2	3	4	5	6	7	8	9	A	B	C	D	E	SO2 EMN RTE	NOX EMN RTE	AUX PWR	SEC 11 TST	SEC 12 TST	SEC 13 TST	SEC 8 TST	SEC 9 TST	USED FOR COMP PNT
SEC AIR 4A UPPER LEVEL FLOW - TMP CMP	GFT2OTC	KLB/HR		0	150	X	1	2									B			E									
SA FLOW RATE CMB 4B	GFT2F	KLB/HR		0	137																								X
SEC AIR 4B UPPER LEVEL FLOW - TMP CMP	GFT2FTC	KLB/HR		0	150	X	1	2									B			E									
S/U BURNER 4A AIR FLOW RATE	GFT2I	KLB/HR		0	50																								X
S/U BURNER 4B AIR FLOW RATE	GFT2J	KLB/HR		0	50																								X
S/U BURNER 4C AIR FLOW RATE	GFT2K	KLB/HR		0	50																								X
S/U BURNER 4D AIR FLOW RATE	GFT2L	KLB/HR		0	50																								X
S/U BURNER 4E AIR FLOW RATE	GFT2M	KLB/HR		0	50																								X
S/U BURNER 4F AIR FLOW RATE	GFT2N	KLB/HR		0	50																								X
4B HEAT FLUX @ 31'	GHF300	B/H/F^2	BTU	0	30000																				X				
4B HEAT FLUX @ 34'	GHF301	B/H/F^2	BTU	0	30000																				X				
4B HEAT FLUX @ 38'	GHF302	B/H/F^2	BTU	0	30000																				X				
4B HEAT FLUX @ 44'	GHF303	B/H/F^2	BTU	0	30000																				X				
4B HEAT FLUX @ 54'	GHF304	B/H/F^2	BTU	0	30000																				X				
4B HEAT FLUX @ 66'	GHF305	B/H/F^2	BTU	0	30000																				X				
4B HEAT FLUX @ 79'	GHF306	B/H/F^2	BTU	0	30000																				X				
4B HEAT FLUX @ 92'	GHF307	B/H/F^2	BTU	0	30000																				X				
4B HEAT FLUX @ 105'	GHF308	B/H/F^2	BTU	0	30000																				X				
4B HEAT FLUX @ 118'	GHF309	B/H/F^2	BTU	0	30000																				X				
PRIMARY AIR HEATER OUTLET AIR PRESSURE	GPT1A		IN WC	0	80																								
PRIMARY AIR HEATER OUTLET AIR PRESSURE	GPT1B		IN WC	0	80																								
FURNACE PRESS @ EL 25	GPT300	IN WC		0	50																							X	
FURNACE PRESS @ EL 31	GPT301	IN WC		0	50																							X	
FURNACE PRESS @ EL 34	GPT302	IN WC		0	50																							X	
FURNACE PRESS @ EL 38	GPT303	IN WC		0	50																							X	
FURNACE PRESS @ EL 44	GPT304	IN WC		0	50																							X	
FURNACE PRESS @ EL 54	GPT305	IN WC		0	50																							X	
FURNACE PRESS @ EL 66	GPT306	IN WC		-5	20																							X	
FURNACE PRESS @ EL 79	GPT307	IN WC		-5	20																							X	
FURNACE PRESS @ EL 92	GPT308	IN WC		-5	20																							X	
FURNACE PRESS @ EL 105	GPT309	IN WC		-5	20																							X	
PRESS AT TOP OF LOOP SEAL 4B	GPT312	IN WC		0	75																					X			
AIR HEATER GAS OUTLET PRESSURE	GPT318		IN WC	-20	0																								
4A PA PRESSURE UNDERBED	GPT52	IN WC		0	80																							X	
4B PA PRESSURE UNDERBED	GPT53	IN WC		0	80																							X	
ID FAN INLET PRESSURE	GPT79		IN WC	-35	5																								
PRESS 93' ABOVE DIST PLATE IN 4A	GPT7A	IN WC		-15	15	X														E								X	
PRESS 93' ABOVE DIST PLATE IN 4A	GPT7B	IN WC		-15	15	X														E								X	
PRESS 93' ABOVE DIST PLATE IN 4A	GPT7C	IN WC		-15	15	X														E								X	
PRESS 93' ABOVE DIST PLATE IN 4B	GPT8A	IN WC		-15	15	X														E								X	
PRESS 93' ABOVE DIST PLATE IN 4B	GPT8B	IN WC		-15	15	X														E								X	
PRESS 93' ABOVE DIST PLATE IN 4B	GPT8C	IN WC		-15	15	X														E								X	
CYCLONE 4A/4B OUTLET PRESS	GPT9A	IN WC		-2	3																					X			
PA FAN SPEED	GST1		RPM	0	2120																								
SA FAN SPEED	GST2		RPM	0	800																								
ID FAN SPEED	GST9		RPM	0	1125																								
PA AH AIR OUT TEMP	GTE1A	DEGF		0	500																								X
PA AIR HEATER AIR OUTLET TEMP	GTE1AVGA			0	100																								
PA AIR HEATER AIR OUTLET TEMP	GTE1AVGC			0	100																								
PA AH AIR OUT TEMP	GTE1B	DEGF		0	500																								X
PA AH AIR OUT TEMP	GTE1C	DEGF		0	500																								X
PA AH AIR OUT TEMP	GTE1D	DEGF		0	500																								X
SA AH AIR OUT TEMP	GTE2A	DEGF		0	500																								X
SA AIR HEATER AIR INLET TEMP	GTE2AVGA			0	100																								
SA AIR HEATER AIR OUTLET TEMP	GTE2AVGC			0	100																								
SA AH AIR OUT TEMP	GTE2B	DEGF		0	500																								X
COMB CHMB 4B HEAT FLUX @ 31'	GTE300A		DEGF	0	2000																				X				
COMB CHMB 4B HEAT FLUX @ 31'	GTE300B		DEGF	0	2000																				X				
COMB CHMB 4B HEAT FLUX @ 34'	GTE301A		DEGF	0	2000																				X				
COMB CHMB 4B HEAT FLUX @ 34'	GTE301B		DEGF	0	2000																				X				

LOCATION DESCRIPTION	TAG NUM	CALIB RANGE LOW	CALIB RANGE HIGH	CALIB UNITS	ELMNT TYPE	XMTTR TYPE	LAST CAL DATE	CAL INTVL (DAYS)	NEXT CAL DATE	COEFF NEEDS CHKD/CHNGD	REMARKS
SEC AIR 4A UPPER LEVEL FLOW - TMP CMP	GFT2OTC	0	6.89	IN WC	AIRFOIL	DP3	6/15/87	180	12/12/87		CLC FROM GFT2O,GTE2A,GTE2B
SA FLOW RATE CMB 4B	GFT2F										
SEC AIR 4B UPPER LEVEL FLOW - TMP CMP	GFT2FTC	0	6.89	IN WC	AIRFOIL	DP3	6/15/87	180	12/12/87		CLC FROM GFT2F,GTE2A,GTE2B
S/U BURNER 4A AIR FLOW RATE	GFT2I										
S/U BURNER 4B AIR FLOW RATE	GFT2J										
S/U BURNER 4C AIR FLOW RATE	GFT2K										
S/U BURNER 4D AIR FLOW RATE	GFT2L										
S/U BURNER 4E AIR FLOW RATE	GFT2M										
S/U BURNER 4F AIR FLOW RATE	GFT2N										
4B HEAT FLUX @ 31'	GHF300	-	-	-	-	-		NR	-		WRONG - GTE300A&B READ SAME
4B HEAT FLUX @ 34'	GHF301	-	-	-	-	-		NR	-		BAD-SEE GTE301A & GTE301B
4B HEAT FLUX @ 38'	GHF302	-	-	-	-	-		NR	-		SUSPICIOUS - SEE GTE302B
4B HEAT FLUX @ 44'	GHF303	-	-	-	-	-		NR	-		
4B HEAT FLUX @ 54'	GHF304	-	-	-	-	-		NR	-		
4B HEAT FLUX @ 66'	GHF305	-	-	-	-	-		NR	-		
4B HEAT FLUX @ 79'	GHF306	-	-	-	-	-		NR	-		
4B HEAT FLUX @ 92'	GHF307	-	-	-	-	-		NR	-		SUSPICIOUS - SEE GTE307B
4B HEAT FLUX @ 105'	GHF308	-	-	-	-	-		NR	-		
4B HEAT FLUX @ 118'	GHF309	-	-	-	-	-		NR	-		
PRIMARY AIR HEATER OUTLET AIR PRESSURE	GPT1A										
PRIMARY AIR HEATER OUTLET AIR PRESSURE	GPT1B										
FURNACE PRESS @ EL 25	GPT300	0	50	IN WC	STATIC TAP	OP4	10/13/87	180	4/10/88	X	BAD RDG ON HWY 10/28/87
FURNACE PRESS @ EL 31	GPT301	0	50	IN WC	STATIC TAP	OP4	10/12/87	180	4/9/88	X	
FURNACE PRESS @ EL 34	GPT302	0	50	IN WC	STATIC TAP	OP4	10/12/87	180	4/9/88	X	
FURNACE PRESS @ EL 38	GPT303	0	50	IN WC	STATIC TAP	OP4	10/12/87	180	4/9/88	X	
FURNACE PRESS @ EL 44	GPT304	0	50	IN WC	STATIC TAP	OP4	10/13/87	180	4/10/88	X	HWY RDG=8.4 W/NO PURGE AIR
FURNACE PRESS @ EL 54	GPT305	-4	20	IN WC	STATIC TAP	OP4	10/13/87	180	4/10/88	X	DISCREPANCY : TB & BB & CAL LIM
FURNACE PRESS @ EL 66	GPT306	-4	20	IN WC	STATIC TAP	OP4	10/12/87	180	4/9/88	X	
FURNACE PRESS @ EL 79	GPT307	-4	20	IN WC	STATIC TAP	OP4	10/8/87	180	4/5/88	X	
FURNACE PRESS @ EL 92	GPT308	-4	20	IN WC	STATIC TAP	OP4	10/8/87	180	4/5/88	X	
FURNACE PRESS @ EL 105	GPT309	-4	20	IN WC	STATIC TAP	OP4	10/8/87	180	4/5/88	X	
PRESS AT TOP OF LOOP SEAL 4B	GPT312	0	75	IN WC	STATIC TAP	OP4	6/10/87	180	12/7/87	X	
AIR HEATER GAS OUTLET PRESSURE	GPT318										
4A PA PRESSURE UNDERBED	GPT52	0	80	IN WC	STATIC TAP	OP4	8/11/87	180	2/7/88		
4B PA PRESSURE UNDERBED	GPT53	0	80	IN WC	STATIC TAP	OP4	8/11/87	180	2/7/88		
ID FAN INLET PRESSURE	GPT79										
PRESS 93' ABOVE DIST PLATE IN 4A	GPT7A	-4	20	IN WC	STATIC TAP	DP3	5/20/87	180	11/16/87		
PRESS 93' ABOVE DIST PLATE IN 4A	GPT7B	-4	20	IN WC	STATIC TAP	DP3	5/21/87	180	11/17/87		
PRESS 93' ABOVE DIST PLATE IN 4A	GPT7C	-4	20	IN WC	STATIC TAP	DP3	5/21/87	180	11/17/87		
PRESS 93' ABOVE DIST PLATE IN 4B	GPT8A	-4	20	IN WC	STATIC TAP	DP3	5/21/87	180	11/17/87		
PRESS 93' ABOVE DIST PLATE IN 4B	GPT8B	-4	20	IN WC	STATIC TAP	DP3	5/21/87	180	11/17/87		
PRESS 93' ABOVE DIST PLATE IN 4B	GPT8C	-4	20	IN WC	STATIC TAP	DP3	5/21/87	180	11/17/87		
CYCLONE 4A/4B OUTLET PRESS	GPT9A	-2	3	IN WC	STATIC TAP	DP2	2/23/87	180	8/22/87		
PA FAN SPEED	GST1										
SA FAN SPEED	GST2										
ID FAN SPEED	GST9										
PA AH AIR OUT TEMP	GTE1A										
PA AIR HEATER AIR OUTLET TEMP	GTE1AVGA										
PA AIR HEATER AIR OUTLET TEMP	GTE1AVGC										
PA AH AIR OUT TEMP	GTE1B										
PA AH AIR OUT TEMP	GTE1C										
PA AH AIR OUT TEMP	GTE1D										
SA AH AIR OUT TEMP	GTE2A										
SA AIR HEATER AIR INLET TEMP	GTE2AVGA										
SA AIR HEATER AIR OUTLET TEMP	GTE2AVGC										
SA AH AIR OUT TEMP	GTE2B										
COMB CHMB 4B HEAT FLUX @ 31'	GTE300A			DEGF	K	-	10/15/87	NR	-		
COMB CHMB 4B HEAT FLUX @ 31'	GTE300B			DEGF	K	-	10/15/87	NR	-		RDGS SAME AS GTE300A, SO HF=0
COMB CHMB 4B HEAT FLUX @ 34'	GTE301A			DEGF	K	-	10/15/87	NR	-		TC HAS GONE BAD
COMB CHMB 4B HEAT FLUX @ 34'	GTE301B			DEGF	K	-	10/15/87	NR	-		TC HAS GONE BAD

DATE: 4/26/8

INSTRUMENT CALIBRATION DATA

						USED IN PERFORMANCE CALCULATION NUMBER																							USED										
LOCATION DESCRIPTION	TAG NUM	UNITS REQ'D	HIWAY UNITS	BOT BAR	TOP BAR	PERF CALC	1	2	3	4	5	6	7	8	9	A	B	C	D	E	SO2 EMN RTE	NOX EMN RTE	AUX PWR	SEC 11 TST	SEC 12 TST	SEC 13 TST	SEC 8 TST	SEC 9 TST	FOR COMP PNT	CALIB RANGE LOW	CALIB RANGE HIGH	CALIB UNITS	ELMNT TYPE	XMTTR TYPE	LAST CAL DATE	CAL INTVL (DAYS)	NEXT CAL DATE	COEFF NEEDS CHKD/CHNGD	REMARKS
COMB CHMB 4B HEAT FLUX @ 38'	GTE302A		DEGF	0	2000																				X							DEGF	K	-	10/15/87	NR	.		
COMB CHMB 4B HEAT FLUX @ 38'	GTE302B		DEGF	0	2000																				X							DEGF	K	-	10/15/87	NR	.		READINGS APPEAR TO BE LOW
COMB CHMB 4B HEAT FLUX @ 44'	GTE303A		DEGF	0	2000																				X							DEGF	K	-	10/15/87	NR	.		
COMB CHMB 4B HEAT FLUX @ 44'	GTE303B		DEGF	0	2000																				X							DEGF	K	-	10/15/87	NR	.		
COMB CHMB 4B HEAT FLUX @ 54'	GTE304A		DEGF	0	2000																				X							DEGF	K	-	10/15/87	NR	.		
COMB CHMB 4B HEAT FLUX @ 54'	GTE304B		DEGF	0	2000																				X							DEGF	K	-	10/15/87	NR	.		
COMB CHMB 4B HEAT FLUX @ 66'	GTE305A		DEGF	0	2000																				X							DEGF	K	-	10/15/87	NR	.		
COMB CHMB 4B HEAT FLUX @ 66'	GTE305B		DEGF	0	2000																				X							DEGF	K	-	10/15/87	NR	.		
COMB CHMB 4B HEAT FLUX @ 79'	GTE306A		DEGF	0	2000																				X							DEGF	K	-	10/15/87	NR	.		
COMB CHMB 4B HEAT FLUX @ 79'	GTE306B		DEGF	0	2000																				X							DEGF	K	-	10/15/87	NR	.		
COMB CHMB 4B HEAT FLUX @ 92'	GTE307A		DEGF	0	2000																				X							DEGF	K	-	10/15/87	NR	.		
COMB CHMB 4B HEAT FLUX @ 92'	GTE307B		DEGF	0	2000																				X							DEGF	K	-	10/15/87	NR	.		READINGS APPEAR TO BE LOW
COMB CHMB 4B HEAT FLUX @ 105'	GTE308A		DEGF	0	2000																				X							DEGF	K	-	10/15/87	NR	.		
COMB CHMB 4B HEAT FLUX @ 105'	GTE308B		DEGF	0	2000																				X							DEGF	K	-	10/15/87	NR	.		
COMB CHMB 4B HEAT FLUX @ 118'	GTE309A		DEGF	0	2000																				X							DEGF	K	-	10/15/87	NR	.		
COMB CHMB 4B HEAT FLUX @ 118'	GTE309B		DEGF	0	2000																				X							DEGF	K	-	10/15/87	NR	.		
CYCLONE 4B SOLIDS OUTLET TEMP	GTE310	DEGF		0	2000																					X						DEGF	K	-		NR			
AIR HEATER OUTLET TEMP GRID (WEST)	GTE319A	DEGF		0	500	X		2																			X					DEGF	E	-	10/15/87	NR	.		RDG FRM 8 TCs:GTE319A1 THRU 8
AIR HEATER OUTLET TEMP GRID (EAST)	GTE319B	DEGF		0	500	X		2																			X					DEGF	E	-	10/15/87	NR	.		RDG FRM 8 TCs:GTE319B1 THRU 8
AIR HEATER INLET GAS TEMP AVERAGE	GTE320A		DEGF	0	1000																																		
AIR HEATER INLET GAS TEMP AVERAGE	GTE320B		DEGF	0	1000																																		
TEMP IN COMB 4A 20" ABOVE DIST PLATE	GTE3A	DEGF		1000	2000	X														E								X				DEGF	K	-	2/19/87	NR	.		
TEMP IN COMB 4A 20" ABOVE DIST PLATE	GTE3B	DEGF		1000	2000	X														E								X				DEGF	K	-	2/19/87	NR	.		
TEMP IN COMB 4A 20" ABOVE DIST PLATE	GTE3C	DEGF		1000	2000	X														E								X				DEGF	K	-		NR			
TEMP IN COMB 4A 20" ABOVE DIST PLATE	GTE3D	DEGF		1000	2000	X														E								X				DEGF	K	-	2/19/87	NR	.		
TEMP IN COMB 4A 20" ABOVE DIST PLATE	GTE3E	DEGF		1000	2000	X														E								X				DEGF	K	-		NR			
TEMP IN COMB 4A 20" ABOVE DIST PLATE	GTE3F	DEGF		1000	2000	X														E								X				DEGF	K	-		NR	.		
TEMP IN COMB 4A 20" ABOVE DIST PLATE	GTE3G	DEGF		1000	2000	X														E								X				DEGF	K	-	2/24/86	NR	.		
TEMP IN COMB 4A 20" ABOVE DIST PLATE	GTE3H	DEGF		1000	2000	X														E								X				DEGF	K	-		NR	.		
TEMP IN COMB 4A 20" ABOVE DIST PLATE	GTE3I	DEGF		1000	2000	X														E								X				DEGF	K	-		NR			
TEMP IN COMB 4A 20" ABOVE DIST PLATE	GTE3J	DEGF		1000	2000	X														E								X				DEGF	K	-	2/25/86	NR	.		
TEMP IN COMB 4A 20" ABOVE DIST PLATE	GTE3K	DEGF		1000	2000	X														E								X				DEGF	K	-	2/24/86	NR	.		
TEMP IN COMB 4A 20" ABOVE DIST PLATE	GTE3L	DEGF		1000	2000	X														E								X				DEGF	K	-	2/24/88	NR	.		
TEMP IN COMB 4B 20" ABOVE DIST PLATE	GTE4A	DEGF		1000	2000	X														E								X				DEGF	K	-		NR			
TEMP IN COMB 4B 20" ABOVE DIST PLATE	GTE4B	DEGF		1000	2000	X														E								X				DEGF	K	-	2/24/88	NR	.		
TEMP IN COMB 4B 20" ABOVE DIST PLATE	GTE4C	DEGF		1000	2000	X														E								X				DEGF	K	-	2/24/86	NR	.		
TEMP IN COMB 4B 20" ABOVE DIST PLATE	GTE4D	DEGF		1000	2000	X														E								X				DEGF	K	-	2/20/87	NR	.		
TEMP IN COMB 4B 20" ABOVE DIST PLATE	GTE4E	DEGF		1000	2000	X														E								X				DEGF	K	-	2/26/87	NR	.		
TEMP IN COMB 4B 20" ABOVE DIST PLATE	GTE4F	DEGF		1000	2000	X														E								X				DEGF	K	-		NR			
TEMP IN COMB 4B 20" ABOVE DIST PLATE	GTE4G	DEGF		1000	2000	X														E								X				DEGF	K	-	2/28/87	NR	.		
TEMP IN COMB 4B 20" ABOVE DIST PLATE	GTE4H	DEGF		1000	2000	X														E								X				DEGF	K	-	2/24/86	NR	.		
TEMP IN COMB 4B 20" ABOVE DIST PLATE	GTE4I	DEGF		1000	2000	X														E								X				DEGF	K	-	2/24/86	NR	.		
TEMP IN COMB 4B 20" ABOVE DIST PLATE	GTE4J	DEGF		1000	2000	X														E								X				DEGF	K	-	2/24/86	NR	.		
TEMP IN COMB 4B 20" ABOVE DIST PLATE	GTE4K	DEGF		1000	2000	X														E								X				DEGF	K	-	2/24/86	NR	.		
TEMP IN COMB 4B 20" ABOVE DIST PLATE	GTE4L	DEGF		1000	2000	X														E								X				DEGF	K	-	2/25/87	NR	.		
PRI AIR TO AIR PRE HTR TEMP	GTE50A	DEGF		0	150	X	1	2																								DEGF	E	-		NR	.		
PA AIR HEATER AIR INLET TEMP	GTE50AVG			0	100																																		
PRI AIR TO AIR PRE HTR TEMP	GTE50B	DEGF		0	150	X	1	2																								DEGF	E	-		NR	.		
PRI AIR TO AIR PRE HTR TEMP	GTE50C	DEGF		0	150	X	1	2																								DEGF	E	-		NR	.		
SEC AIR TO AIR PRE HTR TEMP	GTE51A	DEGF		0	150	X	1	2																								DEGF	E	-	2/17/87	NR	.		
PA AIR HEATER AIR INLET TEMP	GTE51AVG			0	100																																		
SEC AIR TO AIR PRE HTR TEMP	GTE51B	DEGF		0	150	X	1	2																								DEGF	E	-	2/17/87	NR	.		
SEC AIR TO AIR PRE HTR TEMP	GTE51C	DEGF		0	150	X	1	2																								DEGF	E	-	2/17/87	NR	.		
TEMP IN COMB 4A 40" ABOVE DIST PLATE	GTE54A	DEGF		1000	2000																							X				DEGF	K	-	2/27/87	NR	.		
COMB 4A BED TEMP 40" AVERAGE	GTE54AVG			0	100																																		
TEMP IN COMB 4A 40" ABOVE DIST PLATE	GTE54B	DEGF		1000	2000																							X				DEGF	K	-	2/27/87	NR	.		
TEMP IN COMB 4A 40" ABOVE DIST PLATE	GTE54C	DEGF		1000	2000																							X				DEGF	K	-	2/27/87	NR	.		
TEMP IN COMB 4A 40" ABOVE DIST PLATE	GTE54D	DEGF		1000	2000																							X				DEGF	K	-	2/27/87	NR	.		
TEMP IN COMB 4A 80" ABOVE DIST PLATE	GTE55A	DEGF		1000	2000																							X				DEGF	K	-	2/27/87	NR	.		
COMB 4A BED TEMP 80" AVERAGE	GTE55AVG			0	100																																		

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INSTRUMENT CALIBRATION DATA

LOCATION DESCRIPTION	TAG NUM	UNITS REQ'D	HIWAY UNITS	BOT BAR	TOP BAR	PERF CALC	USED IN PERFORMANCE CALCULATION NUMBER: 1	2	3	4	5	6	7	8	9	A	B	C	D	E	SO2 EMN RTE	NOX EMN RTE	AUX PWR	SEC 11 TST	SEC 12 TST	SEC 13 TST	SEC 6 TST	SEC 9 TST	USED FOR COMP PNT	CALIB RANGE LOW	CALIB RANGE HIGH	CALIB UNITS	ELMNT TYPE	XMTTR TYPE	LAST CAL DATE	CAL INTVL (DAYS)	NEXT CAL DATE	COEFF NEEDS CHKD/CHNGD	REMARKS
TEMP IN COMB 4A 80" ABOVE DIST PLATE	GTE55B	DEGF		1000	2000																							X				DEGF	K	-	2/27/87	NR	-		
TEMP IN COMB 4A 80" ABOVE DIST PLATE	GTE55C	DEGF		1000	2000																							X				DEGF	K	-	2/27/87	NR	-		
TEMP IN COMB 4A 80" ABOVE DIST PLATE	GTE55D	DEGF		1000	2000																							X				DEGF	K	-		NR	-		
TEMP IN COMB 4B 40" ABOVE DIST PLATE	GTE56A	DEGF		1000	2000																							X				DEGF	K	-	2/26/87	NR	-		
COMB 4B BED TEMP 40" AVERAGE	GTE56AVG			0	100																																		
TEMP IN COMB 4B 40" ABOVE DIST PLATE	GTE56B	DEGF		1000	2000																							X				DEGF	K	-	2/27/87	NR	-		
TEMP IN COMB 4B 40" ABOVE DIST PLATE	GTE56C	DEGF		1000	2000																							X				DEGF	K	-		NR	-		
TEMP IN COMB 4B 40" ABOVE DIST PLATE	GTE56D	DEGF		1000	2000																							X				DEGF	K	-		NR	-		
TEMP IN COMB 4B 80" ABOVE DIST PLATE	GTE57A	DEGF		1000	2000																							X				DEGF	K	-	2/26/87	NR	-		
COMB 4B BED TEMP 80" AVERAGE	GTE57AVG			0	100																																		
TEMP IN COMB 4B 80" ABOVE DIST PLATE	GTE57B	DEGF		1000	2000																							X				DEGF	K	-		NR	-		
TEMP IN COMB 4B 80" ABOVE DIST PLATE	GTE57C	DEGF		1000	2000																							X				DEGF	K	-		NR	-		
TEMP IN COMB 4B 80" ABOVE DIST PLATE	GTE57D	DEGF		1000	2000																							X				DEGF	K	-		NR	-		
CYCLONE 4A GAS INLET TEMP	GTE58	DEGF		1030	2000	X														E						X						DEGF	K	-		NR	-		
CYCLONE 4A GAS INLET TEMP	GTE59	DEGF		1000	2000	X														E						X	X					DEGF	K	-		NR	-		
CYCLONE 4A GAS OUTLET TEMP	GTE61	DEGF		1000	2000																					X		X				DEGF	K	-		NR	-		
CYCLONE 4B GAS INLET TEMP	GTE62	DEGF		1000	2000	X														E						X						DEGF	K	-		NR	-		
CYCLONE 4B GAS INLET TEMP	GTE63	DEGF		1000	2000	X														E						X						DEGF	K	-		NR	-		
CYCLONE 4B GAS OUTLET TEMP	GTE64	DEGF		1000	2000																					X		X				DEGF	K	-		NR	-		
CYCLONE 4B GAS OUTLET TEMP	GTE65	DEGF		1000	2000																					X		X				DEGF	K	-		NR	-		
LOOP SEAL 4A SOLIDS INLET TEMP	GTE66A	DEGF		300	800																					X				[illegible]	2000	DEGF	K	-		NR	-		
LOOP SEAL 4A SOLIDS INLET TEMP	GTE66B	DEGF		300	800																					X				[illegible]	2000	DEGF	K	-		NR	-		
LOOP SEAL 4B SOLIDS INLET TEMP	GTE67A	DEGF		300	800																					X				1000	2000	DEGF	K	-		NR	-		
LOOP SEAL 4B SOLIDS INLET TEMP	GTE67B	DEGF		300	800																					X				1000	2000	DEGF	K	-		NR	-		
PRIMARY SUPERHEATER GAS OUTLET TEMP	GTE68		DEGF	1000	2000																																		
PRIMARY SUPERHSATER GAS OUTLET TEMP	GTE69		DEGF	1000	2000																																		
CYCLONE 4A GAS OUTLET TEMP	GTE60	DEGF		1000	2000																					X		X				DEGF	K	-		NR	-		
FINISH SUPERHEATER GAS OUTLET TEMP	GTE76		DEGF	1000	2000																																		
CYCLONE 4B OUTLET REFRACTORY TEMP	GTE84A	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B OUTLET REFRACTORY TEMP	GTE84B	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B OUTLET REFRACTORY TEMP	GTE84C	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B UPPER CYCLONE REFR TEMP	GTE85A	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B UPPER CYCLONE REFR TEMP	GTE85B	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B UPPER CYCLONE REFR TEMP	GTE85C	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B LOWER CYCLONE REFR TEMP	GTE86A	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B LOWER CYCLONE REFR TEMP	GTE86B	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B LOWER CYCLONE REFR TEMP	GTE86C	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B LOOP SEAL REFR TEMP	GTE87A	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B LOOP SEAL REFR TEMP	GTE87B	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B LOOP SEAL REFR TEMP	GTE87C	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
BTM ASH CLG FAN 4A DISCH TEMP	GTE88	DEGF		0	150	X	1																									DEGF	E	-		NR	-		
COMB 4A BED TEMP AVERAGE	GTEAVG1			0	100																																		
COMB 4B BED TEMP AVERAGE	GTEAVG2			0	100																																		
COMB 4B SA FLOW	GTT2FTC																																						
PA FAN WATTS	GWM025	KW		0	8000																	X																	
SA FAN WATTS	GWM026	KW		0	1500																	X																	
ID FAN WATTS	GWM027	KW		0	8000																	X																	
H P BLOWER 4A WATTS	GWM028	KW		0	250																	X																	
H P BLOWER 4B WATTS	GWM029	KW		0	250																	X																	
BOTTOM ASH COOLING FAN WATTS	GWM030	KW		0	800																	X																	
TURBINE 4A 1ST STAGE PRESSURE	KPT2	PSIG		0	2000																								X										
FINAL STEAM PRESS	KPT300	PSIG		0	1800	X	1																					X		0	1800	PSIG	STATIC TAP	GPS	10/12/87	180	4/9/88		
FINAL STEAM TEMP	KTE1	DEGF		0	1500	X	1																					X	X			DEGF	E	-		NR	-		
EXT STEAM FROM UNIT 4 TO UNITS 1-3 PRESSURE	LPT63		PSIG	0	800																																		
EXT STEAM FROM UNIT 4 TO UNITS 1-3 TEMP	LTE61		DEGF	0	1000																																		
COAL FLOW FEEDER TOTAL	O001X115																																						
COMB 4A BED TEMP 20" MEDIAN	O001X195																																						
COMB 4A FURNACE DRAFT	O002X073																																						
COMB 4B FURNACE DRAFT	O002X113																																						
CYCLONE OUTLET MEDIAN GAS PRESSURE	O002X133																																						

DATE 4/26/88

LOCATION DESCRIPTION	TAG NUM	UNITS REQ'D	HIWAY UNITS	BOT BAR	TOP BAR	PERF CALC	USED IN PERFORMANCE CALCULATION NUMBER: 1	2	3	4	5	6	7	8	9	A	B	C	D	E	SO2 EMN RTE	NOX EMN RTE	AUX PWR	SEC 11 TST	SEC 12 TST	SEC 13 TST	SEC 6 TST	SEC 9 TST	USED FOR COMP PNT	CALIB RANGE LOW	CALIB RANGE HIGH	CALIB UNITS	ELMNT TYPE	XMTTR TYPE	LAST CAL DATE	CAL INTVL (DAYS)	NEXT CAL DATE	COEFF NEEDS CHKD/CHKOD	REMARKS
COMB 4B BED TEMP 20" MEDIAN	O003X115																																						
PA TO S/U BURNER A - TEMP COMP	O007X011	KLB/HR															B			E										0	7.6	IN WC	AIRFOIL	DP		180			CLC FROM GFT2I,GTE1A,GTE1B
PA TO S/U BURNER B - TEMP COMP	O007X041	KLB/HR															B			E										0	7.8	IN WC	AIRFOIL	DP		180			CLC FROM GFT2J,GTE1A,GTE1B
PA TO S/U BURNER C - TEMP COMP	O007X062	KLB/HR															B			E										0	7.8	IN WC	AIRFOIL	DP		180			CLC FROM GFT2K,GTE1A,GTE1B
PA TO S/U BURNER D - TEMP COMP	O007X091	KLB/HR															B			E										0	7.8	IN WC	AIRFOIL	DP		180			CLC FROM GFT2L,GTE1A,GTE1B
PA TO S/U BURNER E - TEMP COMP	O007X112	KLB/HR															B			E										0	7.8	IN WC	AIRFOIL	DP		180			CLC FROM GFT2M,GTE1A,GTE1B
PA TO S/U BURNER F - TEMP COMP	O007X132	KLB/HR															B			E										0	7.8	IN WC	AIRFOIL	DP		180			CLC FROM GFT2N,GTE1A,GTE1B
GAS FLOW TO S/U BURNER 4E	OFT10	KLB/HR	KSCFH	0	50																							X		0	100	IN WC		DP4	6/13/87	180	12/10/87		
GAS FLOW TO S/U BURNER 4F	OFT12	KLB/HR	KSCFH	-20	50																							X		0	100	IN WC		DP4	6/13/87	180	12/10/87		
GAS FLOW TO DUCT BURNER 4A	OFT14	KLB/HR	KSCFH	0	50																							X		0	100	IN WC		DP4	6/13/87	180	12/10/87		
GAS FLOW TO DUCT BURNER 4B	OFT16	KLB/HR	KSCFH	0	50																							X		0	100	IN WC		DP4	6/13/87	180	12/10/87		
GAS FLOW TO S/U BURNER 4A	OFT2	KLB/HR	KSCFH	0	50																							X		0	100	IN WC		DP4		180			DAMAGED XMTTR RMVD 5/7/87
GAS FLOW TO S/U BURNER 4B	OFT4	KLB/HR	KSCFH	0	50																							X		0	100	IN WC		DP4	6/13/87	180	12/10/87		
GAS FLOW TO S/U BURNER 4C	OFT6	KLB/HR	KSCFH	-20	50																							X		0	100	IN WC		DP4	6/13/87	180	12/10/87		
GAS FLOW TO S/U BURNER 4D	OFT8	KLB/HR	KSCFH	0	50																							X		0	100	IN WC		DP4	6/13/87	180	12/10/87		
PA UNDERBED TEMP TO COMB 4A	OTE1AVG		0	100																																			
PA UNDERBED TEMP TO COMB 4B	OTE2AVG		0	100																																			
EXT STEAM FROM UNIT 4 TO UNITS 1-3 FLOW	PFT62																																						
BAGHOUSE 1 INLET TEMP	PTE10	DEGF		100	300																							X											
BAGHOUSE 2 INLET TEMP	PTE11	DEGF		100	300																							X											
BAGHOUSE 3 INLET TEMP	PTE12	DEGF		100	300																							X											
BAGHOUSE 4A INLET TEMP	PTT14	DEGF		0	300																							X		100	300	DEGF							THERMO ELECTRIC - 4246
COAL FEEDER 4B (A-FRONT, WEST)	OFT1	KLB/HR		0	72	X	1	2	3	4	5		7				B				X	X					X			0	60	KLBS/HR		BELT SCA	11/3/87	30	12/3/87		
COAL FEEDER 4C (A-FRONT, EAST)	OFT2	KLB/HR		0	72	X	1	2	3	4	5		7				B				X	X					X			0	60	KLBS/HR		BELT SCA	11/3/87	30	12/3/87		
COAL FEEDER 4A (A-REAR)	OFT25	KLB/HR		0	72	X	1	2	3	4	5		7				B				X	X					X			0	60	KLBS/HR		BELT SCA	11/15/87	30	12/15/87		
COAL FEEDER 4D (B-REAR)	OFT26	KLB/HR		0	72	X	1	2	3	4	5		7				B				X	X					X			0	60	KLBS/HR		BELT SCA	11/15/87	30	12/15/87		
COAL FEEDER 4F (B-FRONT, WEST)	OFT3	KLB/HR		0	72	X	1	2	3	4	5		7				B				X	X					X			0	60	KLBS/HR		BELT SCA	11/3/87	30	12/3/87		
COAL FEEDER 4E (B-FRONT, EAST)	OFT4	KLB/HR		0	72	X	1	2	3	4	5		7				B				X	X					X			0	60	KLBS/HR		BELT SCA	11/3/87	30	12/3/87		
CYCLONE A EXIT SO2	RAT1		PPM	100	500																																		
CYCLONE B EXIT SO2	RAT2		PPM	0	500																																		
L STONE FEEDER 4B FLOW	RFT13	KLB/HR	LB/HR	0	7200	X	1	2	3	4	5		7				B										X			1	2.5	KLBS		LOAD CEL	11/11/87	30	12/11/87		
L STONE FEEDER 4A FLOW	RFT4	KLB/HR	LB/HR	0	7200	X	1	2	3	4	5		7				B										X			1	2.5	KLBS		LOAD CEL	11/15/87	30	12/15/87		
CEM OPACITY (6 MIN AVG)	SAT50	%		0	100																							X		-	-	-	-	-	-	-	-		WE WON'T BE SEEING ANY DOCMNTN
CEM NOX (LB/MMBTU)	SAT51	LB/MMBTU		0	1000																	X						X		-	-	-	-	-	-	-	-		WE WON'T BE SEEING ANY DOCMNTN
CEM SO2 (LB/MMBTU)	SAT52	LB/MMBTU																			X							X		-	-	-	-	-	-	-	-		WE WON'T BE SEEING ANY DOCMNTN
CEM SO2(LB/MMBTU)	SAT53	LB/MMBTU	#/MBTU	0	1000																									-	-	-	-	-	-	-	-		WE WON'T BE SEEING ANY DOCMNTN
FLY ASH FLOW	TFT305	KLB/HR	TPH	0	60	X		2		4	5		7				B										X							SCHENCK		60			
BOTTOM ASH HOPPER WEIGHT (4A)	TLT302	KLB		0	50	X		2		4	5		7				B																	LOAD CELL		60			
BOTTOM ASH HOPPER WEIGHT (4B)	TLT303	KLB		0	50	X		2		4	5		7				B																	LOAD CELL		60			
4A BED PRESSURE	TPT1A	IN WC		0	75	X														E										0	50	IN WC	STATIC TAP	GP4	5/4/87	180	10/31/87		
4A BED PRESSURE	TPT1B	IN WC		0	75	X														E										0	50	IN WC	STATIC TAP	GP4	5/4/87	180	10/31/87		
4A BED PRESSURE	TPT1C	IN WC		0	75	X														E										0	50	IN WC	STATIC TAP	GP4	5/4/87	180	10/31/87		
4B BED PRESSURE	TPT2A	IN WC		0	75	X														E										0	50	IN WC	STATIC TAP	GP4	5/4/87	180	10/31/87		
4B BED PRESSURE	TPT2B	IN WC		0	75	X														E										0	50	IN WC	STATIC TAP	GP4	5/4/87	180	10/31/87		
4B BED PRESSURE	TPT2C	IN WC		0	75	X														E										0	50	IN WC	STATIC TAP	GP4	5/4/87	180	10/31/87		
BED DRN MATRL TEMP @ SCREW CLR 4A OUTLET	TTE300	DEGF		0	400	X		2																								DEGF	E	.	10/15/87	NR	-		
BED DRN MATRL TEMP @ SCREW CLR 4B OUTLET	TTE301	DEGF		0	400	X		2																								DEGF	E	.	10/15/87	NR	-		
ASH EQUIP COOLING WATER FLOW	XFT300	KLB/HR	GPM	0	500	X		2																						0	13.3	IN WC	ANF	DP3	10/7/87	180	4/4/88		
ASH EQUIP COOLING WATER HX INLET TEMP	XTE301	DEGF		0	200	X		2																								DEGF	E	.	10/15/87	NR	-		
ASH EQUIP COOLING WATER HX OUTLET TEMP	XTE50	DEGF		0	200	X		2																								DEGF	E	.		NR	-		
GEN OUTPUT	YAM14	MW		0	120																																		
UNIT AUX TRANSFORMER LOAD	YWM20	MW		0	21																		X																

DATE 4/26/88

Appendix B

PERFORMANCE CALCULATIONS

Appendix B

PERFORMANCE CALCULATIONS

During the performance tests several process variable measurements will be made. These measurements will be used to calculate a number of process related performance results. These process performance results will be the basis for comparison of various tests and for optimization of the unit performance. This appendix contains functional descriptions of the process performance calculations that Colorado-Ute will make for each of the performance tests conducted. Equations that meet these functional descriptions were developed by EPRI and coded into the VAX computer Performance Monitoring Software by EPRI's contractors.

The primary performance measurements of interest to the Test Program are:

- Boiler Efficiency (Input-Output and Losses Method)
- Material Balances
- Calcium/Sulfur Molar Ratio
- SO_2 Retention
- Calcium Utilization
- Combustion Efficiency
- Carbon Conversion (Input-Output and Losses Method)
- Excess Air
- Flue Gas Flow Rate
- Flue Gas Molecular Weight
- Superficial Velocity (Air Inlet and Flue Gas Methods)
- Air Heater Efficiency
- Size Distributions and Mean Particle Size

BOILER EFFICIENCY

The gross boiler efficiency is defined as the output of the boiler divided by the heat input from the fuel plus the heat credits. The procedures for calculating the gross boiler efficiency are outlined in the ASME Power Test Code PTC 4.1. The gross boiler efficiency can be calculated by the input-output method or by the loss method. The input-output boiler efficiency is calculated by the following expression:

$$\eta_{GB(I-O)} = 100 \frac{\text{Output}}{\text{Input} + \Sigma\text{Credits}}$$

where output is the total heat absorbed by all of the working fluids. The loss method boiler efficiency is calculated using the following expression:

$$\eta_{GB(L)} = 100 \left(1 - \frac{\Sigma \text{Losses}}{\text{Heat Input} + \Sigma \text{Credits}}\right)$$

The fuel efficiency is defined as the percentage of fuel heat input that is converted into usable steam. The fuel efficiency is calculated by the loss method using the following formula:

$$\eta_{F} = 100 \left(1 - \frac{\Sigma \text{Losses} - \Sigma \text{Credits}}{\text{Heat Input}}\right)$$

The unit efficiency will be calculated using the ASME Power Test Code PTC 4.1. However PTC 4.1 does not account for all of the additional credits and losses associated with fluidized bed combustion. Where specific items are not fully covered in PTC 4.1, EPRI developed specific guidelines for implementation on all of their Demonstration Programs. Figure B-1 shows the heat balance boundary chosen for the Nucla plant. All sensible heats will be referenced to 77 °F.

<u>Heat Output</u>

D0 Enthalpy of Main Steam Exiting Superheater

This is the enthalpy of the steam as it leaves superheater III in Btu/hr. The steam flow is calculated by a mass balance around the water system.

D1 Enthalpy of Feed Water

This is the enthalpy of the feed water entering the boiler in Btu/hr.

D2 Enthalpy of Attemperator Streams

The enthalpy of the attemperator streams entering the system is calculated based on the flow rates of all of the attemperators and the temperature and pressures of the attemperator water.

Total Output = D0 - (D1 + D2)

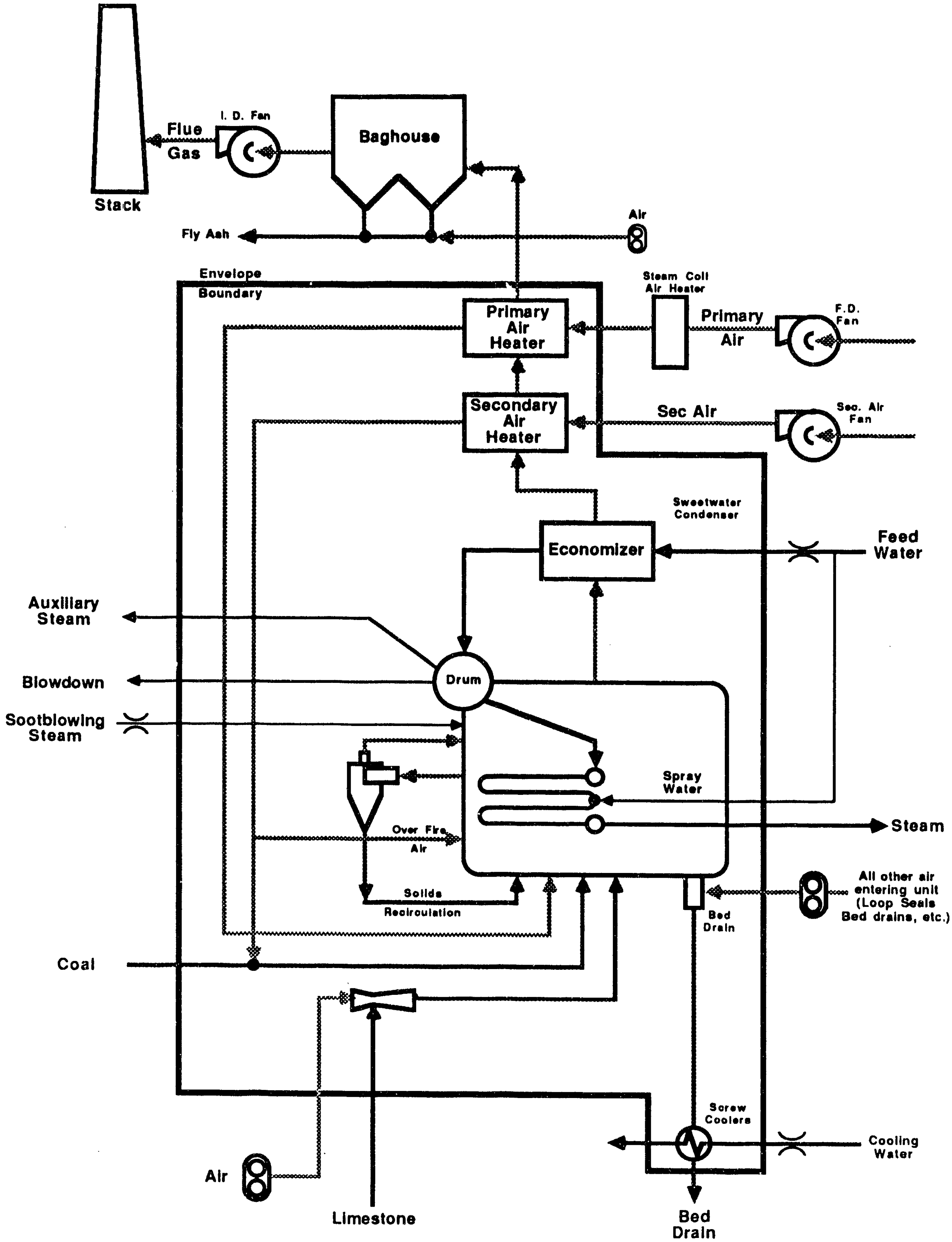

Figure B-1. Heat Balance Boundary for the Nucla Boiler

Heat Input

H1. Chemical Heat of the As-Fired Fuel

This is the heat of combustion of the as-fired fuel measured at the fuel feeders.

Credits

B1. Primary Air Sensible Heat Credit

This is the sensible heat in the moist primary air stream measured between the steam coil air heater and the primary air heater.

B2. Secondary Air Sensible Heat Credit

This is the sensible heat of the moist secondary air measured between the secondary air fan and the secondary air heater.

B3. Transport Air Sensible Heat Credits

This is the sum of the sensible heats for all of the air assist and pneumatic conveying streams that enter the boiler. It does not include any secondary air that is used to assist the coal feed since this heat is already accounted for in B2. These heats are measured after their air compressors and before they enter the boiler.

B4. Solids Sensible Heat Credits

This is the sum of the sensible heats of the coal, limestone, and sand that enters the boiler. These heats are measured up stream of the pneumatic pick-up point.

B5. Heat Credit for Sulfation

This is the chemical heat released by the sulfur capture reaction:

$$CaO + SO_2 + \frac{1}{2} O_2 \Rightarrow CaSO_4$$

The heat of this reaction is 6,728 BTU/lb of sulfur captured.

B6. Heat Credit from Auxiliary Power

B7. Heat Credit for Soot Blowing Steam

The sootblowing steam is taken from SHI outlet. This credit is the difference between the steam enthalpy at SHI and the vapor enthalpy at the reference temperature.

Heat Losses

L1. Heat Loss Due to Dry Flue Gas

This is the sensible heat of the dry flue gas at the conditions of the stack. The stack flue gas flow rate is calculated from the flue gas composition measured at the stack. The enthalpy of the flue gas is based on the flue gas temperature at the inlet to the I.D. Fan. The flue gas flow rate will be adjusted for the additional carbon dioxide released by the calcination of the limestone sorbent.

L2. Heat Loss Due to Moisture in "As-Fired" Fuel and Sorbent

This loss is the change in enthalpy between the enthalpy of the saturated liquid moisture in the solid streams entering the boiler and the enthalpy of the water vapor at the stack. The enthalpy of the saturated liquid is evaluated at the reference temperature.

L3. Heat Loss Due to Moisture from Burning Hydrogen

This is the heat loss associated with the change in enthalpy of the moisture created by the burning of hydrogen in the fuel. The amount of fuel moisture formed is based on the hydrogen content of the fuel. The enthalpy change is the same as for L2.

L4. Heat Loss Due to Moisture in the Air

This loss is the change in enthalpy between the enthalpy of the saturated water vapor in all of the air streams entering the boiler and the enthalpy of the water vapor at the stack. The enthalpy of the saturated water vapor is evaluated at the reference temperature.

L5. Heat Loss Due to Unburned Coal

This is the chemical heat contained in the solid refuse streams. The heating value of the solid waste streams is evaluated based upon the carbon and hydrogen content. The carbon content is adjusted for the CO_2 that is contained in any uncalcined limestone in the solid. The unburned carbon has a heating value of 14,500 BTU per pound of carbon. The hydrogen has a heating value of 60,976 BTU per pound of hydrogen.

L6. Heat Loss Due to Calcination of Sorbent

This is the chemical heat absorbed by the following endothermic calcination reaction:

$$CaCO_3 + Heat \Rightarrow CaO + CO_2$$

This chemical reaction absorbs 1,913 BTU per pound of calcium that calcines. Magnesium is assumed to be in the form of dolomite $CaMg(CO_3)_2$. The dissociation of the magnesium portion of the dolomite absorbs 2,262 BTU per pound of magnesium.

L7. Heat Loss Due to Formation of Carbon Monoxide

This is the heat loss associated with burning the CO in the flue gas to CO_2. The heat of this reaction is 10,130 BTU per pound of carbon in the CO and represents the difference between burning carbon as it occurs in the fuel to CO_2 and burning carbon as it occurs in the fuel to CO.

L8. Heat Loss Due to Unburned Hydrocarbons

This is the chemical heat contained in the hydrocarbons at the stack. All hydrocarbons are assumed to be methane for the purpose of estimating the heating value.

L9. Heat Loss Due to Surface Radiation and Convection

This heat loss will be estimated based on temperature measurements made around the surface of the boiler during operation. See Section 10.2 for more details on this loss.

L10. Heat Loss Due to Sensible Heat in Dry Refuse

This is the sensible heat contained in the dry refuse streams from the boiler. The two streams of interest are the bottom ash and the baghouse reject streams. The bottom ash sensible heat is measured at the outlet to the bottom ash cooling screws. The baghouse reject stream sensible heat is evaluated at the baghouse inlet temperature. The flow rate of the baghouse reject stream will be calculated by performing an inerts balance around the combustor. This is described below.

L11. Heat Loss Due to Sootblowing Steam

This is the enthalpy rise of the water vapor used for sootblowing between the stack conditions and the reference temperature.

L12. Heat Loss Due to Pickup by Cooling Water

The heat pick-up by the cooling water in the bottom ash cooler screws is a heat loss. This is measured by the flow rate of cooling water and the temperature rise across the cooling screws.

MATERIAL BALANCES

Materials balances will be performed on the following elements:

- Carbon
- Hydrogen
- Oxygen
- Sulfur
- Nitrogen
- Calcium
- Magnesium
- Iron

In addition to the above elemental balances, material balances will be performed on the inerts and the total mass. These material balances will serve as checks on the measurements taken. Closure of the balances within the measured uncertainty band will indicate the quality of the data and achievement of steady state. The boundary for the material balances will be the same as for the boiler efficiency as shown in Figure B-1.

The flow rate of each of the elements will be calculated from the compositions of the following streams:

Input Streams
- Coal
- Sorbent
- Air (All Sources)

Output Streams
- Flue Gas
- Fly Ash
- Bottom Ash

In order to perform these mass balances the coal will be analyzed for:

- Total Moisture
- Air Dry Moisture
- Volatiles
- Fixed Carbon
- Ash
- Carbon
- Hydrogen
- Nitrogen
- Sulfur
- Oxygen (by difference)
- Calcium
- Magnesium
- Iron

The sorbent will be analyzed for the following elements:

- Total Moisture
- Ash
- Sulfur
- Calcium
- Magnesium
- CO_2

Bottom ash and fly ash will be analyzed for the following elements:

- Ash
- Carbon (total including CO_2)
- Hydrogen
- Nitrogen
- Sulfur
- Calcium
- Magnesium
- CO_2

The following discussion describes the calculation procedure for each of the material balances.

<u>Total Mass</u>

The total mass balance will utilize the total flow rate of each of the above streams. The coal, air, sorbent, and bottom ash flow rates will be measured by plant instrumentation. The flow rate of flue gas will be calculated from the flue gas compositions and the coal feed rate as part of the boiler efficiency calculations. This flow rate will be reported as the Wet Flue Gas Flow Rate by O_2 Method, and will be the flue gas flow rate used for all subsequent mass balances. The flow rate of the fly ash will be calculated by forcing closure of the inerts balance.

Since approximately 90% of the total mass passing through the boiler is the air and flue gas, the total mass balance will serve as a check on the integrity of the air flow rate measurements. Also as part of the total mass balance, a flue gas flow rate will be calculated that will close the total mass balance. This flow rate will be reported as the Wet Flue Gas Flow Rate by Total Method.

Carbon

The carbon mass balance will calculate the carbon flow rate in all of the mass streams. Carbon in the coal, fly ash, and bottom ash will be calculated from the total carbon analysis. Carbon in the sorbent will be calculated from the CO_2 composition. No carbon is assumed to be in the air streams. Carbon in the flue gas is based on the measured CO_2, CO, and hydrocarbons (assumed to be methane). These flue gas measurements are measured on a volumetric basis and must be converted to a mass basis using the flue gas density. The carbon balance serves as a check on the fuel flow rate and the CO_2 analysis of the flue gas.

Hydrogen

Hydrogen in the fuel is in the form of elemental hydrogen and also in the fuel moisture. Moisture in the sorbent and the air are also sources of hydrogen. Hydrogen is contained in moisture in the flue gas. Hydrogen in the fly ash and the bottom ash is measured by the chemical analysis for hydrogen. The hydrogen balance serves as a check on the water in the system.

Oxygen

Oxygen in the fuel is in the form of elemental oxygen and the fuel moisture. Oxygen in the sorbent is in the form of CO_2. Dry air contains 23.1792% oxygen by mass. The water contains 88.810% oxygen by weight. Flue gas oxygen is in the form of O_2, CO_2, CO, SO_2, and water vapor. The fly ash and the bottom ash contain oxygen in the form of $CaCO_3$, CaO, $CaSO_4$. The oxygen balance serves as a check on the air flow rate and the flue gas oxygen measurement.

Sulfur

Sulfur is contained in the coal as elemental sulfur. Some limestones contain a small amount of sulfur, probably as sulfates. The sulfur in the flue gas is measured in ppm by volume of SO_2. Sulfur in the fly ash and bottom ash streams is assumed to be sulfates. The sulfur balance is an indicator of steady state operation, as the inventory of sulfur in the bed is one of the slowest changing parameters in the combustor. Closure of the sulfur balance is also an indication of good quality sulfur capture data.

Calcium

Calcium in the fuel is reported as a percentage of the total fuel. Sorbent is usually the largest input stream of calcium in the system. Air and flue gas are assumed to contain no calcium. The fly ash and bottom ash are the only output streams that contain calcium. A calcium balance is a good indication of the accuracy of the solid flow rate measurements as well as steady state operation.

Magnesium and Iron

Like calcium, magnesium and iron in the fuel are reported as a percentage of the total fuel. Magnesium and iron are also present in some sorbents. No magnesium or iron are assumed to be in the air or flue gas streams. The fly ash and bed drain are the only output streams that contain magnesium and iron.

Inerts

Inerts are defined as all non reactive constituents except CO_2 and SO_3 in the limestone, coal ash, sand, bottom ash, and fly ash. The percentage of inerts in the coal is the % ash of the as-fired coal. The percentage of inerts in the limestone is:

$$100\% - \%CO_2 - \%H_2O.$$

Sand is assumed to be all inerts except for the moisture. The percentage of inerts in the bottom ash and the fly ash is:

$$100\% - \%\ CO_2 - \%S\ \frac{80}{32} - (\%C - \%CO_2\ \frac{12}{44}).$$

An inerts balance will be used to calculate the fly ash flow rate leaving the combustor. Because the fly ash flow rate is calculated to close the inerts balance, this balance will always be equal to 100%.

MISCELLANEOUS CALCULATIONS

Calcium/Sulfur Molar Ratio

This is defined as the ratio of moles of calcium in the limestone to moles of sulfur in the fuel. The total calcium/sulfur ratio will also be calculated based on the total moles of calcium in the fuel and limestone divided by the total moles of sulfur in the fuel and limestone.

SO_2 Retention

The percent sulfur retention (sulfur capture) is given as the percentage of the sulfur in the fuel that is converted into calcium sulfate. This can be calculated two ways, either based on the flue gas emissions of SO_2 or based the sulfur in the solid waste streams. Generally, the SO_2 retention based on the flue gas analysis is the more accurate value. This is the value that will be calculated for Nucla.

Calcium Utilization

Calcium utilization is defined as the percentage of the calcium in the feed stream that is converted to calcium sulfate. This is calculated as the ratio of the percent sulfur retention divided by the calcium/sulfur ratio.

Combustion Efficiency

Combustion efficiency is defined as the percentage of chemical heat fed to the combustor that is released in the combustor. This is calculated by calculating the chemical heat losses from the system. The losses include:

- unburned fuel in the fly ash
- unburned fuel in the bottom ash
- carbon monoxide in the flue gas

Heating value of the solid waste streams is calculated based on the chemical composition of carbon and hydrogen in these streams.

Carbon Conversion

Carbon conversion is defined as the percentage of carbon in the fuel that is converted to gaseous products. The carbon conversion will be calculated by the input-output method, which is based on the flue gas composition, and by the loss method, which is based on the composition of the solid waste streams.

Excess Air

Excess air is defined as the percentage of the input air fed to the combustor that is in excess of the stoichiometric amount required to burn the fuel in the boiler. The excess air is calculated from the flue gas analysis at the inlet to the air heater. In this way, the excess air reflects the actual conditions within the combustor, rather than any air leakage into the air heater or the baghouse.

Furnace Velocities

The superficial velocity is defined as the volumetric flow rate of gas in actual cubic feet per second divided by the cross sectional area of the combustor. It is generally calculated by the following formula:

$$Vs = \frac{W}{r \bullet A \bullet 3600} \qquad \text{ft/sec}$$

Where: W = the flow rate of gas in lb/hr

r = the density of the gas in lb/ft^3

A = the cross sectional area of the duct in ft^2

The velocity will be calculated on both an inlet air basis and on the flue gas basis, above the secondary air ports. The inlet air basis uses the total flow rate of air to the combustor and the density of air at the conditions of bed temperature and pressure equal to one half of the combustor pressure drop. This velocity will be reported as the Inlet Air Method on the Performance Summary Report Sheet. The flue gas basis will use the wet flue gas flow rate calculated by the flue gas composition at the inlet of the baghouse and the density of the flue gas at the conditions of bed temperature and pressure equal to one half of the combustor pressure drop. This velocity will be reported as the O_2 Method on the Performance Summary Report Sheet.

Air Heater Efficiency

Heat exchanger efficiency is defined as the ratio of the actual heat transfer rate to the thermodynamically limited maximum possible heat transfer rate that would be achieved in a counter-flow heat exchanger of infinite heat transfer area. Generally, the efficiency of an air heater can be calculated using the following formula:

$$\eta = \frac{T_{ao} - T_{ai}}{T_{gi} - T_{ai}}$$

Where: T_{ao} = temperature of the exiting air

T_{ai} = temperature of the inlet air

T_{gi} = temperature of the inlet gas

However for the Pyropower air heater the above expression does not apply, since there are two separate air streams that are heated by the flue gas. In this case, the definition of the air heater efficiency must be used to derive a new expression for the overall efficiency of the air heater.

The actual heat transfer rate is given by:

$$q = W_{pa} C_{pa} (T_{pao} - T_{pai}) + W_{sa} C_{pa} (T_{sao} - T_{sai})$$

Where
W_{pa} = the flow rate of primary air, lb/h
W_{sa} = the flow rate of secondary air, lb/h
C_{pa} = the mean heat capacity of the primary and secondary air, BTU/lb °F
T_{pai} = primary air inlet temperature, °F
T_{pao} = primary air outlet temperature, °F
T_{sai} = secondary air inlet temperature, °F
T_{sao} = secondary air outlet temperature, °F

The maximum possible heat transfer rate is given by:

$$q_{max} = W_{pa} C_{pa} (T_{gin} - T_{pai}) + W_{sa} C_{pa} (T_{gin} - T_{sai})$$

Where T_{gin} = flue gas inlet temperature, °F

The above two equations can be combined to give an expression for the air heater efficiency $\frac{q}{q_{max}}$ as follows:

$$h = \frac{W_{pa} (T_{pao} - T_{pai}) + W_{sa} (T_{sao} - T_{sai})}{W_{pa} (T_{gin} - T_{pai}) + W_{sa} (T_{gin} - T_{sai})}$$

Note: this equation reduces to the original definition for a conventional air heater.

SIZE DISTRIBUTIONS AND MEAN PARTICLE SIZES

Size distributions will be reported for the coal, sorbent, sand, bottom ash, and fly ash. The distributions will be reported on a percent less than basis. In addition to the distributions, several of mean particle diameters will be calculated for each of the streams. The mean diameters that will be calculated are the weight mean, the surface-volume mean, the surface mean, the volume mean, the arithmetic mean, and the geometric mean. These mean sizes are described below. In all of the expressions below, the term X_i refers to the weight of sample retained on screen i and the term D_i refers to the average diameter of screen cut i in microns.

Weight Mean

The weight mean is the diameter of a sphere whose surface area times the total number of particles in the sample equals the surface area per unit weight of the sample. This diameter is given by:

$$\text{Weight Mean Diameter, } D_{WM} = \Sigma\, (D_i \cdot X_i)$$

Surface-Volume Mean

The surface-volume mean diameter, sometimes referred to as the Sauter mean, defines the total surface of a unit weight for a sample of mixed size particles.

$$\text{Surface-Volume Diameter, } D_{SV} = \frac{1}{\sum \frac{X_i}{D_i}}$$

Surface Mean

The surface mean diameter represents an average spherical particle whose surface area multiplied by the total number of particles in the sample would equal the total surface area of the sample.

$$\text{Surface Mean Diameter, } D_{SM} = \left(\frac{\sum \frac{X_i}{D_i}}{\sum \frac{X_i}{D_i{}^3}}\right)^{(1/2)}$$

Volume Mean

The volume mean equals the diameter of a spherical particle whose volume times the total number of particles in the sample equals the total particle volume of the sample.

$$\text{Volume Mean Diameter, } D_{VM} = \left(\frac{1}{\sum \frac{X_i}{D_i{}^3}}\right)^{(1/3)}$$

Arithmetic Mean

The arithmetic mean diameter equals the sum of diameters of all particles divided by the number of particles.

$$\text{Arithmetic Mean Diameter, } D_{AM} = \frac{\sum \frac{X_i}{D_i{}^2}}{\sum \frac{X_i}{D_i{}^3}}$$

Geometric Mean

The geometric mean diameter equals the n^{th} root of the product of the number of particles, n, in the sample.

$$\text{Geometric Mean Diameter, DGM} = \frac{\sum \frac{X_i}{D_i^3} \log(D_i)}{\sum \frac{X_i}{D_i^3}}$$

Appendix C

UNCERTAINTY ANALYSIS OF PERFORMANCE CALCULATIONS

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UNCERTAINTY ANALYSIS OF THE PERFORMANCE CALCULATIONS

An uncertainty analysis of the performance calculations will provide information on the measurement uncertainty of the calculated results. This is especially important when comparing performance from two different boilers. ASME PTC 19.1 provides guidelines for determining the measurement uncertainty of the various plant measurements that feed the performance calculation program. PTC 19.1 also provides guidelines for propagating these uncertainties throughout the performance calculations.

The procedure for calculating the uncertainty of the results of a given calculation can be summarized as follows:

1. Determine the average values of the independent parameters ($\overline{P}_i$) that enter into the result (r) of the calculation.

2. Determine the precision index of the average value ($S_{\overline{P}_i}$) for each $\overline{P}_i$.

3. Determine the bias limit for each of the measured parameters ($B_{\overline{P}_i}$).

4. Determine the degrees of freedom associated with each $\overline{P}_i$ ($\nu_{\overline{P}_i}$).

5. Use the perturbation method to determine the bias limit of the result (B_r).

6. Use the perturbation method to determine the precision index of the result (S_r).

7. Calculate the degrees of freedom of the result (ν_r).

8. Find the Student's t factor (t) corresponding to n_r.

9. Calculate the total uncertainty of the result by the root-sum-square method ($U_{r_{RSS}}$).

A more detailed description of this procedure follows.

STEP 1: Find $\overline{P}i$

The average value for each of the inputs is given by:

$$\overline{P}_i = \frac{1}{N} \sum_{k=1}^{N} P_{i-k} \qquad \text{(C-1)}$$

Where: P_{i-k} = the k^{th} measurement of the i^{th} input variable.
N = The number of repeat measurements

STEP 2: Find $S_{\overline{P}_i}$

The precision error, or random error, for a given input parameter is assumed to be made up entirely of the precision index of the average of the measurements of that parameter. As described in PTC 19.1, the precision index, S, is an estimate of the standard deviation and is defined as:

$$S = \left\{ \frac{\sum_{k=1}^{N} (P_{i-k} - \overline{P}_i)^2}{(N - 1)} \right\}^{.5} \qquad \text{(C-2)}$$

The quantity S is a measure of the error that can be expected if any one measurement, P_{i-k}, is used to estimate the true average of the population sampled. However, if the average value, $\overline{P}_i$, is used, the precision index of the average is defined as:

$$S_{\overline{P}_i} = \frac{S}{\sqrt{N}} \qquad \text{(C-3)}$$

Thus the precision error is reduced by using the average instead of any of the individual measurements. Equations C-2 and C-3 are used to determine the precision index of the average chemical analyses.

For the data points taken from the data highway, a slightly different procedure is required. Points on the data highway are stored as average values over a short time period, usually 15 minute averages, $\overline{P}_{i-j}$, along with a standard deviation, S_{i-j}, calculated for that average time period.

When the test period is defined, the M values of $\overline{P}_{i-j}$ are averaged to obtain $\overline{P}_i$. The estimate of the pooled precision index for the individual $\overline{P}_{i-j}$'s is given by:

$$S_{pooled} = \left\{ \frac{\sum_{j=1}^{M} S_{i-j}^2}{M} \right\}^{.5} \qquad (C-4)$$

The precision index of the grand average $\overline{P}_i$ is then given by:

$$S_{\overline{P}_i} = \frac{S_{pooled}}{\sqrt{H*M}} \qquad (C-5)$$

Where H is the number of measurements that are averaged to give $\overline{P}_{i-j}$ and M is the number of stored readings that are averaged to give $\overline{P}_i$.

STEP 3: Determine $B_{\overline{P}_i}$

Bias limits for the input parameters are estimated from the manufacturers' performance specifications. There are six main types of measurements that are used as inputs to the performance calculations:

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

The bias limits for the pressure and pressure differential measurements are obtained from the calibration data and the amount of drift observed between calibrations. Bias limits for temperatures are available from the vendors catalogs. Bias limits on the air heater exit gas temperature thermocouples were determined by inserting each thermocouple into boiling water, and measuring the difference between the reading and 212 °F. No bias error is assumed to be associated with the location of the thermocouples.

Fluid flow measurements, such as those for feed water, steam, and air are based on the output from differential pressure (ΔP) instruments. These instruments measure the ΔP across and orifice plant or other similar flow device. The signal from the ΔP transmitter is processed through a square-root extractor, which puts out a signal that is proportional to the square root of the signal entering it. This square-root extractor output signal is then a linear function of the flow rate. Because of this, the bias limit on the fluid flow rate measurements are not only a function of the bias limit on the ΔP reading, but also a function of flow rate as well. The bias limit for these instruments was obtained from the calibration data.

The bias limit for the solid flow rate measurements is obtained from the calibration data of each instrument. The bias limit for the gas analyzers are also obtained from the calibration data. The gas analyzers will be calibrated on a regular schedule to eliminate any other sources of bias error. Chemical analyses biases were obtained from the calibration data obtained from the laboratory.

STEP 4: Determine $\nu\overline{P}_i$

The degrees of freedom associated with the calculation of each $S\overline{P}_i$ is given by

$$\nu\overline{P}_i = N-1 \qquad \text{(C-6)}$$

Where N is the total number of measurements that went into the average value (N is equal to H*M for values on the data highway).

STEP 5: Calculate Br

The bias limit of the result, Br, is the uncertainty of the result that is due to the bias limits of the input parameters. The value of Br is given by:

$$Br = \left[\sum_{i=1}^{N}(\theta_i \; B\overline{P}_i)^2\right]^{.5} \qquad \text{(C-7)}$$

Where θ_i is the relative sensitivity coefficient for the i^{th} parameter. θi is defined in PTC 19.1 as follows:

$$\theta_i = \frac{\partial r}{\partial \overline{P}_i}. \qquad \text{(C-8)}$$

θ_i is the partial derivative of the result with respect to the i^{th} input parameter. The value of θ_i can be calculated by taking the partial derivatives of all of the mathematical expressions used to calculate the result. This method is called the analytical method. A simpler way to determine the partial derivatives is to use the perturbation method, where the value of $\overline{P}_i$. is replaced in the calculation with ($\overline{P}_i$ + $\Delta\overline{P}_i$), where $\Delta\overline{P}_i$ is a small increment of $\overline{P}_i$ (usually 1% of $\overline{P}_i$), and a value of $r(\overline{P}_i + \Delta\overline{P}_i)$ is calculated. The value of θ_i is then given by:

$$\theta_i = \frac{r(\overline{P}_i + \Delta\overline{P}_i) - r}{\Delta\overline{P}_i} \qquad \text{(C-9)}$$

for each input parameter. This method has been found to give the same result as the analytical method, and while it requires considerably more calculations, it is much easier to implement on the VAX computer than the analytical method.

STEP 6: Calculate S_r

The precision index of the calculated result, S_r, is the uncertainty of the result that is due to the precision index of the input parameters. The calculation of S_r is identical to B_r, except that $S_{\overline{P}_i}$ is substituted for $B_{\overline{P}_i}$ in equation C-7.

STEP 7: Calculate ν_r

The degrees of freedom of the calculated result is a function of the precision index of the result, the precision index of the input variables, and the degrees of freedom of the input variables. The Welch-Satterwaite formula given in PTC 19.1 is used to calculate ν_r as follows:

$$\nu_r = \left\{ \frac{S_r^{\,4}}{\displaystyle\sum_{i=1}^{N} \frac{(\theta_i\, S_{\overline{P}_i})^4}{n_{\overline{P}_i}}} \right\} \qquad \text{(C-10)}$$

The perturbation results for θ_i are used in both equations C-7 and C-10.

STEP 8: Find t

The precision index of the result, S_r, is related to the precision error of the calculated result by a factor known as the Student's t value. The precision error of the calculated result is $(t*S_r)$. The value of t is a function of the number of degrees of freedom and the probability that the true value of r will be inside of the range of $r \pm t\ S_r$. The value of t was evaluated at a probability interval of 95%. Table C-1 lists values of t for the 95% probability interval as a function of ν degrees of freedom.

Table C-1. Student's t Values at the 95% Probability Level

n	t	n	t
1	12.71	16	1.120
2	4.303	17	2.110
3	3.182	18	2.101
4	2.776	19	2.093
5	2.571	20	2.086
6	2.447	21	2.080
7	2.365	22	2.074
8	2.306	23	2.069
9	2.262	24	2.064
10	2.228	25	2.060
11	2.201	26	2.056
12	2.179	27	2.052
13	2.160	28	2.048
14	2.145	29	2.045
15	2.131	30	2.042
		40	2.021
		60	2.000
		120	1.980
		∞	1.960

STEP 9: Calculate U_{rRSS}

The last step in the calculation of the uncertainty of the result is to combine the values of B_r and S_r to obtain U_{rRSS}. PTC 19.1 recommends using the root-sum-square model for combining the bias error and the precision error. The equation for the overall uncertainty is:

$$U_{rRSS} = [B_r^2 + (t\ S_r)^2]^{.5} \qquad \text{(C-11)}$$

Using the values of t from Table C-1 gives an uncertainty interval of 95%. The final result can be expressed with its uncertainty interval as:

$$r \pm U_{rRSS} \qquad \text{(C-12)}$$

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