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DEVELOPMENT AND TESTING OF A HIGH EFFICIENCY ADVANCED COAL COMBUSTOR PHASE III INDUSTRIAL BOILER RETROFIT

DOE CONTRACT NO. DE-AC 22-91PC91160

ABB- PPL CONTRACT NO. 33691

PROOF OF CONCEPT TESTING SUMMARY (TASK 3.0 FINAL TOPICAL REPORT)

Prepared by:

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July 1995

PETC Project Manager: Mr. Douglas F. Gyorke

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Table of Contents

List of Figures

Appendices:

List of Tables

Executive Summary

Economics may one day dictate that it makes sense to replace oil or natural gas with coal in boilers that were originally designed to burn oil or gas. In recognition of this future possibility the U.S. Department of Energy, Pittsburgh Energy Technical Center (PETC) has supported a program led by ABB Power Plant Laboratories in cooperation with the Energy and Fuels Research Center of Penn State University to develop the High Efficiency Advanced Coal Combustor (HEACC). The objective of the program is to demonstrate the technical and economic feasibility of retrofitting a gas/oil designed boiler to burn micronized coal.

In support of the overall objective the following specific areas were targeted:

- A coal handling/preparation system that can meet the technical requirements for retrofitting microfine coal on a boiler designed for burning oil or natural gas.
- Maintaining boiler thermal performance in accordance with specifications when burning oil or natural gas.
- Maintaining NOx emissions at or below 0.6 lb NO_2 per million Btu.
- Achieving combustion efficiencies of 98% or higher.
- Calculating economic payback periods as a function of key variables.

The work carried out under this program is broken into five major Tasks:

1.0) Review of current state-of-the-art coal firing system components.

2.0) Design and experimental testing of a prototype HEACC burner.

3.0) Installation and testing of a HEACC system in a retrofit application.

4.0) Economic evaluation of the HEACC concept for retrofit applications.

5.0) Long term demonstration under user demand conditions.

This report summarizes the work done under Task 3, the installation and testing of the HEACC burner in a 15,000 lb/hr package boiler located at Penn State. The period of testing was approximately 400 hours. Key findings were as follows:

Coal Handling/Preparation

A coal handling/preparation system can be designed to meet the technical requirements for retrofitting microfine coal in an oil or gas designed boiler.

Coal handling problems were experienced during the execution of Task 3. The problems were due to a combination of extreme weather conditions, i.e. the winter of '93/'94, and the design of some of the equipment used at the Penn State site. Raw coal was stored outside. Because of extreme snowfall, considerable quantities of ice and/or snow were contained in the coal shipments that were received in the raw coal hopper at the Penn State site. Those components in the coal handling system that were most sensitive to coal moisture were the surge hopper and the screw feeder. There were times when Penn State personnel had to break up large coal/ice chunks to get them through the grate above the raw coal receiving hopper. The surge hopper was prone to plugging when the crushed coal was wet and operation of the screw feeder was also adversely affected by coal that had a high moisture content. Since the coal preparation/feed system was of a direct fired type, i.e. coal was fed to the microfine coal pulverizer and then directly to the burner, any hang-ups in the feed system to the mill caused interruptions in the coal feed to the burner.

Two changes to the components most affected by the wet coal were recommended: (1) the surge bin bottom should be converted to a mass-flow design, and (2) the volumetric screw feeder should be replaced with a gravimetric feeder. These two changes would prevent problems due to "normally" wet coal. The point here is that some of the conditions experienced were beyond the normal realm of expected weather-related conditions. Under such adverse conditions even those who routinely handle coal would have and did have problems during the winter of '93/'94. It is acknowledged that better (covered) storage of the raw coal before shipping would have gone a long way toward alleviating the problems experienced.

The aforementioned changes to the most affected components will have been completed before the 1000 hour demonstration is initiated.

Boiler Thermal Performance

Boiler thermal performance when firing microfine coal was essentially comparable to that achieved when firing natural gas. In fact because of the greater latent heat loss when burning natural gas (greater formation of water due to higher hydrogen content) firing microfine coal actually gave slightly higher boiler efficiencies despite the need to run at higher excess air levels.

During the relatively short operating periods, usually less than 16 hours, ash deposits did not cause significant changes to the boiler thermal performance. However it is recognized that longer term operation could result in greater build-up of ash deposits which could impact heat transfer. Because of the relatively short duration of the tests any build-up of ash deposits would slough off when the boiler was shut down. A better test of the possible impacts of ash deposits will occur during the long term demonstration phase of the work (Task 5).

NOx Emissions

The NOx emission target was 0.6 lb NO_2 per million Btu fired; this translates to about 450 ppm. Testing with 100% microfine coal showed that this target can be met while meeting nearly all other required conditions. A NOx value of 0.56 lb NO_2 per million Btu was routinely obtained. It is acknowledged that the optimum conditions for low NOx will generally exacerbate carbon conversion efficiencies. Indeed, this was the case with the HEACC burner and the challenge was to find a reasonable balance between meeting the NOx target while not aggravating the carbon conversion efficiency.

Combustion Efficiency

The target for combustion efficiency was 98%. The highest combustion efficiency obtained during testing in Task 3 was slightly over 96%. However, this value was not compatible with meeting the NOx target and was not able to be routinely repeated. A value of 95% combustion efficiency was able to be routinely achieved and was compatible with meeting the NOx target.

Considerable effort was spent in trying to determine how combustion efficiency might be improved to meet the target. The challenge to meet the combustion efficiency target of 98% is, indeed, a very difficult one. The bulk boiler residence time is about 0.7 seconds. Further complicating the task is the aspect ratio of the boiler, i.e. the length of the boiler is not very much greater than its height or width (approximately 8 ft long x 8 ft high x 6 ft wide). It is likely that the particle residence time is even shorter than the bulk residence time, which further aggravates the situation. Burner modifications are being looked at which might increase the particle residence time.

Coal particle size distribution was also evaluated, the premise being that carbon content must be directly proportional to particle size. While the larger particle size fraction of the collected particulate did contain higher carbon contents than the smaller size fractions the differences were not as great as expected. For example, it would not be possible to dramatically reduce the carbon content of the fly ash by eliminating coal particles larger than 150 microns.

Interestingly, when the economic analysis was done the difference in payback period between 98% combustion efficiency and 95% combustion efficiency was negligible.

From the standpoint of ash disposal and possible impacts that carbon content might have on ash disposal it should be noted that 98% carbon conversion would result in an ash with about 40% carbon whereas 95% carbon conversion would result in an ash with about 60% carbon. It is doubtful that this difference would affect disposal, i.e. if it is alright to dispose of 40% carbon ash it is probably alright to dispose of 60% carbon ash also.

1.0 Introduction/ Background

Under U.S. Department of Energy, Pittsburgh Energy Technology Center (PETC) support, the development of a High Efficiency Advanced Coal Combustor (HEACC) has been in progress since 1987 at the ABB Power Plant Laboratories (Rini, et al., 1987, 1988). As summarized in previous publications on the subject, the initial work produced an advanced coal firing system that was capable of firing both water-based and dry pulverized coal in an industrial boiler environment (Rini, et al., 1990).

With continued DOE-PETC support, carried out in cooperation with the Energy and Fuels Research Center of The Pennsylvania State University (Penn State), the HEACC burner concept has been used the basis for development of the major component in a system intended for industrial-scale, coal fired retrofit applications. The overall objective of the current work is to demonstrate the technical and economic feasibility of retrofitting a gas/oil-designed industrial boiler to burn micronized coal. In this respect, the key technical goals for the burner/firing system design were:

- A compact, easy to retrofit burner design
- Low NOx generation, while maintaining high combustion efficiency
- Commercially acceptable combustion air pressure drop and burner turndown ratio
- Integration of coal preparation/firing system controls into the boiler control system

The design of the HEACC burner is based on the well-established principle of internal air staging for NOx control. In an internally staged flame, combustion is initiated at the burner exit in a primary zone that contains less air than is required to completely burn the coal; this (substoichiometric) combustion zone promotes the conversion of fuel nitrogen to molecular N_2 instead of NOx. Combustion is then completed downstream of the burner where stoichiometric ratios of 1.15 to 1.25 exist to maximize carbon burnout. Burner swirl and mass flow control are employed to establish the substoichiometric, primary combustion zone. Hot combustion products are circulated back to the root of the flame in the primary zone, which provides ignition energy and promotes flame stability. Furthermore, with a properly designed air register, the primary zone is maintained at the correct stoichiometric condition throughout the load range. A critical consideration when firing coal in an oil/natural gas designed boiler is the limited residence time; burner design and the use of micro-fine coal represent two important factors in compensating for this decreased residence time.

The work carried out in this program consists of five major tasks:

1) A review of current state-of-the-art coal firing system components.
2) Design and experimental testing of a prototype HEACC burner.
3) Installation and testing of a HEACC system in a commercial retrofit application.
4) Economic evaluation of the HEACC concept for retrofit applications.
5) Long term demonstration under commercial user demand conditions

The results of Tasks 1 and 2 have been summarized in recent technical publications (Rini, et al., 1993, Jennings, et al., 1993). Task 3, which involved the proof-of-concept testing of the HEACC system in an gas/oil - designed package boiler at Penn State, is the subject of this report.

Under the second task of the development program, a commercially oriented, redesigned HEACC burner was tested at a scale of 18.5 x 10^6 Btu/hr. This design, as shown in Figure 1.1 contained features from CE's commercial wall-fired burner (the RO II) to facilitate its commercial application. The RO II is a utility sized wall fired burner for the low NOx retrofit market (Darroch, et al., 1991). Key features of the RO II burner which were incorporated into the HEACC burner were the tangential fuel inlet and the venturi coal diffuser. For commercial applicability, the air side of the HEACC register was simplified. For the tertiary air, burner swirl is produced by air entering tangentially to the register. The swirl is then regulated and evenly distributed by a series of adjustable blades located within the register. For the secondary air, a removable, axial flow type swirler design is used to produce the swirling flow.

The prototype industrial scale HEACC burner was designed to fire at a rate of 50 MBtu/hr which is a thermal input approximately 2.5 times higher than that required of the burner in the Penn State boiler. Scaling by a constant velocity criteria was used to design the 18.5 MBtu/hr burner for the Penn State boiler. The swirlers, coal nozzles, and other aspects of the burner were scaled using this criteria and previous CE burner design experience. The burner was sized to satisfy the geometric constraints of the host boiler: i.e.; windbox, burner openings, mounting plate sizes, fuel pipe locations, etc. Also, natural gas firing capability was added to make this a dual fuel burner.

Since the secondary air swirl is critical to the control of near field aerodynamics, a series of the secondary air swirlers were designed. Three co-rotational swirlers with

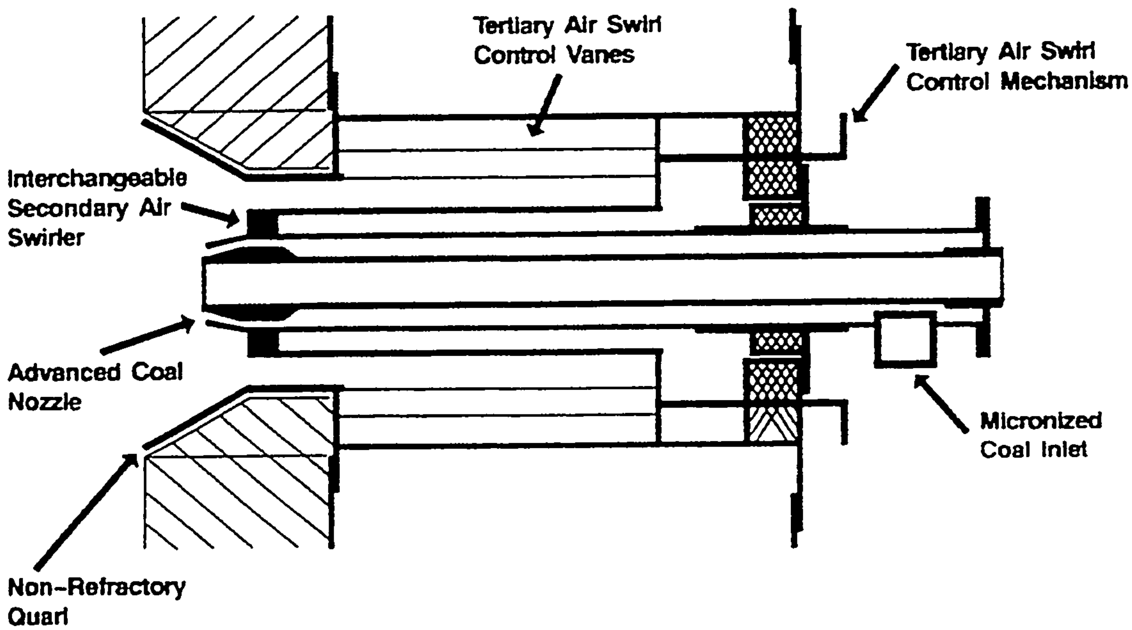


Figure 1.1 ABB/CE Industrial Scale Micronized Coal Burner

swirl numbers of 0.8, 1.0 and 1.5 and one counter-rotational swirler (swirl number = 1.0) were designed and fabricated. Two coal nozzles were designed. One was the Impinging Jet (I-Jet) injector which was developed and tested under the earlier phases of the HEACC program. The patented I-Jet provides eight individual coal streams that converge to produce a low axial momentum, concentrated cloud of pulverized coal. This type of solids/gas flow pattern when produced in a hot, substoichiometric environment has been shown to limit NOx formation. The second coal nozzle tested was a variation of CE's optimized commercial product for the RO II burner.

This second generation HEACC burner was tested in the Industrial Scale Burner Facility (ISBF) located at Combustion Engineering's ABB Power Plant Laboratories (PPL) in Windsor, Connecticut. This facility was designed to replicate the residence time and thermal environment of a typical industrial boiler. A key objective of the 100 hour burner validation tests at PPL was to confirm burner operating characteristics and demonstrate operation over the range of conditions expected for the field boiler tests.

During the testing in the ISBF, the improved HEACC burner successfully achieved the project performance goals during these performance verification tests. For example, the effect of various hardware configurations on NOx emissions is shown in Figure 1.2. The 400 test series (I-Jet and reverse secondary air swirler) produced the best results (a flame environment in which the incoming coal was rapidly mixed, heated and devolatilized in a near-ideal substoichiometric environment for controlling NOx).

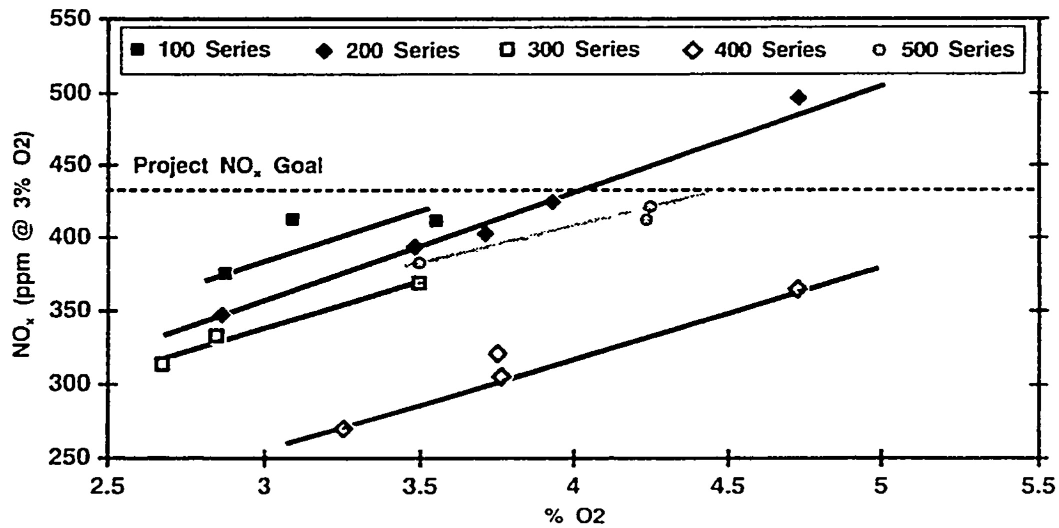


Figure 1.2 Effect of Hardware Configurations on NOx Emissions

The successful testing at PPL demonstrated the technical validity of the design improvements incorporated into the second generation HEACC. This burner was then installed as part of a complete coal handling and firing system in Penn State's demonstration boiler for the proof-of-concept system test program.

A schematic of the micronized coal preparation/firing system at Penn State is shown in Figure 1.3. As can be seen, the cleaned coal comes on site and is stored in a large hopper. The coal is crushed and sent via a screw feeder to the micronized coal mill. The coal is then micronized to 80% through 325 mesh (18 microns MMD) and pneumatically conveyed to the HEACC burner where it is then burned in the demonstration boiler. This boiler is an oil/gas designed Tampella Keeler Model DS-15; a package D-type watertube boiler capable of producing 15,000 lb/hr of saturated steam at 300 psig. It represents a typical gas/oil - designed system with a furnace volumetric heat release rate of 50,000 Btu/hr ft^3, standard for this class of boiler. Furthermore, its design is similar to that of many other manufacturers' (including Combustion Engineering) models.

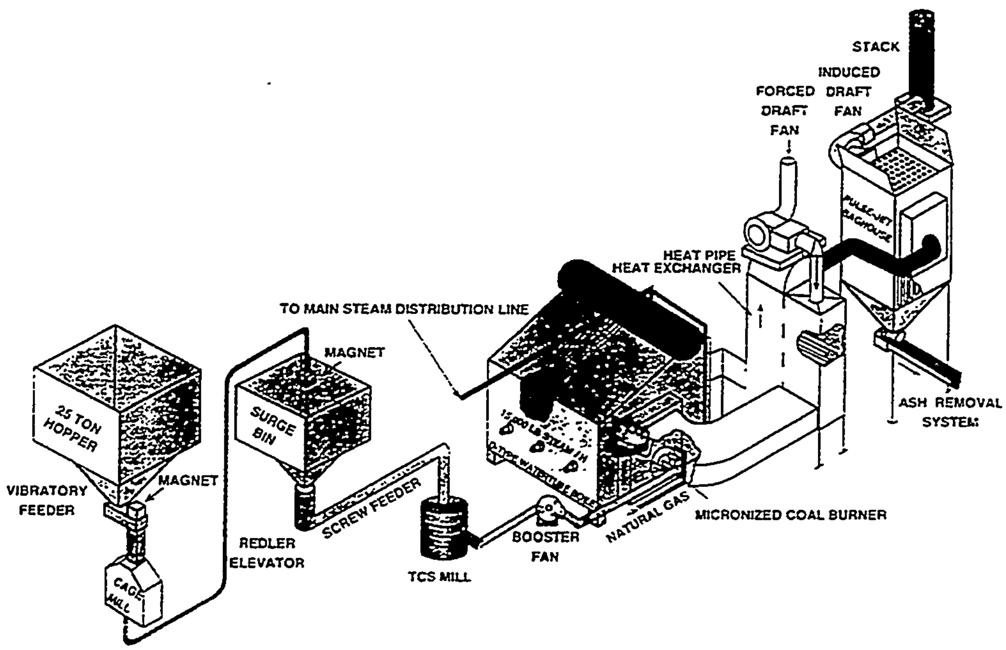


Figure 1.3 Micronized Coal Preparation System

As will be summarized in this report, the initial tests of the burner included a shakedown series of tests using natural gas firing. After the shakedown period, a brief series of tests were performed for various hardware configurations to confirm the optimum hardware configuration for this boiler and system. The chosen hardware configuration was then to undergo further testing during a 400 hour proof-of-concept test program.

During the 400 hour proof-of-concept test period, the system was to be operated over a range of operating conditions to determine system performance. This included testing of the boiler over a variety of load ranges, excess air, combustion air damper settings and burner swirl levels. In addition, for selected test points a second coal was to be tested to compare the system performance with the first coal. During the test period, boiler performance data, emissions data, electric parasitic and house compressed air consumption data as well as other data required for the technical and economical analysis of the system were obtained. The specific performance-related objectives were to obtain steady state operation on coal only while achieving a carbon conversion efficiency of 98%, without increasing NOx emissions above 0.6 lb/MBtu (~450 PPM). The testing was also designed to show that consistent, reliable operation of the integrated system could be achieved; this would serve as a prerequisite to the demonstration phase of the project.

The following report and associated Appendices summarize the results of the proof-of-concept testing program at Penn State, thus represent a summary of the Task 3 work.

2.0 Preliminary Testing

Prior to the 400 hour proof-of-concept testing period using pulverized coal, a test program consisting of about 100 hours of baseline testing on natural gas was carried out. Since the boiler was originally firing natural gas, it was felt that a logical frame of reference would be the results from testing that was carried out on 100% natural gas firing. Numerous system modifications and improvements were made during this preliminary test program. This section documents the results of this initial work (covering the time span from September to the end of December 1993) and summarizes the initial experimental results. Complete details of this work are given in the Quarterly Progress reports of ABB-CE (Jennings, et al., 1994) and Penn State (Miller, et al., 1993).

2.1 Experimental Results- Natural Gas Baseline Testing

Under this experimental task, testing was conducted to obtain economic and technical baseline data on natural gas for comparison to micronized coal firing data. As summarized in this section, this phase of the work was completed in early October 1993.

A test matrix was developed prior to the testing to ensure that sufficient data would be obtained for an accurate comparison of natural gas vs. microfine coal. As can be seen in Table 2.1, the planned test matrix included variations in: load, excess oxygen, tertiary air swirl and tertiary/secondary air split. The RO II coal nozzle and medium intensity secondary air swirler were installed during the natural gas testing since they represented the most likely hardware combination for the 400 hour coal testing.

Under a previous coal water fuel test program at Penn State, a baghouse was installed on the boiler to control particulate emissions. To avoid acid condensation problems, caused by running below the dewpoint, the baghouse temperature could not be operated under 250^{o} F. When the boiler was operated at below 75% of full firing rate, the acceptable minimum baghouse temperature could not be maintained. Although natural gas does not contain sulfur, residual ashes (from previous coal firing) in the baghouse do, and the formation of acid is possible. Therefore, Tests #5 - #9 (below 75% of full firing rate) were eliminated and Tests #M1 and #M2 were added to the matrix.

Test No.	Date Conducted	Load[a] (%)	Excess O_2 (%)	TA Swirl[b]	TA/SA[c] (%/%)	Test Duration (h)
1	09/23/93	100	2	Maximum	100/100	6
2	09/24/93	100	3	Maximum	100/100	6
3	09/27/93	100	1	Maximum	100/100	6
4	09/28/93	75	2	Maximum	100/100	6
5	N.C.[d]	50	2	Maximum	100/100	6
6	N.C.[d]	25	2	Maximum	100/100	6
7	N.C.[d]	25	3	Maximum	100/100	6
8	N.C.[d]	25	1	Maximum	100/100	6
9	N.C.[d]	Minimum	As Required	Maximum	100/100	6
10	09/27/93	100	2	Maximum	50/100	2
11	10/04/93	100	2	Maximum	100/50	2
12	09/24/93	100	2	Medium	100/100	2
13	09/24/93	100	2	Minimum	100/100	2
M1	09/30/93	75	3	Maximum	100/100	5.5
M2	10/04/93	75	1	Maximum	100/100	2

[a]Load is percentage of full firing rate (~17.3 million Btu/h)

[b]Tertiary air swirl

[c]Ratio of teriary air to secondary air damper openings (expressed as percentage of damper openings)

[d]Not conducted

Table 2.1 Natural Gas Test Matrix

Before the tests were begun, the furnace waterwall tubes were thoroughly cleaned to provide representative natural gas fired data. Later in the test series, a repeat of one or more of the natural gas fired tests was conducted on a "dirty" boiler to obtain information on the effects of long term coal firing on the thermal performance of the boiler when firing natural gas. A summary of the natural gas baseline test results are presented in Table 2.2.

Boiler efficiencies were calculated based on the ASME PTC 4.1 heat loss method. The boiler efficiency envelope contains the boiler, air preheater and TCS mill. Steam losses from the calorimeter (used to measure steam quality) and sensible heat loss from the blowdown are not included in the boiler efficiency calculations. These will be classified as system losses in the economic evaluation. An example of the efficiency calculation is given in Appendix A. Data was collected on a Keithly Data Acquisition System (DAS) and was logged every 30 seconds. In addition board data was taken at 30 minute intervals as a back up. The parameters currently logged by the DAS included the following:

· Emissions	O2 (%)	
	CO (ppm)	
	CO2 (%)	
	SO2 (ppm)	
	NOx (ppm)	
· Flows	Natural Gas (lb/hr)	
	Natural Gas (Btu/hr, calc)	
	Steam (lb/hr)	
	Blowdown (lb/hr)	
	Primary Air (CFM)	
· Pressures	Bagfilter Delta (inches H_2O)	
	Furnace Draft (inches H_2O)	
	Steam (psig)	
	Natural Gas (psig)	
	Air heater delta (inches H_2O)	
· Temperatures	Ambient	(°F)
	Air heater entrance	(°F)
	Air heater exit	(°F)
	Windbox	(°F)
	Flue gas boiler exit	(°F)
	Flue gas air heater exit	(°F)
	Bagfilter inlet	(°F)
	Bagfilter outlet	(°F)

Summary of Natural Gas Fired Baseline Testing					
TEST/DESCRIPTION:	NO. 1	NO. 2	NO. 3	NO. 4	NO. 10
	100% load	100% load	100% load	75% load	100% load
	2% O2, 6h	3% O2, 6h	1% O2, 6h	2% O2, 6h	2% O2, 2h
	Max.100/100	Max.100/100	Max.100/100	Max.100/100	Max.50/100
WATER/STEAM SIDE					
Steam flow rate; lb/h	14,616	14,542	14,496	10,502	14,488
Water temperature into boiler; °F	224	227	219	185	217
Drum pressure; psig	219	220	220	220	219
Calorimeter temperature; °F	316	317	317	316	317
Steam temperature; °F	394	394	394	393	394
Steam quality; %	99.99	100.05	100.05	100.00	100.05
Blowdown rate; lb/h	3,237	3,244	3,244	3,244	3,237
AIR,FUEL, FLUE GAS SIDE					
Natural gas flow rate; lb/h, MMBtu/h	741, 17.3	741, 17.3	739, 17.2	558,13.0	739, 17.2
Coal flow rate; lb/h, MMBtu/h	Not Applicable (NA)	NA	NA	NA	NA
Furnace outlet temperature; °F	569	573	564	510	566
Gas temperature leaving air heater; °F	348	349	340	302	349
Air temperature entering air heater; °F	76	72	70	67	70
Air temperature leaving air heater; °F	365	363	364	347	375
Air temperature into boiler; °F	338	334	335	314	348
Ash content of particulate; %	NA	NA	NA	NA	NA
Carbon content of furnace ash; %	NA	NA	NA	NA	NA
HHV of fly ash; Btu/lb	NA	NA	NA	NA	NA
HHV of furnace ash; Btu/lb	NA	NA	NA	NA	NA
Combustion air flow; acfm	13,842	14,487	12,933	10,372	13,670
Boiler draft; in H2O	-0.08	-0.10	-0.06	-0.08	-0.07
Boiler efficiency; %	82.9	83.2	83.2	83.6	86.4
Relative humidity, %	60	60	60	60	60
Mill air flow rate; lb/h	847	859	723	1,019	2,170
Mill outlet temperature; °F	67	67	63	67	69
Natural gas temperature; °F	71	69	68	68	68
EMISSIONS					
O2; %	2.1	3	1	2	1.9
CO; ppm	5	12	33	25	20
CO2; %	11.3	11.1	11.7	11.3	11.2
SO2; ppm	NA	NA	NA	NA	NA
NOx; ppm	159	183	173	147	153
Particulates; gr/SCF	NA	NA	NA	NA	NA
O2 before and after air heater; %,%	2.1, Not Measured(NM)	3, NM	1.0, NM	2, NM	1.9, NM
ECONOMIC ANALYSIS DATA					
ID fan power consumption; w/h	28.9 A	33 A	NM	NM	NM
FD fan power consumption; w/h	12.2 A	13.5 A	NM	NM	NM
Pulverizer power consumption; w/h	NA	NA	NA	NA	NA
Booster fan power consumption; w/h	3.1 A @ 20Hz	3.2 A @20 Hz	NM	NM	5.5 A@ 65 Hz
Ash collection power consumption; w/h	NA	NA	NA	NA	NA
Crusher power consumption; w/h	NA	NA	NA	NA	NA
Reddler conveyor power consumption; w/h	NA	NA	NA	NA	NA
Feed screw power consumption; w/h	NA	NA	NA	NA	NA
Feedwater pump power comsumption; w/h	21.4 A	21.9 A	NM	20.1 A	20.5 A
Total air usage; scfm (Pilot burner)	24.50	24.00	25.50	25.00	27.00
Maximum load (derating); %	98.09	97.60	97.29	NA	97.23
Coal related downtime	NA	NA	NA	NA	NA

Table 2.2 Summary of Natural Gas Fired Baseline Testing

DATE/DESCRIPTION:	NO. 11	NO. 12	NO. 13	NO. M1	NO. M2
	100% load	100% load	100% load	75% load	75% load
	2% O2,2h	2% O2, 2h	2% O2,2h	3% O2, 5.5h	1% O2, 2h
	Max,100/50	Med,100/100	Min,100/100	Max,100/100	Max,100/100
WATER/STEAM SIDE					
Steam flow rate: lb/h	14,484	14,663	14,707	11,057	11,201
Water temperature into boiler: °F	222	235	227	222	224
Drum pressure: psig	223	219	219	217	219
Calorimeter temperature: °F	317	317	317	316	317
Steam temperature: °F	395	394	394	392	393
Steam quality: %	100.02	100.05	100.05	100.01	100.06
Blowdown rate: lb/h	3,265	3,237	2,549	3,224	2,548
AIR,FUEL, FLUE GAS SIDE					
Natural gas flow rate: lb/h, MMBtu/h	745, 17.4	713,16.6	741, 17.3	553, 12.9	557, 13.0
Coal flow rate: lb/h, MMBtu/h	NA	NA	NA	NA	NA
Furnace outlet temperature: °F	567	567	563	526	517
Gas temperature leaving air heater: °F	346	340	341	305	299
Air temperature entering air heater: °F	76	77	69	61	64
Air temperature leaving air heater: °F	364	365	360	346	347
Air temperature into boiler: °F	334	338	334	317	314
Ash content of particulate: %	NA	NA	NA	NA	NA
Carbon content of furnace ash: %	NA	NA	NA	NA	NA
HHV of fly ash: Btu/lb	NA	NA	NA	NA	NA
HHV of furnace ash: Btu/lb	NA	NA	NA	NA	NA
Combustion air flow: lb/h	12,195	13,189	14,042	9,383	10,126
Boiler draft: in H2O	-0.03	-0.05	-0.05	-0.003	0.002
Boiler efficiency: %	83.4	83.7	84	83.1	83.6
Relative humidity, %	60	60	60	60	60
Mill air flow rate: acfm	654	708	705	689	663
Mill outlet temperature: °F	64	68	65	63	60
Natural gas temperature: °F	72	71	69	70	70
EMISSIONS					
O2: %	2	1.9	2	3	1.1
CO: ppm	25	23	20	32	24
CO2: %	11.3	11.5	11.7	10.8	11.8
SO2: ppm	NA	NA	NA	NA	NA
NOx: ppm	166	187	174	196	186
Particulates: gr/SCF	NA	NA	NA	NA	NA
O2 before and after air heater: %,%	2, NM	1.9, NM	2.0,NM	3, NM	1.1, NM
ECONOMIC ANALYSIS DATA					
ID fan power consumption: w/h	NM	NM	NM	NM	NM
FD fan power consumption: w/h	NM	NM	NM	NM	NM
Pulverizer power consumption: w/h	NA	NA	NA	NA	NA
Booster fan power consumption: w/h	3.2 A@20 Hz	NM	NM	3.3 A@20 Hz	3.3 A@20 Hz
Ash collection power consumption: w/h	NA	NA	NA	NA	NA
Crusher power consumption: w/h	NA	NA	NA	NA	NA
Reddler conveyor power consumption: w/h	NA	NA	NA	NA	NA
Feed screw power consumption: w/h	NA	NA	NA	NA	NA
Feedwater pump power comsumption: w/h	19.2 A	NM	NM	19.9 A	19.9 A
Total air usage: scfm (Pilot burner)	26.00	24.00	24.20	26.00	27.00
Maximum load (derating): %	97.21	98.41	98.70	NA	NA
Coal related downtime	NA	NA	NA	NA	NA

Table 2.2 (cont.) Summary of Natural Gas Fired Baseline Testing

Natural gas	(°F)
Feedwater	(°F)
High pressure steam	(°F)
Calorimeter	(°F)
Mill Entrance (air)	(°F)
Mill Exit (air)	(°F)
Booster air fan exit	(°F)
Primary air at burner	(°F)

During the data analysis, data from each test was checked to verify that the boiler was operating at steady state conditions during the test period. Examples of the steady state conditions are shown for Test No. 2 in Figures 2.1, 2. 2 and 2.3. Figure 2.1 shows both O2 and CO2 emissions for the 6 hour period while Figure 2.2 shows the CO and NO_X emissions over the same period. The boiler exit gas temperature is shown in Figure 2.3. As can be seen in each of these figures, the system was at steady state conditions during the test. There was a period where the O_2 increased for a short time. This data was removed prior to averaging.

Although the boiler reached steady state operation, the steam production varied around the 14,500 lb/hr average approximately $\pm$ 1000 Lbs/hr (~ $\pm$ 7%). Figure 2.4 shows steam production vs. time over a one hour period during Test No. 2. Since the swings are cyclic, it was believed that they were related to the steam control valve that permits steam to enter the University steam distribution line. Another potential source of the swings could be a cyclical nature of the feedwater inlet. In any case, it was concluded that the steam production swings were a function of water or steam flow, and not due to boiler operation.

In addition to the data taken by the data logger and manually, for Tests No. 1 and 2, in-furnace suction pyrometry measurements were taken. Figure 2.5 gives a plan view of the demonstration boiler which shows the locations of the suction pyrometer temperature measurements. The results are shown in Table 2.3 as well as Figure 2.6 and 2.7. Temperature readings were reported to the nearest 50 degrees. Of particular interest are the "cold" spots in the corners of the left hand wall (when facing the boiler front). These could indicate areas where the furnace volume was not being utilized. Also, the average furnace temperatures for Test #1 were slightly higher than those for Test #2. Test #1 was run at a lower excess air (less mass flow) than Test #2 and therefore the temperatures were expected to be higher.

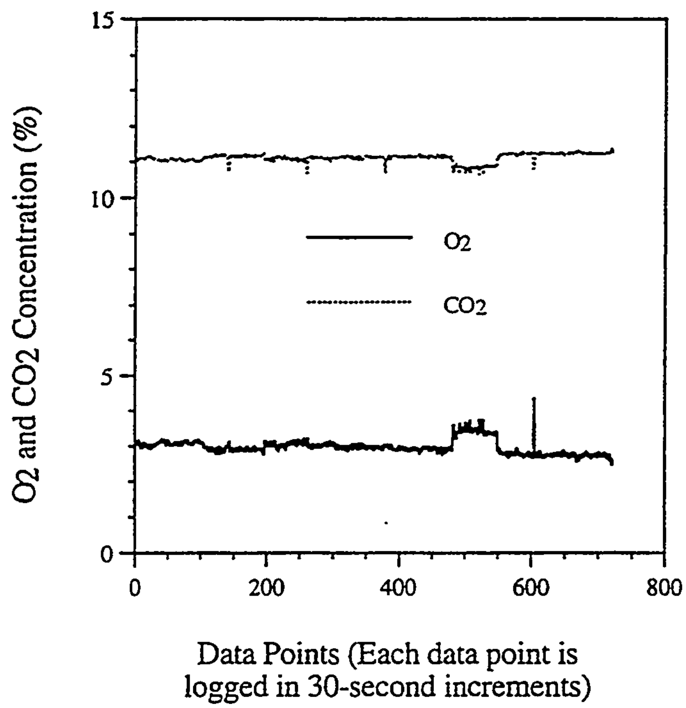


Figure 2.1 O_2 and CO_2 Emissions for Test #2

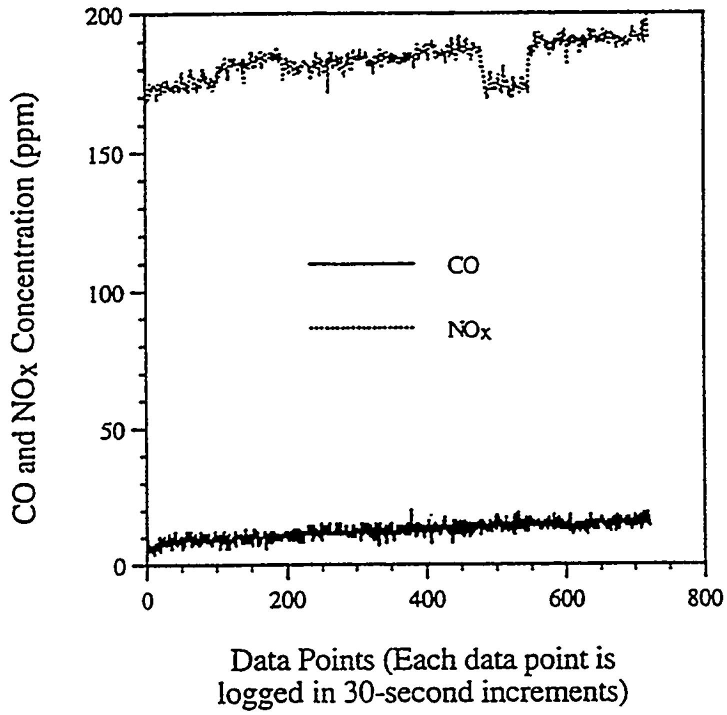


Figure 2.2 CO and NO_x Emissions for Test #2

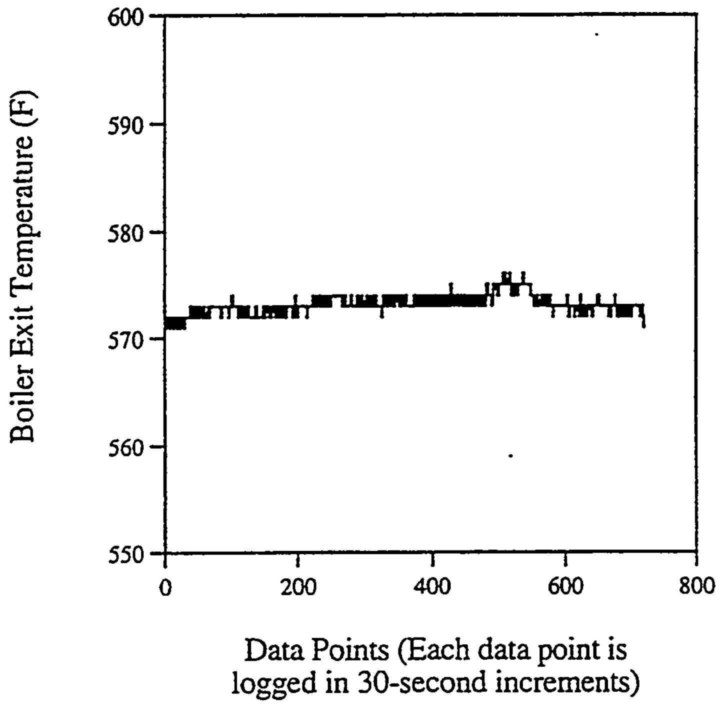


Figure 2.3 Boiler Exit Gas Temperature During Test #2

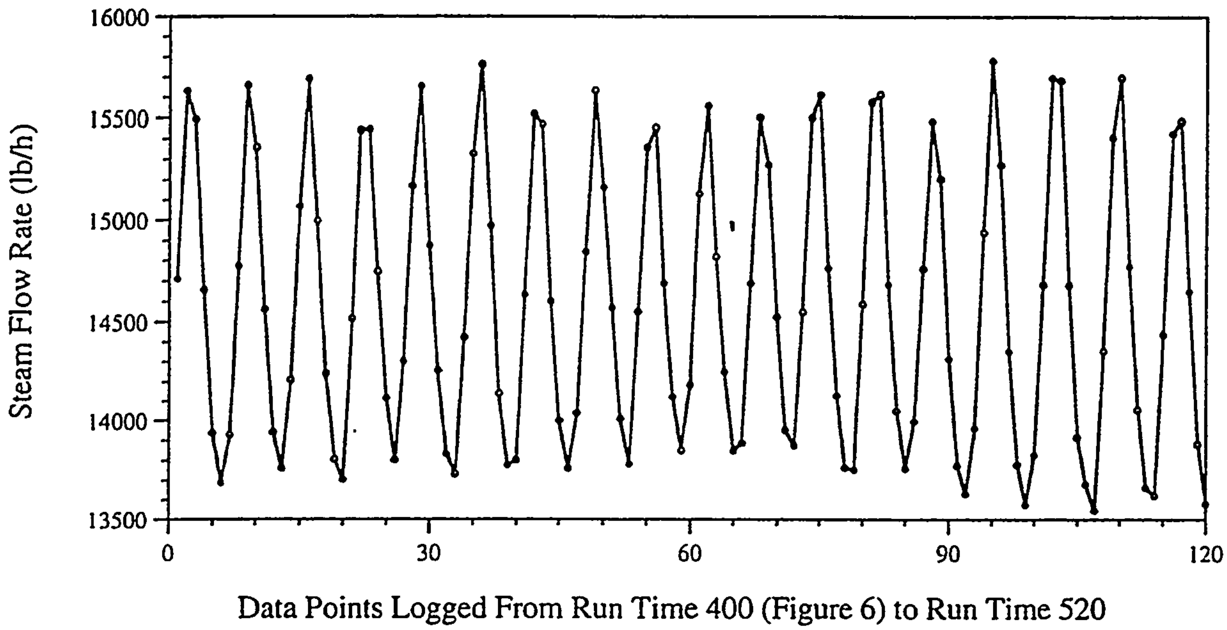


Figure 2.4 Steam Production During Test #2

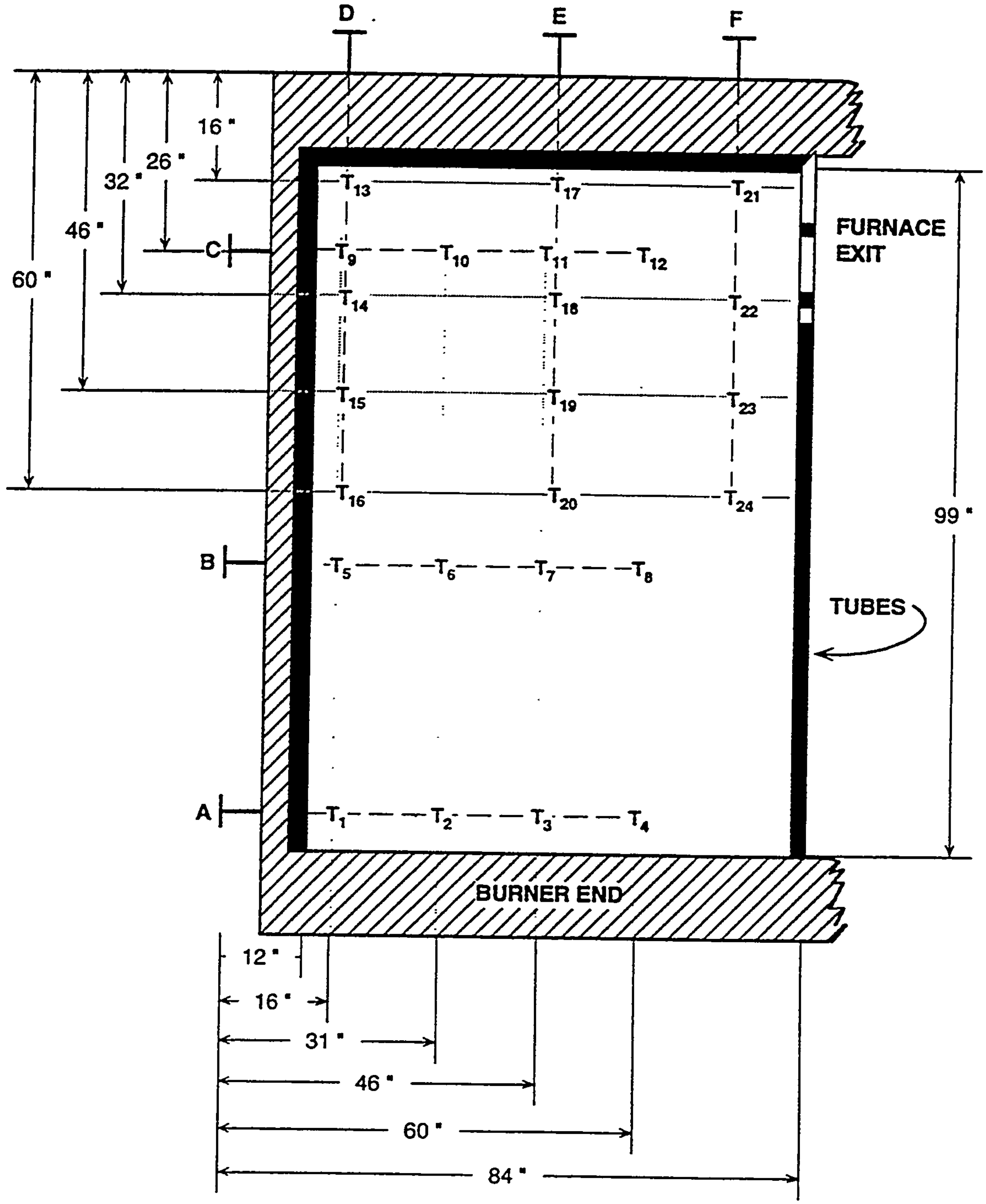


Figure 2.5 Plan View of Demonstration Boiler

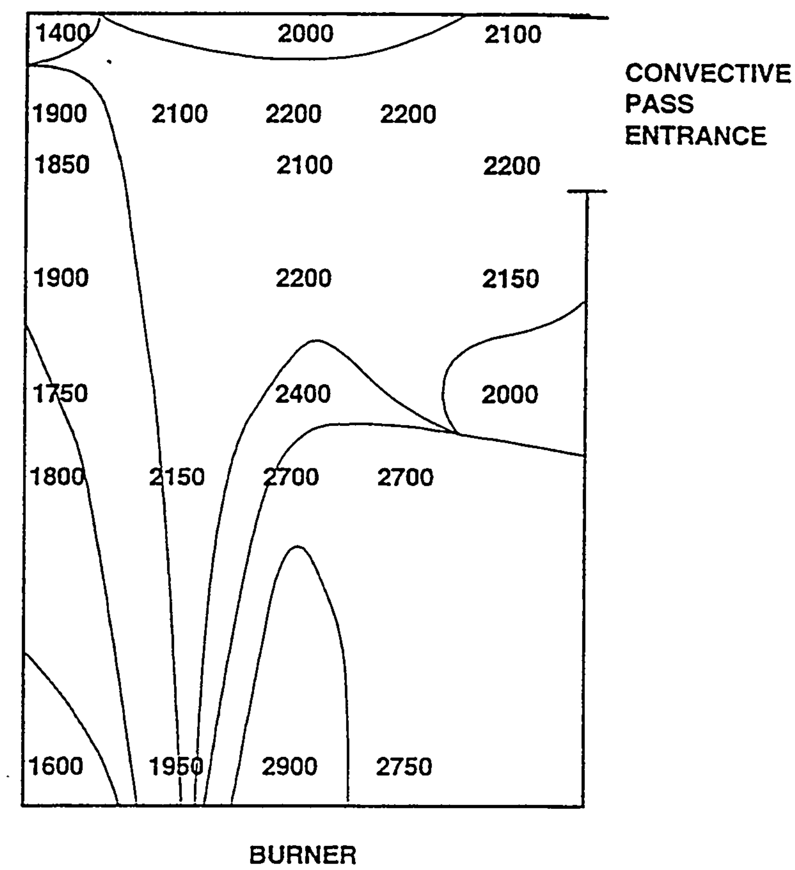


Figure 2.6 Gas Temperatures in the Demonstration Boiler During Test #1

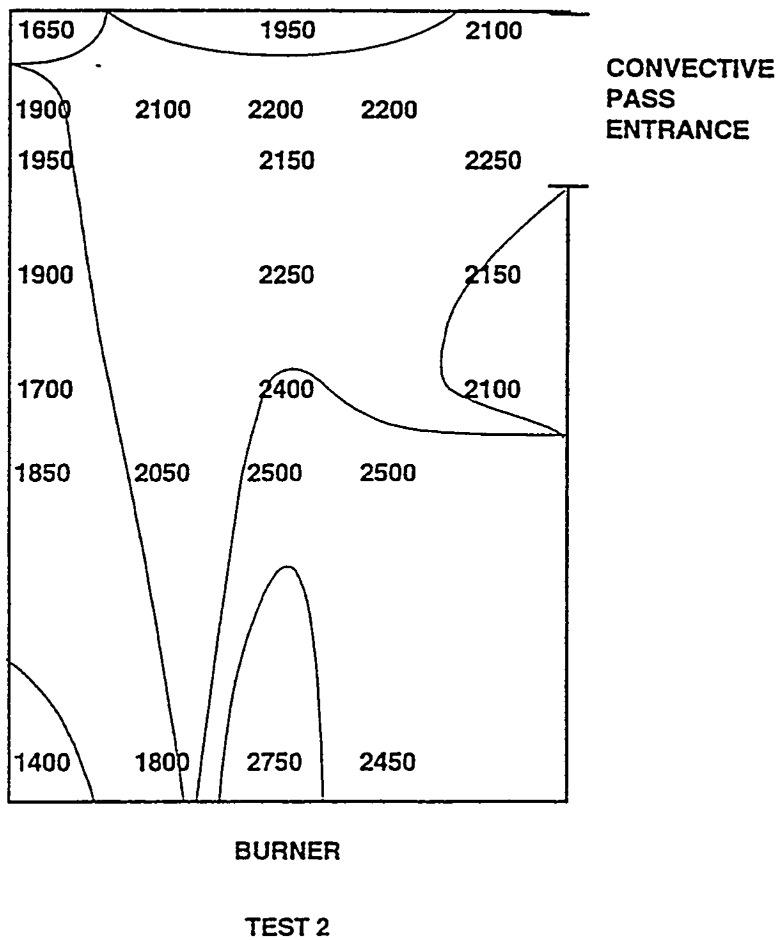


Figure 2.7 Gas Temperatures in the Demonstration Boiler During Test #2

Port	Thermocouple Number	Temperature (°F) Test #1	Test #2
A	T_1	1,591	1,415
	T_2	1,945	1,785
	T_3	2,905	2,745
	T_4	2,725	2,425
B	T_5	1,755	1,835
	T_6	2,145	2,035
	T_7	2,665	2,495
	T_8	2,665	2,475
C	T_9	1,885	1,875
	T_{10}	2,075	2,095
	T_{11}	2,175	2,215
	T_{12}	2,185	2,245
D	T_{13}	1,365	1,635
	T_{14}	1,835	1,935
	T_{15}	1,865	1,905
	T_{16}	1,725	1,665
E	T_{17}	1,975	1,945
	T_{18}	2,095	2,145
	T_{19}	2,175	2,245
	T_{20}	2,365	2,395
F	T_{21}	2,095	2,095
	T_{22}	2,200	2,235
	T_{23}	2,125	2,145
	T_{24}	1,995	2,115

Table 2.3 Gas Temperatures in the Demonstration Boiler

The test results are presented in Table 2.2. As previously discussed, all tests were run at either 100% load or 75% load. Tests were performed over an excess O_2 range of 1% - 3%, three tertiary air swirl levels and three variations of secondary air to tertiary air mass flow split.

At 100% load, the NOx values ranged from a high of 187 ppm (0.22 Lbs/MBtu) to a low of 153 ppm (0.18 Lbs/MBtu). At 75% load, NO_x varied from a high of 196 ppm (0.24 Lbs/MBtu) to a low of 147 ppm (0.17 Lbs/MBtu). These values are typical for a gas burner using preheated combustion air. With the addition of flue gas recirculation, the NO_x levels of this burner could be reduced, however it is not currently designed for flue gas recirculation.

Boiler efficiency calculations indicated that boiler operating conditions had an effect on efficiency. Test Nos. 1, 10, 11, 12 and 13 were all run at the same excess air and firing rate (2% and 17.2 MBtu/hr, respectively) with variations on air mass flow splits and tertiary air swirl level. The efficiency calculations show that there is no significant difference due to either changing the tertiary air swirl level or the air splits. At the 17.2 MBtu/hr firing rate and 2% excess oxygen the boiler efficiencies ranged from 83.0% to 83.2% which is not a significant difference. There are efficiency differences for both load and excess air, however. Data trends for boiler efficiency are shown for both the boiler load and excess air. This trend is shown in Figure 2.8. The data shows that boiler efficiencies are higher at the 75% firing rate and that as excess air increases, the boiler efficiency decreases.

2.2 Other Variations of Natural Gas Operation

2.2.1 Natural Gas Co-firing Tests

While awaiting booster fan modifications, a series of tests were conducted to determine what effects natural gas co-firing had on coal combustion efficiency. These tests were run at 45, 30, 15 and 0% gas co-firing support. The percentages of fuel input are on a heat input basis. All tests were performed at O_2 levels of ~3%. Results of this testing are shown in Table 2.4 and graphically in Figures 2.9, 2.10, and 2.11. They show that coal combustion efficiency increased from 94.4% to 97.4% from the 0% support to 45% support. In addition, the gaseous emissions data show that CO, SO_2 and NO_x all decrease with increasing levels of natural gas co-firing.

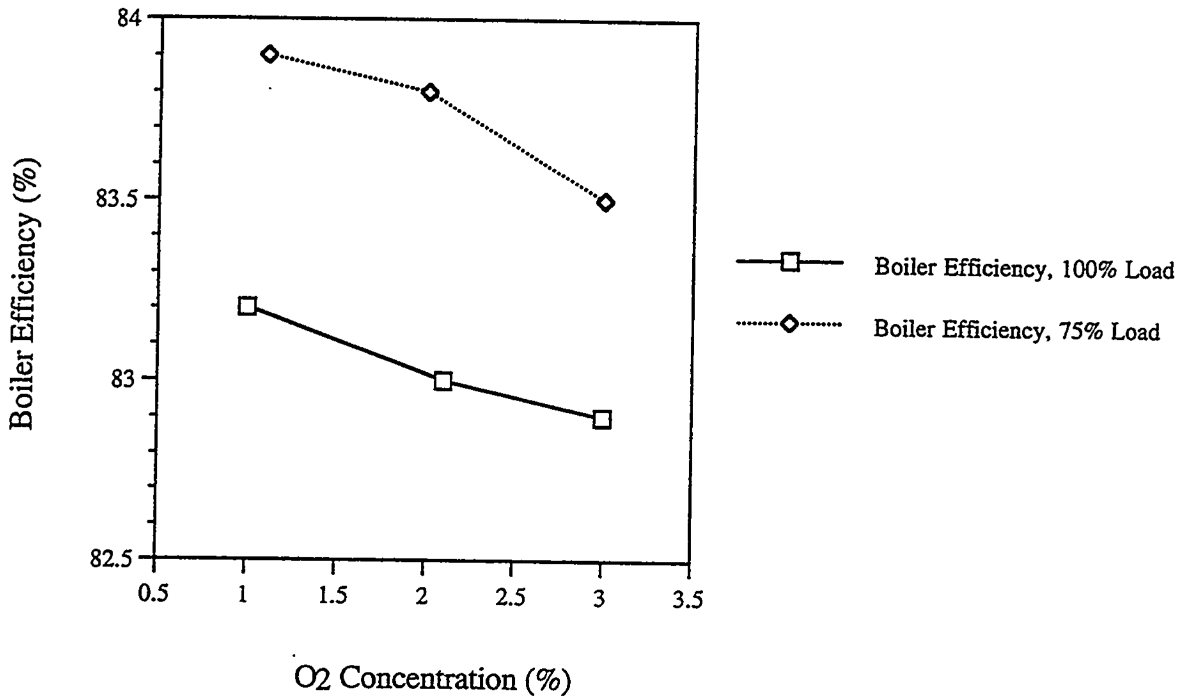


Figure 2.8 Boiler Efficiency as a Function of O_2 Concentration for 75% and 100% Load

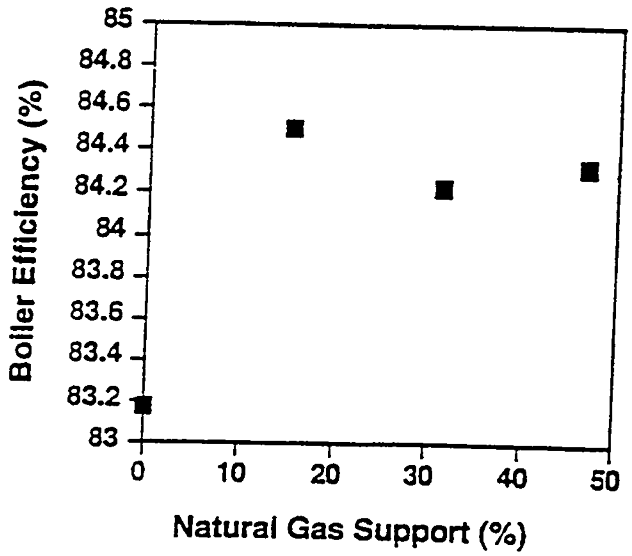


Figure 2.9 **Boiler Efficiency as a Function of Natural Gas Support Level**

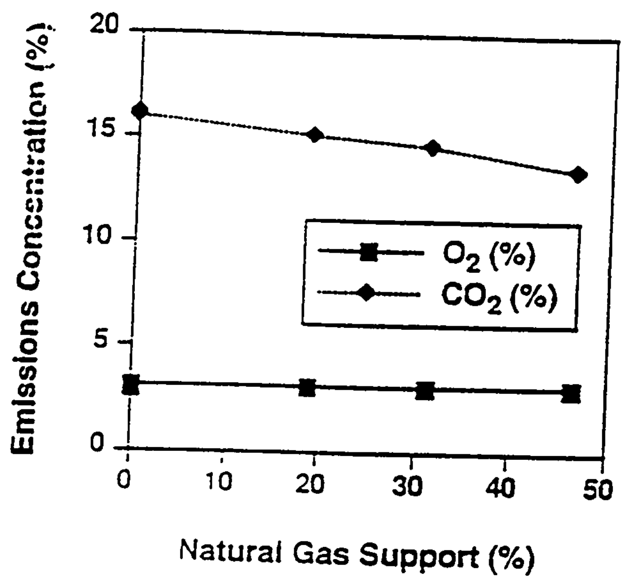


Figure 2.10 Concentration of O_2 and CO_2 in the Flue Gas as a Function of the Level of Natural Gas Support

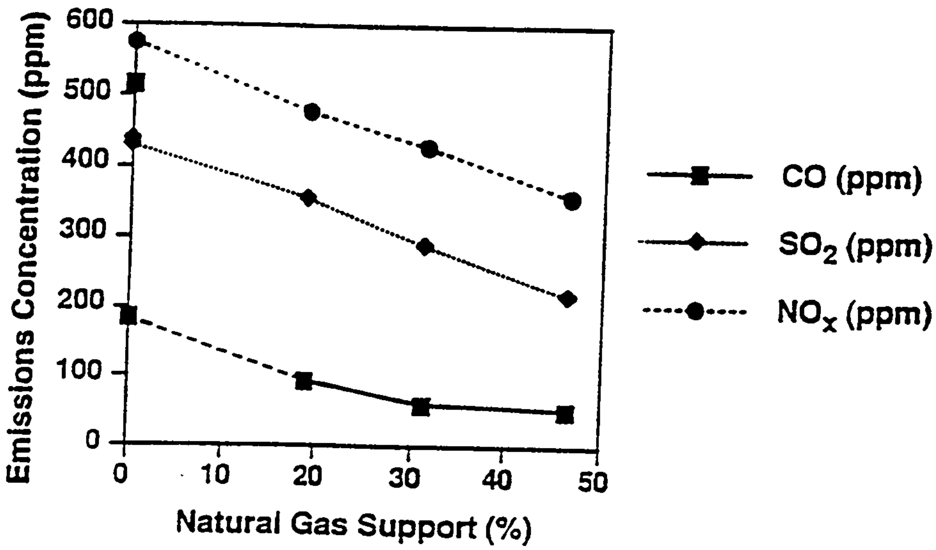


Figure 2.11 Emission of CO, SO2, NOx as a Function of the Level of Natural Gas Support

Table 2.4. Summary of Natural Gas Cofiring Testing

TEST/DESCRIPTION:	10/18/93 45% nat. gas no football; RO-II; medium swirl; 1.75 h	10/21/93 30% nat. gas no football; RO-II; medium swirl; 2h	10/22/93 15% nat. gas no football; RO-II; medium swirl; 2h	10/22/93 0% nat. gas no football; RO-II; medium swirl; 0.75 h
WATER/STEAM SIDE				
Steam flow rate; lb/h	13,630	13,617	13,319	7,063
Water temperature into boiler; °F	233	224	226	221
Drum pressure; psig	221	224	226	225
Calorimeter temperature; °F	209	318	318	320
Steam temperature; °F	395	395	396	398
Steam quality; %	93.79	100.08	100.07	100.15
Blowdown rate; lb/h	2,557	2,576	2,587	1,470
AIR,FUEL, FLUE GAS SIDE				
Natural gas flow rate; lb/h, MMBtu/h	342, 7.98	229, 5.36	142, 3.32	NA
Coal flow rate; lb/h, MMBtu/h	675, 9.19	864, 11.76	1053, 14.23	1215, 16.5
Air temperature entering air heater; °F	71	77	60	69
Air temperature leaving air heater; °F	368	371	369	390
Air temperature into boiler; °F	340	343	338	357
Furnace outlet temperature; °F	567	575	580	604
Gas temperature leaving air heater; °F	349	354	350	363
Bagfilter inlet temperature; °F	333	330	332	343
Bagfilter outlet temperature; °F	306	305	303	309
Ash content of particulate; %	Not Measured (NM)	NM	NM	NM
Carbon content of furnace ash; %	NM	NM	NM	NM
HHV of fly ash; Btu/lb	NM	NM	NM	NM
HHV of furnace ash; Btu/lb	NM	NM	NM	NM
Combustion air flow; lb/h	16119	16,182	16,745	15,241
Boiler draft; in H2O	-0.01	0.02	0.02	0.04
Boiler efficiency; %	84.33	84.23	84.51	83.17
Relative humidity, %	60	60	60	60
Mill air flow rate; acfm	1,740	1,713	1,561	1,502
Mill inlet temperature; °F	77	77	73	77
Mill outlet temperature; °F	249	233	233	248
Burner inlet temperature; °F	180	182	185	195
Natural gas temperature; °F	82	75	71	Not Appl. (NA)
Coal combustion efficiency; %	97.4	96	96.2	94.4
EMISSIONS				
O2; %	3	3	3.1	2.9
CO; ppm	53	62	94	515
CO2; %	13.5	14.6	15.1	16.1
SO2; ppm	217	287	353	435
NOx; ppm	357	430	478	594
Particulates; gr/SCF	NM	NM	NM	NM
O2 before and after air heater; %,%	3, NM	3, NM	3.1, NM	2.9, NM
ECONOMIC ANALYSIS DATA				
ID fan power consumption; w/h	32.6 A	33.7 A	32.9 A	31.7 A
FD fan power consumption; w/h	13.0 A	12.9 A	12.9 A	12.6 A
Pulverizer power consumption; w/h	NM	NM	NM	NM
Booster fan power consumption; w/h	4.4 A @45Hz	6 A @60 Hz	6.4 A @62 Hz	5.2 @ 62 HZ
Ash collection power consumption; w/h	NM	NM	NM	NM
Crusher power consumption; w/h	NM	NM	NM	NM
Reddler conveyor power consumption; w/h	NM	NM	NM	NM
Feed screw power consumption; w/h	NM	NM	NM	NM
Feedwater pump power comsumption; w/h	18.6 A	18.7 A	18.2 A	17.3 A
Total air usage; scfm (Pilot burner)	25.00	26.00	25.00	32.00
Maximum load (derating); %	91.48	91.39	89.39	47.40
Coal related downtime	Not Determined (ND)	ND	ND	ND

Table 2.4 Summary of Natural Gas Cofiring Testing

2.2.2 Clean vs "Dirty" Boiler Testing

In October (10/10/93) and early November (11/09/93), tests were conducted on natural gas in a clean boiler. The furnace walls were not cleaned prior to this testing, however the convective sootblower was used. This testing was conducted to determine if there was any performance degradation on natural gas due to previously firing coal in the boiler. These tests were compared to the Natural Gas Baseline Test No. 2 and the results are shown in Table 2.5. There were no significant differences in the data between tests. The boiler efficiencies for the two "dirty" tests were 81.8% (@4% O_2) and 82.4 % (@2.8% O_2) which compares to 82.9% (@ 3% O_2) efficiency on the clean boiler. The boiler outlet temperatures were also similar at 591°F and 573 °F for the two "dirty" boiler tests vs 576°F for the clean boiler test. It should be noted that the two dirty boiler tests had firing rates which were 1% higher (0.2 MBtu/hr) than the clean boiler test.

Table 2.5. Summary of Natural Gas-Fired Testing in the Demonstration Boiler with Clean Tubes and After Coal Was Fired (Dirty Tubes)			
TEST/DESCRIPTION:	Baseline #2	10/20/93	11/9/93
	100% nat. gas	100% nat. gas	100% nat. gas
	3% O2, 6h	dirty boiler'	dirty boiler'
	Max. 100/100	5.5 h	4 h
WATER/STEAM SIDE			
Steam flow rate; lb/h	14,542	14,769	14,314
Water temperature into boiler; °F	227	226	216
Drum pressure; psig	220	224	224
Calorimeter temperature; °F	317	318	311
Steam temperature; °F	394	395	389
Steam quality; %	100.05	100.08	99.12
Blowdown rate; lb/h	3,244	2,577	2,572
AIR,FUEL, FLUE GAS SIDE			
Natural gas flow rate; lb/h, MMBtu/h	741, 17.3	749,17.5	749, 17.48
Coal flow rate; lb/h, MMBtu/h	Not Appl.(NA)	NA	NA
Air temperature entering air heater; °F	72	65	52
Air temperature leaving air heater; °F	363	366	352
Air temperature into boiler; °F	334	338	325
Furnace outlet temperature; °F	573	591	576
Gas temperature leaving air heater; °F	349	362	357
Bagfilter inlet temperature; °F	336	345	345
Bagfilter outlet temperature; °F	309	315	316
Ash content of particulate; %	NA	NA	NM
Carbon content of furnace ash; %	NA	NA	NM
HHV of fly ash; Btu/lb.	NA	NA	NM
HHV of furnace ash; Btu/lb	NA	NA	NM
Combustion air flow; lb/h	14,487	14,486	15,602
Boiler draft; in H2O	-0.1	-0.02	0.03
Boiler efficiency; %	82.9	82.4	81.84
Relative humidity, %	60	60	60
Mill air flow rate; acfm	859	314	397
Mill inlet temperature; °F	67	62	53
Mill outlet temperature; °F	67	62	52
Burner inlet temperature; °F	69	60	49
Natural gas temperature; °F	69	66	60
EMISSIONS			
O2; %	3	2.8	4.2
CO; ppm	12	15	12
CO2; %	11.1	10.9	10.1
SO2; ppm	NA	NA	NA
NOx; ppm	183	190	NM
Particulates; gr/SCF	NA	NA	NM
O2 before and after air heater; %,%	3.0, NM	2.8, NM	4.2, NM
ECONOMIC ANALYSIS DATA			
ID fan power consumption; w/h	33 A	33.2 A	34.9 A
FD fan power consumption; w/h	13.5 A	13.5 A	13.6 A
Pulverizer power consumption; w/h	NA	NM	NM
Booster fan power consumption; w/h	3.2 A @ 20Hz	3.2 A @ 20Hz	3.0 A @ 15Hz
Ash collection power consumption; w/h	NA	NA	NM
Crusher power consumption; w/h	NA	NA	NM
Reddler conveyor power consumption; w/h	NA	NA	NM
Feed screw power consumption; w/h	NA	NA	NM
Feedwater pump power comsumption; w/h	21.9 A	19.6 A	21.3 A
Total air usage; scfm (Pilot burner)	24.00	24.00	24.00
Maximum load (derating); %	97.60	99.12	96.07
Coal related downtime	NA	NA	ND

Table 2.5 Summary of Natural Gas Firing- Clean vs "Dirty" System

3.0 System Integration

3.1 System Hardware Optimization and Testing

At the conclusion of baseline natural gas testing, the boiler operation returned to hardware optimization and testing. During this phase of the work, a major objective was to obtain consistent, repeatable 100% coal fired runs. This goal, along with minor modifications to the system to increase carbon conversion efficiency resulted in several short term tests being conducted. Table 3.1 gives a summary of the significant results obtained during this testing phase. These tests consist of runs where several hours of steady state operation were achieved.

During this time, three steady state, 100% coal fired tests were conducted, one test in October (1993) and two tests in December (1993). The tests were conducted at firing inputs of 15.1, 10.3 and 11.1 MBtu/hr. The carbon conversion efficiencies for these three tests were 96.2%, 95.4% and 93.8%. Boiler efficiencies for these tests were 84.6%, 83.6% and 83%. NO_X values for these tests were 575, 474 and 313 ppm, respectively. As all tests were run at 3% excess oxygen, this correlates to approximately 0.78, 0.64 and 0.42 Lbs / MBtu. It is clear that as the carbon conversion efficiency increases, the NO_X levels increase. This same trend was also shown in previous testing at ABB.

A summary of the month-by month boiler operation during this period is given below.

October 1993

During this month, emphasis was placed on increasing the carbon conversion efficiency. To accomplish this several items were addressed. The mill speed was increased from 1,940 to 2,080 RPM to reduce coal particle size. The D50 was reduced from about 20 μm to about 8 μm. The D50 is defined as the volume median diameter and was determined using a Malvern 2600 Particle and Droplet Sizer. It is important to note that the samples for these analyses were not obtained using ASTM standards; therefore, they may not have been representative samples.

The increased mill speed resulted in high mill outlet air temperatures and a fire occurred in the coal piping. Consequently, the mill speed was reduced to its previous level before further testing was conducted. In addition, TCS, Inc. began working with

Table 3.1 Summary of Testing Conducted in October, November, and December 1993					
TEST/DESCRIPTION:	10/18/93	10/20/93	10/21/93	10/22/93	10/22/93
	45% nat. gas	100% nat. gas	30% nat. gas	15% nat. gas	0% nat. gas
	no football;		no football;	no football;	no football;
	RO-II; medium	dirty boiler'	RO-II; medium	RO-II; medium	RO-II; medium
	swirl; 1.75 h	5.5 h	swirl; 2h	swirl; 2h	swirl; 0.75 h
WATER/STEAM SIDE					
Steam flow rate; lb/h	13,630	14,769	13,617	13,319	7,063
Water temperature into boiler; °F	233	226	224	226	221
Drum pressure; psig	221	224	224	226	225
Calorimeter temperature; °F	209	318	318	318	320
Steam temperature; °F	395	395	395	396	398
Steam quality; %	93.79	100.08	100.08	100.07	100.15
Blowdown rate; lb/h	2,557	2,577	2,576	2,587	1,470
AIR,FUEL, FLUE GAS SIDE					
Natural gas flow rate; lb/h, MMBtu/h	342, 7.98	749,17.5	229, 5.36	142, 3.32	NA
Coal flow rate; lb/h, MMBtu/h	675, 9.19	Not Appl.(NA)	864, 11.76	1053, 14.23	1215, 16.5
Air temperature entering air heater; °F	71	65	77	60	69
Air temperature leaving air heater; °F	368	366	371	369	390
Air temperature into boiler; °F	340	338	343	338	357
Furnace outlet temperature; °F	567	591	575	580	604
Gas temperature leaving air heater; °F	349	362	354	350	363
Bagfilter inlet temperature; °F	333	345	330	332	343
Bagfilter outlet temperature; °F	306	315	305	303	309
Ash content of particulate; %	Not Measured (NM)	NA	NM	NM	NM
Carbon content of furnace ash; %	NM	NA	NM	NM	NM
HHV of fly ash; Btu/lb	NM	NA	NM	NM	NM
HHV of furnace ash; Btu/lb	NM	NA	NM	NM	NM
Combustion air flow; lb/h	16119	14,484	16,182	16,745	15,241
Boiler draft; in H2O	-0.01	-0.02	0.02	0.02	0.04
Boiler efficiency; %	84.33	82.41	84.23	84.51	83.17
Relative humidity, %	60	60	60	60	60
Mill air flow rate; acfm	1,740	314	1,713	1,561	1,502
Mill inlet temperature; °F	77	62	77	73	77
Mill outlet temperature; °F	249	62	233	233	248
Burner inlet temperature; °F	180	60	182	185	195
Natural gas temperature; °F	82	66	75	71	NA
Coal combustion efficiency; %	97.4	NA	96	96.2	94.4
EMISSIONS					
O2; %	3	2.8	3	3.1	2.9
CO; ppm	53	15	62	94	515
CO2; %	13.5	10.9	14.6	15.1	16.1
SO2; ppm	217	NA	287	353	435
NOx; ppm	357	190	430	478	594
Particulates; gr/SCF	NM	NA	NM	NM	NM
O2 before and after air heater; %,%	3, NM	2.8, NM	3, NM	3.1, NM	2.9, NM
ECONOMIC ANALYSIS DATA					
ID fan power consumption; w/h	32.6 A	33.2 A	33.7 A	32.9 A	31.7 A
FD fan power consumption; w/h	13.0 A	13.5 A	12.9 A	12.9 A	12.6 A
Pulverizer power consumption; w/h	NM	NM	NM	NM	NM
Booster fan power consumption; w/h	4.4 A @45Hz	3.2 A @ 20Hz	6 A @60 Hz	6.4 A @62 Hz	5.2 @ 62 HZ
Ash collection power consumption; w/h	NM	NA	NM	NM	NM
Crusher power consumption; w/h	NM	NA	NM	NM	NM
Reddler conveyor power consumption; w/h	NM	NA	NM	NM	NM
Feed screw power consumption; w/h	NM	NA	NM	NM	NM
Feedwater pump power comsumption; w/h	18.6 A	19.6 A	18.7 A	18.2 A	17.3 A
Total air usage; scfm (Pilot burner)	25.00	24.00	26.00	25.00	32.00
Maximum load (derating); %	91.48	99.12	91.39	89.39	47.40
Coal related downtime	Not Determined (ND)	NA	ND	ND	ND

Table 3.1 Summary of System Hardware Optimization and Testing

Table 3.1 (cont.)

	10/28/93	11/9/93	12/7/93	12/10/93
TEST/DESCRIPTION:	center pipe	100% nat. gas	100% Coal	100% Coal
	no football;	dirty boiler'	no football;	no football;
	4.5 h test	4 h	5 h test	1.5 h test
WATER/STEAM SIDE				
Steam flow rate; lb/h	12,683	14,314	13,334	10,192
Water temperature into boiler; °F	226	216	215	214
Drum pressure; psig	221	224	216	215
Calorimeter temperature; °F	317	311	310	202
Steam temperature; °F	393	389	385	385
Steam quality; %	100.06	99.12	99.83	93.65
Blowdown rate; lb/h	2,557	2,572	2,530	2,526
AIR,FUEL, FLUE GAS SIDE				
Natural gas flow rate; lb/h, MMBtu/h	NA	749, 17.48	NA	NA
Coal flow rate; lb/h, MMBtu/h	1107, 15.07	NA	745, 10.27	821, 11.13
Air temperature entering air heater; °F	62	52	132	132.5
Air temperature leaving air heater; °F	387	352	403	387.6
Air temperature into boiler; °F	353	325	371	351
Furnace outlet temperature; °F	588	576	586	539.3
Gas temperature leaving air heater; °F	359	357	382	348.1
Bagfilter inlet temperature; °F	338	345	372	340.3
Bagfilter outlet temperature; °F	308	316	336	299.8
Ash content of particulate; %	NM	NM	NM	NM
Carbon content of furnace ash; %	NM	NM	NM	NM
HHV of fly ash; Btu/lb	NM	NM	NM	NM
HHV of furnace ash; Btu/lb	NM	NM	NM	NM
Combustion air flow; lb/h	13,973	15,602	9,331	10,390
Boiler draft; in H2O	0.02	0.03	0.01	-0.02
Boiler efficiency; %	84.61	81.82	83.64	83
Relative humidity, %	60	60	60	60
Mill air flow rate; acfm	1,588	397	1,951	374
Mill inlet temperature; °F	75	53	84	82.5
Mill outlet temperature; °F	239	52	232	229.7
Burner inlet temperature; °F	191	49	190	179.1
Natural gas temperature; °F	NA	60	NA	NA
Coal combustion efficiency; %	96.2	NA	95.4	93.8
EMISSIONS				
O2; %	3	4.2	2.9	3.11
CO; ppm	184	13	183	461.5
CO2; %	16	10.1	16.3	15.9
SO2; ppm	430	NA	431	414.8
NOx; ppm	575	NM	474	313.1
Particulates; gr/SCF	NM	NM	NM	NM
O2 before and after air heater; %,%	3, NM	4.2, NM	2.9, NM	3.11,NM
ECONOMIC ANALYSIS DATA				
ID fan power consumption; w/h	31.8 A	34.9 A	31.5 A	28.6 A
FD fan power consumption; w/h	12.4 A	13.7 A	11.9 A	11.0 A
Pulverizer power consumption; w/h	NM	NM	NM	NM
Booster fan power consumption; w/h	6.7 A @ 62 Hz	3.0 A @ 15Hz	10.5A @88 Hz	6.5A @74 Hz
Ash collection power consumption; w/h	NM	NM	NM	NM
Crusher power consumption; w/h	NM	NM	NM	NM
Reddler conveyor power consumption; w/h	NM	NM	NM	NM
Feed screw power consumption; w/h	NM	NM	NM	NM
Feedwater pump power comsumption; w/h	17.5 A	21.4 A	19.8 A	18.5 A
Total air usage; scfm (Pilot burner)	25.00	24.00	25.11	26.00
Maximum load (derating); %	85.12	96.07	89.49	68.40
Coal related downtime	ND	ND	ND	ND

Table 3.1 (Cont.) Summary of System Hardware Optimization and Testing

the supplier of the booster fan to increase the air flow through the mill. Increased air flow was required to keep the mill outlet temperatures at acceptable levels (< 200 °F).

While waiting for the booster fan upgrades, an air injection nozzle was designed to simulate the increased air flow through the burner. This nozzle consisted of a 3/4" pipe inserted through the coal register which injected more air into the primary air zone. One perceived benefit of the increased air at the center of the burner was an increase in carbon conversion efficiency due to earlier mixing of coal and air. It was believed that some valuable insights into burner design/performance might be gained.

Figure 4.1 shows design of air injection nozzle configurations (A - E). The first nozzle injector tested was configuration A. The pipe was inserted into the boiler approximately 2 feet and was perforated. The use of this pipe resulted in a stable flame and a 4 hour test was conducted using this set up. Although the results showed higher combustion efficiencies (~96%), a pipe inserted into the furnace is not considered commercially acceptable. In order to test the increased air flow without inserting a pipe into the furnace, an open ended pipe that entered the boiler (Configuration B) at the exit of the coal nozzle was tried next. The resulting flame was narrow, and impinged on the back wall and was therefore considered unacceptable.

<u>November 1993</u>

Due to the success of the first air injector, this testing continued during the first part of November. None of the remaining configurations tested, C, D, or E were successful and testing was terminated. Part of the problem may have been due to erratic coal feed. In early November the cage mill speed was decreased in order to increase the top size from ~ 1/8" to 1/4". This was done primarily to facilitate better coal handling in the surge bin. The increased top size resulted in segregation at the conveyor outlet and in the surge bin. This segregation created erratic coal feed problems and therefore the cage mill speed was increased to its previous level.

During this month the booster fan was upgraded from 5 to 10 Hp to increase the maximum air flow through the system. Through operating experience, it was determined that the optimum operating conditions from a mill standpoint was approximately 400 cfm as measured at the mill inlet (80 °F). This produced acceptable mill outlet temperatures (~ 200 °F) and pressure drops (4" - 6" wg) and resulted in stable mill operation. Also, via testing experience, it was determined that there are

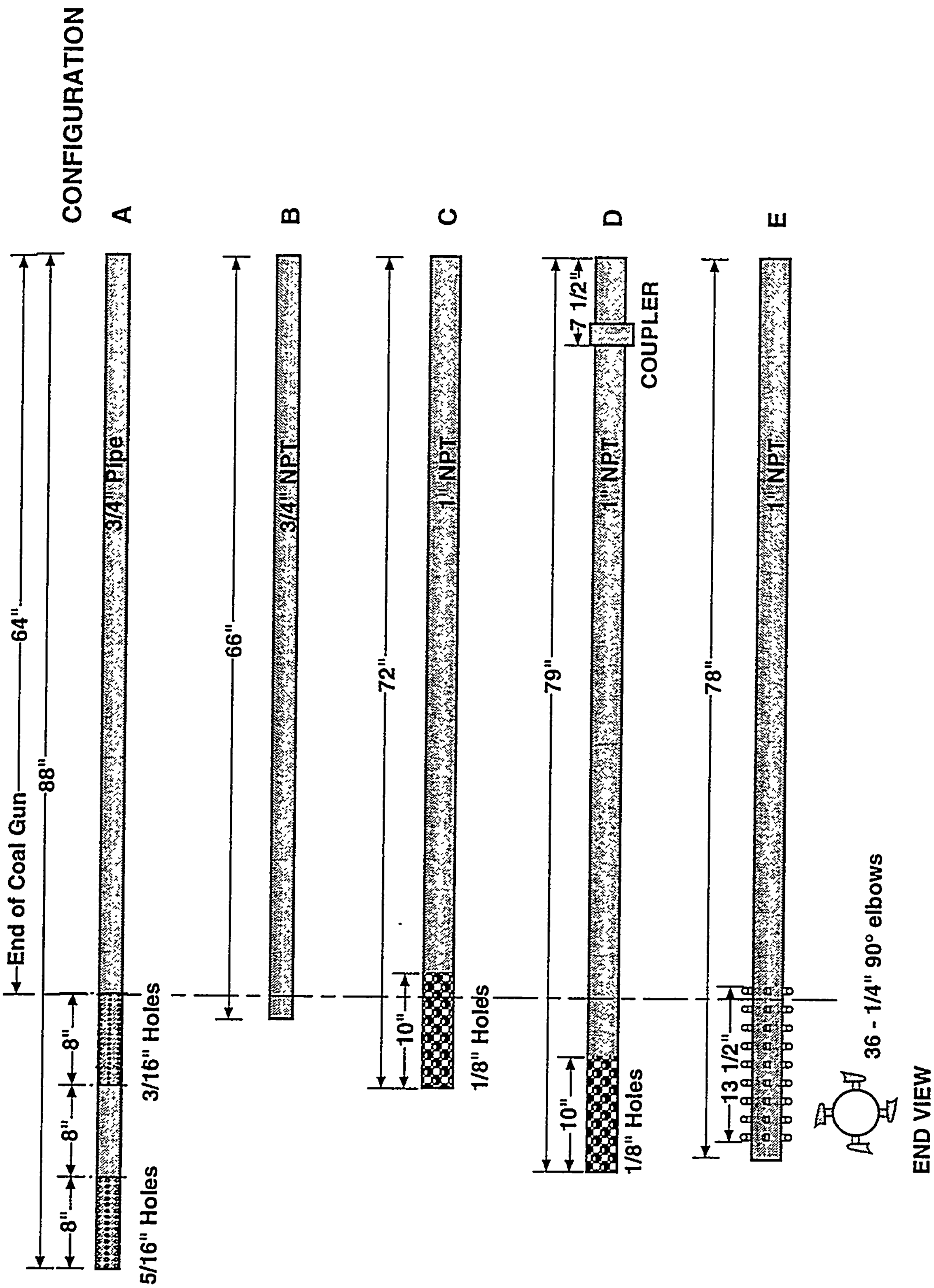


Figure 4.1 Air Injection Nozzle Configurations (A - E)

dynamic interactions between the mill and the booster fan and sudden increases or decreases in the mill air flow results in quick changes in the coal inventory in the mill, thereby causing fluctuations in the coal feed rate.

The burner was designed for a mill air flow of ~300 cfm (at 150 °F), and therefore the actual coal pipe velocities are higher than the design velocities. To accommodate the increased volumetric air flow, the RO II venturi was replaced with a straight 3" pipe.

December 1993

During December several changes were made to the burner and burner piping (see furnace instabilities below). After these changes were made, several tests were conducted. On 12/7/93 a five hour test was conducted on the RO II nozzle at a firing rate of ~ 10.3 MBtu/hr. Another test was conducted at a fuel ratio of 50/50 coal/natural gas and at primary air flow variations of 360 to 400 cfm. These tests were performed to observe any instabilities due to variations in mill air flow. At the tested conditions, no changes were noted.

Another test was conducted on 12/10/93 as a repeat of the test conducted on 12/7/93. The results of the testing are different, however. The combustion efficiency was lower (93.8 vs. 95.4%), the boiler exit temperature was lower (539 °F vs. 586 °F) and steam production was lower (10,200 vs. 13,300). The firing rate was then increased and the boiler/burner became unstable and testing was discontinued. Boiler feed pump problems were noted at the end of the December test period.

3.2 Characterization and Solution of Furnace Instabilities

As noted above, furnace instabilities were observed during the initial testing program. Several potential causes were postulated for these fluctuations: mill/booster fan interactions, coal roping at the burner exit, and coal slugging.

The mill / booster fan interactions were shown to be one cause of the fluctuations. The mill (which contains a fan) and the booster fan are in series. It was observed that the coal flow at the mill outlet reacted to changes in the booster fan settings even at constant coal feed into the mill. Booster fan setting changes resulted in several instances of boiler/ furnace instabilities. This problem was avoided by making incremental changes in the booster fan settings.

One other noted source of burner/ furnace instabilities was an apparent coal "rope" in the fuel line. Such roping can create instabilities due to the fluctuating flame. A coal rope occurs when the coal and primary air segregate and coal dense areas occur in the pipeline. This often occurs in long radius bends where the coal moves to the outside of the pipe due to centrifugal forces. It was theorized that a coal rope might be occurring in this burner because the flame at the exit of the coal nozzle tip was not uniform or concentric; this is indicative of non uniform coal and air mixing in the coal nozzle. At low loads the coal flame typically occupied only half of the tip exit area. The problem decreased with increasing load but did not disappear.

In order to reduce the coal roping thought to be due to the coal piping, the stainless steel flexible hose to the burner was replaced with the original rubber hosing. The stainless steel hose had a large radius of curvature that was believed to be the cause for creating a coal rope. In addition, the guide vanes located at the coal inlet to the burner were adjusted to break up the coal rope. Also, a No. 5 screen was installed at the burner inlet and additional studs were welded onto the center tube. The original studs were to center the pipe in the burner. A total of 18 studs are located on the pipe to break up the rope and evenly distribute the coal flow.

The third potential cause of furnace fluctuations was coal slugging in the piping between the mill and the booster fan. To investigate this, plots of the primary air pressure at burner, CO and O_2 vs. time were generated on days of "good" operation and "bad" operation. In general, the following preliminary conclusions were drawn:

- The primary air pressure at burner (17" to 21" H2O) was slightly higher on unsuccessful days
- The primary air pressure at burner (12.5" to 14" H2O) during successful days exhibited smaller and less frequent fluctuations.
- The CO and O_2 fluctuations were more pronounced during tests on unsuccessful days.

The most important modification that was made to eliminate the roping/slugging problem was an increase in the size of the center spacer tube.

4.0 PROOF OF CONCEPT TEST PROGRAM

A key objective of the proof of concept testing was to determine the operating characteristics of the complete, integrated system in contrast to the operation of the individual components. Although all of the system components installed at demonstration boiler host site were proven in either commercial operation or prior testing, the complete system from micro-fine coal production to steam production at this scale has not been previously demonstrated/proven.

The testing at Penn State indicated areas that should be carefully engineered in a commercial design. Specifically, it was anticipated that if any problems occurred, they would likely be related to the burner (the least developed system component), however, the coal handling and feeding sub-system proved to be a critical component during initial testing, in particular as it responded to wet or frozen coal.

Details of the experimental test program when the system was firing pulverized coal follow:

4.1 Test Program Overview/ Boiler System Operability

This section summarizes the relevant details of boiler operability/coal handling and preparation problems that occurred during January through April, 1994. A detailed day-by-day summary of the proof-of concept test program is given in Appendix B.

During the initial testing period, a number of operational problems regarding boiler system operability were encountered. They were primarily related to the weather (cold, snow), the coal (particle size, moisture content), the burner/boiler system (unstable, low u.v. signal), or mechanical difficulties (feedwater pump, steam valves, etc.).

In January through April '94, there were 85 potential work days (Monday through Friday of each week). Of these 85 days, testing occurred on 62 days. The breakdown by month was 10 days of testing out of a possible 21 days in January, 19 out of 20 in February, 12 out of 23 in March, and 21 out of 21 in April. During the 62 days of testing, there were 79 instances where the boiler was either automatically (e.g., low u.v. signal) or manually shut down (high CO concentration). The causes for boiler shut downs were primarily weather related (frozen coal, etc.) in January and February, and system-related (component failures/ problems) in March and April. A more detailed breakdown of the causes for boiler shutdown is contained in the following monthly summaries.

January

In January, testing occurred during 10 days out of a possible 21 days. Of the 11 days where testing did not occur, there were five days where the University was either shut down or its natural gas supply was shut off due to snow storms and extremely cold weather. Testing was not conducted during the other six days because of mechanical problems (repairing the feedwater pump or repairing broken damper blades/handles).

During the 10 days where testing was conducted, there were 25 instances where the boiler was shut down. Nine of these were the result of burner/boiler instability (i.e., pressure spikes in the boiler, furnace chamber going black, or coal being blown out of the boiler's sight ports), two were due to a low u.v. signal (the uv flame sensor decreasing to 2-5 volts), twelve were due to the loss of coal feed, and two were due mechanical problems. Shutdowns caused by loss of coal feed (total of 12) were comprised of coal ratholing in the surge bin (8), mill overloads (2), and mill vibrations (2). Mill overload and vibration problems were the result of non uniform coal feed to the mill from the screw feeder resulting in 'clumps' of coal dropping into the mill.

February

Testing occurred during 19 days out of a possible 20 days in February. During the 19 days where testing was conducted, there were 33 instances where the boiler was shut down. Two of these were the result of burner/boiler instability, two were due to a low u.v. signal, 23 were due to the loss of coal feed, and six were due to mechanical problems. Shutdowns caused by loss of coal feed (total of 23) were comprised of coal ratholing in the surge bin, bridging, and adhering to the sides (14), screw feeder plugging (4), crusher plugging (2), screen plug at the burner inlet (1), and mill vibrations (2). The mechanical problems (total of 6 instances) included broken windbox damper linkage and handles (1), feedwater pump breakdown (1), malfunctioning oxygen analyzer (2), replacement of forced-draft fan belts (1), and replacement of oil pump(1).

March

Testing occurred during 12 days out of a possible 23 days in March. Testing did not occur on eleven days due to inclement weather, steam valve/regulator repair, delays in receiving coal, or system modifications.

During the 12 days where testing was conducted, there were nine instances where the boiler was shut down. One shutdown was caused by a low u.v. signal, three were due to the loss of coal feed, and five were due to mechanical problems. The mechanical problems (total of 5 instances) included feedwater pump failure (1), excessive draft pressure (1), burner modifications (1), steam regulator/valve repair (1), and mill outlet piping modification (1).

April

Testing occurred on each of the 21 available days in April. There were 14 instances where the boiler was shut down. Five shutdowns were caused by burner/boiler instability, seven were due to low u.v. signal, one was due to the loss of coal feed, and one was due to mechanical problems. Ratholing in the surge bin caused the loss of coal feed. Of the five shutdowns due to burner/boiler instability, three were due to high CO concentration. Six of the seven low u.v. signals were experienced during the two days when the Y-Jet coal gun was tested. A low power spike during a thunderstorm caused the single mechanical problem.

4.2 System Component Operation

4.2.1 Coal Feed System

As documented above, the coal feed system was a major cause of system shutdowns during January and February '94. The primary reason for coal feed problems was the high moisture content of the Brookville Seam coal and its relatively small particle size (Kentucky coal which was tested later in April was not cleaned.). The Brookville coal was cleaned in June, 1993 and was stockpiled at a local coal mine. The reduction of the coal particle size for cleaning, in conjunction with the heavy snowfalls received, resulted in a feedstock that was difficult to handle in the coal hoppers and screw feeder. A discussion of problems encountered with the coal feed system follows.

Table 4.1 contains the Brookville Seam and Kentucky coal particle size distributions

Sieve (U.S. Standard)	Micron Equivalent	Kentucky Coal		Brookville Seam Coal	
		Bottom of Main Hopper	Screw Feeder	Bottom of Main Hopper	Screw Feeder
1"	25,400	84.71	100.00	100.00	100.00
3/4"	19,000	52.28	100.00	98.94	100.00
5/8"	16,000	S.N.U.[a]	S.N.U.	96.68	100.00
1/2"	9,510	37.97	100.00	S.N.U.	S.N.U.
3/8"	12,700	12.34	96.46	72,30	100.00
1/4"	6,350	8.89	92.46	56.47	100.00
No. 4	4,760	S.N.U.	S.N.U.	47.23	100.00
No. 6	3,360	7.04	84.01	38.89	100.00
No. 8	2,380	6.47	76.36	31.42	98.27
No. 12	1,680	S.N.U.	S.N.U.	S.N.U.	96.07
No. 16	1,190	5.49	58.31	17.57	89.74
No. 20	841	5.02	49.60	14.38	81.15
No. 30	595	4.47	40.18	10.31	67.41
No. 40	420	3.99	32.26	7.92	54.33
No. 60	250	3.13	21.13	4.86	26.90
No. 80	177	2.66	16.04	3.18	21.69
No. 100	149	2.47	14.32	2.61	16.95
No. 140	105	2.01	10.07	1.93	11.76
No. 170	88	1.82	8.81	1.40	8.15
No. 200	74	1.64	7.36	0.94	7.15

[a] Sieve Not Used

Table 4.1 Kentucky and Brookville Seam Coal Particle Size Distributions

(PSDs) obtained from sieving. These results are plotted in Figure 4.2 along with PSDs of micronized coal collected at the burner inlet. It should be noted that coal samples were collected prior to the crusher (bottom of main hopper), after the crusher (screw feeder), and after the TCS Mill (Burner inlet). The particle size distributions were determined using sieves except for the burner inlet samples in which case particle size distributions were determined using a Malvern 2600 Particle Sizer, where the results are on a volume, not a weight basis. The as-received Brookville Seam coal was finer than the Kentucky coal as sampled/analyzed from the main hopper and after the crusher (screw feeder). The combination of fines in the Brookville Seam coal coupled with the presence of moisture resulted in handling problems.

Figure 4.3 shows the moisture content of Brookville Seam coal as collected from various sampling locations during testing from September, 1993 to April, 1994. The solid vertical lines separate months and the dashed vertical lines indicate coal delivery dates. Higher coal moisture contents occurred in January and February which correspond to the time frame where the majority of the coal handling problems were encountered. Difficulties in feeding lessened as the coal dried in the hoppers. Higher moisture contents occurred immediately after coal delivery (Samples # 7, 35, 57, and 67). The coal samples collected near the end of the shipment approached 5-6 wt.% moisture. Coal samples containing 5-6 wt.% moisture were handled with relative ease. Thus, there were very few problems encountered in April where the moisture content was 3-6 wt.%.

4.2.2 25-Ton Main Hopper, Crusher, and Redler Conveyor

The Brookville Seam coal delivered into the main hopper during the winter (primarily during January and February) contained considerable moisture due to snow and ice mixed in with the coal. The wet coal blocked the main hopper outlet when transferring coal into the surge bin. The coal feed would stop due to bridging in the main hopper and require banging on the side or poking from the top of the main hopper to regain feed. The wet coal also clogged the cage mill (crusher) resulting in an operator having to open the mill and extract the packed wet coal. The Redler conveyor also tended to bind and, at one point, broke when feeding wet coal. An overload breaker corrected this problem. The breaker shuts down the system and the operator then has the opportunity to correct the problem. With lower moisture in the coal, the feed system tends to operate more reliably. The syntron feeder (vibratory feeder located below

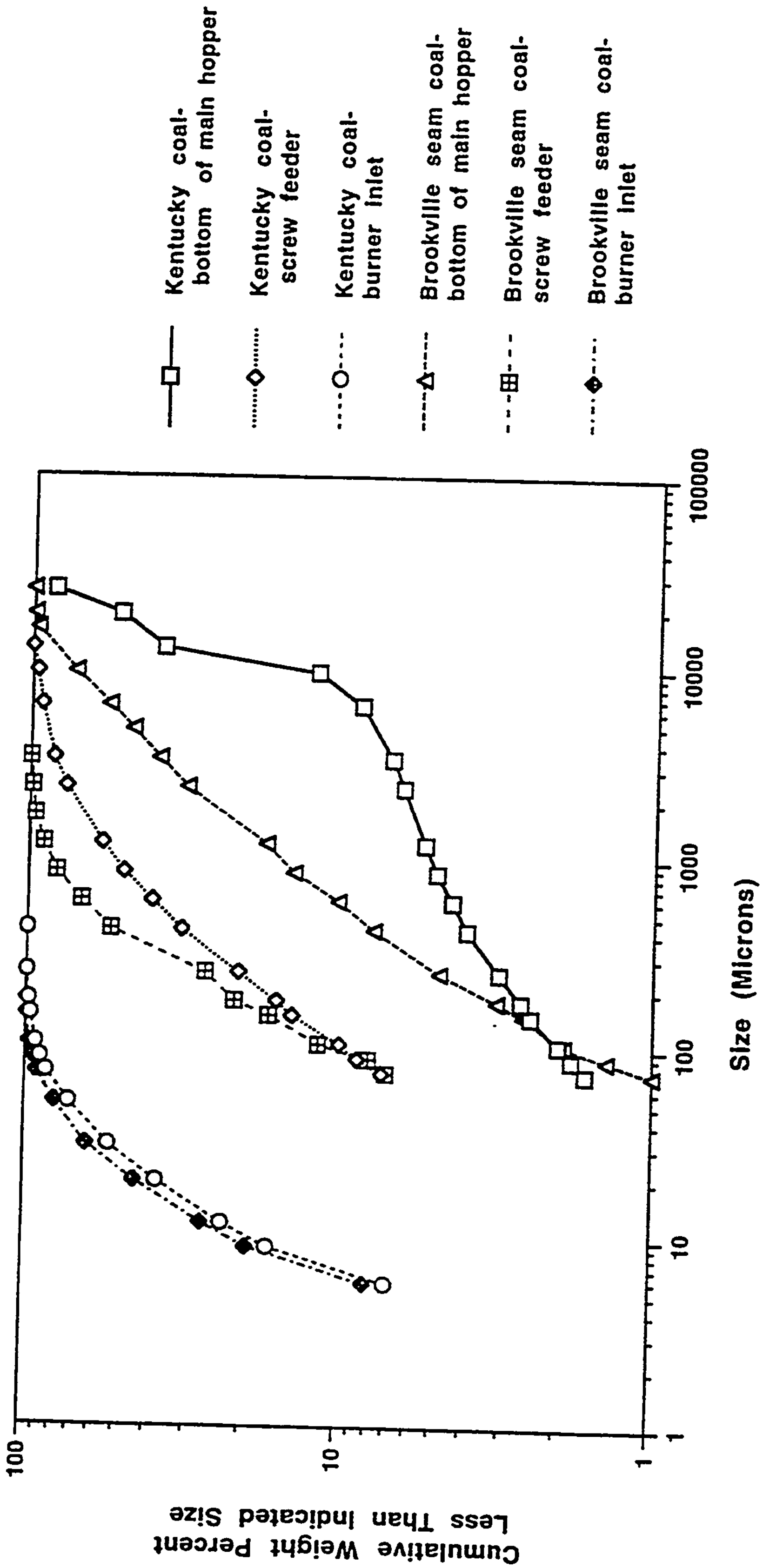


Figure 4.2 Comparison of Kentucky and Brookville Seam Coal Particle Size Distributions

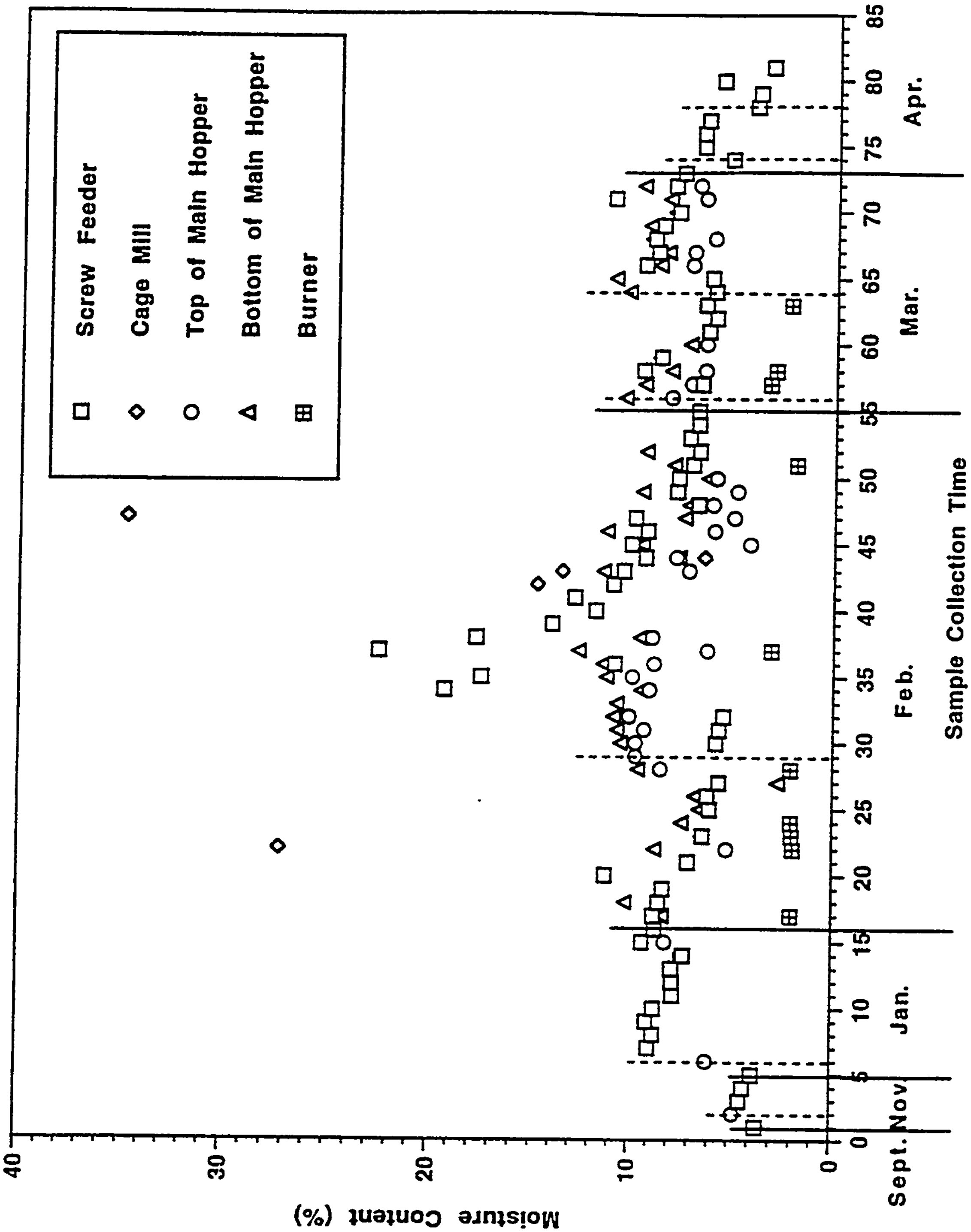


Figure 4.3 **Coal Moisture Content of Samples Collected from Various Locations During Testing**

the main hopper), the rotary valve (located prior to the cage mill), the cage mill, and the Redler conveyor have few problems when operating with dry coal. The main hopper however, still experiences occasional bridging even with dry coal.

4.2.3 Surge Bin

Problems similar to those experienced with the main hopper were experienced when using wet coal in the surge bin. Bridging and ratholing of the coal required constant attention and corrective action. Initially, coal was manually removed from the sides of the hopper to break up the bridging. Air sparge ports were installed on the sides of the hopper to reduce manual coal removal. The sparges helped greatly, but bridging and ratholing occasionally occurred with both wet and dry coals. The sparges themselves needed periodic monitoring because they are susceptible to wear and blow-out. Although the baghouse air system (system to suppress dust) was connected to the surge bin, the increased pressure of the sparges exerted excessive pressure on the Redler conveyor's coal dust seals and blew them out. The operators replaced the seals on the Redler conveyor and slightly opened the man-hole on top of the surge bin to relieve the excess pressure.

Due to ratholing, bridging, and a low coal level in the surge bin, coal feed was erratic. The operators had to maintain constant vigilance of the hopper's coal level in order to maintain constant feed. A level sensor (bindicator) that automatically starts the equipment to fill the surge bin is located at a level that is lower than the level required to maintain constant coal feed. Therefore, the operator had to manually start and stop the filling of the surge bin.

4.2.4 Screw Feeder

The operators could maintain a consistent feed from the surge bin to the screw feeder, but the coal feed rate of the screw feeder still varied over time. This was verified by direct measurement of the coal feed rate. The rate of coal feed from the screw feeder was influenced by the moisture and particle size of the coal. Because high moisture content coal dries relatively quickly in the heated building, the coal feed rate could vary on a daily basis. If the operators fill the surge bin at the end of a shift, the moisture in the fresh coal could cause variation in the feed rate in the screw feeder. Also, the air sparges may dry the coal in the surge bin over time which, in turn, affects the feed rate.

In addition, as the level, of coal in the surge bin drops, the operators have observed that the air from the sparge ports preferentially transports the smaller particles from the sides of the bin toward the middle and hence, into the screw feeder.

4.2.5 TCS Mill

The TCS mill and booster fan operated well without constant supervision. Initial system testing, however, revealed a coal settling problem in the mill outlet duct. This problem was corrected by a specially designed diffuser/transition section fitted to the mill exit. As documented in Appendix C, a detailed experimental study was carried out to characterize the effect of mill air flow rate, coal feed rate, and mill speed, on coal particle size distribution (PSD) and top size using two coals. This was done as part of an effort to determine the milling conditions necessary to reduce the coal PSD and top size in order to achieve maximum coal combustion efficiency. In addition, the results were used to evaluate the feasibility for external classification to reduce the coal top size.

Selected results from this characterization study are shown in Fig. 4.4. This figure shows the Brookville Seam coal particle size distribution for a near constant mill air flow rate and the two values of mill speed. As can be seen, the mill speed was a most important parameter to obtain the desired coal PSD. The results from these tests were used to optimize the mill settings for coal fineness during the experimental test program. The following table presents typical optimized mill operating conditions.

Mill Performance Summary

Typical mill air flow rate: 370-400 acfm
Typical coal feed rate: 16.5- 18.5 lb/min

Particle Size (microns)	Brookville Seam Coal	Kentucky Coal
Top Size	190-300	250-275
D_{80}	50-70	50-70
D_{50}	25-30	25-30

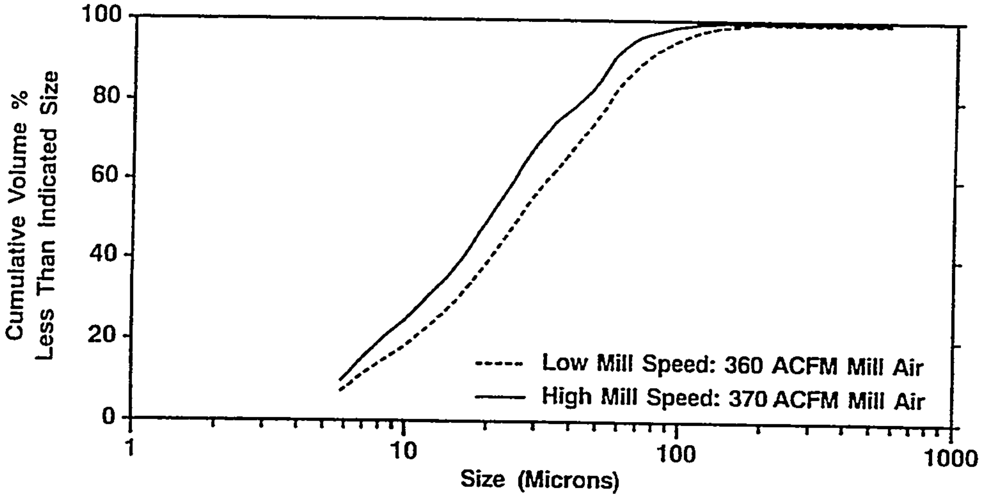


Figure 4.4 Brookville Seam Coal PSDs (Fixed coal feed rate)

4.3. Boiler Furnace Operation/ Modifications

During the initial testing period, a number of operational problems involving the coal handling and boiler system were encountered. They were primarily related to the weather (cold, snow), the coal (particle size, moisture content), the burner/boiler system (unstable/ low u.v. signal), or mechanical difficulties (feedwater pump, steam valves). With the exception of the coal handling problems caused by high moisture, these problems were all addressed and solved during the shakedown test series.

The furnace geometry was modified in April '94 by installing a ceramic tunnel (wall) during the last week of Brookville Seam coal testing in order to alter the gas patterns and temperature profile in the boiler. This was done because analytical (CFD) modeling showed that the flame was skewed from the burner to the furnace outlet and that the entire furnace volume was not being used (A plan view of the boiler is given in Figure 4.5 showing the location of the burner and furnace outlet.). Model results were subsequently verified by suction pyrometry (Miller, Poe, and Scaroni, 1993) . Details of the wall are shown in Figure 4.6. It was reasoned that carbon burnout might be improved if a greater percentage of the furnace volume could be used.

A) Temperature Measurements

During testing gas temperatures and total heat flux measurements were made in the boiler. Figure 4.7 shows the effect of the wall when firing natural gas at 17.3 million Btu/h. The temperature profiles shown in Figure 4.7 (a) were measured during the natural gas baseline testing conducted in September, 1993 (Miller et al., 1993a). The temperature profile was changed by installation of the wall and higher temperatures were observed near the front wall (wall containing the burner) and along the wall opposite the connective pass entrance.

Figure 4.8 gives a comparison of the gas temperatures when firing natural gas (Figure 4.8 (a)) and micronized coal (Figure 4.8 (b)) with the wall installed. The firing rates are not identical in Figure 4.8, being 17.3 and 15.0 million Btu/h for natural gas and micronized coal, respectively. The natural gas-fired suction pyrometery measurements were performed at a high firing rate (during September, 1993);

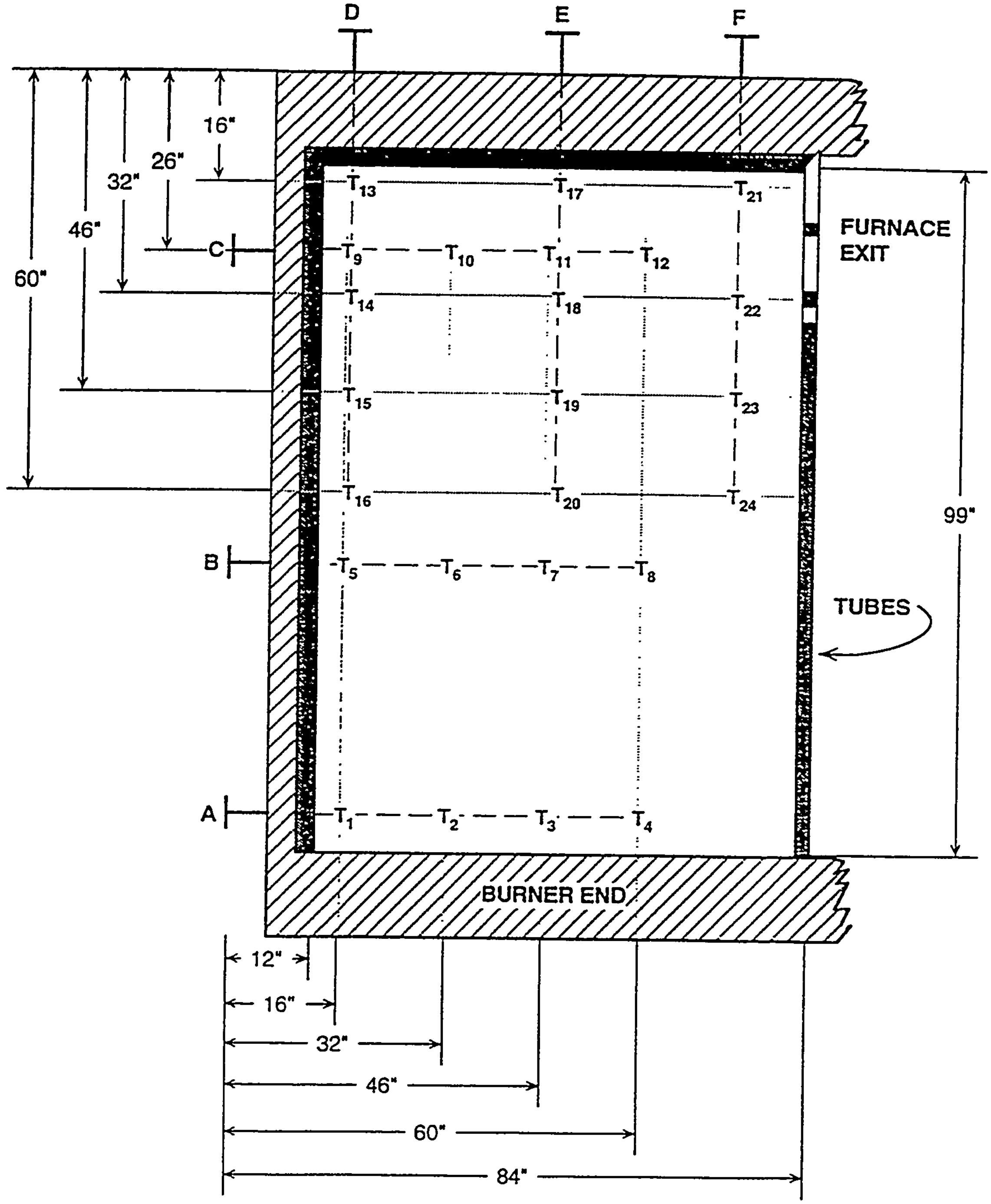


Figure 4.5 Plan View of Demonstration Boiler

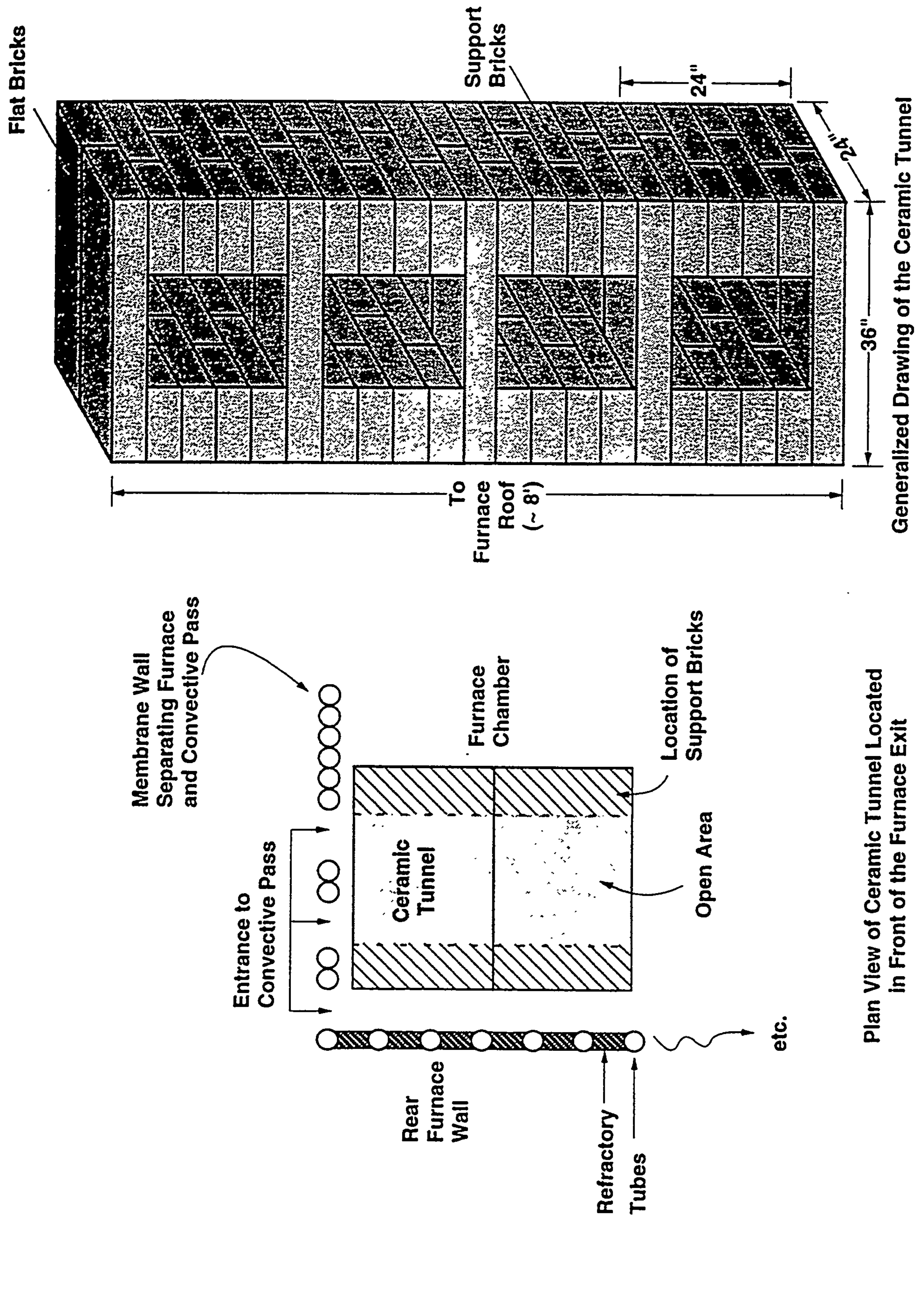
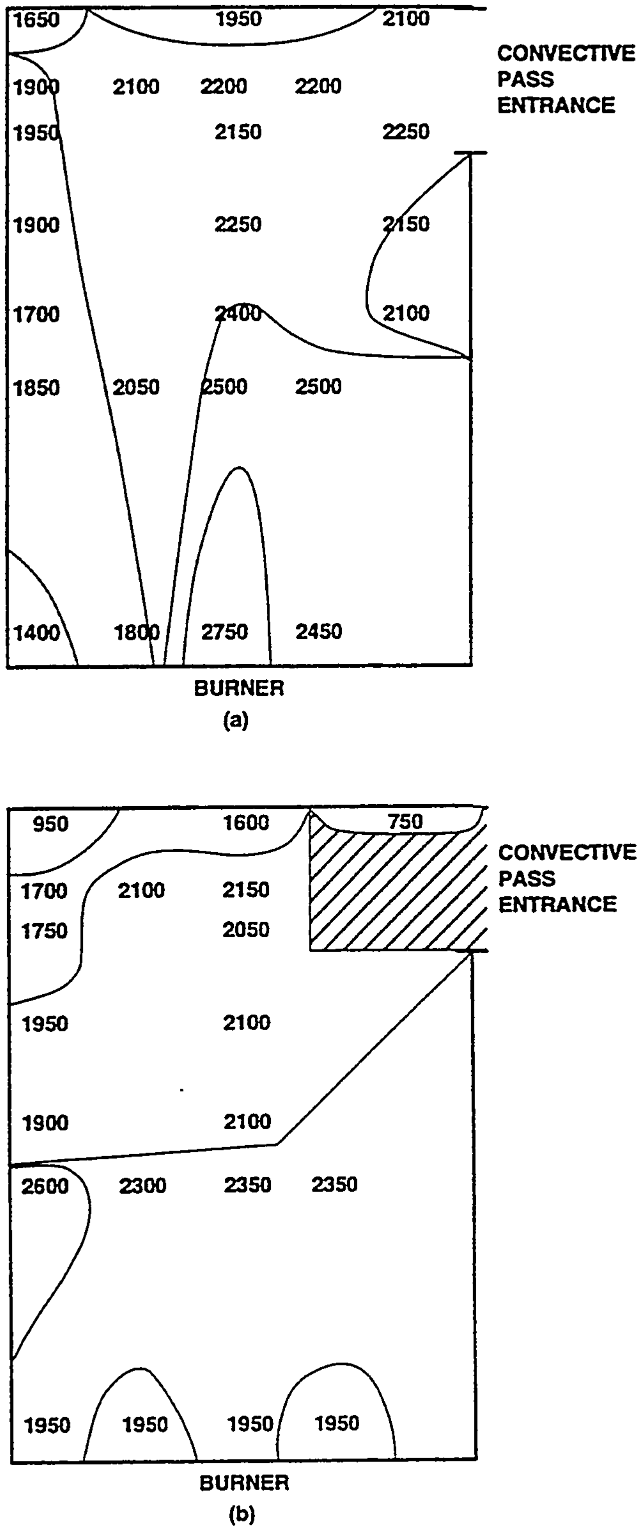
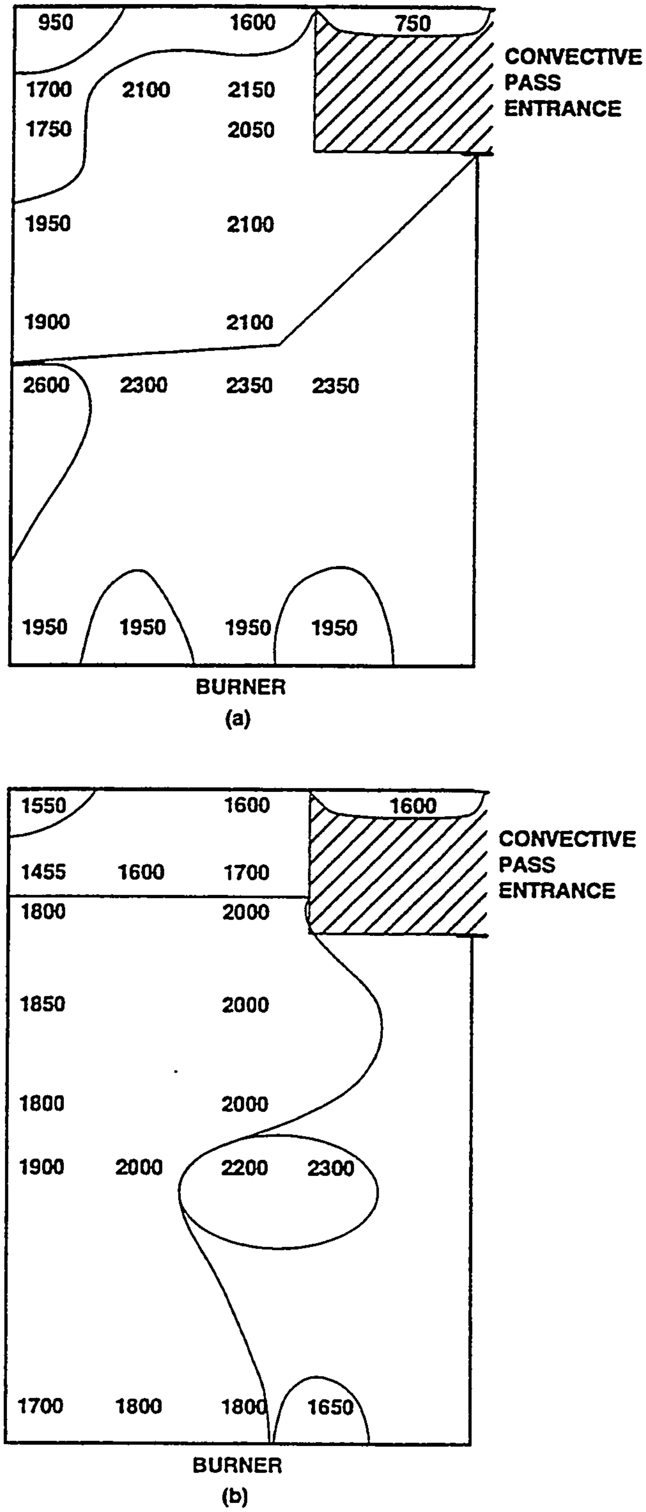


Figure 4.6 Generalized Drawing of Ceramic Wall



(a) GAS TEMPERATURES (°F) IN THE DEMONSTRATION BOILER DURING NATURAL GAS BASELINE TEST #2 (17.3 million Btu/h) - No Wall;
(b) GAS TEMPERATURES WITH THE WALL (17.3 million Btu/h)

Figure 4.7 Gas Temperatures in Demonstration Boiler- Natural Gas



(a) GAS TEMPERATURES (°F) IN THE DEMONSTRATION BOILER DURING NATURAL GAS BASELINE TEST #2 - With Wall; (b) GAS TEMPERATURES WHEN FIRING MICRONIZED COAL AT 15 MILLION Btu/h - With Wall

Figure 4.8 Gas Temperatures in Demonstration Boiler- With Wall

however, the coal firing rate was lower because ash deposition was a concern at firing rates greater than ~15 million Btu/h (deposition is discussed in a subsequent subsection). Although the firing rates differ between natural gas and coal, similar profiles are observed. In both cases (natural gas and coal), there are higher temperatures near the burner wall and along the wall opposite the convective pass entrance when compared to temperatures with natural gas firing without a wall. Where the natural gas and coal firing gas temperature profiles do vary somewhat is that the highest temperatures observed during the coal firing are near the middle of the boiler whereas they are nearer the front wall during natural gas firing Figures 4.8 (a) and (b). This difference is the result of the delay in ignition of the coal, compared to the gas.

B) Total Heat Flux Measurements

Total heat flux measurements were made during two coal firing tests prior to installing the wall (Figure 4.9) and with the wall installed (Figure 4.10). A direct comparison is difficult because the measurements were made when the coals were fired at two rates, 13.2 and 15.0 million Btu/h, and the coal combustion efficiencies differed, ~90% at a firing rate of 15 million Btu/h and ~95% at a firing rate of 13.2 million Btu/h. Nevertheless, the total heat flux was higher for the test with the wall where the firing rate was 13.2 million Btu/h and the combustion efficiency was 95%. The total heat flux in the middle of the boiler during the test with the wall installed was greater than for the other test where the wall was not installed. Additional testing should be conducted to determine the effect of the wall on heat release patterns in the boiler.

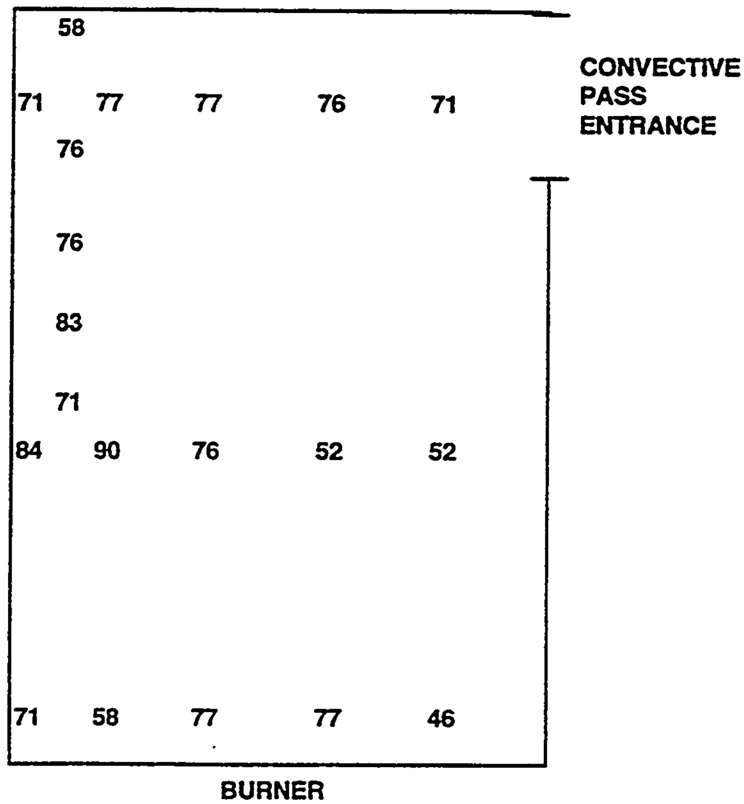


Figure 4.9 Total Heat Flux Measurements- No Wall

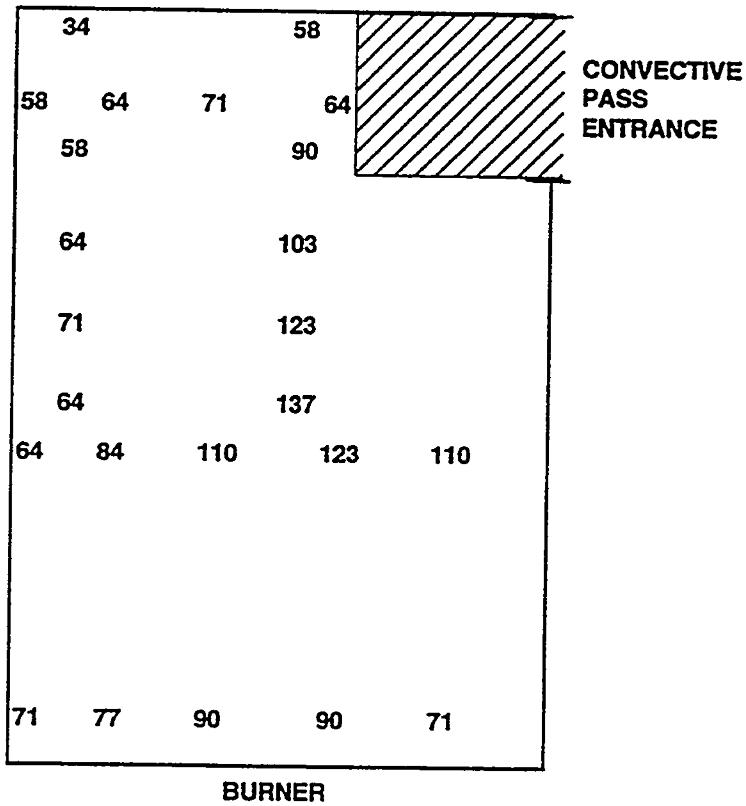


Figure 4.10 Total Heat Flux Measurements- With Wall

4.4 Combustor/ Boiler Performance Evaluation: Proof of Concept Tests

4.4.1 Overview

Under the 400 hour test program, Brookville Seam and Kentucky coals were evaluated, the furnace geometry was modified by installing a ceramic wall, two coal guns (the RO-II with and without a coal deflector/accelerator and the I -Jet) were tested, and the operating conditions (excess air and firing rate) were varied. During the course of the long term coal only tests, no support fuel was required and the burner operated with excellent ignition stability. A typical summary of the microfine coal firing (both coals) is given in the following table.

Microfine Coal Firing Results

Boiler Operation:	
Steam Flow Rate (lb/hr)	13,240
Boiler Efficiency (%)	84.1 (3% O_2)
Combustion Performance	
Carbon Conversion Efficiency (%)	95.3
NOx at 3% O_2 (ppm)	413 (0.56 lb/MBtu)
Burner Pressure Drop (in H_2O)	8

During this test program, key performance variables were monitored in detail: boiler efficiency, combustion efficiency, and NOx emissions. A summary of the results involving these parameters follows.

Boiler Thermal Performance

Boiler thermal performance when firing micro-fine coal was essentially comparable to that achieved when firing natural gas. In fact, because of the greater latent heat loss when burning natural gas (greater formation of water due to higher hydrogen content), firing micro-fine coal actually gave slightly higher boiler efficiencies despite the need to run at higher excess air levels.

During the relatively short operating periods, usually less than 16 hours, ash deposits did not cause significant changes to the boiler thermal performance. It is recognized, however, that longer term operation could result in greater build-up of ash deposits which could impact heat transfer. Because of the relatively short duration of the tests, any build-up of ash deposits would slough off when the boiler was shut down. A better test of the possible impact of ash deposits will occur during the long term demonstration phase of the work (Task 5.0).

Combustion Efficiency

The target for combustion efficiency was 98%. The highest combustion efficiency obtained during the test program was slightly over 96%. However, this value was not compatible with meeting the NOx target, and was not able to be routinely repeated. As shown in Figure 4.11, a value of 95% combustion efficiency was able to be routinely achieved, and was compatible with meeting the NOx target.

NOx Emissions

The NOx emissions target was 0.6 lb NOx per million Btu fired; this translates to about 450 ppm at 3% O_2. As shown in Figure 4.12, testing with 100% microfine coal showed that this target was achieved (in general a NOx emissions value of 0.56 lb NOx per million Btu was routinely met) while meeting nearly all other required conditions. It is acknowledged that the optimum conditions for low NOx will generally exacerbate carbon conversion efficiencies. Indeed, this was the case with the HEACC burner and the challenge was to find a reasonable balance between meeting the NOx target while not aggravating the carbon conversion efficiency.

Selected data are shown in Table 4.2 for testing conducted in March and April. Table 4.3 contains a complete summary of the testing conducted from February through April, 1994. Complete details of the test program follow.

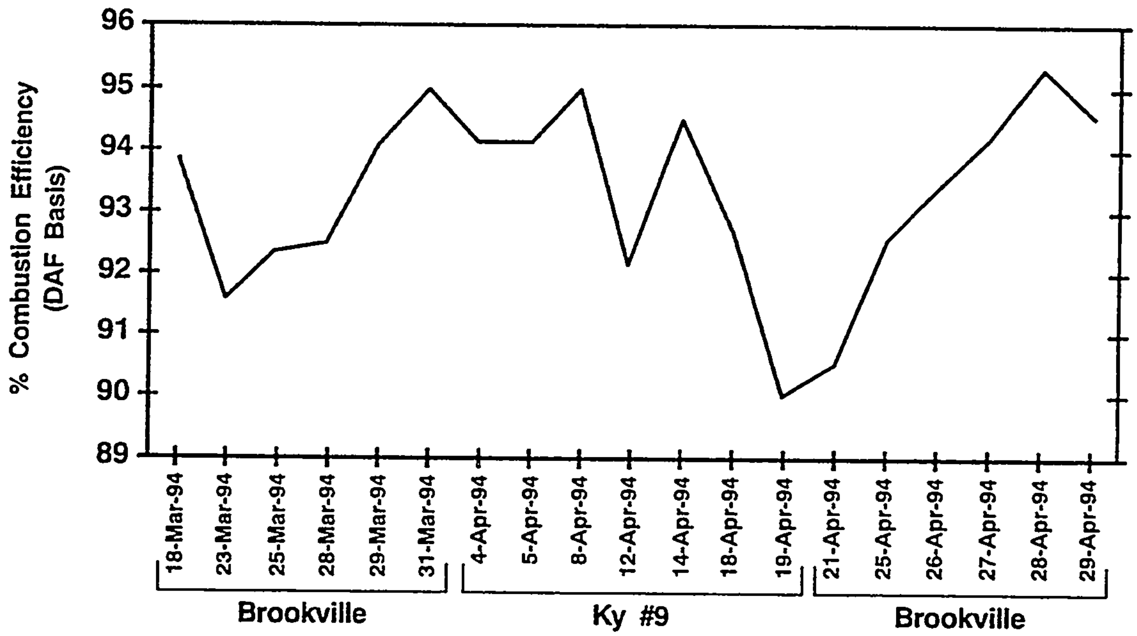


Figure 4.11 Combustion Efficiencies During Proof of Concept Testing

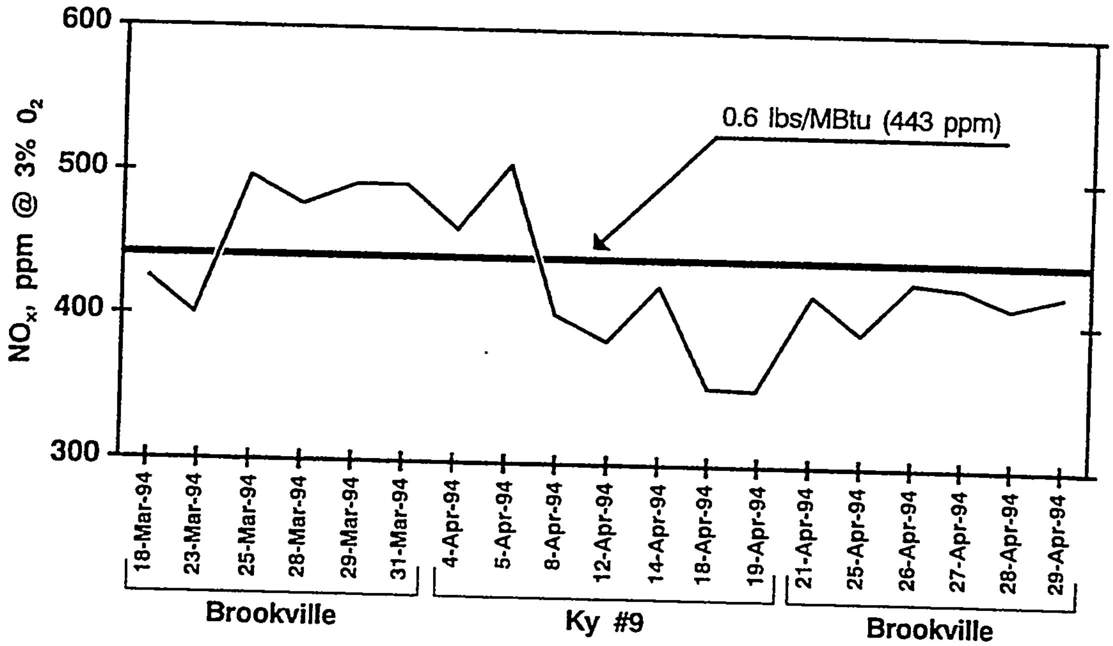


Figure 4.12 NOx Emissions During Proof of Concept Testing

Date	Coal	Boiler Efficiency	Combustion Efficiency (%)	Flue Gas Concentration: O_2 (%)	CO (ppm)	SO_2 (ppm)	NOx (ppm)	Firing Rate (MMBtu/h)
April 4	Kentucky	83.5	94.2	3.7	332	581	447	15.2
April 5	Kentucky	83.1	94.2	3.2	374	598	502	14.8
April 8	Kentucky	84.0	95.0	3.9	312	627	384	11.6
April 12	Kentucky	81.9	92.2	3.6	375	538	372	15.5
April 14	Kentucky	83.3	94.5	3.4	746	646	416	17.6
April 18	Kentucky	82.5	92.7	3.4	464	549	346	11.8
April 19	Kentucky	80.2	90.0	2.9	438	696	353	15.1
April 21	Brookville Seam	80.1	90.5	3.2	506	417	416	14.3
April 25	Brookville Seam	82.4	92.7	3.2	396	425	388	15.1
April 26	Brookville Seam	83.0	93.4	3.2	442	481	425	15.1
April 27	Brookville Seam	83.9	94.2	3.5	202	437	415	11.7
April 28	Brookville Seam	84.1	95.3	3.7	414	419	397	13.2
April 29	Brookville Seam	84.0	94.5	3.2	441	432	418	15.1
March 11[a]	Brookville Seam	83.2	94.4	3.7	654	410	260	12.4
March 23[a]	Brookville Seam	81.5	91.6	4.0	619	419	380	14.7
March 25[a]	Brookville Seam	81.4	92.4	4.3	294	389	461	14.4
March 28[a]	Brookville Seam	81.8	92.5	3.5	417	371	465	15.6
March 29[a]	Brookville Seam	83.3	94.1	3.2	227	417	488	14.8

a Without Wall

Table 4.2 Selected Results for Brookville Seam and Kentucky Coal

TEST/DESCRIPTION:	10-Mar-AM	10-Mar-PM	11-Mar	18-Mar	23-Mar	25-Mar
WATER/STEAM SIDE						
Steam flow rate; lb/h	9,321	11,674	10,917	13,457	10,361	12,605
Water temperature into boiler; °F	217	217	217	217	217	218
Drum pressure; psig	207	211	210	206	211	212
Calorimeter temperature; °F	202	202	203	289	202	203
Steam temperature; °F	383	384	383	383	383	384
Steam quality; %	93.65	93.65	93.69	98.62	93.65	93.73
Blowdown rate; lb/h	3,157	3,180	3,178	3,147	3,182	3,190
AIR,FUEL, FLUE GAS SIDE						
Natural gas flow rate; lb/h,MMBtu/h	308; 7.2	140; 3.3	0	138; 3.2	0	0
Coal flow rate; lb/h,MMBtu/h	471; 6.2	799; 10.6	942; 12.4	995; 13.4	1,085;14.7	1,093;14.4
Air temperature entering air heater; °F	135	135	141	47	169	134
Air temperature leaving air heater; °F	412	412	398	362	389	398
Air temperature into boiler; °F	376	376	363	330	349	364
Furnace outlet temperature; °F	597	597	568	587	530	575
Gas temperature leaving air heater; °F	386	386	365	354	354	377
Bagfilter inlet temperature; °F	386	386	362	348	348	376
Bagfilter outlet temperature; °F	342	342	319	310	309	334
Ash content of particulate; %	52.14	50.45	40.18	35.39	28.30	29.96
Carbon content of furnace ash; %	Not Measured	NM	NM	NM	NM	NM
HHV of fly ash; Btu/lb	NM	NM	NM	NM	NM	NM
HHV of furnace ash; Btu/lb	NM	NM	NM	NM	NM	NM
Combustion air flow; lb/h	12,672	13,253	11,243	15,931	13,526	13,551
Boiler draft; in H2O	-0.04	-0.02	-0.01	-0.02	0.01	0.00
Boiler efficiency; %	82.7	83.9	83.2	83.4	81.5	81.4
Relative humidity, %	60.0	60.0	60.0	60.0	60.0	60.0
Mill air flow rate; acfm	420	369	366	358	368	305
Mill inlet temperature; °F	66	68	78	72	73	77
Mill outlet temperature; °F	151	188	196	NM	NM	NM
Burner inlet temperature; °F	118	147	156	153	152	158
Natural gas temperature; °F	85	85	61	81	69	67
Coal combustion efficiency; %	95.2	96.7	94.4	93.9	91.6	92.4
EMISSIONS						
O2; %	3.5	3.8	3.7	4.0	4.0	4.3
CO; ppm	120	195	654	161	619	294
CO2; %	12.7	14.4	15.3	13.9	15.2	14.8
SO2; ppm	129	322	410	311	419	389
NOx; ppm	466	314	260	403	380	461
Particulates; gr/SCF	NM	NM	NM	NM	NM	NM
O2 after air heater; %	NM	NM	NM	NM	NM	NM
ECONOMIC ANALYSIS DATA						
ID fan power consumption; Amperage	28.8	29.7	28.6	32.2	28.5	31.3
FD fan power consumption; Amperage	12.0	12.1	11.6	13.2	11.1	12.2
Pulverizer power consumption; Amperage	62.0	81.8	83.3	85.3	81.0	91.7
Booster fan power consumption; Amperage	6.4	6.0	6.4	6.5	6.8	6.3
Ash collection power consumption; Amperage	NM	NM	NM	NM	NM	NM
Crusher power consumption; Amperage	NM	NM	NM	NM	NM	NM
Redler conveyor power consumption; Amp.	NM	NM	NM	NM	NM	NM
Feed screw power consumption; Amperage	NM	NM	NM	1.7	1.7	NM
Feedwater pump power comsumption; Amp.	18.0	16.8	16.4	18.4	17.4	20.6
Total air usage; scfm (Pilot burner)	39	20	13	38	46	45
Maximum load ; %	62.6	78.3	73.3	90.3	69.5	84.6
Coal related downtime	ND	ND	ND	ND	ND	ND

Table 4.3 Summary of Tests Conducted in March and April

TEST/DESCRIPTION:	28-Mar	29-Mar	31-Mar	4-Apr	5-Apr	8-Apr
WATER/STEAM SIDE						
Steam flow rate; lb/h	11,842	12,688	11,827	12,780	13,420	10,963.00
Water temperature into boiler; °F	216	217	217	216	216	216.46
Drum pressure; psig	207	209	209	203	205	201.22
Calorimeter temperature; °F	308	228	201	304	291	201.02
Steam temperature; °F	382	383	381	379	380	378.34
Steam quality; %	99.74	95.15	93.62	99.51	98.76	93.60
Blowdown rate; lb/h	3,150	3,169	3,164	3,122	3,134	3107.93
AIR,FUEL, FLUE GAS SIDE						
Natural gas flow rate; lb/h	0	0	0	0	0	0
Coal flow rate; lb/h,MMBtu/h	1,175;15.6	1,162;15.4	1,112;14.8	1,117;15.1	1,123;14.8	868;11.6
Air temperature entering air heater; °F	137	142	144	145	158	159
Air temperature leaving air heater; °F	403	399	405	400	408	405
Air temperature into boiler; °F	369	366	367	366	375	369
Furnace outlet temperature; °F	577	565	572	571	582	560
Gas temperature leaving air heater; °F	380	372	373	377	388	369
Bagfilter inlet temperature; °F	375	368	371	373	383	367
Bagfilter outlet temperature; °F	334	329	325	333	337	323
Ash content of particulate; %	30.34	36.11	40.47	48.09	47.44	50.56
Carbon content of furnace ash; %	NM	NM	NM	NM	NM	NM
HHV of fly ash; Btu/lb	NM	NM	NM	NM	NM	NM
HHV of furnace ash; Btu/lb	NM	NM	NM	NM	NM	NM
Combustion air flow; lb/h	14,096	13,681	13,671	13,760	13,040	10,636
Boiler draft; in H2O	-0.02	-0.02	-0.01	-0.01	-0.01	0.02
Boiler efficiency; %	81.8	83.4	83.6	83.5	83.1	84.0
Relative humidity, %	60.0	60.0	60.0	60.0	60.0	60.0
Mill air flow rate; acfm	307	296	297	290	284	320
Mill inlet temperature; °F	78	81	77	82	80	80
Mill outlet temperature; °F	NM	NM	218	NM	NM	271
Burner inlet temperature; °F	161	167	164	170	178	216
Natural gas temperature; °F	68	65	65	65	74	69
Coal combustion efficiency; %	92.5	94.1	95.0	94.2	94.2	95.0
EMISSIONS						
O2; %	3.5	3.2	3.9	3.6	3.2	3.9
CO; ppm	417	227	193	332	373	312
CO2; %	15.5	15.9	15.0	15.5	16.0	15.5
SO2; ppm	371	417	408	581	598	627
NOx; ppm	465	488	468	447	502	384
Particulates; gr/SCF	NM	NM	NM	NM	NM	NM
O2 after air heater; %	NM	NM	NM	NM	NM	NM
ECONOMIC ANALYSIS DATA						
ID fan power consumption; Amperage	31.2	30.2	30.3	30.5	31.2	27.6
FD fan power consumption; Amperage	12.2	12.0	11.8	11.9	12.1	11.3
Pulverizer power consumption; Amperage	91.8	85.3	92.0	98.6	99.5	108.8
Booster fan power consumption; Amperage	6.1	5.9	5.6	5.9	6.0	6.3
Ash collection power consumption; Amperage	NM	NM	NM	NM	NM	NM
Crusher power consumption; Amperage	NM	NM	NM	NM	NM	NM
Redler conveyor power consumption; Amp.	NM	NM	NM	NM	NM	NM
Feed screw power consumption; Amperage	1.7	1.7	1.7	1.7	1.7	1.7
Feedwater pump power comsumption; Amp.	15.8	17.5	17.4	18.7	19.1	17.6
Total air usage; scfm (Pilot burner)	45	47	45	43	45	45
Maximum load ; %	79.5	85.2	79.4	85.8	90.1	73.6
Coal related downtime	ND	ND	ND	ND	ND	ND

Table 4.3 (cont.) Summary of Tests Conducted in March and April

TEST/DESCRIPTION:	12-Apr	14-Apr	18-Apr	19-Apr	21-Apr	25-Apr
WATER/STEAM SIDE						
Steam flow rate; lb/h	13,300.00	15,558.00	10,887.00	12,004.00	14,693.00	13,608.00
Water temperature into boiler; °F	218.94	215.80	216.44	212.62	218.05	214.84
Drum pressure; psig	191.81	200.98	198.96	207.69	206.72	207.48
Calorimeter temperature; °F	270.26	200.46	244.14	199.44	202.82	308.86
Steam temperature; °F	376.23	378.51	378.70	380.89	383.37	382.22
Steam quality; %	97.56	93.57	96.06	93.51	93.70	99.76
Blowdown rate; lb/h	3034.06	3106.06	3090.31	3157.82	3150.42	3156.27
AIR,FUEL, FLUE GAS SIDE						
Natural gas flow rate; lb/h	0	0	0	0	0	0
Coal flow rate; lb/h,MMBtu/h	1,177;15.5	1,350;17.6	889;11.8	1,174;15.1	1,098;14.3	1,121;15.1
Air temperature entering air heater; °F	152	161	171	171	145	169
Air temperature leaving air heater; °F	399	409	412	419	402	393
Air temperature into boiler; °F	363	382	372	383	372	363
Furnace outlet temperature; °F	570	587	557	573	573	541
Gas temperature leaving air heater; °F	380	402	369	385	385	375
Bagfilter inlet temperature; °F	377	396	364	382	381	372
Bagfilter outlet temperature; °F	325	354	322	338	342	339
Ash content of particulate; %	48.11	46.27	41.45	38.95	33.35	31.63
Carbon content of furnace ash; %	NM	NM	NM	NM	NM	NM
HHV of fly ash; Btu/lb	NM	NM	NM	NM	NM	NM
HHV of furnace ash; Btu/lb	NM	NM	NM	NM	NM	NM
Combustion air flow; lb/h	14,072	15,784	10,642	13,185	12,926	13,293
Boiler draft; in H2O	0.02	0.02	-0.05	0.02	0.00	-0.05
Boiler efficiency; %	81.9	83.3	82.5	80.2	80.1	82.4
Relative humidity, %	60.0	60.0	60.0	60.0	60.0	60.0
Mill air flow rate; acfm	353	361	306	379	330	297
Mill inlet temperature; °F	85	88	86	83	80	84
Mill outlet temperature; °F	240	184	214	182	199	213
Burner inlet temperature; °F	204	171	174	175	176	189
Natural gas temperature; °F	66	82	72	85	73	89
Coal combustion efficiency; %	92.2	94.5	92.7	90.0	90.5	92.6
EMISSIONS						
O2; %	3.6	3.4	3.4	2.9	3.2	3.2
CO; ppm	375	746	464	438	506	396
CO2; %	15.7	15.9	15.9	16.6	15.9	15.7
SO2; ppm	538	646	549	696	417	425
NOx; ppm	372	416	346	353	416	388
Particulates; gr/SCF	NM	NM	NM	NM	NM	NM
O2 after air heater; %	NM	NM	NM	NM	NM	NM
ECONOMIC ANALYSIS DATA						
ID fan power consumption; Amperage	30.7	32.8	27.7	29.5	32.4	31.2
FD fan power consumption; Amperage	12.0	12.4	11.0	11.4	12.2	11.9
Pulverizer power consumption; Amperage	113.7	96.3	116.4	94.9	98.5	95.0
Booster fan power consumption; Amperage	8.6	9.1	5.6	11.9	7.8	6.0
Ash collection power consumption; Amperage	NM	NM	NM	NM	NM	NM
Crusher power consumption; Amperage	NM	NM	NM	NM	NM	NM
Redler conveyor power consumption; Amp.	NM	NM	NM	NM	NM	NM
Feed screw power consumption; Amperage	1.7	1.7	1.7	1.7	1.7	1.7
Feedwater pump power comsumption; Amp.	18.1	17.8	16.5	17.7	18.3	20.2
Total air usage; scfm (Pilot burner)	45	45	45	41	45	44
Maximum load ; %	89.3	104.4	73.1	80.6	98.6	91.3
Coal related downtime	ND	ND	ND	ND	ND	ND

Table 4.3 (cont.) Summary of Tests Conducted in March and April

TEST/DESCRIPTION:	26-Apr	27-Apr	28-Apr	29-Apr
WATER/STEAM SIDE				
Steam flow rate; lb/h	14,783.00	11,654.00	13,239.00	14,075.00
Water temperature into boiler; °F	213.67	213.79	214.76	216.10
Drum pressure; psig	203.52	202.96	202.37	195.70
Calorimeter temperature; °F	200.35	200.78	201.95	232.18
Steam temperature; °F	380.30	379.99	379.58	376.97
Steam quality; %	93.56	93.58	93.65	95.38
Blowdown rate; lb/h	3125.75	3121.39	3116.79	3064.83
AIR,FUEL, FLUE GAS SIDE				
Natural gas flow rate; lb/h	0	0	0	0
Coal flow rate; lb/h,MMBtu/h	1,096;15.1	847;11.7	972;13.2	1,086;15.1
Air temperature entering air heater; °F	169	173	161	158
Air temperature leaving air heater; °F	406	410	412	411
Air temperature into boiler; °F	379	378	379	377
Furnace outlet temperature; °F	560	560	564	567
Gas temperature leaving air heater; °F	388	376	387	387
Bagfilter inlet temperature; °F	382	371	384	381
Bagfilter outlet temperature; °F	342	333	342	336
Ash content of particulate; %	36.22	37.28	41.70	37.55
Carbon content of furnace ash; %	NM	NM	NM	NM
HHV of fly ash; Btu/lb	NM	NM	NM	NM
HHV of furnace ash; Btu/lb	NM	NM	NM	NM
Combustion air flow; lb/h	13,363	10,524	11,991	13,347
Boiler draft; in H2O	-0.04	-0.03	-0.07	-0.01
Boiler efficiency; %	83.1	83.9	84.1	84.0
Relative humidity, %	60.0	60.0	60.0	60.0
Mill air flow rate; acfm	344	388	378	402
Mill inlet temperature; °F	92	93	83	86
Mill outlet temperature; °F	203	196	245	188
Burner inlet temperature; °F	185	183	223	175
Natural gas temperature; °F	91	90	77	73
Coal combustion efficiency; %	93.4	94.2	95.3	94.5
EMISSIONS				
O2; %	3.2	3.5	3.7	3.2
CO; ppm	442	202	414	441
CO2; %	15.5	15.5	15.8	16.0
SO2; ppm	481	437	419	432
NOx; ppm	425	415	397	418
Particulates; gr/SCF	NM	NM	NM	NM
O2 after air heater; %	NM	NM	NM	NM
ECONOMIC ANALYSIS DATA				
ID fan power consumption; Amperage	32.0	29.4	30.6	31.3
FD fan power consumption; Amperage	12.0	11.6	11.8	12.0
Pulverizer power consumption; Amperage	96.5	78.6	110.3	85.2
Booster fan power consumption; Amperage	9.1	8.1	12.7	10.9
Ash collection power consumption; Amperage	NM	NM	NM	NM
Crusher power consumption; Amperage	NM	NM	NM	NM
Redler conveyor power consumption; Amp.	NM	NM	NM	NM
Feed screw power consumption; Amperage	1.7	1.7	1.7	1.7
Feedwater pump power comsumption; Amp.	19.2	18.6	17.8	16.8
Total air usage; scfm (Pilot burner)	45	25	45	45
Maximum load ; %	99.2	78.2	88.9	94.5
Coal related downtime	ND	ND	ND	ND

Table 4.3 (cont.) Summary of Tests Conducted in March and April

4.4.2 Brookville Seam Coal Combustion - Boiler Efficiency and Emissions

Figure 4.13 shows the effect of the coal firing rate on boiler and combustion efficiency. The data are presented with and without the furnace geometry modified (with and without the ceramic wall). The combustion and boiler efficiencies varied from ~ 90 to 95% and from ~80 to 84%, respectively. Firing rate did not have an effect on boiler and combustion efficiency, nor was there any discernible difference between tests with and without the ceramic wall.

Figure 4.14 is similar to Figure 4.13 in that boiler and combustion efficiencies are plotted as a function of excess air (oxygen concentration in the flue gas). Boiler and combustion efficiencies with the wall installed are slightly higher than those without the wall at ~3.55 and 3.7% O_2. However, because there is considerable variability in the efficiencies at ~3.2-3.5% O_2, with and without the wall, it is difficult to be highly conclusive on the effects of the wall. This is confirmed in Figure 4.15, which shows the relationship between boiler and combustion efficiency (and firing rate). As expected, the boiler efficiency tends to increase with increasing combustion efficiency. Though there is considerable variability in the results, it does appear that the presence of the wall enhances performance as evidenced by the three highest boiler efficiencies with the wall in place.

The effect of coal firing rate and excess air on emissions is shown in Figures 4.16 and 4.17, respectively. No trends are evident from the results. The emissions of CO, SO_2, and NO_x varied from approximately 200 to 700, from 375 to 500, and from 375 to 500 ppm, respectively. Variability in the burner settings necessary for a stable flame are the likely reason for the variability in the CO emissions and for not observing a trend in the NO_x emissions as the excess air was increased.

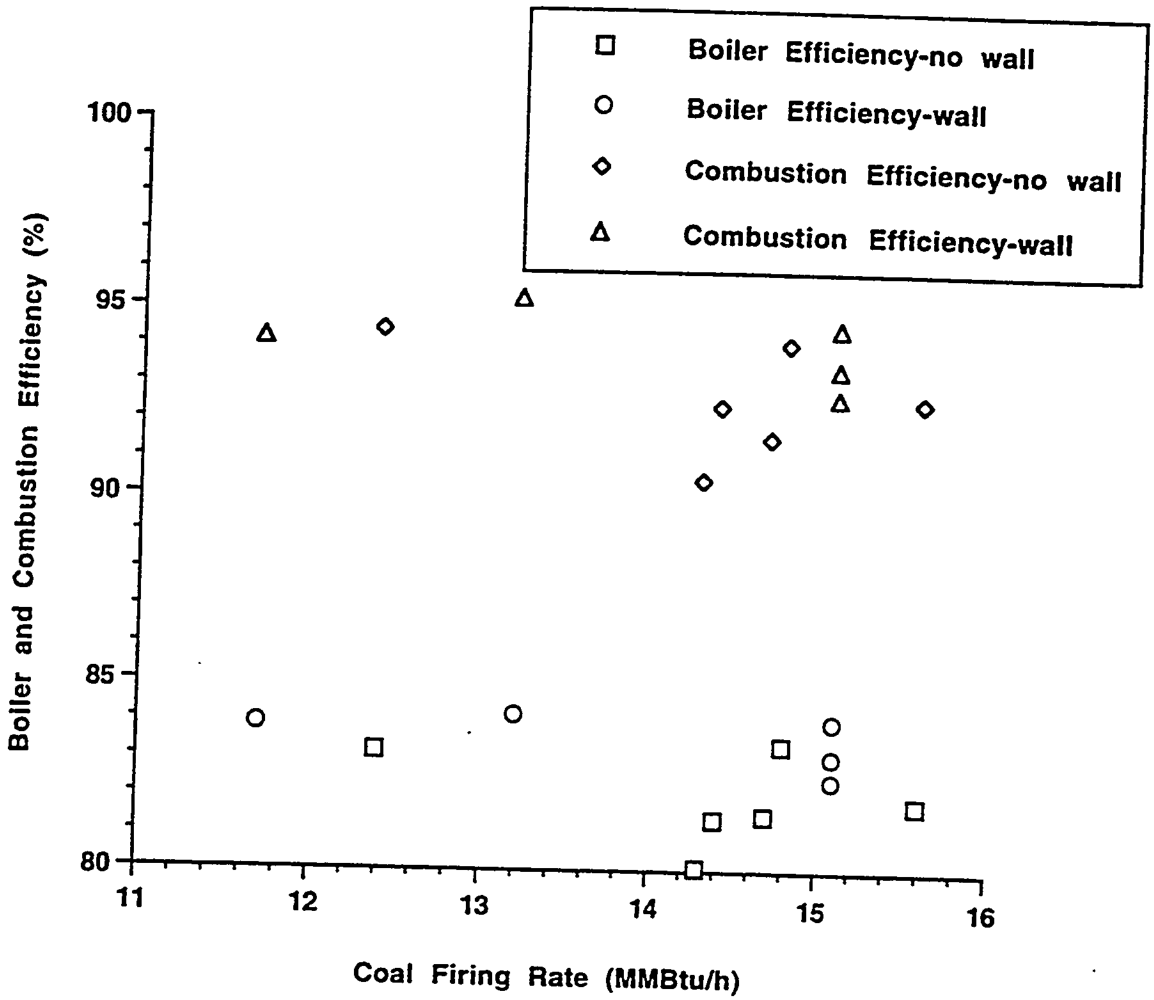


Figure 4.13 Effect of Wall and Coal Firing Rate on Boiler and Combustion Efficiency- Brookville Seam Coal

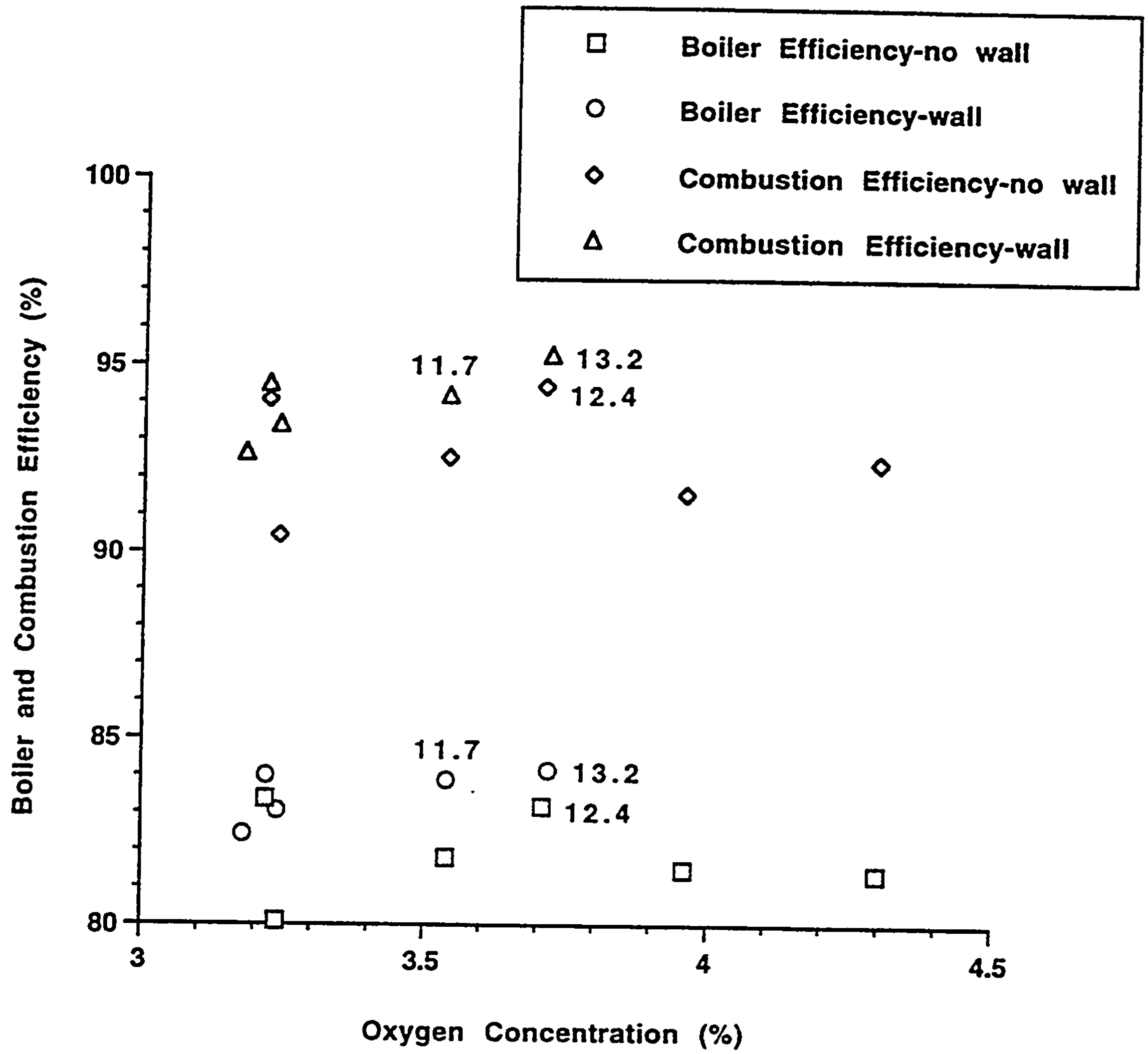


Figure 4.14 Effect of Wall and Oxygen Concentration on Boiler and Combustor Efficiency- Brookville Seam Coal

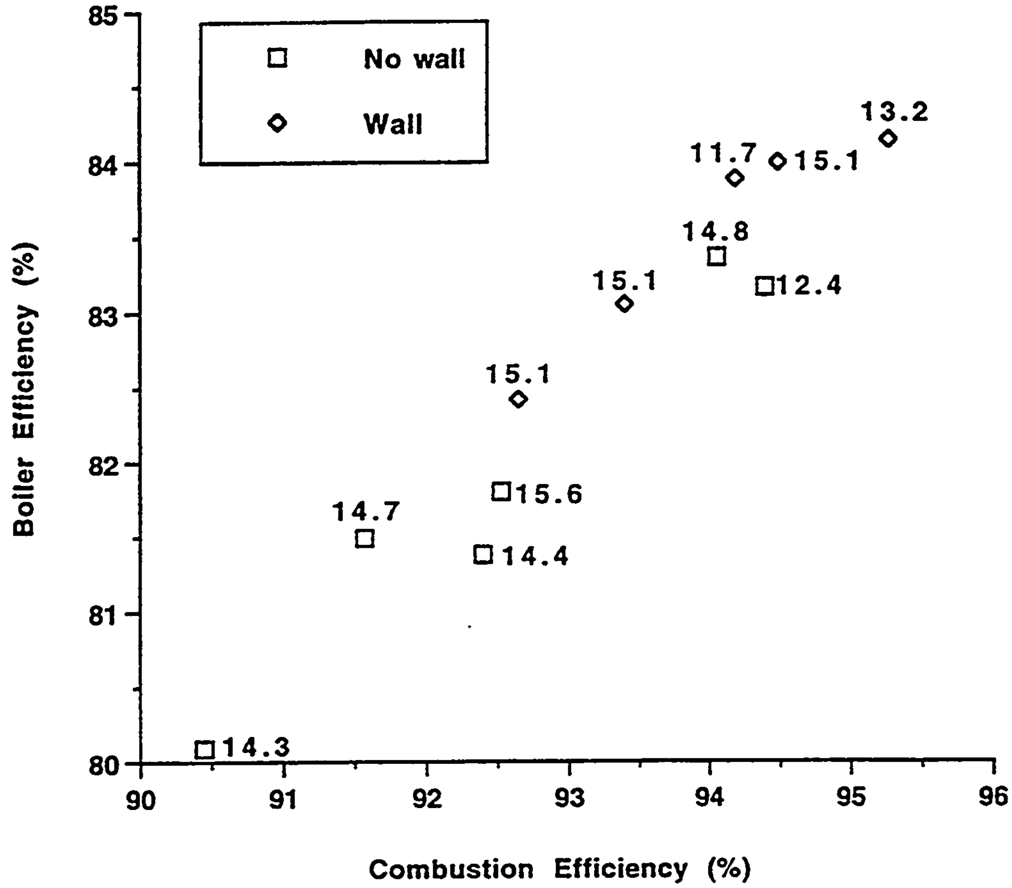


Figure 4.15 Effect of Combustion Efficiency on Boiler Efficiency

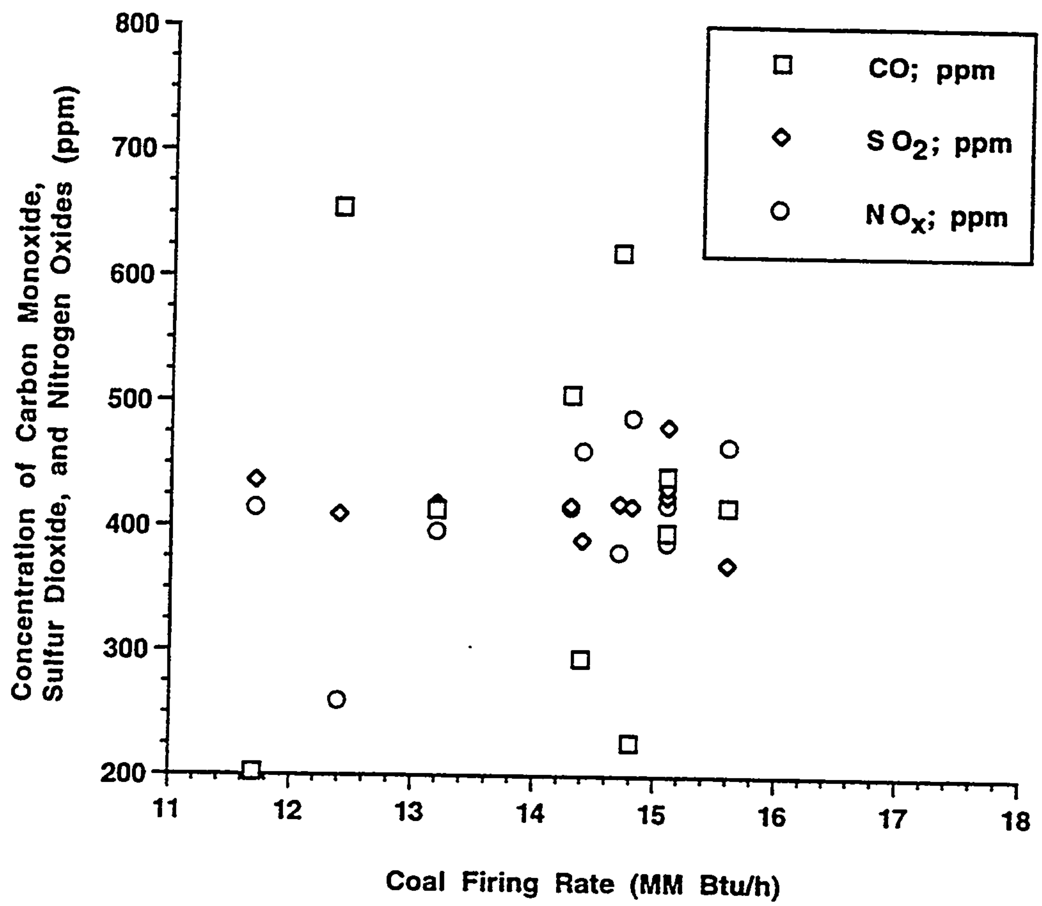


Figure 4.16 Emissions as a Function of Firing Rate-Brookville Seam Coal

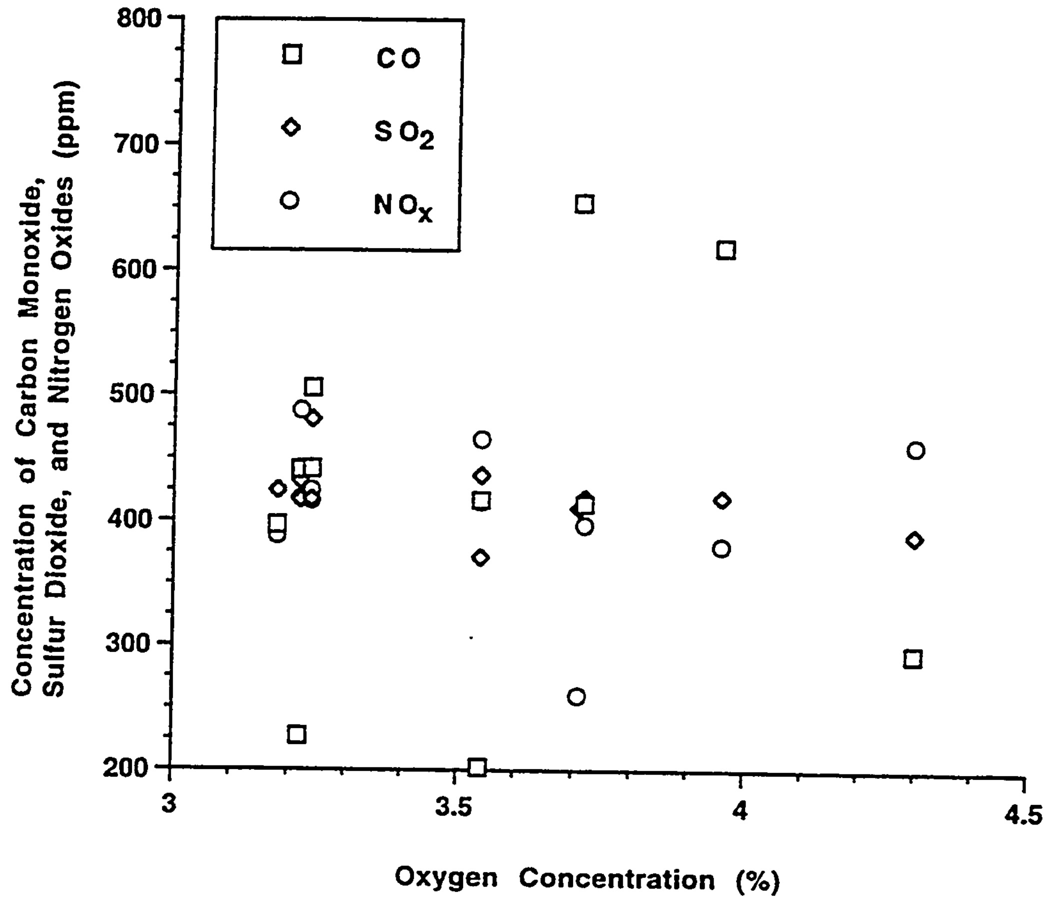


Figure 4.17 Emissions as a Function of Oxygen Concentration-Brookville Coal

4.4.3 Kentucky Coal Combustion and Boiler Efficiency and Emissions

Approximately two weeks of testing was conducted in April with a low-ash coal from Kentucky. This was done to: (1) utilize a coal with a lower moisture content to eliminate previous coal handling/burner performance problems experienced with wet coal and (2) provide ABB-CE with comparative performance data from the boiler using the same coal that was tested in ABB-CE's test facility. The tests, the results of which were previously documented in Tables 4.2 and 4.3, were conducted prior to the furnace modifications already discussed.

All of the testing was conducted with the RO-II coal gun, most of which was conducted without the 'football' (coal deflector/accelerator for producing low NO_x). The football was installed for one day, April 5, 1994, and resulted in a longer flame and slightly unstable operating conditions. The results from the 'football' test were also contained in Tables 4.2 and 4.3.

Figures 4.18 and 4.19 show the boiler and combustion efficiencies as functions of the firing rate and excess air, respectively. The boiler and combustion efficiencies ranged from approximately 80 to 84, and from 90 to 95%, respectively. The shaded symbols in Figures 4.18 and 4.19 are results from testing with the football. The boiler and combustion efficiencies are within the variability of testing without the 'football'.

Similarly, Figures 4.20 and 4.21 show the emissions as functions of the firing rate and excess air, respectively. The CO, SO_2, and NO_x ranged from approximately 300 to 725, from 550 to 700, and from 350 to 500 ppm, respectively. The shaded symbols in Figures 4.19 and 4.20 are results from testing with the football. The CO and SO_2 emissions are within the variability of the non-football testing; the NO_x emissions were the highest with the 'football'.

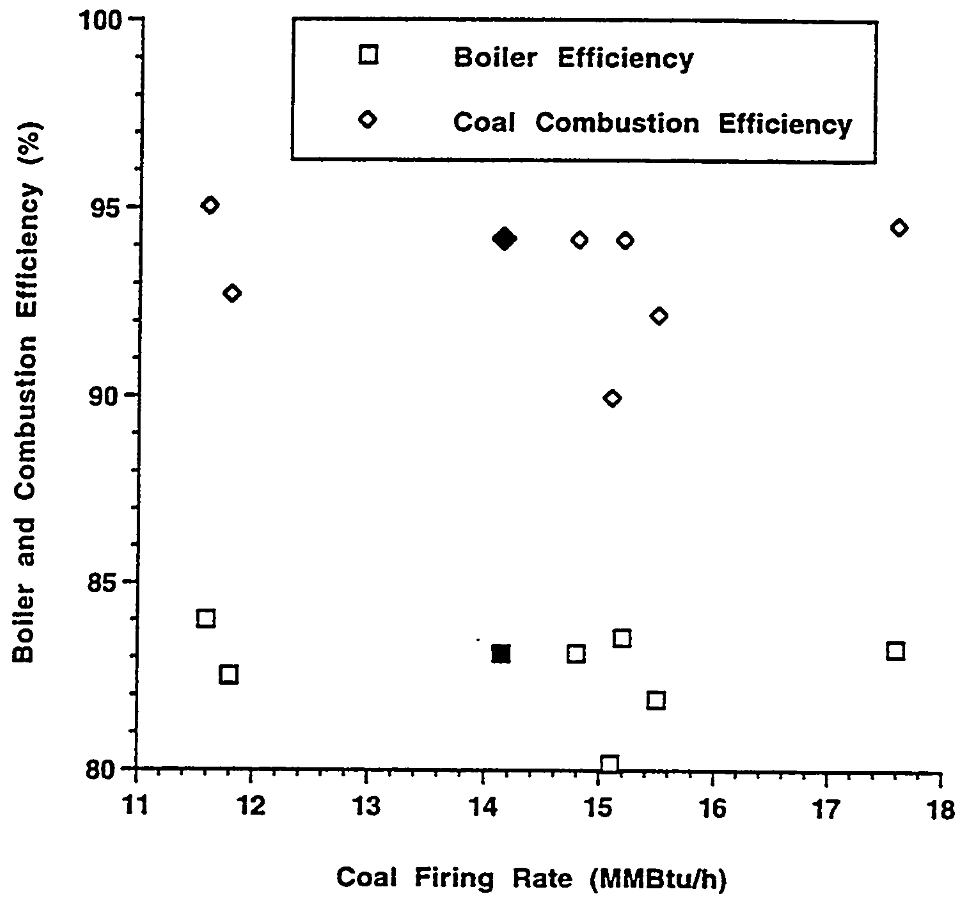


Figure 4.18 Boiler and Combustion Efficiency as a Function of Firing Rate- Kentucky Coal

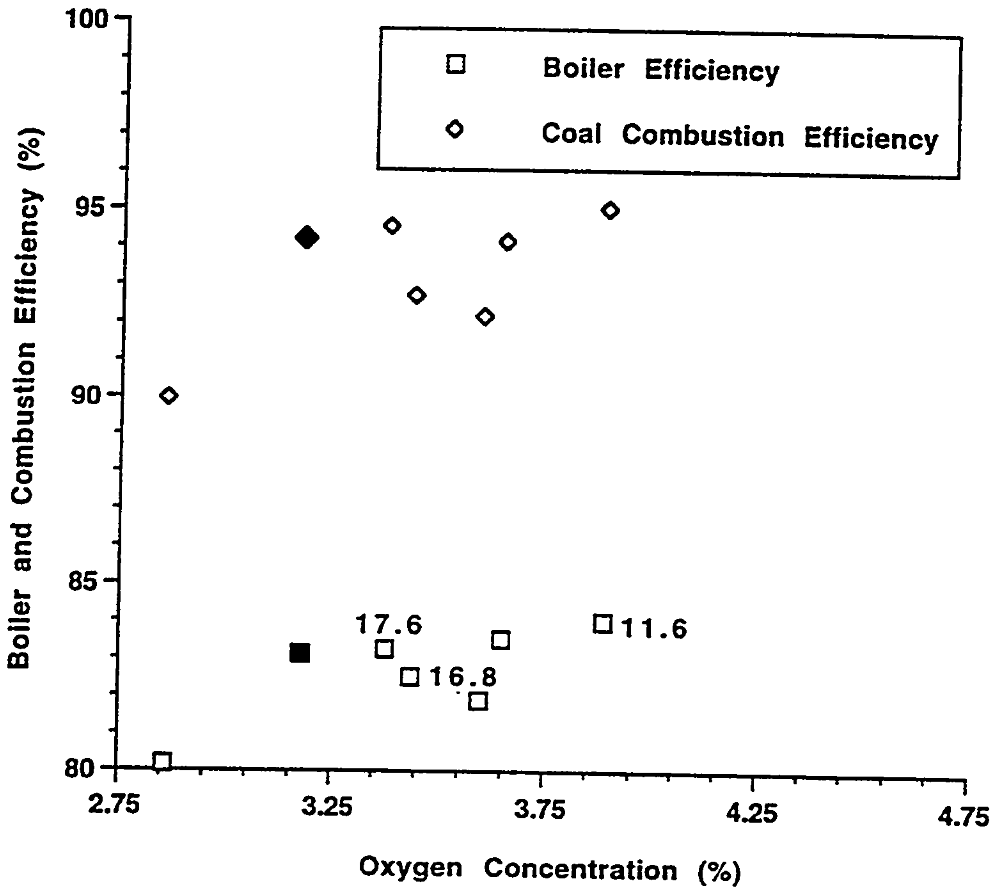


Figure 4.19 Boiler and Combustion Efficiency as a Function of Oxygen Concentration- Kentucky Coal

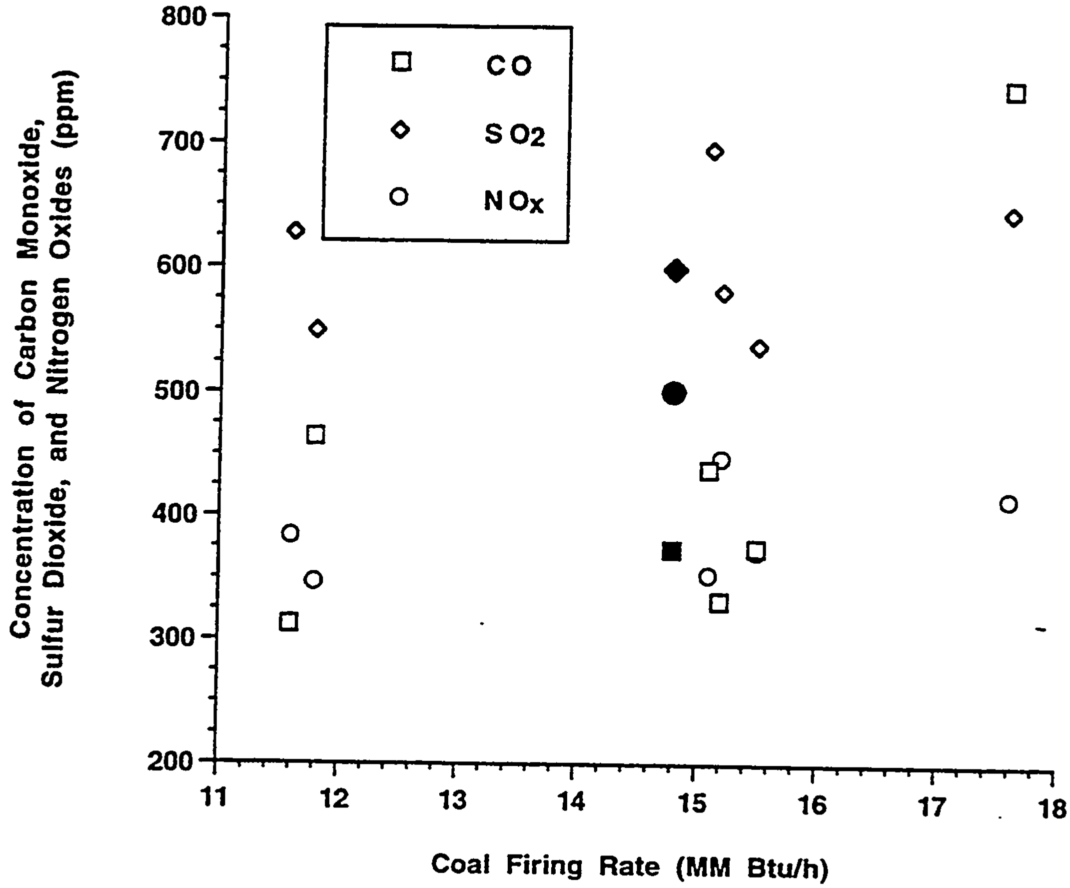


Figure 4.20 Emissions as a Function of Coal Firing Rate-Kentucky Coal

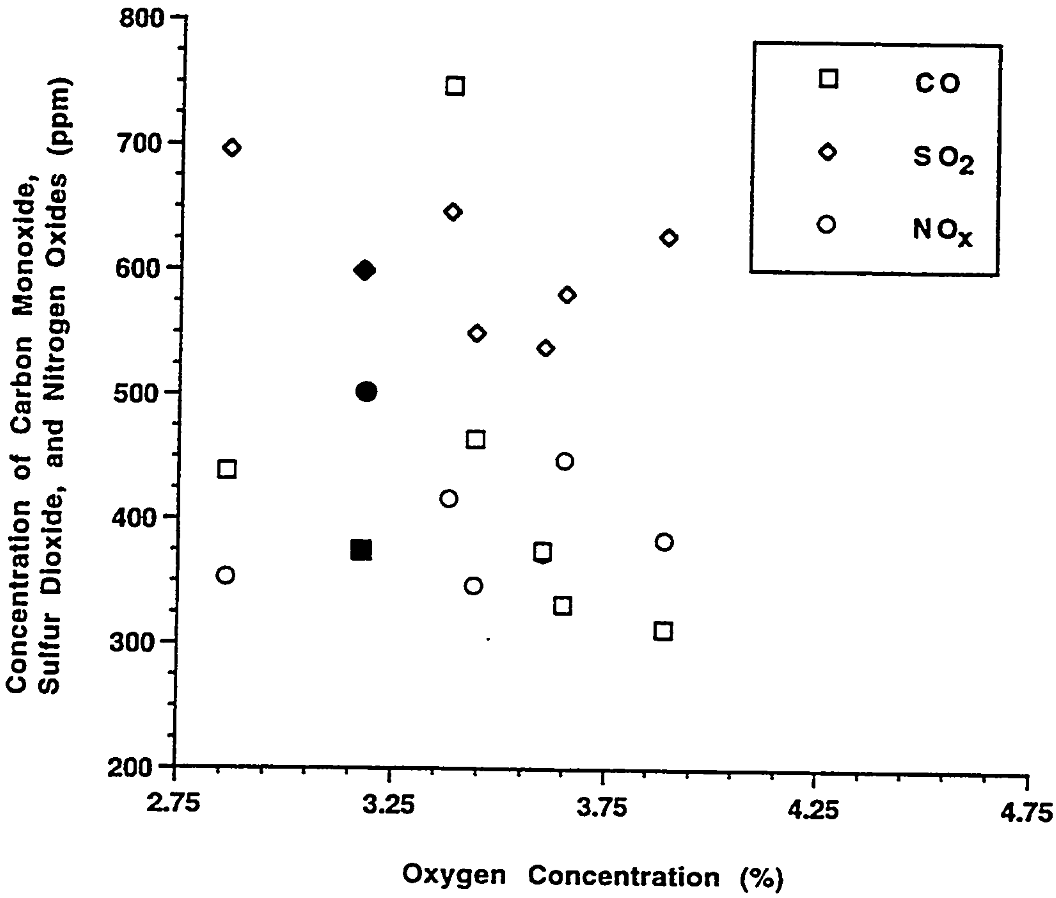


Figure 4.21 Emissions as a Function of Oxygen Concentration-Kentucky Coal

4.4.4 Ash Deposition Considerations

Successful testing (two-shifts/day, fewer operation problems) was achieved in March and April, 1994 firing 100% coal for 125 hours and cofiring natural gas and coal for 145 hours. Testing prior to March resulted in only 40 hours of 100% coal operation and about 265 hours of cofiring natural gas and coal. Ash deposition in the boiler, convective pass, and connecting breaching between the boiler and heat-pipe heat exchanger increased significantly after February '94. Table 4.4 contains a summary of convective pass soot blowing during March and April testing.

The boiler outlet and baghouse inlet temperatures were monitored and the convective pass steam sootblower was operated when the boiler outlet temperature reached about 600°F. The baghouse inlet temperature would approach 400°F as the boiler outlet temperature reached 600°F; this is the upper limit set for comfortable baghouse operation. Table 4.4 gives the boiler outlet, baghouse inlet, and baghouse outlet temperatures prior to, during, and after soot blowing. Each soot blowing event is given by date and time as well as the amount of coal used since the last time soot blowing occurred. As previously mentioned, the Kentucky coal was tested from April 1 through April 18, 1994. The remaining dates in Table 4.4 signify Brookville Seam coal use.

Figure 4.22 is an example of the boiler outlet temperature history for a day of operation. This figure gives a plot of boiler outlet temperature as a function of time (data acquisition data point) and shows when coal feed was started (time zero; prior to this point the boiler was preheated using natural gas), the period of coal and natural gas cofiring (the first ~240 data points - 2 hours), the switch to 100% coal firing, three convective pass blowdowns, and the termination of the test (approximately data point 1500).

Plots such as Figure 4.22 illustrate the time/temperature history of the boiler outlet but do not give a quantitative indication of the severity of ash deposition. The data in Table 4.4 are presented graphically in Figure 4.23 for the Kentucky coal (from April 1 to April 18, 1994) and in Figure 4.24 for the Brookville Seam coal (04/18/94 to 04/31/94) to show the extent of ash deposition that was experienced.

Figure 4.23 is a plot of coal consumed since the last soot blowdown when using the Kentucky coal. It must be noted that soot blowing routinely occurred at the beginning

Soot Blowdown		Temp. Prior to Blowdown (F)			Temp. during Blowdown (F)			Temp. after Blowdown (F)			Coal Use Since Last Soot Blow-down (lbs)	Other Blowdowns	
Date	Time	B.O.	BH In	BH Out	B.O.	BH In	BH Out	B.O.	BH In	BH Out		Pneumatic	Bottom
7-Mar	12:20	547	310	260	493	300	265	518	301	264	NA	12:20	ND
10-Mar	07:27	538	320	250	506	322	251	530	323	252	405	07:27	6:41
11-Mar	07:05	NO RECORDED DATA									4,018	07:05	7:05
11-Mar	15:40	625	379	325	546	358	325	549	359	317	7,420	15:40	ND
22-Mar	13:38	613	395	348	548	376	340	552	375	340	19,352	13:38	ND
29-Mar	07:32	520	360	296	508	348	295	518	350	296	30,296	07:32	07:32
31-Mar	07:31	574	360	285	514	355	286	524	350	290	11,251	07:31	ND
1-Apr	11:33	600	382	330	515	366	330	533	368	328	3,799	11:33	ND
4-Apr	06:55	512	282	170	489	287	183	510	300	200	6,527	06:55	06:55
4-Apr	13:40	594	383	340	529	370	335	547	366	330	6,583	13:40	ND
5-Apr	14:15	604	392	343	511	382	340	560	377	335	2,487	ND	ND
5-Apr	16:28	592	385	340	565	383	338	560	377	335	2,468	ND	ND
5-Apr	18:40	606	394	350	588	390	349	560	387	348	524	ND	ND
5-Apr	19:08	571	388	348	554	385	346	567	383	340	0	ND	ND
5-Apr	20:25	NO RECORDED DATA									0	20:25	ND
6-Apr	20:13	539	356	315	505	355	314	530	350	300	5,310	20:13	16:43
7-Apr	07:05	504	305	207	498	307	212	513	317	229	0	07:05	ND
8-Apr	17:45	592	378	326	516	376	323	522	353	310	4,643	17:45	ND
8-Apr	20:22	617	377	324	535	370	322	550	363	300	1,606	20:22	ND
11-Apr	07:51	NO RECORDED DATA									0	07:51	7:43
11-Apr	15:48	600	389	342	541	380	339	562	382	340	2,278	15:48	ND
11-Apr	17:22	604	398	351	545	391	348	580	390	346	1,462	17:22	ND
11-Apr	19:05	NO RECORDED DATA									955	19:05	ND
12-Apr	07:23	527	335	253	522	332	255	525	336	260	0	07:23	7:07
12-Apr	11:15	598	389	334	527	380	330	540	370	324	3,206	ND	ND
12-Apr	13:45	585	377	329	544	378	328	551	367	325	1,092	13:45	ND

Table 4.4 Summary of Sootblowing Frequency

Soot Blowdown		Temp. Prior to Blowdown (F)			Temp. during Blowdown (F)			Temp. after Blowdown (F)			Coal Use Since Last Soot Blow-down (lbs)	Other Blowdowns	
Date	Time	B.O.	BH In	BH Out	B.O.	BH In	BH Out	B.O.	BH In	BH Out		Pneumatic	Bottom
12-Apr	15:55	602	395	343	539	393	342	552	373	333	1,155	15:55	ND
13-Apr	07:20	530	354	278	522	352	280	533	353	283	645	07:20	ND
13-Apr	10:15	568	373	330	559	365	328	560	369	327	1,449	10:15	ND
13-Apr	12:24	595	393	333	560	390	335	551	370	340	1,426	1251	ND
13-Apr	13:08	554	380	337	504	375	334	545	369	330	615	1303	ND
13-Apr	14:39	592	393	340	547	391	345	577	388	345	1,465	14:39	ND
13-Apr	16:16	590	387	343	527	383	341	570	379	338	1,597	16:16	ND
14-Apr	07:12	548	355	279	527	354	283	530	351	287	1,728	07:12	ND
14-Apr	10:45	577	385	344	561	382	344	566	380	343	2,920	10:09	ND
14-Apr	12:32	560	367	329	425	320	329	415	314	320	894	12:32	12:32
14-Apr	15:00	513	340	281	529	351	290	537	355	298	0	15:00	ND
14-Apr	16:45	592	393	342	570	381	336	550	376	333	1,254	16:45	ND
14-Apr	17:45	605	400	348	552	397	351	580	393	352	1,305	17:45	ND
14-Apr	18:45	603	403	362	549	397	361	580	394	359	2,552	18:45	ND
15-Apr	10:52	594	370	310	529	366	317	541	360	321	2,099	10:52	ND
18-Apr	07:30	515	297	219	498	300	223	514	307	230	0	07:30	ND
18-Apr	15:30	570	380	337	527	370	327	494	354	322	6,628	15:30	ND
18-Apr	18:10	571	385	339	529	365	333	540	363	330	2,370	ND	ND
18-Apr	19:16	560	361	318	550	362	320	553	363	323	161	19:16	ND
19-Apr	07:00	500	290	198	511	298	208	520	315	220	0	07:00	07:00
19-Apr	16:49	584	391	341	500	388	343	533	371	336	4,840	16:49	ND
19-Apr	18:18	554	365	325	529	360	325	531	361	325	791	18:18	ND
20-Apr	09:45	495	280	177	481	301	195	507	310	206	190	09:45	09:45
20-Apr	14:51	560	377	343	551	376	341	561	377	341	3,121	14:51	ND
20-Apr	17:23	555	378	343	533	375	341	558	370	339	2,303	17:23	ND
20-Apr	19:05	550	362	332	523	356	329	500	350	327	1150	19:05	ND
21-Apr	07:00	480	255	155	479	283	176	499	295	194	0	07:00	ND

Table 4.4 (cont.) Summary of Sootblowing Frequency

Soot Blowdown		Temp. Prior to Blowdown (F)			Temp. during Blowdown (F)			Temp. after Blowdown (F)			Coal Use Since Last Soot Blow-down (lbs)	Other Blowdowns	
Date	Time	B.O.	BH In	BH Out	B.O.	BH In	BH Out	B.O.	BH In	BH Out		Pneumatic	Bottom
21-Apr	10:10	595	385	341	539	378	339	568	377	340	2,144	10:10	ND
21-Apr	13:05	600	397	351	556	390	349	575	385	347	3,203	13:05	ND
21-Apr	14:19	586	388	350	489	380	346	565	376	342	1,354	14:19	ND
21-Apr	15:17	584	385	347	520	380	343	556	375	340	1,061	15:17	ND
21-Apr	16:54	543	354	315	512	345	310	438	328	300	1,017	16:54	ND
22-Apr		NO BLOWDOWNS RECORDED											
25-Apr	11:30	574	388	348	479	385	346	529	372	340	4,264	11:30	ND
25-Apr	18:20	582	387	349	528	376	346	544	374	342	7,667	18:20	ND
26-Apr	11:30	521	380	336	527	370	334	533	368	330	2,940	11:30	ND
26-Apr	13:30	580	390	344	532	387	344	560	383	343	2,191	13:30	ND
26-Apr	14:45	575	390	347	531	387	346	553	381	345	1,370	14:45	ND
27-Apr	09:20	581	383	343	529	377	342	547	363	337	6,011	09:20	ND
28-Apr	07:30	571	361	305	525	349	304	520	338	302	4,766	07:30	07:30
28-Apr	11:00	585	388	344	522	378	342	550	379	340	1,719	11:00	ND
28-Apr	13:00	582	391	347	513	381	345	556	380	344	1,919	13:00	ND
28-Apr	15:14	588	395	347	527	383	346	551	380	341	2,793	15:14	ND
29-Apr	11:45	576	386	335	492	373	331	545	369	327	5,221	11:45	ND
29-Apr	15:15	594	391	340	537	378	337	552	377	333	7,950	15:15	ND
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Pnuematic blowdown is sootblowing of the heat-pipe heat exchanger
Bottom blowdown is blowdown of the mud drum

Table 4.4 (cont.) Summary of Sootblowing Frequency

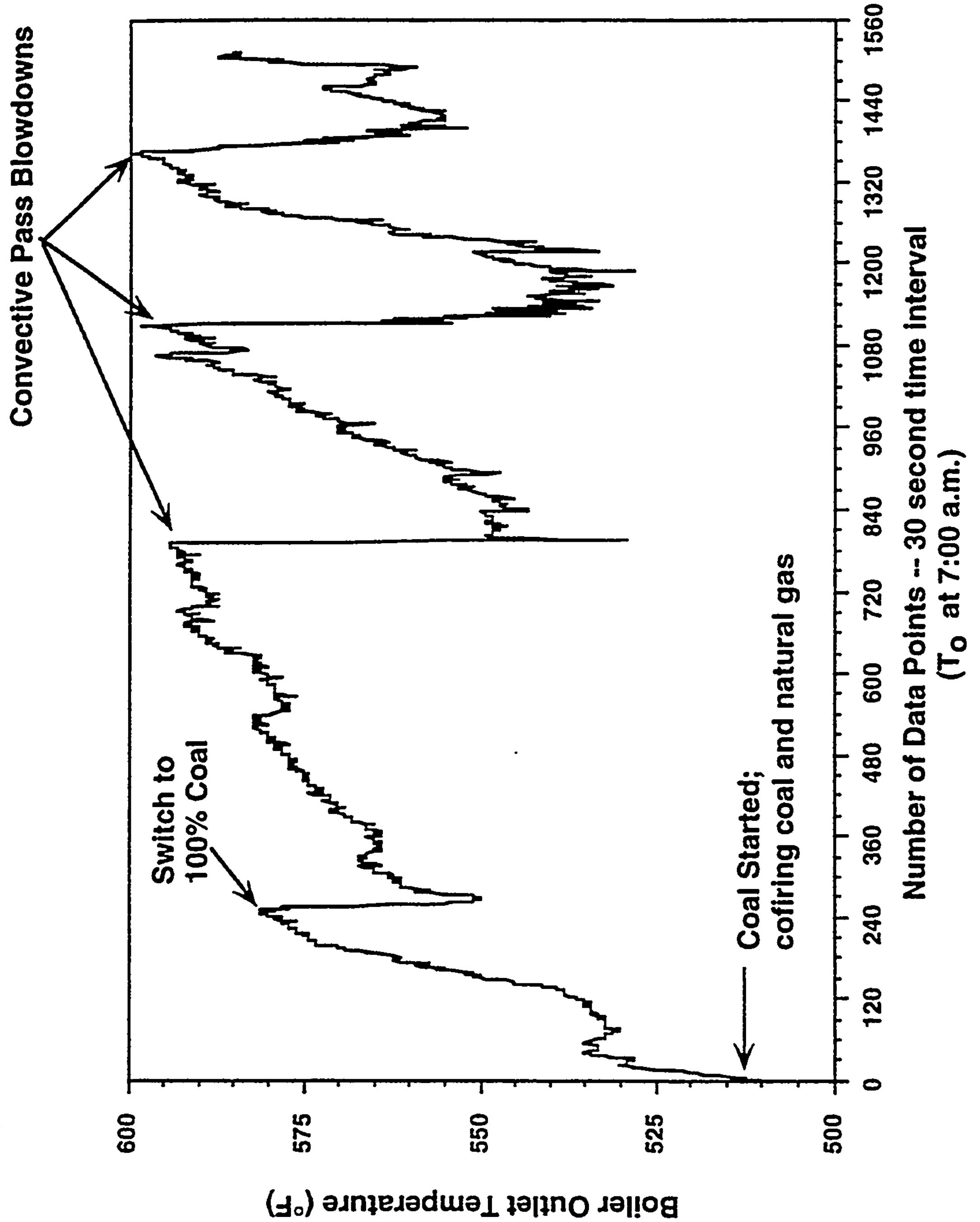


Figure 4.22 Example of Boiler Outlet Temperature vs. Time

(~07:00) and end of most days (~18:00 to 20:00) and was not strictly a function of boiler outlet temperature. Noting this, initially 4,000 to 6,000 lb of coal were consumed between soot blowing events (Events 1-10) which decreased to 1,000 to 2,000 lb of coal consumed between soot blowing events as ash deposition increased (Events 11-26). The boiler was cleaned on April 15, 1994 and coal consumption increased to as high as ~7,000 lb between soot blowing events (Events 26-28).

Testing was stopped on April 15, 1994 because a significant quantity of ash was building up on the floor and walls of the furnace. Approximately 260 and 100 lb of ash were recovered from the boiler and breaching, respectively. The ash buildup in the boiler varied in depth from approximately 6-8" in the front third of the boiler, to 3-4" in the middle third of the boiler and 3" in the rear third of the boiler. As a consequence of this buildup, a manufacturer of commercial soot blowing systems was approached for options for ash entrainment. However, their recommendation of retractable soot blowers was not adopted and Penn State is currently designing, on another program, a floor blast system.

Ash deposition was also observed when firing the Brookville Seam coal and the extent varied considerably. Initially soot blowing occurred after consuming 4,000 to 7,000 lb of coal (March 11, 1994 in Table 4.4). The boiler was cleaned between March 11 and 29 when the transition piece was inserted into the mill. After the boiler was cleaned, the soot blowing frequency decreased to between 11,000 to 30,000 lb of coal consumed between soot blowing events (March 22 to 29, 1994). The Brookville Seam coal testing stopped on March 31, 1994 to begin testing the Kentucky coal. The Brookville Seam coal testing resumed on April 20, 1994. Figure 4.23 is a similar plot to Figure 4.24 but is for the Brookville Seam coal for testing from 04/20/94 to 04/31/94. Coal consumption varied from 1,000 to 3,000 lb between soot blowing events (Events 1-8) after testing the Kentucky coal (no boiler cleaning was done prior to beginning the Brookville Seam coal testing). After the boiler was cleaned, coal consumption varied from 1,000 to 8,000 lb between soot blowing events. Although the extent of ash deposition was less with the Brookville Seam coal than with the Kentucky coal, overall ash deposition is a concern and options to alleviate ash accumulation in the boiler are being investigated and will be incorporated into the boiler system before demonstration testing.

It was initially suspected that the Kentucky coal may have had lower ash fusion

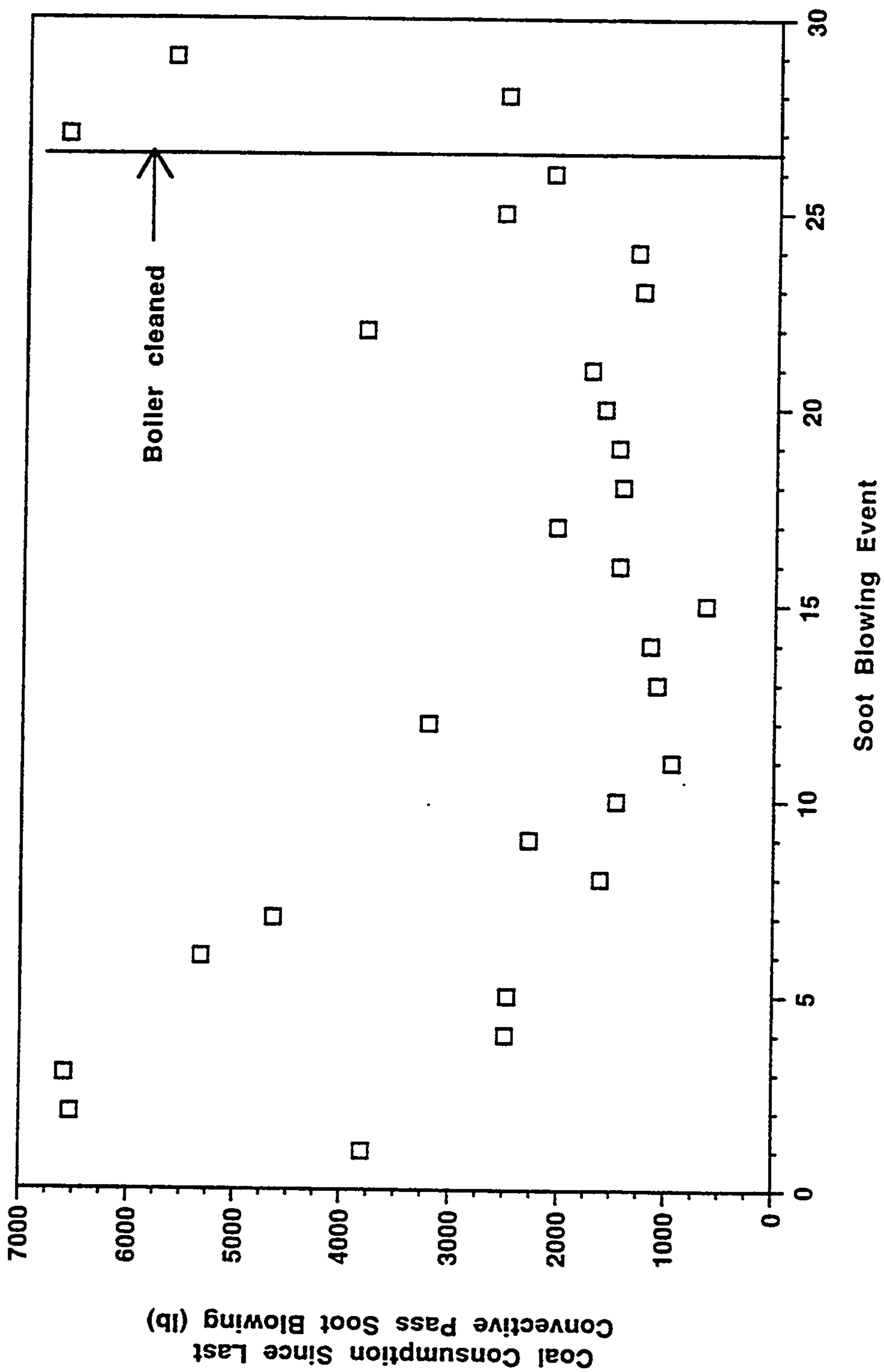


Figure 4.23 Quantity of Kentucky Coal Consumed Since Last Convective Pass Sootblowing

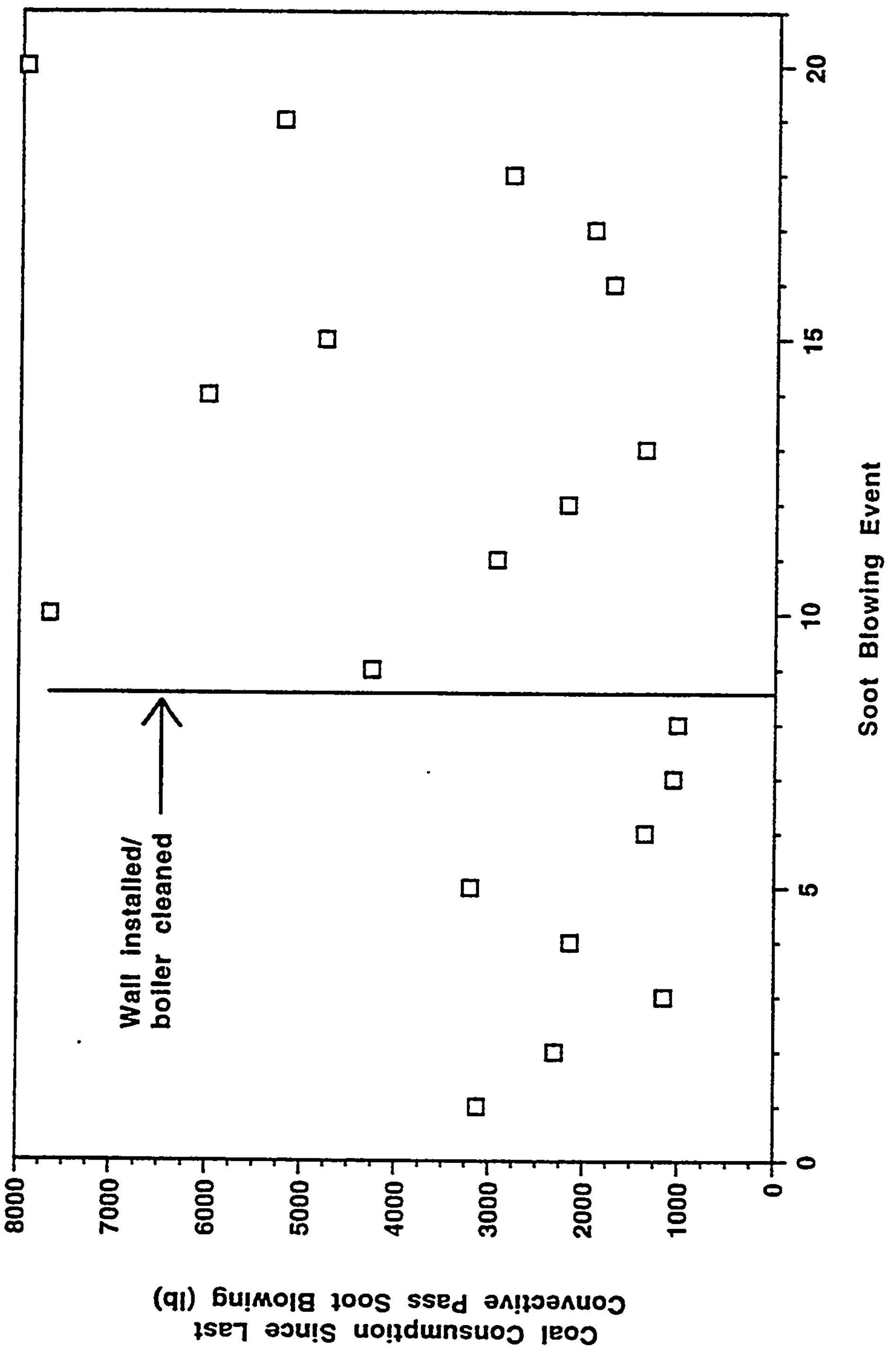


Figure 4.24 **Quantity of Brookville Seam Coal Consumed Since Last Convective Pass Sootblowing**

temperatures than the Brookville Seam coal. However, as Table 4.5 shows, the ash fusion temperatures are similar. The ash fusion temperatures also exhibited some variability.

Coal Sample	Ash Fusion Temperatures (°F)							
	Reducing Conditions				Oxidizing Conditions			
	I.D.[a]	S.T.[b]	H.T.[c]	F.T.[d]	I.D.	S.T.	H.T.	F.T.
Brookville Seam - #1[e]	2,758	2,786	2,792	2,804	2,812	2,850	+3,000	+3,000
Kentucky[f]	2,803	+3,000	+3,000	+3,000	+3,000	+3,000	+3,000	+3,000
Brookville Seam - #2[g]	2,820	+3,000	+3,000	+3,000	+3,000	+3,000	+3,000	+3,000
Brookville Seam - #3[h]	2,757	+3,000	+3,000	+3,000	N.D.[i]	N.D.	N.D.	N.D.

[a] Initial Deformation
[b] Softening Temperature
[c] Hemispherical Temperature
[d] Fluid Temperature
[e] Composite of all screw feeder samples collected from 03/10/94 to 03/31/94
[f] Composite of all screw feeder samples
[g] Sample collected on 04/26/94
[h] A second sample of Brookville Seam - # 2 was ashed and analyzed
[i] Not Determined

Table 4.5 Ash Fusion Temperatures of the Brookville Seam and Kentucky Coals

4.4.5 Analytical Combustion Modeling

One of the technical goals during the 400 hour testing period under Task 3 was to achieve 98% combustion efficiency with 100% micronized coal firing . Results from the 400 hour testing segment show that the highest average steady state combustion efficiency that could be reliably reached in the Penn State boiler was around 95%. Data from the 400 hour testing period were evaluated to understand which of the key parameters might be adjusted to achieve the desired burnout. It was difficult to pinpoint any cause and effect relationships which would help to explain the primary controlling independent variables which might improve combustion efficiency.

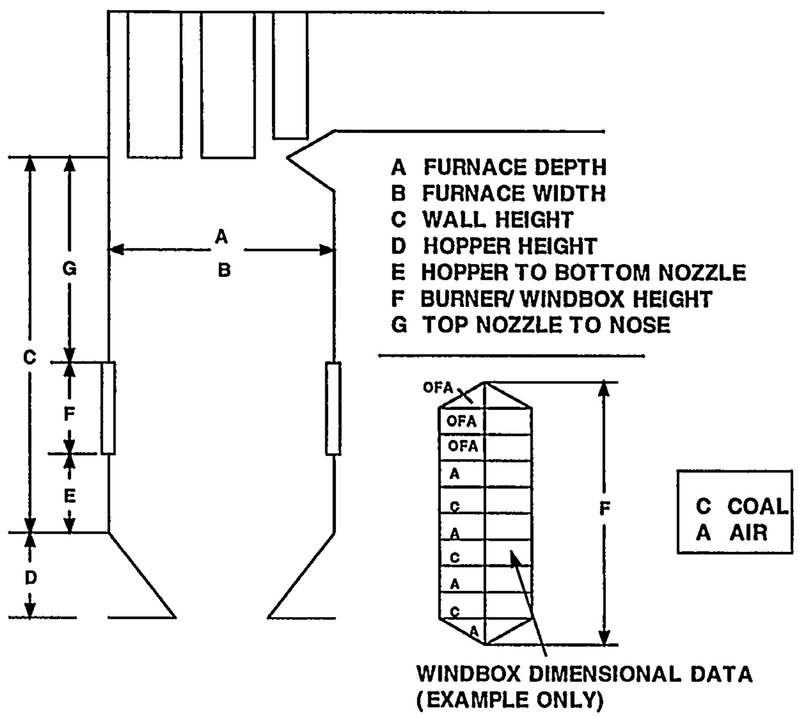
In order to identify reasons for the lower combustion efficiency than the original goal (95% vs. 98%), and to evaluate which key parameters (i.e, fineness, residence time, coal reactivities etc.) are important for maximizing the combustion efficiency, ABB CE's proprietary mathematical model known as the Lower Furnace Program-Slice Kinetic Model (LFP-SKM) was use for simulating the combustion process in the Penn State boiler. The methodology used in this program is depicted in Figures 4.24a and 4.24b. Essentially, the Drop Tube Furnace System-derived kinetic information is used in conjunction with fuel and boiler design and operating information and the mathematical model (LFP-SKM) for predicting carbon loss. The LFP-SKM is one of ABB CE's standard tools for predicting carbon loss in utility scale tangentially fired pulverized coal applications.

Fuel kinetic information for this study was selected for a similar (surrogate) fuel from ABB CE's extensive in-house data base.. Since the Penn State Boiler is considerably smaller and of a different type compared to the normal utility boiler application, some simplified assumptions were required for the LFP-SKM model.

The key input data used for the fuel and operating conditions were:

Burner-Related Inputs

- Coal Feed Rate = 1200 lb/hr
- Excess Air = 20 %



0 % EXCESS AIR
0 % OVER FIRE AIR (% OFA) (IF ANY)
0 % GAS RECIRCULATION (IF ANY)
0 COAL FEED RATE
0 COAL FINENESS (% ON 50 OR 100 MESH AND % -200 MESH)
0 COAL ANALYSIS

FIGURE 4.25a BOILER DIMENSIONAL/ OPERATING DATA REQUIRED FOR ABB CE'S LFP-SKM INPUTS

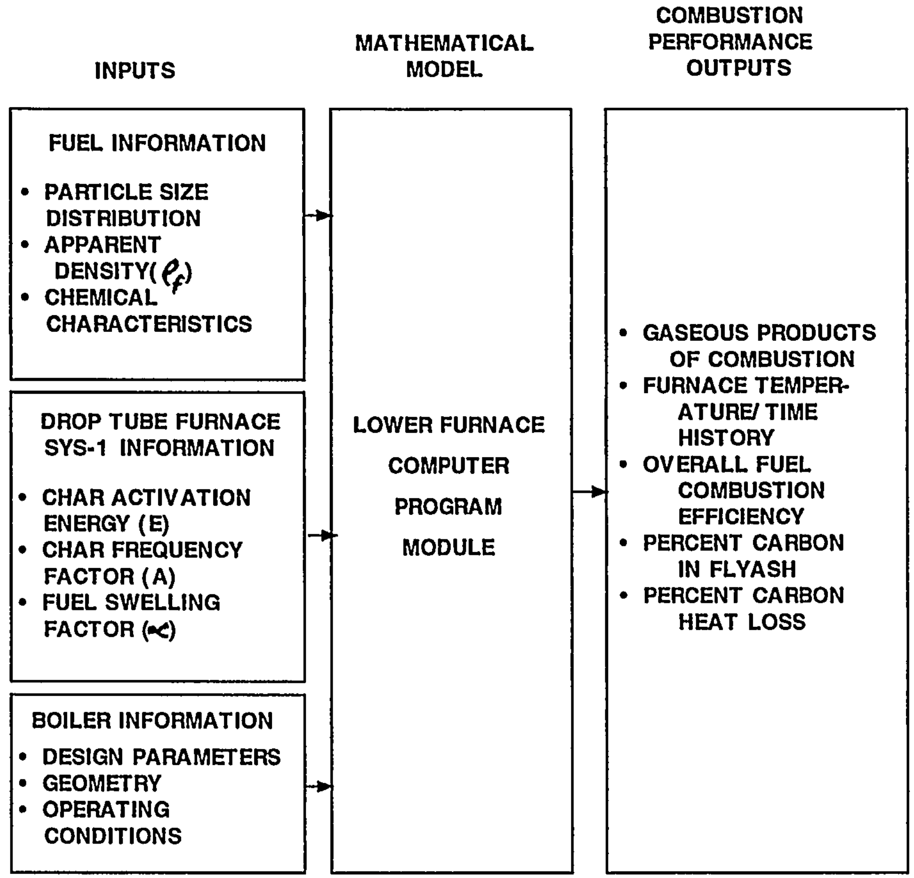


FIGURE 4.25b FLOW DIAGRAM FOR ABB CE'S LOWER FURNACE COMBUSTION PERFORMANCE MODEL SIMULATION

Coal Analysis

- Proximate, wt%
  - Moisture = 8.0
  - Volatile Matter = 34.3
  - Fixed Carbon = 54.9
  - Ash = 2.8

- HHV Btu/lb = 13,100

Based on the size and operating conditions (i.e., volumetric flows, temperature) of the Penn State boiler, the calculated bulk residence time up to connective entrance varies from 0.6 to 0.7 seconds (note: particle residence times can be very different from bulk residence values). Assuming that coal particle residence times could be greater than bulk, gas residence time simulations were made for residence times of up to 1.0 second by intentionally increasing the boiler length (~8 ft vs ~ 13 ft.). The assumption of particle residence times greater than the bulk residence time permitted analysis of particle burnout vs. residence time for a larger time than dictated strictly by bulk residence time.

A typical LFP-SKM result from this work is shown in Fig. 4.25. This figure shows predicted combustion efficiency as a function of bulk residence time for two different coal fineness values. The results clearly show the effect of residence time and fineness (especially top size) on combustion efficiency. Specifically, combustion efficiency can increase by 1% as either residence time increases from 0.7 to 1.0 second or as coal fineness increases from 75% -325M and 0.1% +100 M to 75% -325M and 0.01% +100 M.

In general, the experimental tests showed less sensitivity to particle size than the analytical results from the LFP-SKM model. Although it was difficult to pinpoint any cause and effect relationship from the experimental data, the LFP-SKM simulations clearly show the effects of residence time and coal particle top size on combustion efficiency. Both the experimental and analytical work show that the Penn State boiler (with residence time of about 0.7 sec.) represents a definite challenge for burning coal at high combustion efficiency.

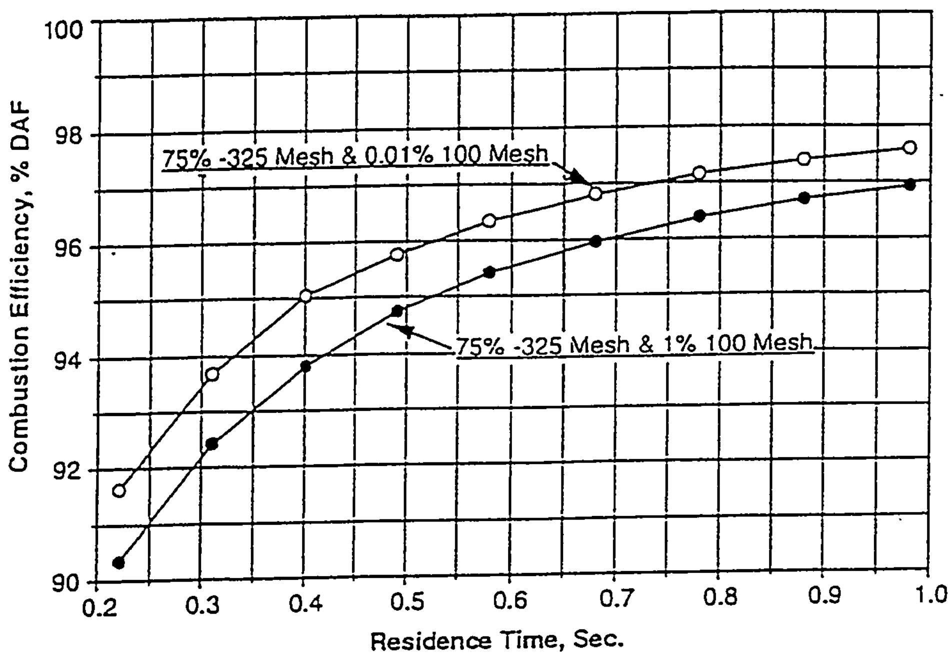


Figure 4.26 Combustion Efficiency vs. Residence Time (2 Values of Coal Fineness)

5.0 CONCLUSIONS/ RECOMMENDATIONS

The following specific conclusions are based on the results of the coal fired testing at Penn State and the initial economic evaluation of the HEACC system:

- A coal handling/ preparation system can be designed to meet technical requirements for retrofitting micro-fine pulverized coal.
- The boiler thermal performance met requirements
- Combustion efficiencies of 95% could be met on a daily average basis, somewhat below target of 98%
- NOx emissions can meet target of 0.6 lb/million Btu

As a result of recent long term tests using micronized coal, Penn State has experienced some convective pass ash deposition problems. To alleviate this problem they are planning to install additional soot blowers. Also, as a result of problems encountered during the 400 hour testing, the following modifications were planned for the Penn State system:

Coal handling improvements

a) Improved raw coal/ storage and transport
b) Redesign/installation of a surge bin mass flow bottom
c) Installation of a gravimetric feeder

Monitoring ash deposit effects

a) Air sparge/soot blower systems
b) Monitoring heat transfer effects in the furnace and the convective pass
c) Ash deposition probes

In addition, ABB CE plans to modify the burner for more precise aerodynamic control of the fuel and air streams to improve the combustion efficiency and NOx emissions.

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APPENDIX A Example of Boiler Efficiency Calculations

Table A1 presents a summary of a typical data and calculation spreadsheet that was prepared for each of the gas and coal fired tests.

	A	B	C	D	E	F
1	**Demonstration**		**Boiler Data**			
2	Date of Operation	9/23/93	; GAS BASELINE TEST #1			
3		100% Gas;100% load; 2% O2;Max;100/100;6h				
4	Pressures and Temperatures		Steam Data			
5						
6	Drum Steam Pressure (Psig)	219	Enthalpy of Sat. Liq. (Btu/lb)	370		
7	Feed Water Temperature (°F)	224	Entahlpy of Feed Water (Btu/lb)	193	(Sat. liquid @ Feed water temp.)	
8	Steam Quality (% moisture)	99.99	Steam Production Rate (PPH)	13,063		
9	Gas Temp.Leaving Boiler (°F)	569	Blow down Rate (PPH)			
10	Gas Temp. Leaving Air Heater (°F)	348	Enthalpy of water vapor at Glvg Temp (Btu/lb)	1218	(Sup. steam @ 1psia&gas lvg temp)	
11	Air Temp Entering Air Heater (°F)	76	Entalpy of water at fuel inlet temp. (Btu/lb)	37	(Sat. liq. @ mill inlet temp.)	
12	Air temp leaving Air Pre Heater (°F)	365	Entalpy of vapor at fuel inlet temp. (Btu/lb)	1091	(Sat. vapor @ mill inlet temp.)	
13	Air Temp Entering Boiler (°F)	338				
14	Mill Inlet Temperature (°F)	69				
15	Mill air flow rate (lb/h)	847	Coal Firing Rate (lb/min)	0	Gas Firing Rate (lb/h)	741
16	Burner inlet temperature (°F)	68	Coal H.H. Value (Btu/lb)	0	Gas Cal. Value (Btu/lb)	23346
17	FUEL DATA		Coal Moisture Content (%)	0		
18	Proximate Analysis					
19	Moisture (Wt%)		Ultimate Analysis (Wt%. d.b)		Gas Analysis (Dry Vol%)	
20	Volatile Matter (Wt%)					
21	Fixed Carbon (Wt%)					
22	Ash (Wt%)		Carbon	0	Methane	95.54
23			Hydrogen	0	Ethane	2.48
24	HHV (Btu/lb,. d.b)		Nitrogen	0	Propane	0
25			Sulfur	0	Butane	0.43
26			Oxygen	0	Hydrogen Sulfide	0
27			Ash	0	Carbon Dioxide	1.55
28			Total	0	Nitrogen	
29					Others	
30	Flue Gas Analysis				Total	100
31					Moisture (wt%)	0.05
32	Oxygen (%)	2.1				
33	Carbon Dioxide (%)	11.3	Ash in Dry Char/Refuse	0		
34	Carbon Monoxide (PPM)	5	TOTAL CARBON CONVERSION	100.00		
35	Sulfur Dioxide (PPM)	NA	COAL CARBON CONVERSION	0.00		
36	Oxides of Nitrogen (PPM)	159				
37						
38						
39						
40						
41						
42						

Table A1 Example Boiler Efficiency Calculations

	A	B	C	D	E	F
43			Summary of Boiler Performance			
44						
45						
46	Date of Operation	9/23/93				
47						
48						
49						
50						
51	Boiler Operating Conditions					
52						
53						
54	Total Firing Rate		17.299386	MMBtu/h		
55	Gas Support (%)		100.00	%		
56	Excess air used (%)		10.11	%		
57						
58	Actual mass of products of combustion	=	14863.35554	lb/lb of "as fired" fuel		
59						
60	Theoretical flue gas composition	%				
61	Carbon Dioxide	8.77				
62	Water vapor	17.40				
63	Oxygen	1.76				
64	Nitrogen	72.07				
65	Sulfur Dioxide (ppm)	0				
66	Total	100.00				
67	Boiler Efficiency Details					
68				%		
69	1. Heat loss due to Dry gas (%)			4.64		
70	2. Heat loss due to unburned carbon			0.00		
71	3. Heat loss due to unburned carbon in dust			Negligible		
72	4. Heat loss due to moisture in "as Fired Fuel"			0.00		
73	5. Heat loss due to moisture produced from burning hydrogen in fuel			10.85		
74	6. Heat loss due to moisture in combustion air			0.13		
75	7. Heat loss due to formation of carbon monoxide			0.00		
76	8. Heat loss due to radiation			1.26		
77	9. Heat loss due to steam drum blowdown			0.00		
78	Total Losses			16.88		
79	Heat Credits					
80	1. Heat supplied by duct burner to entering air			-123.82	Btu/lb of "as fired fuel"	
81	2. Heat supplied by primary (transport) air			-207.94	Btu/lb of "as fired fuel"	
82						
83	BOILER EFFICIENCY (%)			82.88		

Table A1 (Continued) Example Boiler Efficiency Calculations

	G	H	I	J	K	L	M	N	O	P	Q
1				Boiler Performance Calculations							
2											
3											
4		Conversion of Gas Composition from Volume % to Wt%									
5	Fuel Gas Composition (Dry. Vol%)		Density at 60°F (lb/cu.ft)		lbs in each Cu.ft of gas		N. Gas Composition (Wt%, d.b)			As Fired (wt%)	
6	Methane	95.54		0.04246	0.04056628		Carbon	73.40		73.3583626	
7	Ethane	2.48		0.08029	0.00199119		Hydrogen	24.01		23.9954486	
8	Propane	0		0.1196	0		Nitrogen	2.60		2.59618878	
9	Butane	0.43		0.1582	0.00068026		Sulfur	0.00		0	
10	Hydrogen Sulfide	0		0.09109	0		Oxygen	0.00		0	
11	Carbon Dioxide	0		0.117	0		Moisture	0.00		0.05	
12	Nitrogen	1.55		0.07439	0.00115305		Total=	100.00		100.00	
13	Total	100									
14			Density of N. gas (lb/cu.ft) =		0.04439078						
15											
16											
17											
18		Determination of Percent Gas Support									
19											
20											
21											
22	Coal Firing Rate (lb/h)	0									
23	Coal Heat Input(Btu/h)	0		As Fired Coal Composition (Wt)			"As Fired" Fuel (coal+nat. gas) Composition (Wt%)				
24				Carbon	0.00		Carbon	73.36			
25	Gas Heat Input (Btu/h)	17299386		Hydrogen	0.00		Hydrogen	24.00			
26	Total Firing Rate	17299386		Nitrogen	0.00		Nitrogen	2.60			
27	Gas Calorific Value (Btu/lb)	23346		Sulfur	0.00		Sulfur	0.00			
28	Gas Firing Rate (lb/h)	741		Oxygen	0.00		Oxygen	0.00			
29	Gas Support (% of Heat)	100.00		Ash	0.00		Ash	0.00			
30	Fraction of coal	0		Moisture	0		Moisture	0.05			
31	Fraction of GAS	1		Total	0		Total	100.00			
32											
33				HHV	0		HHV	23346			
34				Dry ash%	0		Dry Ash	0.00			
35											
36											
37											
38											
39											
40											
41											
42											

Table A1 (Continued) Example Boiler Efficiency Calculations

	G	H	I	J	K	L	M	N	O	P	Q
43	Calculation of Air Requirement and Theoretical Products of Composition										
44											
45			Theoretical Oxygen Requirement								
46	Carbon= %C/(100*12) *1mole =		0.06113197	moles							
47	Hydrogen= %H/(100*2)*0.5 mole =		0.05998862	moles							
48	Sulfur= %S/(100*32) *1 mole =		0	moles							
49											
50	Oxygen required= Sum of the 3		0.12112059	moles							
51	Oxygen available in the Fuel= %O/(100*32)		0								
52	Net Oxygen required =		0.12112059	moles							
53	Theoretical Dry Air for Combustion = Net Oxygen required/0.21 =										
54			0.57676472	moles/lb of as fired fuel							
55											
56	Calculation of Products of combustion										
57											
58	Excess air used (%)		= 100(O2-CO/2)/(0.264*N2-(O2-CO/2)=			10.11					
59											
60	Actual Dry air Required (moles) = (1+E.A%)* total air required =					0.63509395					
61	Dry air in lbs/lb of "as fired" fuel			= moles of air*29.97 =		19.0337656					
62											
63	Actual wet air used/lb of "as fired" fuel (assuming 60% R.H and 80°F)=										
64		=	lbs of dry air * 1.0013			19.0585095					
65											
66	Weight of products of combustion = Actual wet air used + weight of fuel=										
67					20.0585095	lb/lb of fuel					
68	Actual weight of products =		lbs of fuel burned * Wt of Products/lb of fuel								
69			=		14863.3555	lb of flue gas					
70											
71											
72											
73											
74											
75											
76											
77											
78											
79											
80											
81											
82											
83											

Table A1 (Continued) Example Boiler Efficiency Calculations

	R	S	T	U	V	W	X	Y	Z
1	**Calculation of Theoretical Composition of Products**								
2									
3									
4					Wet Flue Gas Compositon (%)			Dry Flue Gas Comp. (%)	
5	Carbon Dioxide	(=moles of carbon /lb of fuel)		0.06113197	8.77			10.61	
6	Water	(moles of water in fuel +moles							
7		of water in combustion air)		0.12137968	17.40			0.00	
8	Oxygen			0.01224914	1.76			2.13	
9	Nitrogen			0.50265143	72.07			87.26	
10	Sulfur Dioxide			0	0			0.00	
11	Total			0.69741222	100.00			100.00	
12	Carbon Conversion	100	Carbon Conversion of Coa	NA					
13		100.00							
14	**Boiler**	**Efficiency**	**Calculations**						
15									
16	These calculations are based on ASME PTC 4.1using heat loss method								
17									
18	1. Pounds of dry gas per pound of "as fired" composite fuel								
19									
20	Wg' =	((c% d.b) * C.Efficiency *(44.01 (CO2) + 32.00 (O2) + 28.02 (N2) + (28.01 (CO)/12.01 (CO2+CO)) + 12.01 (S)/32.07							
21									
22		16.16709194	lb/lb of as fired fuel						
23									
24	1. Heat loss due to dry gas (%)		Lwg' = Wg' * 0.24 * (348-69)/HHV *100			=	4.64		
25									
26									
27	2. Heat loss due to unburned carbon								
28									
29	Luc =	% Carbon in the "as fired Fuel" * (1-Comb.Efficiency) * 14,500				=	0.00		
30									
31									
32	3. Heat loss due to unburned carbon in dust						Negligible		
33									
34									
35	4. Heat loss due to moisture in "as Fired Fuel"								
36									
37	Lmf=	Moisture in Fuel (Entahlpy of vapor at gas leaving temp -							
38			Enthalpy of water at mill inlet)/HHV*100			=	0.00		
39									
40									
41	5. Heat loss due to moisture produced from burning hydrogen in fuel								
42									

Table A1 (Continued) Example Boiler Efficiency Calculations

	R	S	T	U	V	W	X	Y	Z
43	Lmfh=	8.936 *% hydrogen in "as fired" fuel* (Enthalpy of vapor leaving air heater-							
44			Enthalpy of water at mill inlet temp)/HHV			=	10.85		
45									
46	6. Heat loss due to moisture in combustion air								
47	Theoretical lb of air required for complete combustion/lb of "as fired' fuel								
48		=	(11.52(% carbon) + 34.57(% hydrogen-% oxygen/8) + 4.32 (% sulfur))/HHV=						
49									
50		=	16.75	lb/lb of "as fired" fuel					
51									
52	Actual dry air =	(1+% Excess air/100) lb/lb of "as fired" fuel							
53		18.44	lb						
54	Moisture in air =	0.013 lb /lb of dry air		0.23971576	lbs/lb of "as fired" fuel				
55	Lma =	moisture in air * (enthalpy of water vapor leaving air heater -							
56			enthalpy of vapor at mill inlet temp.)				0.13		
57									
58									
59	7. Heat loss due to formation of carbon monoxide								
60	Lco =	CO/(CO2+CO)*10160 * Combustion Efficiency* % carbon in 'as fired fuel				=	0.00		
61									
62									
63	8. Heat loss due to radiation		10 exp (0.62-0.42log Q)				1.26		
64									
65									
66									
67									
68	Total Losses (%)						16.88	%	
69	HEAT CREDITS								
70									
71	1. Heat supplied by duct burner to entering air					-123.82	Btu/lb of "as Fired" Fuel		
72	2. Heat supplied by primary (transport) air					-207.94	Btu/lb of "as Fired" Fuel		
73									
74	Boiler Efficiency (%)=						82.88		
75									
76									
77									
78									
79									
80									
81									
82									
83									

Table A1 (Continued) Example Boiler Efficiency Calculations

APPENDIX B Summary of Chronological History of Proof-of-Concept Coal fired Experiments

This section contains a summary of the experimental testing activities conducted at Penn State from January through April, 1994.

1) <u>January</u>

During January, the majority of the testing was directed towards the goal of firing the burner on micronized coal without natural gas support. This was an attempt to repeat operating conditions achieved in early December 1993. Operation in January was intermittent because of the weather and operational problems. A day-by-day synopsis of the boiler operation for January follows:

- January 3 -- The rubber hose that connected the end of the coal delivery piping (at the trench outlet) to the burner inlet was removed. Work was started on replacing the hose with piping. In addition, installation of a system to isokinetically sample the micronized coal was started. This included constructing sampling probes and assembling the sample train (fittings, filter canisters, tubing, flowmeter, and vacuum pumps). In addition, work continued (from December 1993) on repairing the feedwater pump. The bearings were being replaced and new packing was being installed.
- January 4 -- There were not sufficient personnel on site to operate the boiler because of a snow storm.
- January 5 -- The permanent connection from the coal delivery piping to the burner was completed and work continued on installing the coal sampling system. Work continued on the feedwater pump repair.
- January 6 -- Feedwater pump repairs were completed. Work continued on installing the coal sampling system.
- January 7 -- The boiler was cofired with micronized coal and natural gas but there were problems with air flow through the burner. The secondary air damper settings had to be set differently from earlier settings. When the damper was thought to be closed, based on previous experience, the damper was actually open, and vice versa. The boiler was shut down and allowed to cool in order to check the damper, which is located in the windbox.

- January 10 -- The three set screws which hold the damper to the handle were found to be loose. The damper was welded onto the handle.
- January 11-- During initial firing of the boiler, steam blew out of the feedwater pump. The boiler was shut down and the feedwater pump repacked. The boiler was fired again and a firing rate of ~60% of full load was achieved before the mill shut down (twice) on overloads (power consumption too high).
- January 12-14 -- The boiler was operated in an intermittent mode. The mill shut down periodically on overloads. No cause was established.
- January 17 -- Boiler operation using two shifts was started this week. Long-term operation (two to three shifts/day for a week) was to be conducted to characterize coal handling and transfer, mill performance, and boiler performance and operation, and to identify logistical problems that needed to be addressed for successful continuous operation.

  A coal sample was collected using the coal sampling system. The system consists of cyclone and filter assembly through which a coal sample is isokinetically drawn using a vacuum pump. Particle size distributions of the material collected in the cyclone and on the filter are determined using a Malvern 2600 Particle and Droplet Sizer. The filter sample constituted ~1.5 wt.% of the total sample collected. The top size of the cyclone sample was <113 μm and the D_{95} (particle size where 95% of the particles are less than that indicated), D_{90}, D_{50}, and D_{10} sizes were 56.6, 45.7, 20.9, and 6.8 μm, respectively. The top size of the filter sample was 25.8 μm and the D_{95}, D_{90}, D_{50}, and D_{10} were 13.2, 10.5, 4.2, and 2.1 μm, respectively. Additional testing was to be conducted to verify isokinetic sampling conditions.
- January 18-21 -- No testing was conducted. The natural gas supply to the University was shut off because of the cold weather, which resulted in the Governor of Pennsylvania declaring a State of Emergency.

  During the period of natural gas shutdown, minor repairs and routine maintenance were performed. Work also was started on building a walkway on the surge bin to allow personnel to safely stand on top of the bin. Because of the weather, wet coal has been causing handling problems resulting in coal clinging to the corners of the bin and a rathole forming. Periodically, the coal must be pushed down from the top of the bin. Beitzel

Engineering was to install additional air-sparge ports on the bin during the next month to promote better coal flow.

- January 24 -- Work continued on the walkway construction.
- January 25 -- The walkway construction was completed. Two shifts of boiler operation were conducted. Periodic loss of coal feed to the boiler resulted in the boiler shutting down several times. The moisture contents of coal collected from the main hopper, surge bin, and burner inlet were approximately 6, 8, and <2%, respectively. By the end of the second shift, the coal in the surge was consumed and coal containing slightly less moisture was transferred from the main hopper to the surge bin.
- January 26 -- Operation was better on this day in that coal feed was fairly constant and the boiler did not shut down due to loss of coal feed. However, after switching from natural gas/coal cofiring to coal only, the boiler/burner became unstable resulting in boiler shutdown.
- January 27 -- It was noticed that the belts on the forced draft fan were loose and it was suspected that the secondary air/tertiary air flow may be the cause, or part of the cause, for the difficulties in firing coal without natural gas support. The belts were tightened and the air flow became steady. However, the boiler/burner was still extremely unstable firing coal without gas support. The medium swirler was used (which is the swirler that produced the best flame pattern during previous operation) and the flame had a small diameter which resembled flames obtained using the high swirler and RO-II nozzle.
- January 28 -- Because the flame still was very compact, the boiler was shut down, the coal nozzle was removed, and the dampers and swirler were inspected. Nothing out of the ordinary was noted.

  The system was reassembled except that the swirler was left off. There was no visible change in the flame appearance. The low swirler was installed and initially, during high natural gas support, the flame looked better it was less compact. However, the boiler was shut down because the u.v. (ultra-violet) sensor reading was very low.
- January 31 -- Initial operation was with the low swirler. The flame was compact and the boiler/burner was unstable. The low swirler was removed and the reverse swirler installed. Initially (with a high level of natural gas

support) the flame was less compact. The flame became more compact as the coal feed rate was increased. Operation on coal only was not achieved.

B) February

During February, the majority of the testing was directed towards the goal of firing the burner on micronized coal without natural gas support. Operation in February was intermittent because of operational and burner/boiler stability problems. The day-by-day synopsis of the boiler operation for February, which was conducted with two shifts per day follows:

- February 1 -- Testing was conducted using the reverse swirler and the RO-II coal gun. Ratholing in the surge bin was experienced because of wet coal. This caused operating problems by disrupting coal feed to the mill and therefore to the burner. A wide, bright, and attached flame was obtained when cofiring natural gas (at ~3 million Btu/h) and coal; however, the flame became detached within minutes after eliminating the natural gas resulting in the boiler shutting down.
- February 2 -- Initially, the flame was very narrow, even at a low coal feed rate of ~4 lb/m. Adjusting the tertiary air damper did not influence the flame shape. The coal feed rate was eliminated to check the natural gas flame. The secondary and tertiary air dampers were adjusted to decrease the combustion air flow which resulted in a slightly wider flame. The resulting windbox pressure was very high (>8" H_2O). It was suspected that there may be problems with the damper. The boiler was drained and cooled down to permit access to the windbox to check the dampers. The dampers were inspected and were judged to be operating correctly.

  Water was added to the boiler and it was fired with natural gas. A wide and attached flame was achieved by closing the tertiary air damper and completely opening the secondary air damper. As the coal feed rate was increased, the tertiary air damper was opened to increase the amount of combustion air. The boiler was operated cofiring natural gas and coal. It was unclear why the flame shape from early in the day was so different from that observed later in the day.

- February 3 -- Coal ratholing in the surge bin was experienced. Despite the ratholing, approximately 8 hours of testing was obtained cofiring coal and natural gas (17% of total heat input).
- February 4 -- Some coal feed problems were encountered early in the day. Approximately four hours of testing was conducted at conditions similar to those on February 3 (17% natural gas support), followed by four hours of firing 100% coal.
- February 7 -- A delivery of coal was received. Because of the recent snow storms, the coal contained a significant quantity of ice.

  Pat Jennings was on site and entered the boiler to inspect the burner and measure tertiary and secondary air flows using a hot-wire anemometer. Figure B1 gives a schematic diagram of the front of the burner showing relative locations of the natural gas spuds, secondary air swirler vanes, and approximate locations where the secondary and tertiary air flow measurements were made. The results of the measurements are given in Figure B2. After taking the measurements in the boiler, the boiler was operated on natural gas late in the day to heat the system up prior to testing the following day.
- February 8 -- Feeding problems were encountered due to the wet coal. In addition, it was difficult to keep the flame anchored to the burner and to obtain a strong u.v. signal. TCS, Inc. ordered parts to install more air-sparge ports on the surge bin.
- February 9 -- Coal feed was interrupted several times due to wet coal adhering to the sides of the surge bin. Personnel used a hand-held air probe to keep the coal feeding from the surge bin.

  The reverse swirler was replaced with the high swirler. A full ring of flame was not obtained. The flame was positioned from 3:00 to 9:00 (lower half circle).
- February 10 -- Additional feeding problems were encountered because of the wet coal. The screw feeder plugged and coal was hanging up in the surge bin. In addition, problems were encountered with the feedwater pump and the boiler was shut down to perform maintenance on the feedwater pump.

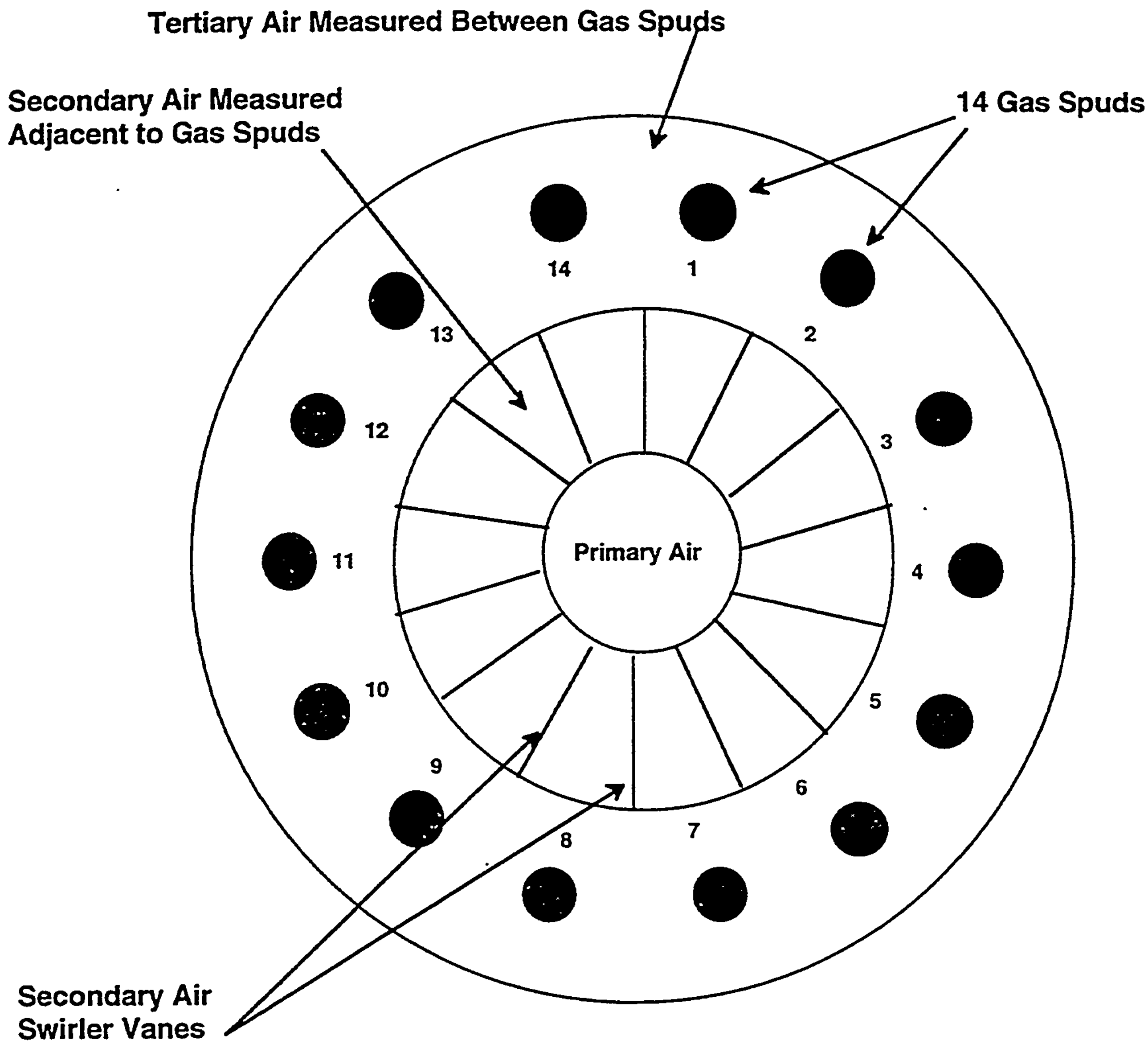

Figure B1 **Front View of the Burner Showing Relative Location of GasSpuds**

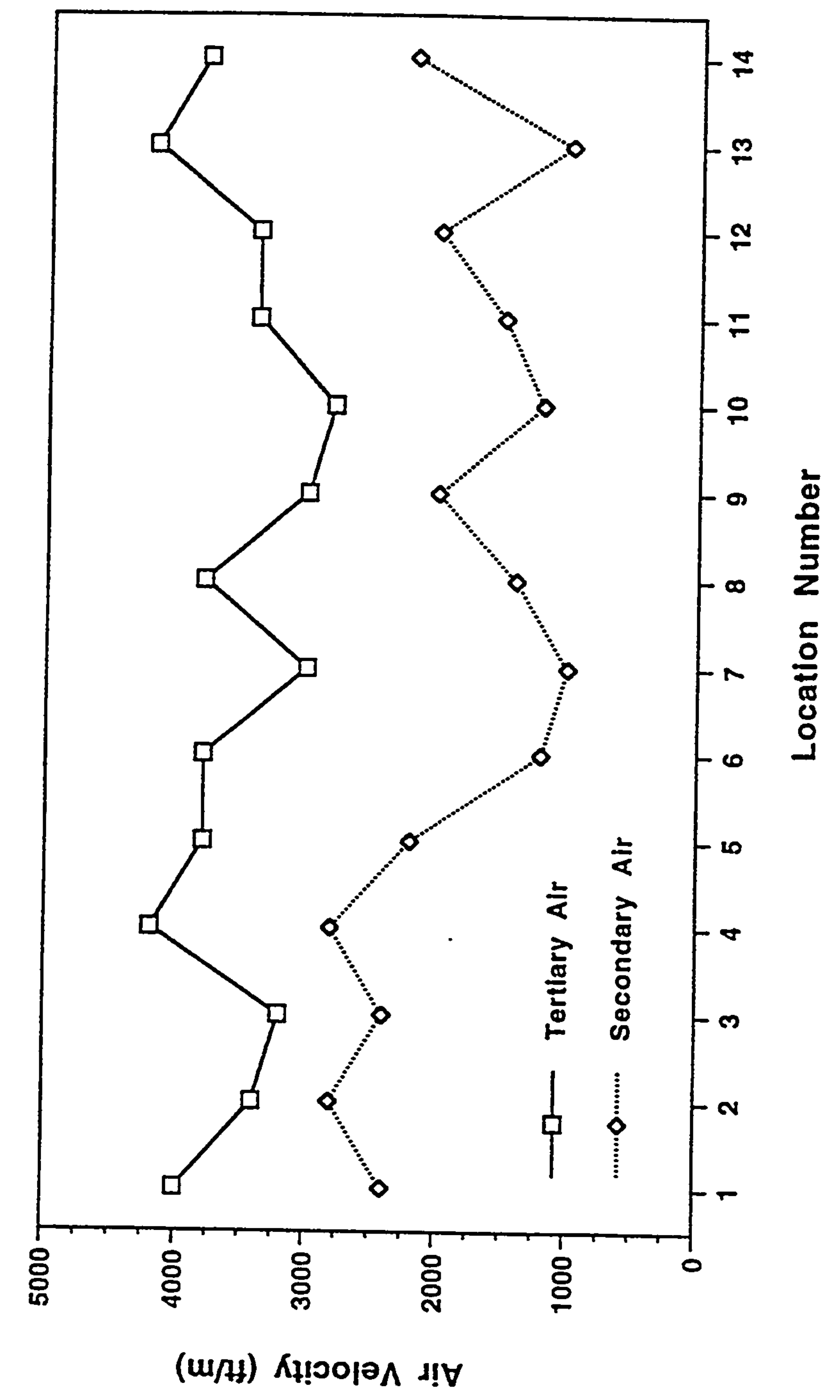

Figure B2 Tertiary and Secondary Air Velocities Measured at the Burner Face

- February 11 -- Pat Jennings suspected, and wanted to verify that the burner was causing nonuniform coal feed. The mill air flow was varied from 300 to 420 acfm with little change in the flame pattern observed.
- February 12 (Saturday) -- Beitzel Engineering, the company which installed the coal process equipment, was on site to install air-sparge ports. Figure B3 shows a schematic diagram of the surge bin giving the locations of the sparge ports.

  There are a total of 22 ports on the surge bin with ten ports actively used. The top three ports on each side (for a total of 12) were not used. Rubber hoses connect from the air-sparge header to the ports on the bin. The lines from the header outlets, numbered 1 through 6 on Figure B3, are divided into two lines using a tee and are connected to two ports on the bin. The sequence of the sparging, the duration of the air blast, and the delay between activating ports is controlled automatically. Solenoids activate one line from the header at a time (i.e., two ports on the side bin at a time) and the timing sequence predominantly used was header outlet 1, followed by 3, 2, 5, 6, 4, and back to 1. Each solenoid was activated for 0.5 s (duration of air blast) with 5.0 s between air blasts. The sparging would cycle from sparge header outlet 1 back to sparge header outlet 1 in ~33 s.
- February 14 -- The screw conveyor was plugged with coal and it took the entire day to clean out the system.
- February 15 -- Several problems were encountered. Initially the flue gas analyzers could not be brought on line because ice had formed in the sample lines. This was addressed and the analyzers were made operational. Next, the feedwater pump began leaking and was repaired. Finally, the TCS mill would not start and a faulty oil pump (for lubricating the bearings) was identified as the problem.
- February 16-18 -- TCS Inc. was on site on February 16th and the oil pump was replaced. When the boiler was started up it was noted that the flue gas analysis was incorrect. Additional leaks were identified, as a result of the ice that had formed in the sample line, and repairs were completed on February 18th. When cofiring coal and natural gas on February 18th, the flame was still only a partial circle.
- February 21 -- Representatives from ABB-CE were on site to observe the burner and meet with Penn State to discuss the status of the project and

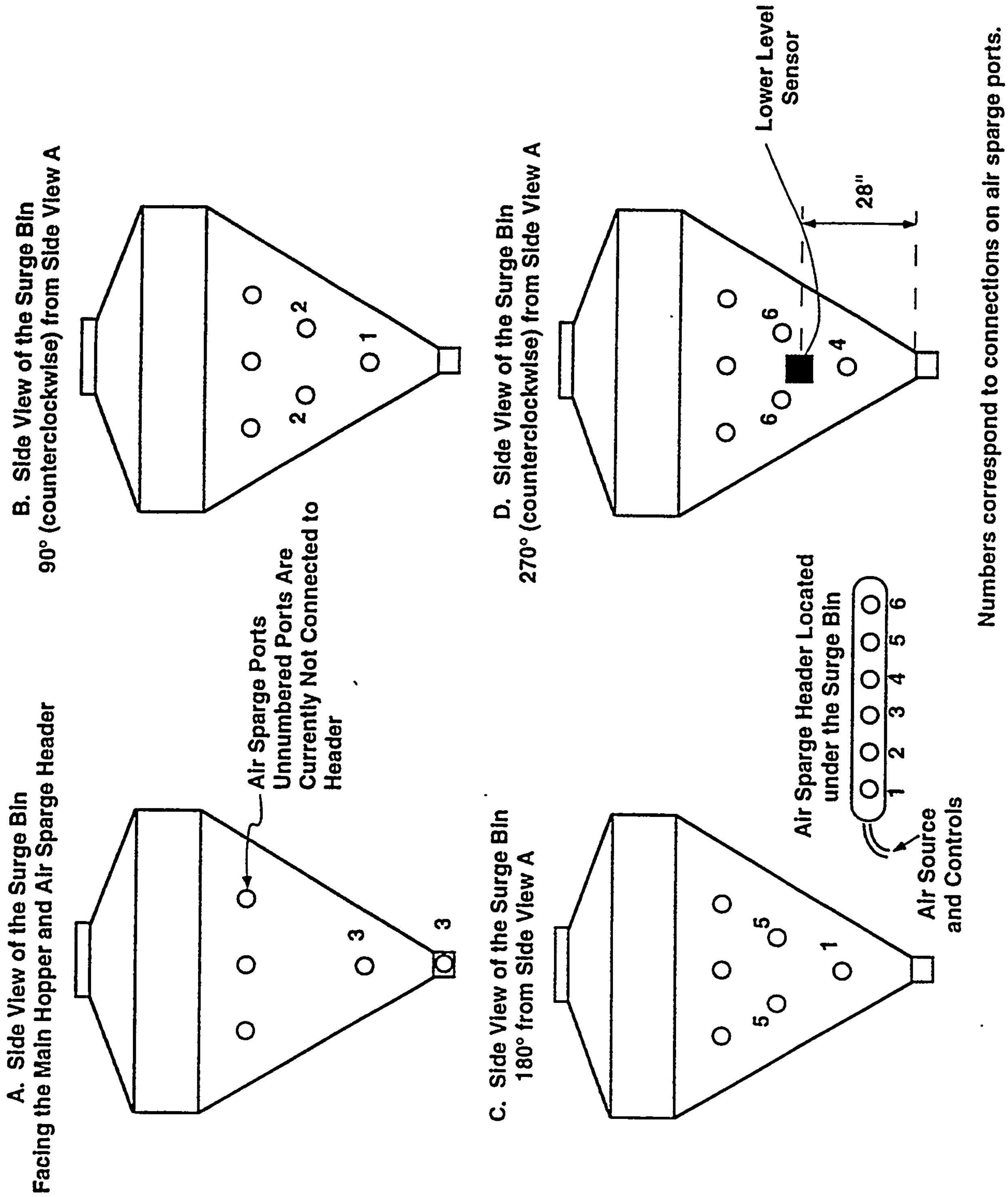

Figure B3 Side Views of the Surge Bin Showing the Locations of the Air Sparge Ports formulate a strategy for the last month of testing. Specific items that were identified to be addressed were:

1) Install secondary and tertiary air pressure taps and manometers (completed 02/21/94).
2) Remove the coal gun center pipe (3" in diameter) and put in a smaller pipe (3/4" diameter) to achieve 30-40 ft/s bulk velocity (completed 02/24/94).
3) Operate the mill with less air after modifying the mill outlet to reduce the cross section (completed 03/17/94).
4) Remove the flexible hose connecting the coal transfer piping with the burner and reinstall the hard pipe with the coal sampling ports (completed 02/21/94).
5) Conduct a mill characterization study (completed 04/28/94).
6) Change the mill speed to reduce the coal top size. This was done during the mill characterization study.
7) Order (by ABB-CE) a truckload of the second test coal (Kentucky, low ash coal) after the current Brookville Seam coal shipment is consumed. It was anticipated that the second coal would be drier than the Brookville Seam coal being stockpiled for the program and would be used to eliminate coal handling problems and for evaluation of the burner performance. This was done in April, 1994. CE used the Kentucky coal when evaluating the burner performance in their test facility and were able to compare the performance of the burner in Penn State's boiler and ABB-CE's combustor.

The boiler was operated cofiring natural gas and coal and a full ring of flame was not obtained. Feeding problems were encountered as the cage mill (crusher) plugged with coal.

- February 22 -- The boiler was operated all day even though coal feeding problems were encountered. Coal was adhering to the sides of the surge bin and the cage mill packed.

  As a consequence of the February 21st meeting, the flexible hose connecting the outlet of the coal pipe to the TCS mill was replaced with the hard pipe which contained the coal sampling ports.

- February 23 -- Initially some feeding problems were encountered; however, the second shift operated the boiler, cofiring coal and natural gas (23% gas support), without losing the flame.
- February 24 -- The boiler was operated at 21% natural gas support. The main coal hopper was emptied and readied for delivery of the second coal.
- February 25 -- The last of the current shipment of the Brookville Seam coal was consumed.

3) March

During March, the primary objective was to fire the burner on micronized coal without natural gas support. Fewer coal handling problems were experienced in March than in February, primarily because the coal was less wet. Consequently, coal only operation was achieved. A day-by-day synopsis of the boiler operation for March, which was conducted on two shifts per day follows:

- March 1 - 5 -- No testing was conducted. The Brookville Seam coal was consumed on February 25, 1994 and delivery of coal from Kentucky was anticipated. However, ABB-CE was unable to obtain dry Kentucky coal and therefore decided that the testing should continue with the Brookville Seam coal. Brookville Seam coal was received on March 2, 1994.

  Data acquisition and safety-related activities were conducted from March 1 to March 4. These included the installation of: guard rails on the surge bin and ash screw conveyor platform, ash screw conveyor belt guard, remote computer screen and pad in the boiler room, and pressure transducers at the mill outlet.

  The University shut down on March 3 due to a snow storm.
- March 7 -- A new coal curve for the screw feeder was generated but only natural gas was fired. Problems (low steam pressure) were encountered with the steam valve/regulator which regulates the flow and pressure of the steam from the demonstration boiler into the University's steam distribution line. The valve was dismantled and inspected. In addition, the ash screw was frozen and had to be dismantled.
- March 8 and 9 -- The ash screw was repaired. The steam valve/regulator was repaired.

- March 10 -- The boiler was cofired with natural gas and coal using the RO-II configuration with the medium swirler. Initially, the flame was poor in that there was only a partial ring of flame (5:00-8:00 as observed through the rear sight port). A 4-inch diameter pipe was placed over the 3-inch diameter pipe that is located in the center of the coal gun to increase the coal/primary air velocity exiting the burner by ~30%. A full-ring of flame was achieved.
- March 11-- Approximately four hours of 100% coal operation were obtained. Ratholing was observed in the main coal hopper. Coal combustion efficiency ranged from ~92 to 96%. After the boiler was shut down at the end of the day, the medium swirler was replaced with the maximum swirler for operation on March 14.
- March 14 -- A good flame was observed in that there was a full ring of flame and it was wider with the medium swirler. Coal feed was lost once. Coal combustion efficiency was ~95-96.5% when firing 100% coal for approximately four hours.
- March 15 -- The boiler was successfully operated firing 100% coal for approximately six hours. Coal combustion efficiency was ~95%. Deposition was noted on the back wall and system temperatures were increasing. It was decided to clean the boiler the following day. The boiler was drained after it was shut down to lower the temperature inside the boiler so that it could be entered and cleaned.
- March 16 - 17 -- The ash deposited on the boiler walls was removed on March 16. In addition, work began on inserting a transition piece into the mill outlet and replacing the piping from the mill to the booster fan so that they would be the same size as the 4" diameter coal transfer pipe from the booster fan to the burner. A drawing of the transition piece is given in Figure B4 with its location in the mill exit ducting shown in Figure B5. The modifications were completed on March 17.
- March 18 -- The boiler was cofired with natural gas and coal while determining the lower level of mill air flow rate that could be achieved without experiencing coal feed problems. The mill air flow was decreased from ~400 acfm to as low as 350 acfm. Most of the operation was at ~380 acfm. One attempt to go to 100% coal firing was unsuccessful when a low u.v. signal shut the boiler down.
- March 21 -- The boiler was not operated because Penn State's Office of Physical Plant was repairing a transfer pump (from a lift station near the

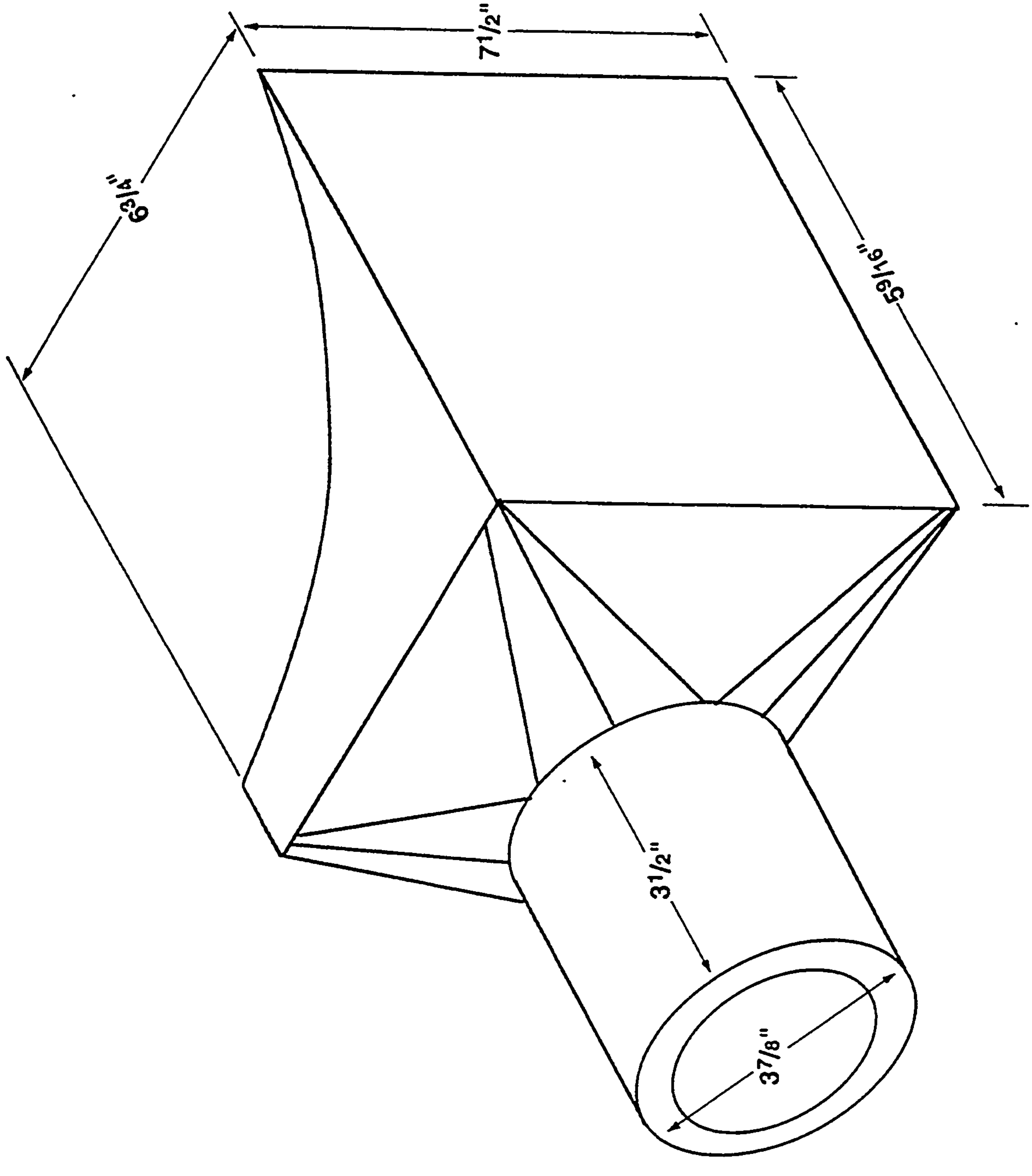

Figure B4 **Drawing of the TCS Mill Exit Transition Section**

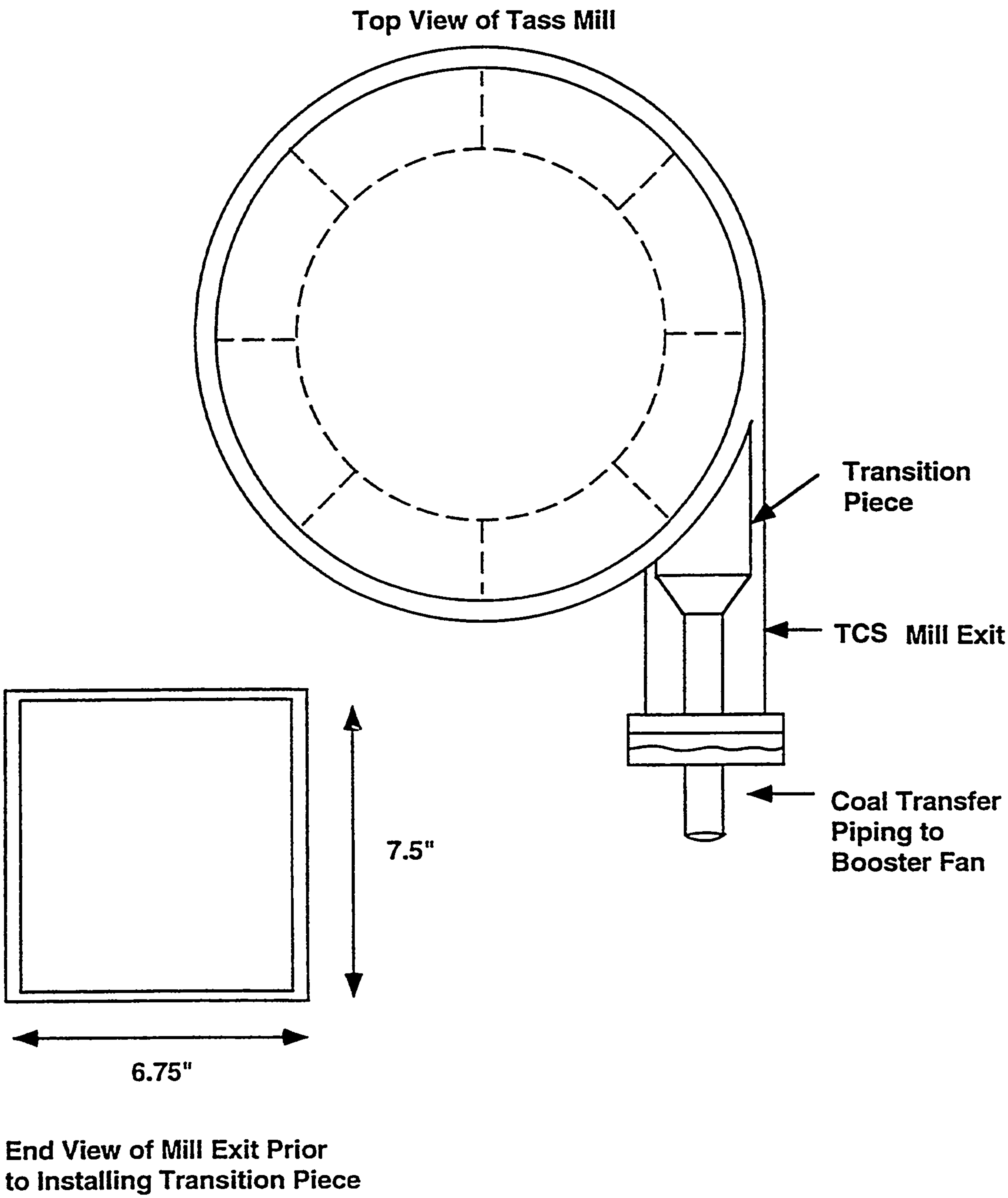

Figure B5 Top View of the TCS Mill Showing Location of Transition Section steam plant to sewage treatment plant) and therefore could not handle normal blowdown from the demonstration boiler.

- March 22 -- The boiler was fired with 100% coal for a short period (~0.5 h) when low feedwater pressure was experienced. The feedwater pump was repaired and ~3.5 hours of cofiring were obtained.
- March 23 -- Approximately 3.5 hours of 100% coal firing were obtained before the coal was consumed. The mill air flow rate was ~370 acfm and the coal combustion efficiency was ~92%. Kentucky coal still was not available. After discussions with ABB-CE, another truckload of Brookville Seam coal was ordered.
- March 24 -- Brookville Seam coal was delivered and a new coal feed curve was generated.
- March 25 -- Testing was conducted and approximately three hours firing 100% coal was obtained. The mill air flow rate was ~370 acfm and the coal combustion efficiency was ~92-93%.
- March 28 -- Testing was conducted and approximately three hours firing 100% coal was obtained. The mill air flow rate was ~305-315 acfm and the coal combustion efficiency was ~91-94%.
- March 29 -- The 4-inch diameter center pipe (bluff body) in the burner was shortened so that it was ~8" shorter than the 6" diameter pipe (housing) that forms the annulus for the primary air/coal stream, in order to reduce the tip velocity. Approximately 5.5 hours firing 100% coal were obtained. The flame was wide and short. The mill air flow was 315-320 acfm and the coal combustion efficiency was ~94-96%.
- March 30 -- No testing was conducted in order to conserve the coal that remained (~6 tons) for March 31 when visitors from DOE and ABB-CE were to be on site to observe the boiler/burner operation.
- March 31 -- Visitors from DOE and ABB-CE were on site to observe the boiler/burner operation. Approximately 9.5 hours of 100% coal firing were obtained before the coal was consumed. The mill was operated at ~290 acfm and coal combustion efficiency was ~94-95%. ABB-CE/DOE officially extended Task 3 by one month until the end of April, 1994.

4) April

During April, the objectives were to test two burner configurations, characterize the mill using two coals, conduct a series of tests varying the firing rate and level of excess air, and determine the effect of modifying the furnace configuration on boiler performance and coal combustion efficiency. Task 3 of the program, the proof-of-concept testing, was concluded in April. A day-by-day synopsis of the boiler operation for April, which was conducted on two shifts per day, follows:

- April 1 -- The first of two shipments of Kentucky coal were received. A new coal curve was generated. There was minimal operational time firing 100% coal; most of the operation was cofiring natural gas and coal.
- April 4 -- The boiler was operated for ~10.5 hours firing 100% coal using the RO-II gun without the football. The objective of this test was to compare these results to those firing Brookville Seam coal under the same conditions. Coal combustion efficiency ranged from 93-96%.
- April 5 -- The football was installed. The flame was longer and the boiler was slightly unstable. Coal combustion efficiency ranged from 93-96%.
- April 6 -- The Y-Jet gun with the high swirler was installed. The flame was not anchored at the burner tip and would change in appearance without making any mechanical changes. There were problems maintaining a strong u.v. signal.
- April 7 -- Testing continued using the Y-Jet gun. The results were similar to those on April 6. The high swirler was replaced with the medium swirler without any improvement.
- April 8 -- The RO-II gun with the maximum swirler was installed. The mill speed was increased from 1,940 to 2,080 rpm by replacing sheaves to determine the effect of mill speed on coal particle size distribution and hence, coal combustion efficiency. The second shipment of Kentucky coal was received. Coal combustion efficiency ranged from 95-96%.
- April 11 -- The mill was characterized at the high mill speed. A nine-point test matrix was set up using the coal feed rates and mill air flow rates of 9, 14, and 18 lb/s and 320, 360, and 400 acfm, respectively. Natural gas support was used during the mill characterization tests. Coal combustion efficiency ranged from 95-97%.
- April 12 -- The boiler was operated for a short time at the high mill speed. Operation was limited by high mill amperage which approached 120 amps

(upper limit) when firing at approximately 11.0 million Btu/h. The sheaves were changed at the end of the day to return the mill speed to 1,940 rpm. Coal combustion efficiency ranged from 93-96%.

- April 13 -- The mill was characterized at the low mill speed using the same test matrix as on April 11. Coal combustion efficiency ranged from 93-97%.
- April 14 -- The boiler was operated at a high firing rate (17 million Btu/h). There was a significant quantity of deposition observed and it was necessary to soot blow the convective pass frequently. The coal curve was redone because the CO concentration was high during this test. Coal combustion efficiency ranged from 94-95%.
- April 15 -- A test firing the boiler at a low load, 11 million Btu/h, was started; however, the test was postponed to clean the boiler because the furnace contained much ash.
- April 18 -- The test firing the boiler at 11 million Btu/h was conducted. Coal combustion efficiency ranged from 92-93%.
- April 19 -- A test firing the boiler at a low oxygen concentration (2%) was conducted. The last of the Kentucky coal was consumed and a shipment of Brookville Seam coal was received. Coal combustion efficiency ranged from 92-93%.
- April 20 -- The mill was characterized using the Brookville Seam coal at a low mill speed in order to compare the performance of the two coals under identical mill operating conditions. Coal combustion efficiency ranged from 92-95%.
- April 21 -- A baseline test was conducted firing Brookville Seam coal prior to modifying the furnace configuration. Coal combustion efficiency ranged from 90-94%.
- April 22 - A wall, two feet in length, was installed to alter the gas flow from the boiler to the entrance to the convective pass (boiler outlet). The wall, which was perpendicular to the flame, started at the convective pass entrance and ended near the center line of the furnace (The boiler is ~6' in width).
- April 25 -- A test was conducted firing the Brookville Seam coal to compare the performance to results prior to installing the wall. Coal combustion efficiency ranged from 90-93%.

- April 26 -- A test was conducted firing the Brookville Seam coal. A shipment of Brookville Seam coal was received. Coal combustion efficiency ranged from 91-95%.
- April 27 -- A low firing rate, ~12 million Btu/h, test was conducted. ABB-CE requested that the sheaves be changed to increase the mill speed. This was done at the end of the day. Coal combustion efficiency ranged from 94-96%.
- April 28 -- The boiler was operated only for a short period of time at the high mill speed because it requires a long time to stabilize the boiler/burner at the high mill speed. Consequently, the sheaves were changed and the mill speed lowered. Coal combustion efficiency ranged from 94-96%.
- April 29 -- A test was conducted firing the boiler at low oxygen concentration (2%). Coal combustion efficiency ranged from 94-96%.

APPENDIX C   Characterization of the TCS Mill

Under this phase of the work, a study was conducted to characterize the effect of mill air flow rate, coal feed rate, and mill speed, on coal particle size distribution (PSD) and top size using two coals. This was done as part of an effort to determine the milling conditions necessary to reduce the coal PSD and top size in order to achieve >98% coal combustion efficiency. In addition, the results are to be used to evaluate the feasibility for external classification to reduce the coal top size.

Table C1 gives a summary of the results of all TCS mill coal PSD measurements. A formal mill characterization study was conducted on April 11, 13, 20, and 28. Most of the PSD graphs which follow were generated using data from these dates. PSD data from other dates in Table 1 (in main text) were also used in some of the comparisons. Descriptions of the test matrix and results follow.

1) Test Matrix Description

The majority of the Tasks 2 and 3 testing was conducted using a Pennsylvania coal from the Brookville Seam that was cleaned using heavy-media cyclones to reduce the mineral matter content down to ~4.0 wt. %. A low-ash (3-5 wt. %) coal from Kentucky was tested for two weeks under Task 3. This coal was similar to that used by ABB-CE when testing the HEACC burner at their facility. The Kentucky coal was used in order for ABB-CE to compare performance between Penn State's boiler and ABB-CE's test combustor. The mill characterization study started when the Kentucky coal was on site. Table C2 contains the Brookville Seam and Kentucky coal analyses. The analyses were of weekly composites formed from daily samples.

On April 11, the Kentucky coal (reported HGI of 45) was tested at a high mill speed (2,080 rpm), three mill inlet air flow rates (~ 320, 360, and 420 acfm), and three coal feed rates (~9.5, 14, and 16.5 lb/m). Normally the mill is operated at 1,940 rpm which is called the low mill speed during this characterization study. The mill speed was varied by changing sheaves on the mill. Mill speeds of 1,940 and 2,080 rpm correspond to sheave diameters of 12 and 13", respectively. Note that a coal sample was not collected at the low mill air flow rate (320 acfm) and high coal feed rate (16.5

Test Date	Test Time	Mill Speed (rpm)	Mill Amps	Mill Air Flow (cfm)	Coal Feed Rate (lb/m)	Mill Temp. (F) Air Inlet	Mill Temp. (F) Mill Outlet	Top Size	Particle Size, in Microns, that is Less Than the Indicated Size <99	<95	<90	<75	<50	<10
3/10/94	0940-1030	1,940	62	450	7.848	65	339	176.0	108.0	78.8	65.8	46.6	23.2	6.9
3/10/94	1115	1,940	62	400	7.848	65	153 (Burner)	176.0	98.6	68.1	57.6	37.8	19.5	5.5
3/10/94	1200	1,940	62	380	7.848	65	163 (Burner)	204.0	120.8	76.8	65.5	47.8	25.9	6.6
3/11/94	1610-1640	1,940	83	350	15.7	78	366	273.0	160.3	93.2	71.4	46.8	25.0	7.0
3/14/94	1830	1,940	N.M.	400	14.91	75	194	204.0	123.0	90.2	72.0	49.1	25.7	6.9
3/22/94	1400	1,940	N.M.	400	15.82	83	202 (B. Fan)	204.0	117.6	83.3	66.3	44.9	23.5	6.3
3/22/94	1200	1,940	N.M.	380	15.82	86	202 (B. Fan)	219.0	126.0	83.3	67.0	45.5	23.5	6.3
3/23/94	900	1,940	81	380	18.35	73	349	422.0	160.3	95.2	73.2	48.6	26.0	6.9
3/29/94	1635	1,940	85	290	19.37	82	216 (B. Fan)	204.0	137.0	92.3	70.9	46.5	23.0	6.3
3/31/94	1045	1,940	92	300	18.536	75	205 (B. Fan)	190.0	123.0	84.3	66.9	44.5	23.0	6.2
3/31/94	1130	1,940	92	295	18.536	76	214 (B. Fan)	190.0	132.0	86.8	66.8	45.8	23.4	6.3
4/4/94	1030	1,940	99	294	18.6	31	266	365.0	200.5	126.4	90.6	53.9	26.5	6.6
4/4/94	1445	1,940	99	286	18.6	84	288	254.0	180.7	114.0	85.4	52.7	28.8	6.5
4/5/94	1450	1,940	96	280	18.71	80	267	236.0	180.7	115.0	86.7	54.8	27.2	6.5
4/5/94	1130	1,940	96	286	18.71	80	261	293.0	198.4	127.6	93.9	67.0	29.3	7.2
4/8/94	1400	1,940	109	310	14.47	69.5	272	204.0	137.0	86.0	64.9	42.7	22.1	6.2
4/8/94	1600	1,940	109	310	14.47	70	270	204.0	126.0	84.9	69.8	46.7	26.1	7.2
4/11/94	1145	2,080	101	320	9.48	73	266	315.0	190.0	96.9	69.5	43.9	24.1	6.8
4/11/94	1230	2,080	92	391	9.48	73	269	316.0	153.0	86.7	66.7	44.8	24.7	7.0
4/11/94	1330	2,080	84	420	9.48	82	241	273.0	132.0	83.8	66.4	45.3	25.7	7.1
4/11/94	1430	2,080	103	395	13.97	82	247	219.0	135.3	82.9	64.2	41.8	22.1	6.1
4/11/94	1500	2,080	102	360	13.97	87	256	141.0	105.0	71.2	56.6	35.4	20.6	5.3
4/11/94	1630	2,080	108	320	13.97	88	270	161.0	109.0	74.6	57.9	36.1	21.1	5.6
4/11/94	1700	2,080	112	360	16.46	90	259	132.0	90.1	65.8	55.8	35.9	20.0	5.9
4/11/94	1800	2,080	N.M.	400	16.46	81	240	176.0	116.3	81.6	66.7	46.7	25.2	6.8
4/12/94	1145	2,080	114	360	19.16	87	238	293.0	153.0	89.1	67.9	43.5	21.2	5.8
4/13/94	900	1,940	70	325	9.48	79	197	392.0	204.0	114.0	84.4	59.3	28.8	7.0
4/13/94	1000	1,940	71	360	9.48	80	191	236.0	153.0	102.8	81.3	52.0	25.9	6.7
4/13/94	1030	1,940	78	400	9.48	81	185	236.0	183.0	102.3	82.1	54.6	29.3	7.2
4/13/94	1200	1,940	84	325	13.97	82	204	219.0	156.7	106.0	83.8	54.3	27.7	6.6
4/13/94	1300	1,940	81	365	13.97	84	190	190.0	140.0	99.6	79.3	51.8	25.9	6.6
4/13/94	1400	1,940	79	400	13.97	84	183	219.0	161.3	112.2	89.0	57.3	29.3	7.0
4/13/94	1446	1,940	83	400	16.46	80	182	254.0	187.2	125.5	97.0	61.6	34.8	6.3
4/13/94	1515	1,940	87	360	16.46	79	183	254.0	183.0	117.6	89.9	56.4	29.1	7.3
4/13/94	1546	1,940	89	320	16.46	78	183	273.0	200.5	120.0	89.9	54.0	28.1	7.0
4/18/94	1430	1,940	116	290	14.81	87	219	273	193.5	120	86.7	54.2	27.5	6.9
4/18/94	1500	1,940	116	300	14.81	88	220	392	172	111.1	83.9	51.7	26.4	6.7
4/18/94	1715	1,940	116	365	14.81	92	209	273	183	116	86.5	55	27.4	6.6
4/20/94	1115	1,940	78	320	9.42	76	179	219	135.3	81.3	63.4	41.4	21.7	6.2
4/20/94	1145	1,940	75	360	9.42	77	179	164	116.3	81.6	66.6	47.5	25.5	7
4/20/94	1230	1,940	N.M.	400	9.42	77	196	236	149.3	90.7	76.1	53.2	30.6	7.9
4/20/94	1315	1,940	N.M.	400	13.94	75	180	392	170	110	83.3	51.8	26.3	6.7
4/20/94	1600	1,940	85	360	13.94	78	188	204	126.0	86.6	70.1	49	25.2	6.4
4/20/94	1530	1,940	83	320	13.94	77	194	190	135.3	86	67.2	45.1	23	6.3
4/20/94	1630	1,940	87	330	16.17	80	201	190	132	82.9	65	45.4	22.1	6.1
4/20/94	1730	1,940	83	360	16.47	82	198	236	156.7	98	75.5	49.8	25.7	6.6

Table C1 Summary of Results for the Mill Characterization Study

Test Date	Test Time	Mill Speed (rpm)	Mill Amps	Mill Air Flow (cfm)	Coal Feed Rate (lb/m)	Mill Temp. (F) Air Inlet	Mill Temp. (F) Mill Outlet	Top Size	Particle Size, In Microns, that is Less Than the Indicated Size <99	<95	<90	<75	<50	<10
4/20/94	1800	1,940	87	400	10.47	82	190	236	160.0	102.6	79.8	53.7	29.2	7.3
4/21/94	1000	1,940	99	300	18.3	82	199	254	160.3	106	79.8	51.4	27.3	7.1
4/21/94	1546	1,940	90	365	18.3	73	190	190	138.7	90.6	70.7	47.8	23.9	6.2
4/27/94	1730	1,940	79	390	14.1	94	199	365	172	99.4	74.7	48.5	25.4	6.7
4/28/94	945	2,080	110	385	9.65	84	248	142	102.3	69.7	58.6	37.3	20.9	6.2
4/28/94	1040	2,080	110	375	13.0	83	245	142	98.6	68.6	58.4	38.6	21.8	6.3
4/28/94	1200	2,080	110	370	16.48	89	246	153	106	69.8	58.3	38.8	20.2	5.9

NOTES:
1) N.M. - Mill amps were not measured
2) Some of the mill air temperatures were measured at the burner inlet (Burner) or the booster fan outlet (B. Fan) instead of the mill outlet

Table C1 (Continued) Summary of Results for the Mill Characterization Study

Date	Coal Type	Full Proximate Analysis				Full Ultimate Analysis					Calorific Value (Dry)
		% Moist	% V.M. (Dry)	% Ash (Dry)	% F.C. (Dry)	% C (Dry)	% H (Dry)	% N (Dry)	% S (Dry)	% O (Dry)	
FEB 22-24	Brookville	07.64	35.76 ± 0.02	03.18 ± 0.00	61.06	80.08 ± 0.03	05.45 ± 0.04	01.57 ± 0.01	00.65 ± 0.00	09.07	14144 ± 14
MAR 10-23	Brookville	07.34	35.91 ± 0.14	03.22 00.01	60.87	79.89 ± 0.06	05.48 ± 0.01	01.56 ± 0.02	00.70 ± 0.00	09.15	14440 ± 02
MAR 25-31	Brookville	08.16	36.08 ± 0.06	03.15 ±0.09	60.77	80.03 ± 0.03	05.46 ± 0.03	01.57 ± 0.01	00.65 ± 0.00	09.14	14437 ± 07
APR 04-08	Kentucky	07.39	35.86 ± 0.21	04.52 ±0.13	59.62	78.01 ± 0.16	05.31 ± 0.01	01.47 ± 0.01	00.81 ± 0.01	09.88	14033 ± 09
APR 11-19	Kentucky	06.76	35.73 ± 0.01	04.87 ± 0.03	59.40	77.89 ± 0.07	05.26 ± 0.04	01.50 ± 0.01	00.83 ± 0.00	09.65	13956 ± 01
APR 19-22	Brookville	06.77	35.98 ± 0.22	03.98 ± 0.05	60.04	79.25 ± 0.16	05.22 ± 0.02	01.57 ± 0.01	00.77 ± 0.00	09.21	13976 ± 08
APR 25-29	Brookville	05.21	35.54 ±0.15	03.35 ±0.00	61.11	79.88 ±0.02	05.29 ±0.00	01.58 ±0.01	00.66 ±0.00	09.24	14389 ± 07

Notes: Moisture values were determined by averaging the moisture values of all screw feed coals included in the composite.
Composite coals consist of screw feed coals on the following dates and their daily log numbers:

<u>Composite FEB 22-24</u>
22FEB94 - #03, #12, #13
23FEB94 - #03, #06, #13
24FEB94 - #02, #09, #18

<u>Composite MAR 10-23</u>
10MAR94 - #03, #12, #20
11MAR94 - #03, #06, #09
14MAR94 - #03, #14
15MAR94 - #01
18MAR94 - #03
22MAR94 - #01, #06, #12
23MAR94 - #01

<u>Composite MAR 25-31</u>
25MAR94 - #02, #07, #10, #22
28MAR94 - #01, #05, #23
29MAR94 - #01, #06
31MAR94 - #01, #07, #24

<u>Composite APR 04-08</u>
04APR94 - #03, #13, #27
05APR94 - #01, #21
08APR94 - #01, #10, #30

<u>Composite APR 11-19</u>
11APR94 - #00, #03, #16
12APR94 - #01, #10
13APR94 - #01, #16
14APR94 - #01, #02
15APR94 - #01
18APR94 - #01, #22
19APR94 - #01, #02

<u>Composite APR 19-22</u>
19APR94 - #13
20APR94 - #01, #16, #35
21APR94 - #01, #19
22APR94 - #01

<u>Composite APR 25-29</u>
25APR94 - #01, #09
26APR94 - #01, #02
27APR94 - #01, #02
28APR94 - #01
29APR94 - #01, #04

Table C2 Screw Feeder Coal Composite Results

lb/m) when using the high mill speed. Natural gas support was used at the low coal feed rate tests in order to maintain a stable flame.

The mill speed was then decreased from 2,080 to 1,940 rpm and a nine-point matrix was conducted using the Kentucky coal on April 13, 1994. The tests were conducted using similar mill air flow rates and coal feed rates.

After the Kentucky coal was tested, which was done over a two week period, additional Brookville Seam coal was received and tested. The mill was characterized using Brookville Seam coal (reported HGI of 54) at the low mill speed using the nine-point matrix on April 20, 1994. Prior to Task 3 ending, the mill speed was changed for a few hours one day in order to obtain a few coal samples using the high mill speed and Brookville Seam coal. This was done on April 28, 1994 and three samples were collected at a mill air flow rate of ~375 acfm and coal feed rates of 9.6, 13.9, and 16.5 lb/m.

The mill characterization results will be presented in subsections by coal (Kentucky and Brookville Seam) and mill speed (high and low). The two coals will then be compared and the results summarized.

2) Coal Particle Collection and Analysis

Coal particles were sampled near the burner inlet using ASTM D197-87 (Standard Test Method for Sampling and Fineness Test of Pulverized Coal). Figure C1 gives a schematic diagram of the equipment used to collect the coal samples. An isokinetic coal sample was collected by traversing two complete diameters 90° apart. The sample was drawn through a cyclone and a filter located upstream of the vacuum pumps (Figure C1 insert). Appendix A of the report of Miller, et al. (1994) contains the sampling procedure and an example of the results generated. Approximately 1.5-4.5 wt. % of the sample was collected by the filter. The filter samples typically had a D_{50} (particle size where 50% of the particles, by volume, are less than that indicated) of 4.0-8.0 μm.

Coal particle sizing was conducted using a Malvern 2600 Particle and Droplet Sizer. Because the filter sample was a small percentage of the total sample collected, the

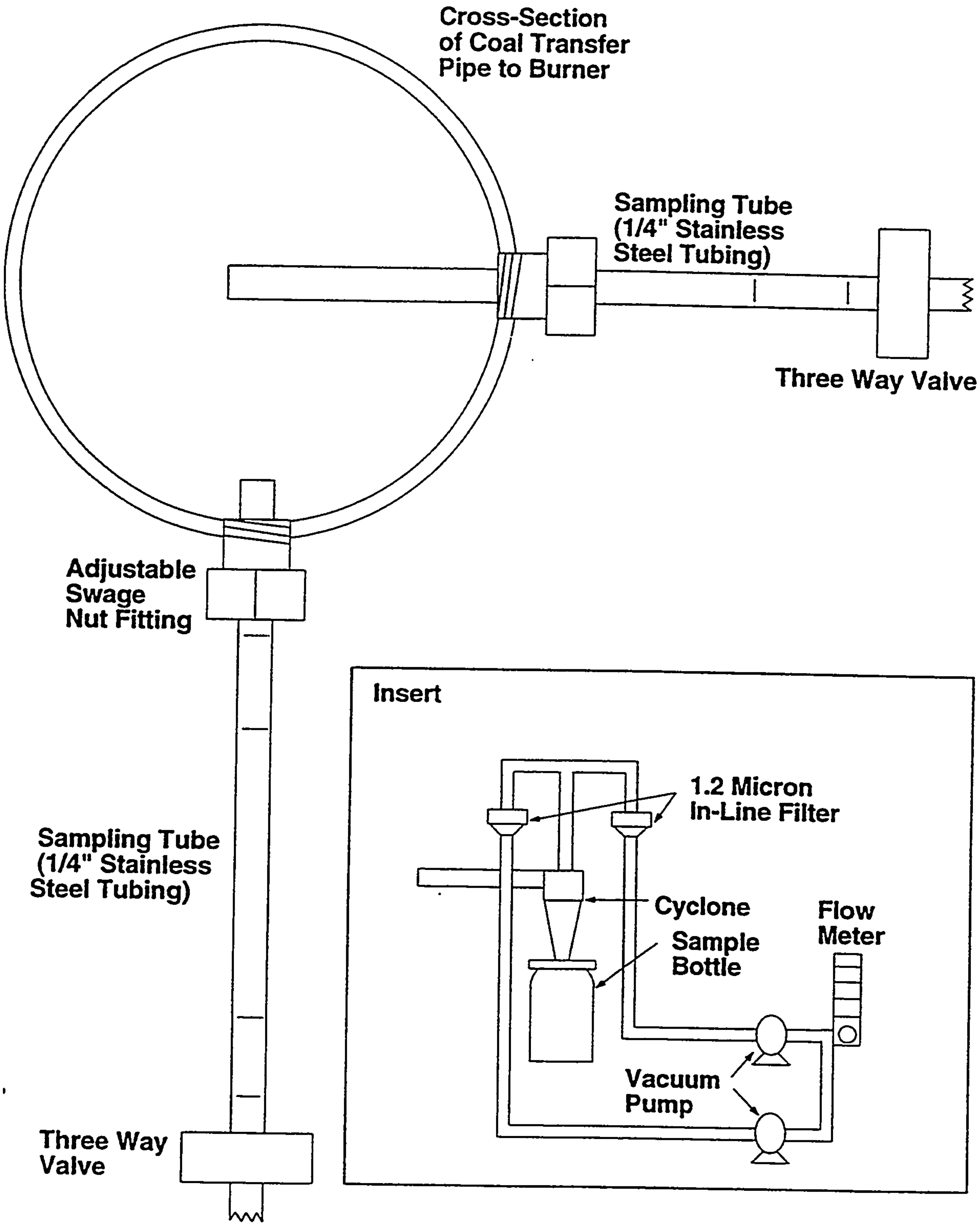

Figure C1 Schematic Diagram of Micronized Coal Sampling Port and Collection Equipment

PSD analyses presented in the following subsections are for the cyclone samples only.

3) Kentucky Coal Characterization

A) High Mill Speed (April 11, 1994)

A test was conducted on April 11, 1994 where coal samples were collected from the burner inlet while feeding coal at rates of 9.5, 14.0, and 16.5 lb/m and operating the mill at air flow rates of approximately 320, 360, and 420 acfm. The results are shown in Figures C2 through C7.

(1) Effect of Mill Air Flow Rate on Coal PSD as a Function of Coal Feed Rate

Figure C2 shows the PSDs for mill air flow rates of 320, 361, and 420 acfm at a coal feed rate of 9.5 lb/m. There is minimal effect of mill air flow rate on PSD at this coal feed rate.

Likewise, Figure C3 shows the PSDs for mill air flow rates of 320, 360, and 395 acfm at a coal feed rate of 14.0 lb/m. Again, there is minimal effect of mill air flow rate on PSD at this coal feed rate.

There is an effect of air flow rate on PSD at the high coal feed rate, 16.5 lb/m, as shown in Figure C4. The PSD is coarser when operating the mill at 400 acfm than at 360 acfm.

(2) Effect of Coal Feed Rate on Coal PSD as a Function of Mill Air Flow Rate

Figure C5 shows the PSDs for coal feed rates of 9.5 and 14.0 lb/m at a mill air flow rate of 320 acfm. The coal PSD is finer for the larger coal feed rate.

Figure C6 shows the PSDs for coal feed rates of 9.5, 14.0, and 16.5 lb/m at a mill air flow rate of 360 acfm. The PSDs for the 14 and 16.5 lb/m coal feed rates are similar and finer than the 9.5 lb/m coal feed rate.

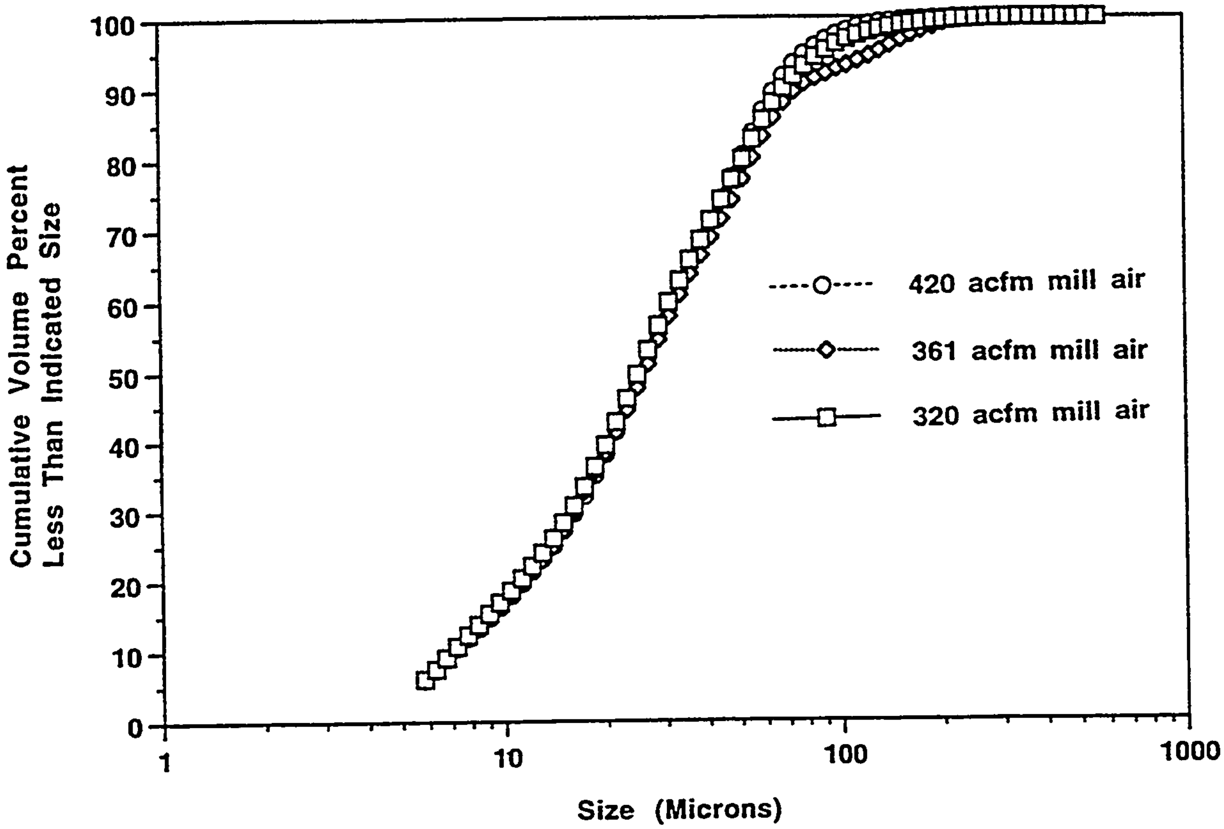

Figure C2 Kentucky Coal PSDs at a 9.5 lb/m Coal Feed Rate and High Mill Speed

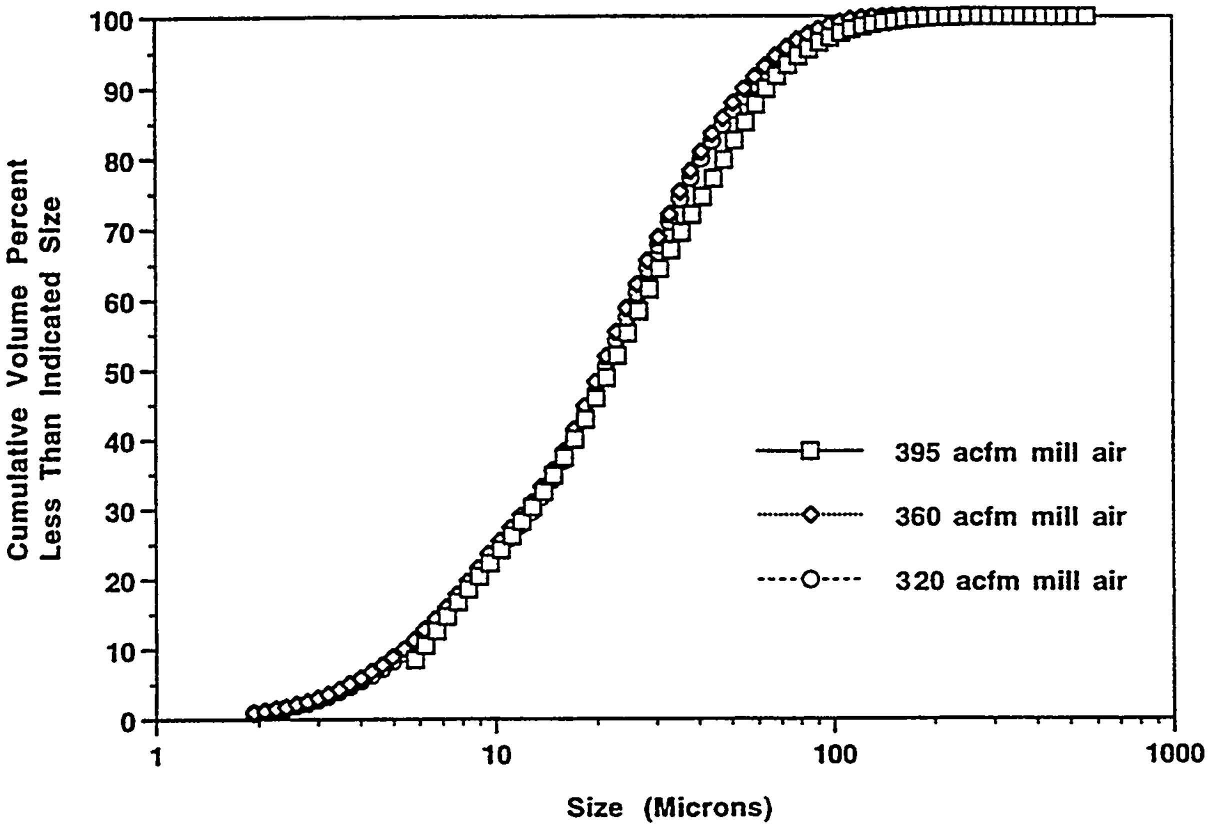

Figure C3 Kentucky Coal PSDs at a 14 lb/m Coal Feed Rate and High Mill Speed

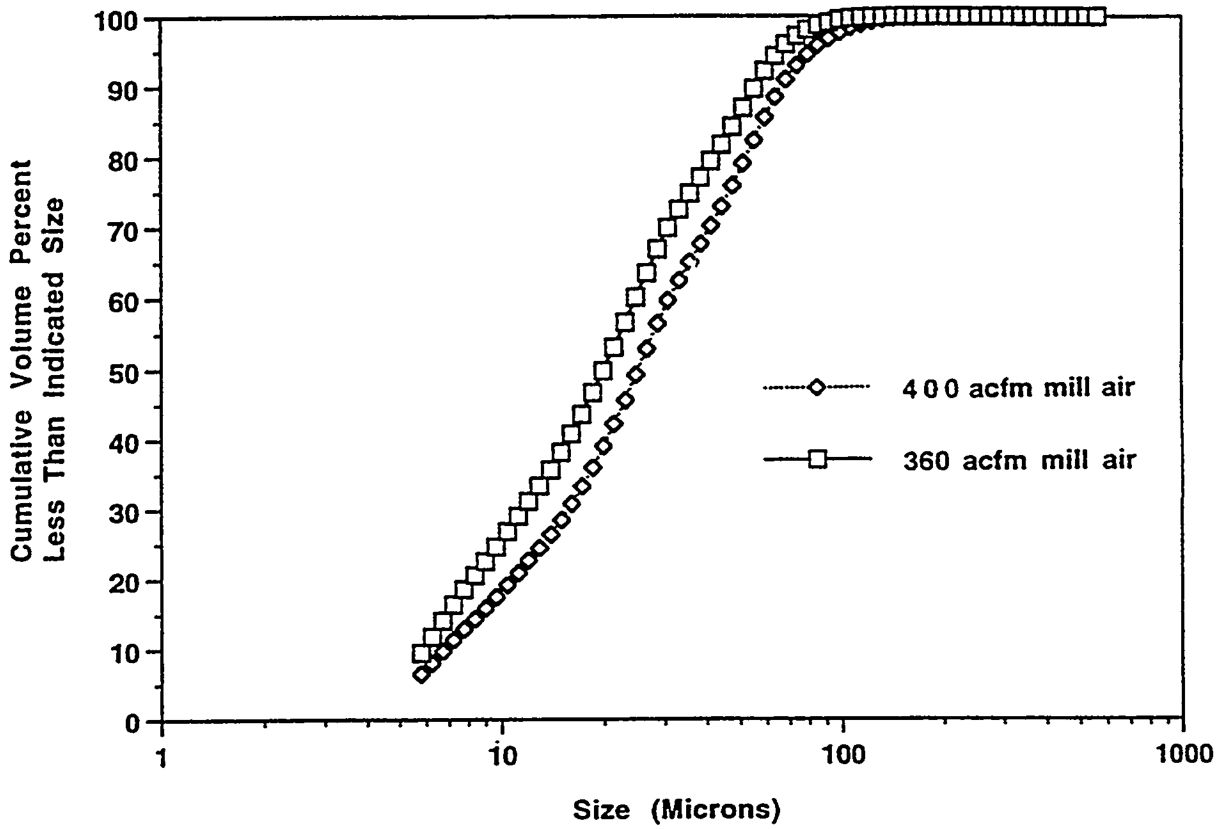

Figure C4 Kentucky Coal PSDs at a 16.5 lb/m Coal Feed Rate and High Mill Speed

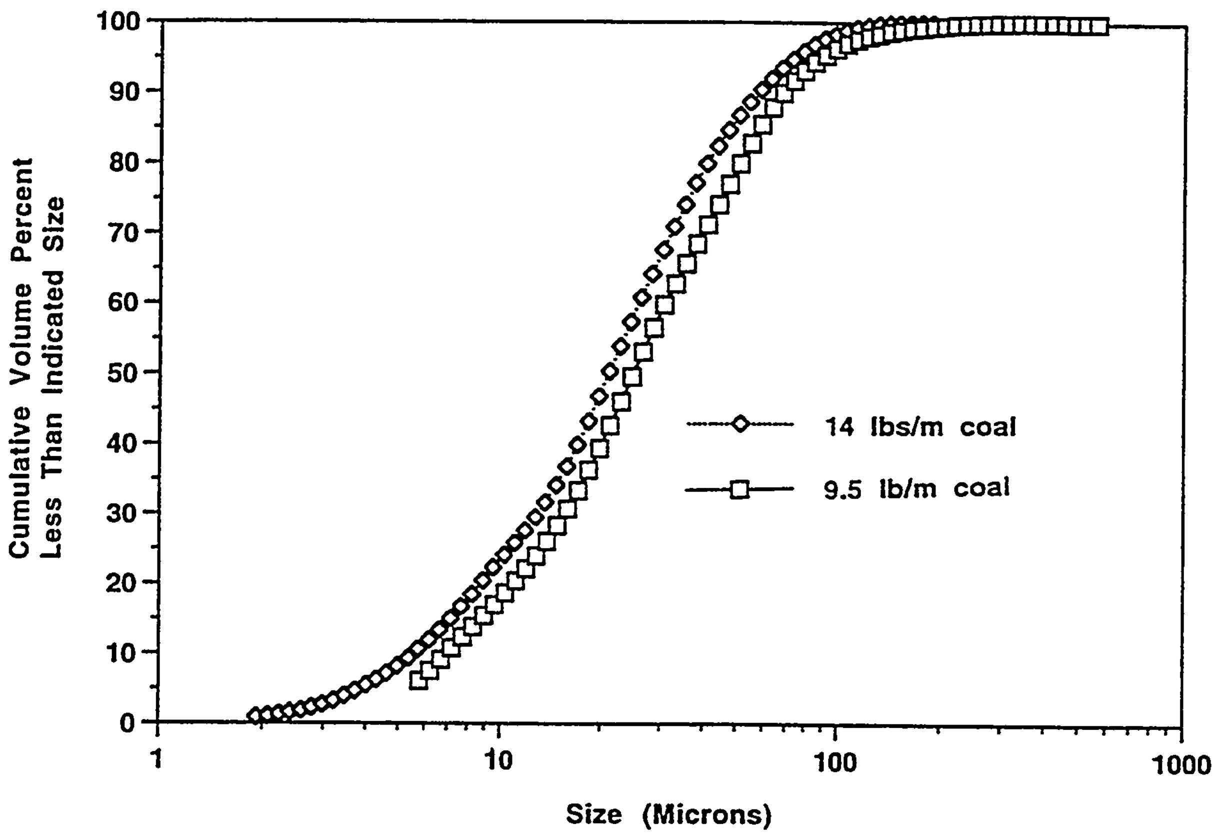

Figure C5 Kentucky Coal PSDs at a Mill Air Flow Rate of 320 acfm, High Mill Speed

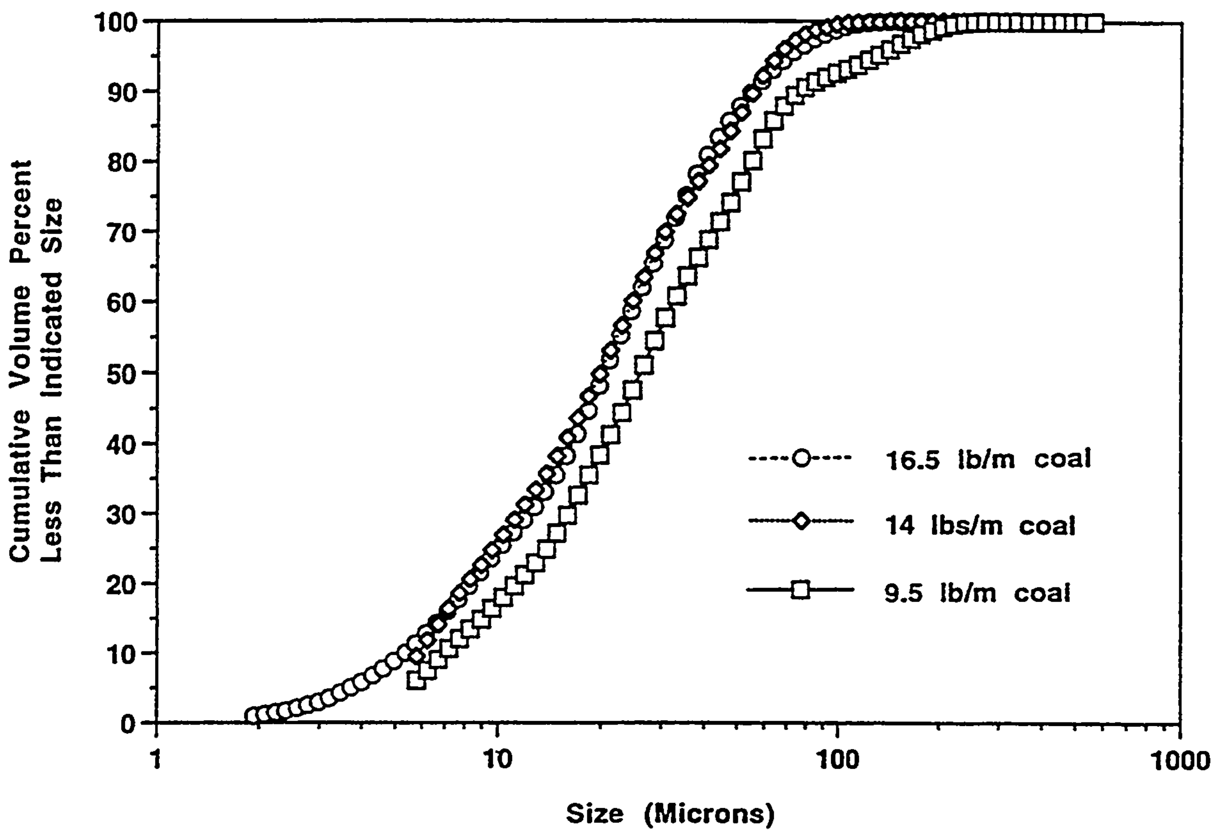

Figure C6 Kentucky Coal PSDs at a Mill Air Flow Rate of 360 acfm, High Mill Speed

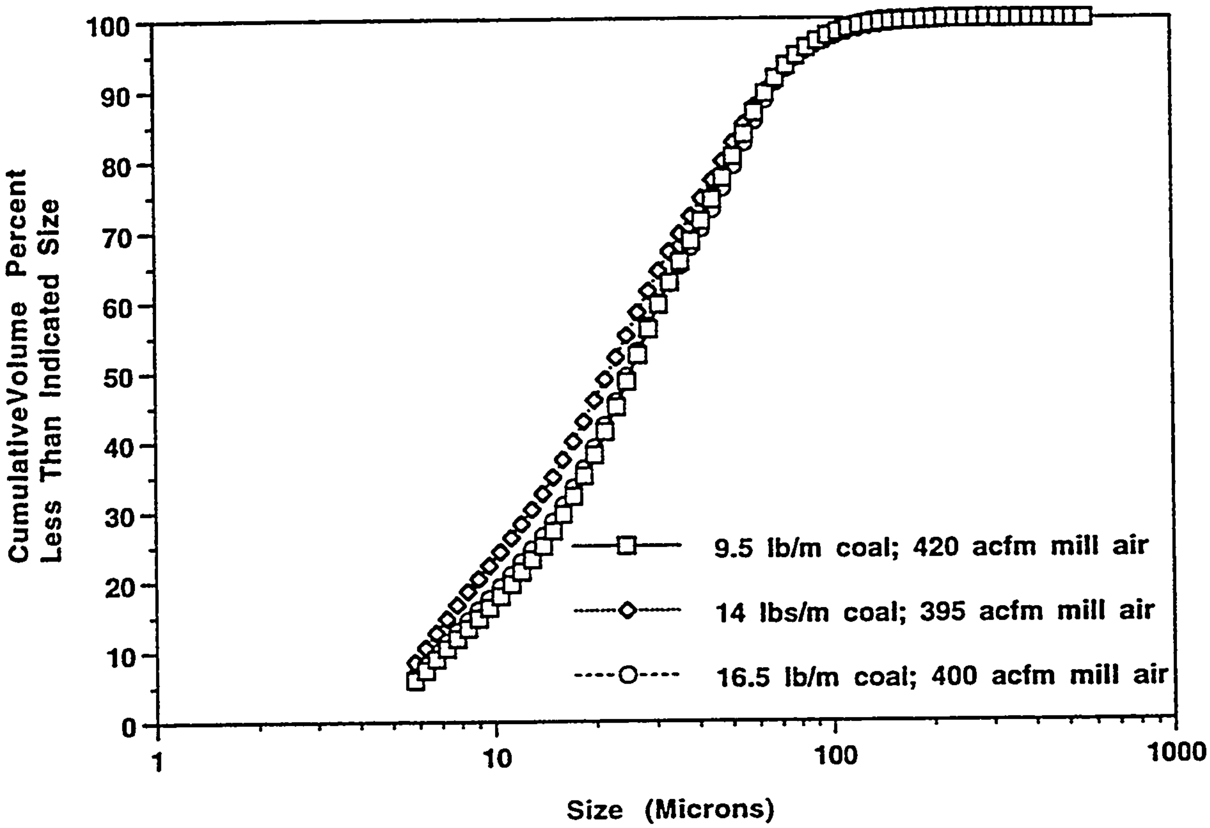

Figure C7 **Kentucky Coal PSDs at a Mill Air Flow Rate of 395-420 acfm, High Mill Speed**

When varying the coal feed rate at the high mill air flow rate, there was some variability in the mill air flow rate. The mill air flow rate varied from 395 to 420 acfm. As shown in Figure C7, the coal feed rate of 14.0 lb/m, with a mill air flow rate of 395 acfm, resulted in a slightly finer coal PSD.

B) Low Mill Speed (April 13, 1994)

A test was conducted on April 13, 1994 where coal samples were collected from the burner inlet while feeding coal at rates of 9.5, 14.0, and 16.5 lb/m and operating the mill at air flow rates of approximately 320, 360, and 400 acfm. The results are shown in Figures C8- C13.

(1) Effect of Mill Air Flow Rate on Coal PSD as a Function of Coal Feed Rate

Figure C8 shows the PSDs for mill air flow rates of 325, 360, and 400 acfm at a coal feed rate of 9.5 lb/m. There is minimal effect of mill air flow rate on PSD at this coal feed rate.

Likewise, Figure C9 shows the PSDs for mill air flow rates of 325, 360, and 400 acfm at a coal feed rate of 14.0 lb/m. Again, there is minimal effect of mill air flow rate on PSD at this coal feed rate.

Figure C10 shows the PSDs for mill air flow rates of 320, 360, and 400 acfm at a coal feed rate of 16.5 lb/m. As the mill air flow rate was increased, the coal PSD became coarser.

(2) Effect of Coal Feed Rate on Coal PSD as a Function of Mill Air Flow Rate

Figure C11 shows the coal PSD as a function of coal feed rate, 9.5, 14.0, and 16.5 lb/m, at a mill air flow rate of 320-325 acfm. There is minimal effect of coal feed rate on PSD at the low mill air flow rate.

Likewise, Figure C12 shows the PSDs for coal feed rates of 9.5, 14.0, and 16.5 lb/m at mill air flow rates of 360-365 acfm. There is a slight effect observed as the PSD for the

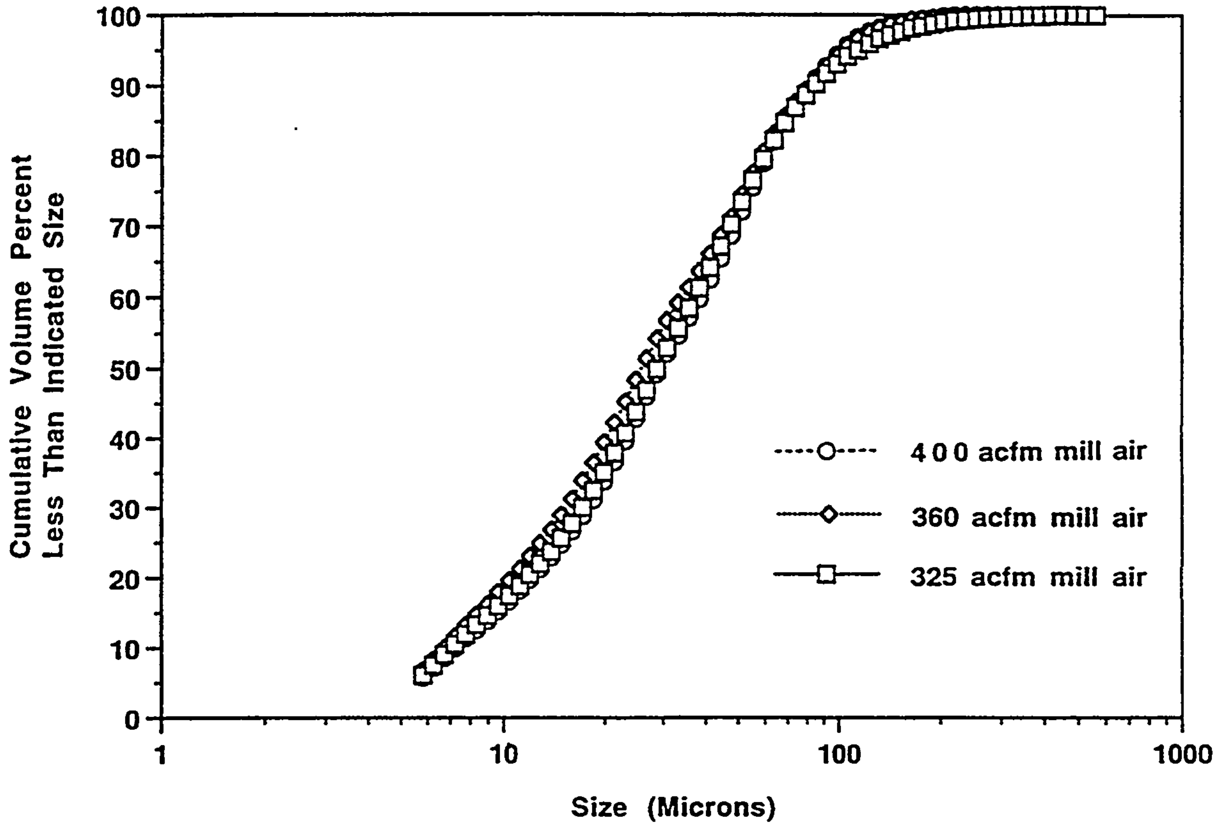

Figure C8 Kentucky Coal PSDs at a 9.5 lb/m Coal Feed Rate and Low Mill Speed

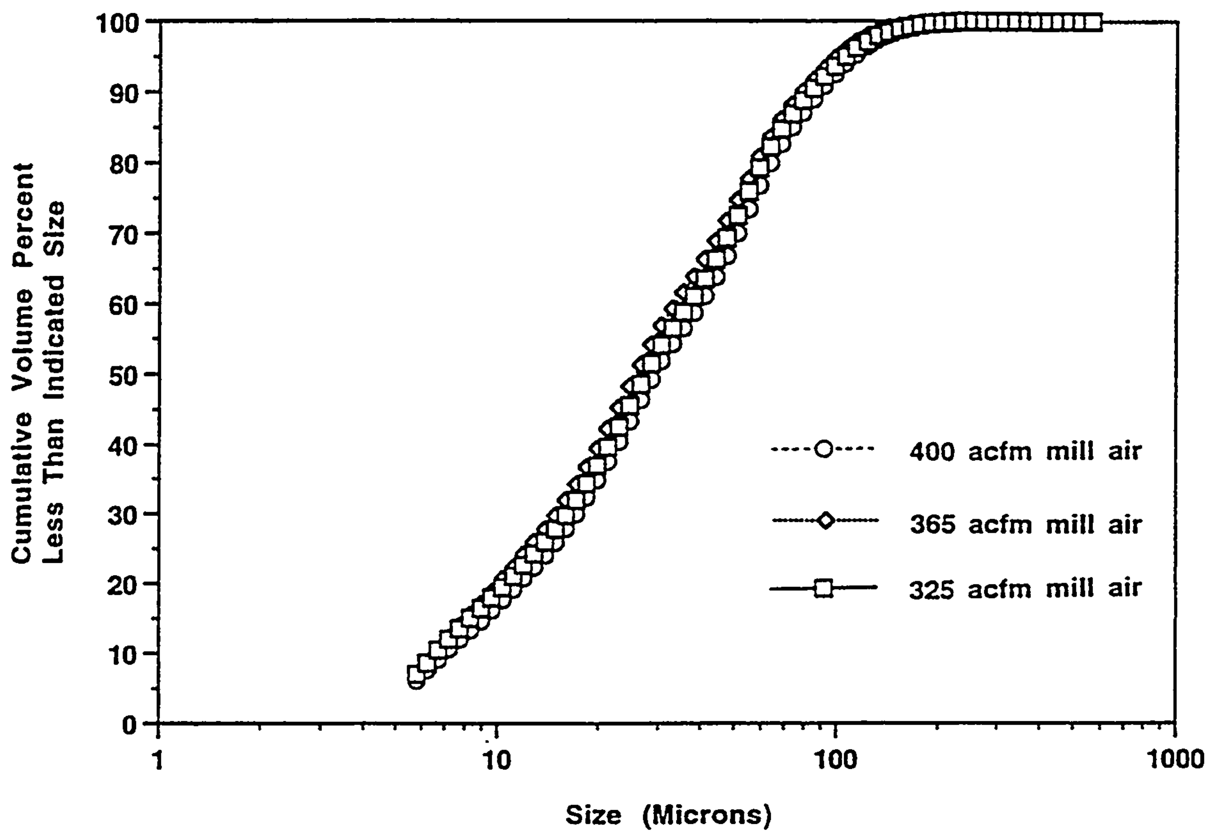

Figure C9 **Kentucky Coal PSDs at a 14 lb/m Coal Feed Rate and Low Mill Speed**

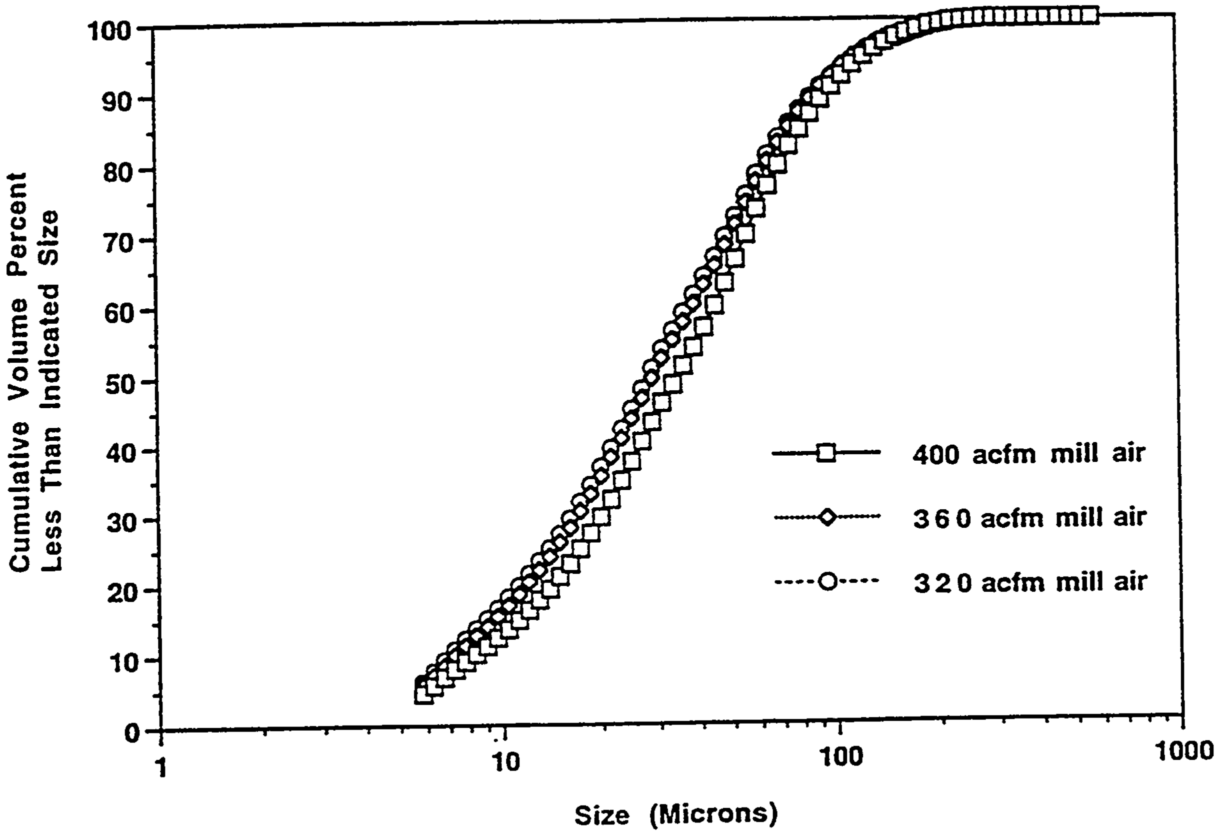

Figure C10 Kentucky Coal PSDs at a 16.5 lb/m Coal Feed Rate and Low Mill Speed

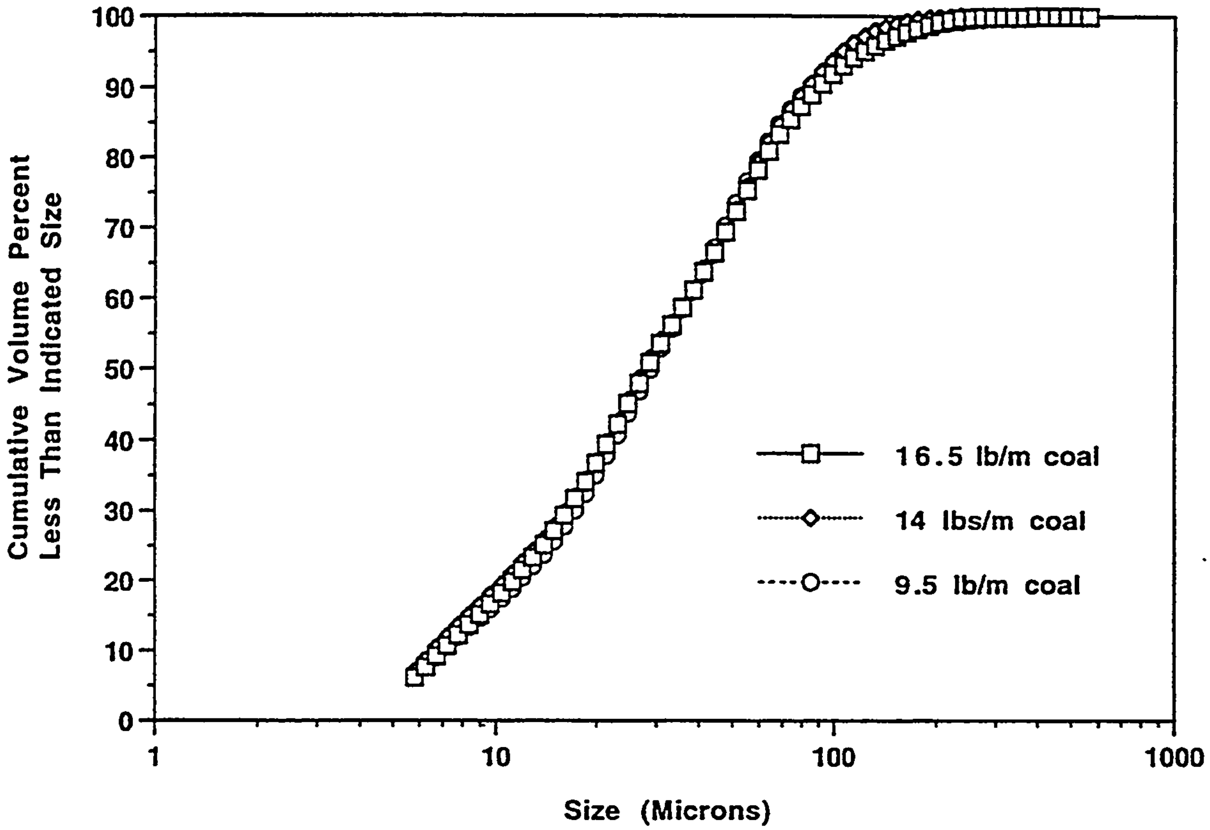

Figure C11 Kentucky Coal PSDs at a Mill Air Flow Rate of 320-325 acfm, Low Mill Speed

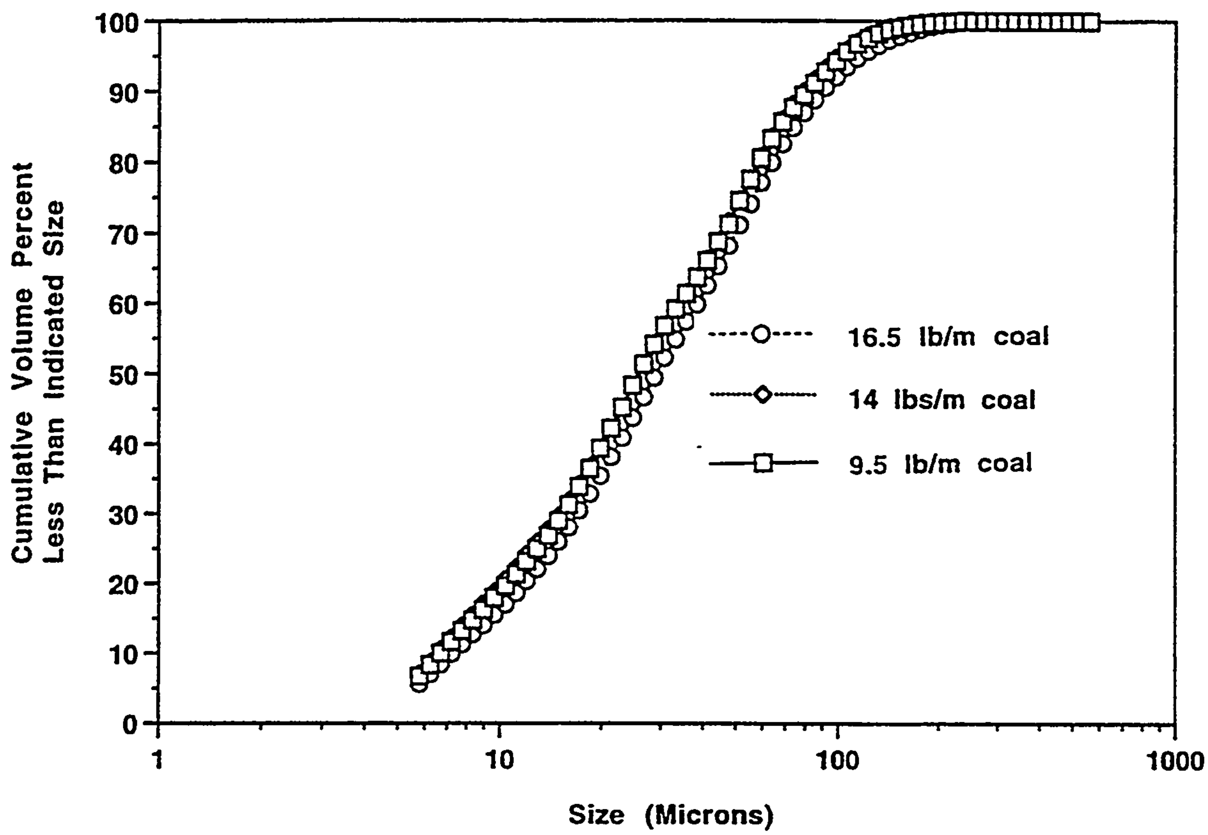

Figure C12 Kentucky Coal PSDs at a Mill Air Flow Rate of 360-365 acfm, Low Mill Speed

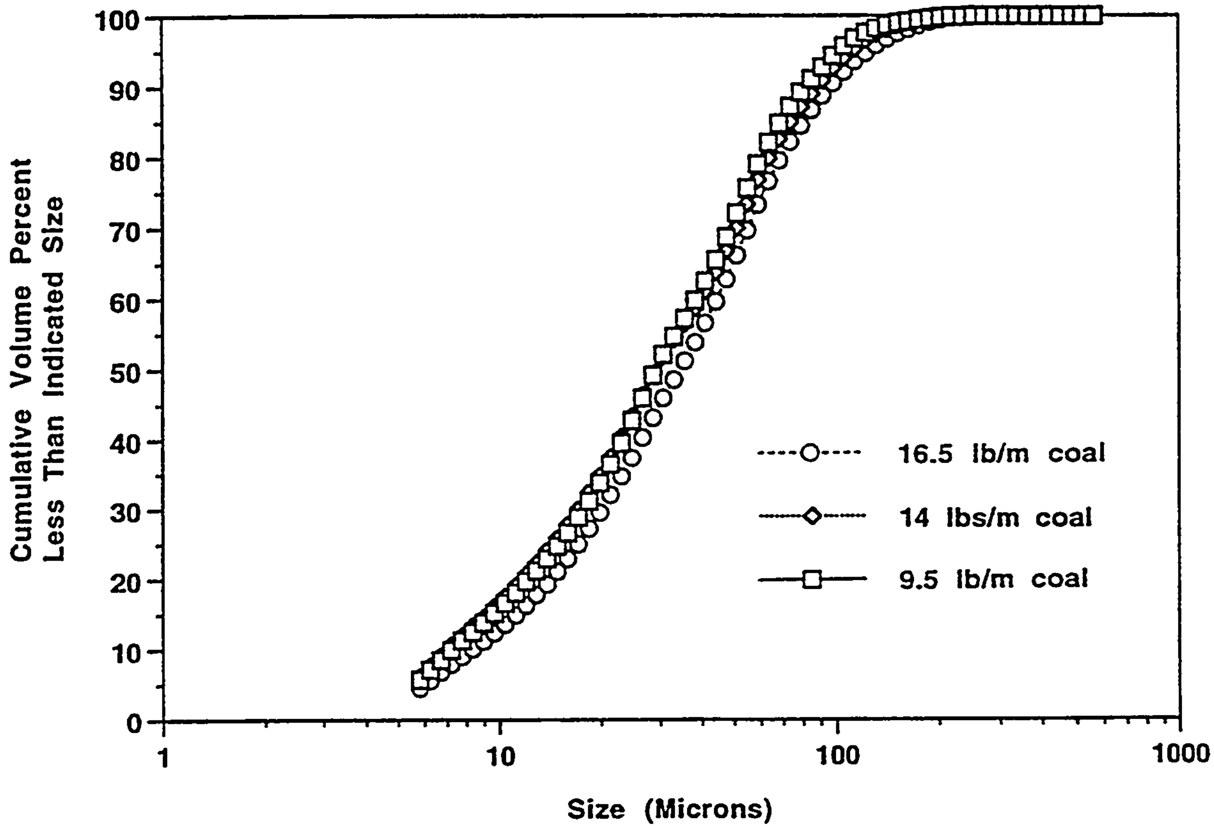

Figure C13 **Kentucky Coal PSDs at a Mill Air Flow Rate of 400 acfm, Low Mill Speed**

high coal feed rate, 16.5 lb/m, is slightly coarser than those for the other two coal feed rates.

Figure C13 shows the PSDs for coal feed rates of 9.5, 14.0, and 16.5 lb/m at a mill air flow rate of 400 acfm. The PSD becomes slightly coarser as the coal feed rate is increased.

C) Comparison of Milling Kentucky Coal at Two Mill Speeds

The coal PSDs, when milling the Kentucky coal at the two mill speeds and mill air flow rates of 320 and 400 acfm, are compared at a coal feed rate of 16.5 lb/m in Figures C14 and C15, respectively. The comparison is with the higher coal feed rate because this is the typical coal feed rate used when operating the boiler. In both cases, the high mill speed resulted in finer coal PSDs.

<u>Summary of Results When Milling Kentucky Coal at Two Mill Speeds</u>

A) There was no effect on coal PSD when varying the mill air flow rate from 320 to 420 acfm at coal feed rates of 9.5 and 14.0 lb/m for either mill speed (Figures C2, C3, C8, and C9).
B) When feeding coal at 16.5 lb/m, the coal PSD was coarser for both mill speeds at 400 acfm mill air (Figures C4 and C10).
C) The coal PSD was finer at a coal feed rate of 14.0 lb/m coal (no 16.5 lb coal/m data are available) than at 9.5 lb/m coal when operating the mill at the high speed and 320 acfm air flow. However, at the low mill speed and 320 acfm mill air flow, there was no effect of varying coal feed rate on coal PSD (Figures C5 and C11).
D) The coal PSD was finer at the higher coal feed rates (14.0 and 16.5 lb/m) than the lower coal feed rate (9.5 lb/m) at a high mill speed and 360 acfm mill air. The effect was minimal at the low mill speed (Figures C6 and C12).
E) The coal PSD was slightly finer at 14.0 lb/m coal and 400 acfm mill air than at 9.5 and 16.5 lb/m coal when operating the mill at high speed. At the lower mill speed, the coal PSD became coarser as the coal feed rate increased (Figures C7 and C13).
F) At the high coal feed rate (16.5 lb/m) and mill air flows of 360-400 acfm, the coal PSD was coarser for the lower mill speed (Figures C14 and C15).

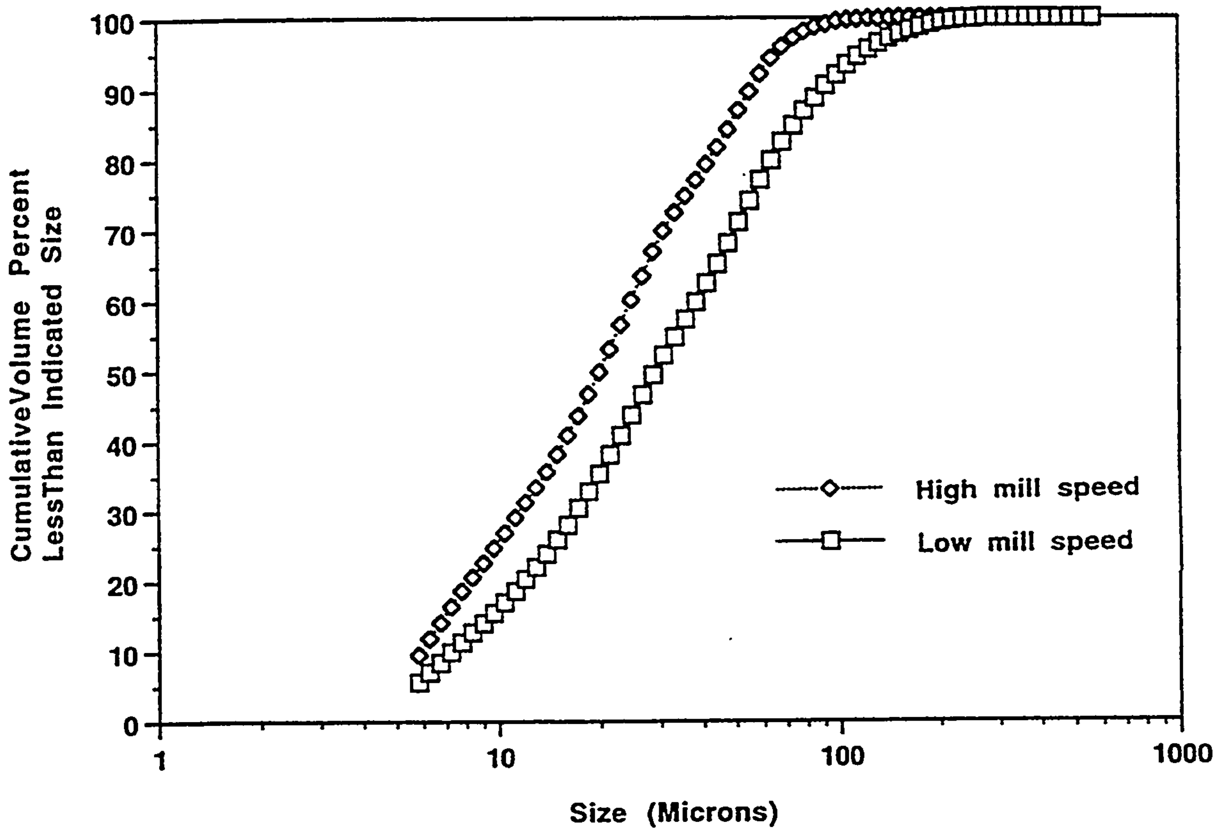

Figure C14 Kentucky Coal PSDs at a Coal Feed Rate of 16.5 lb/m with a Mill Air Flow Rate of 320 acfm

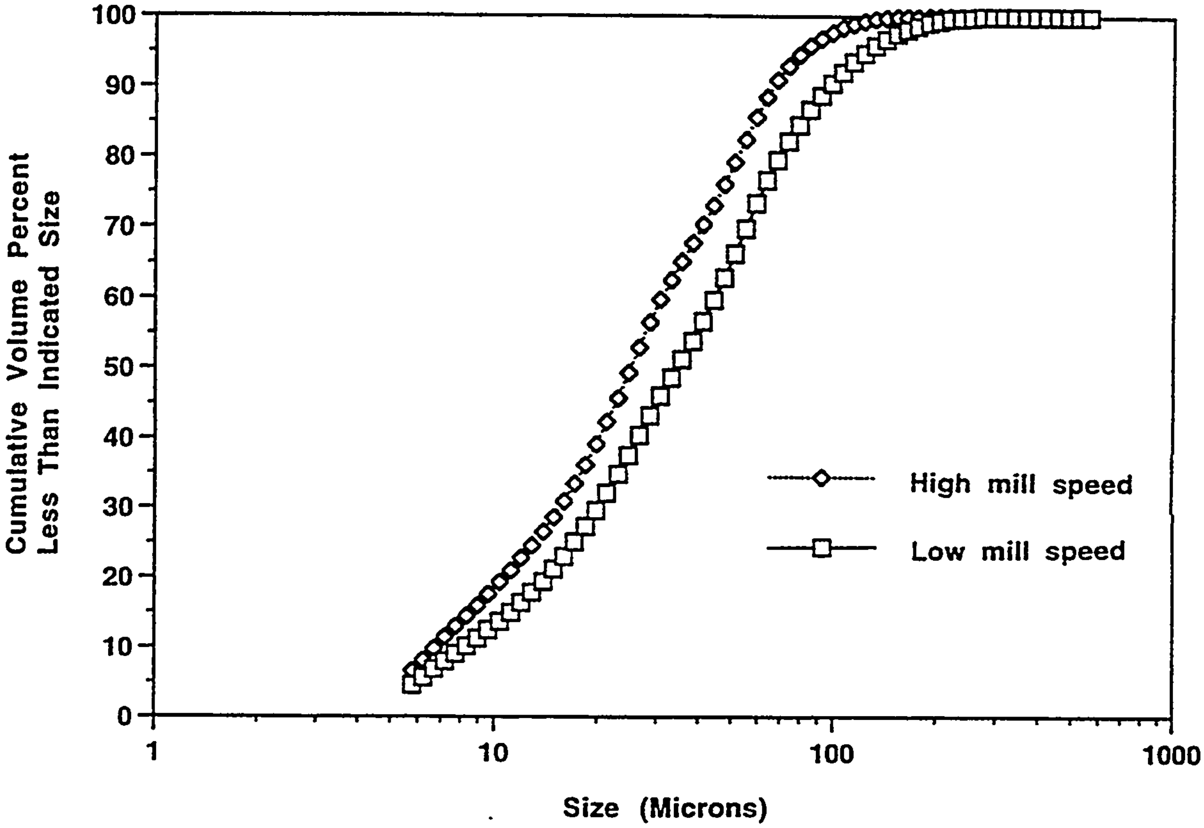

Figure C15 Kentucky Coal PSDs at a Coal Feed Rate of 16.5 lb/m with a Mill Air Flow Rate of 400 acfm

4) Brookville Seam Coal

A) Low Mill Speed (April 20, 1994)

A test was conducted on April 20, 1994 where coal samples were collected from the burner inlet while feeding coal at rates of 9.4, 13.9, and 16.5 lb/m and operating the mill at air flow rates of approximately 320, 360, and 400 acfm. The results are shown in Figures C16 through C21.

(1) Effect of Mill Air Flow Rate on Coal PSD as a Function of Coal Feed Rate

Figure C16 shows the PSDs for mill air flow rates of 320, 360, and 400 acfm at a coal feed rate of 9.4 lb/m. The coal PSD became coarser as the mill air flow was increased.

Likewise, Figure C17 shows the PSDs for mill air flow rates of 320, 360, and 400 acfm at a coal feed rate of 13.9 lb/m. Similarly there is an increase in PSD as the mill air flow increases.

Figure C18 shows the PSDs for mill air flow rates of 330, 360, and 400 acfm at a coal feed rate of 16.5 lb/m. Again, the coal PSD became coarser as the mill air flow was increased.

(2) Effect of Coal Feed Rate on Coal PSD as a Function of Mill Air Flow Rate

Figures C19 and C20 show the PSDs for coal feed rates of 9.4, 13.9, and 16.5 lb/m at mill air flow rates of 320/330 and 360 acfm, respectively. There is minimal effect of coal feed rate and mill air flow on coal PSD.

Figure C21 shows the PSDs for coal feed rates of 9.4, 13.9, and 16.5 lb/m at a mill air flow of 400 acfm. There tends to a slight shift to a finer PSD in the smaller particle size range as the coal feed rate is increased. Unexplainably, the PSD for the 13.9 lb/m coal sample was the finest.

Figure C22 is a compilation of Brookville Seam coal seam PSDs at various coal feed rates when operating the mill with 400 acfm mill air. These samples were collected throughout March and April, 1994. The finest coal PSD was with the lowest coal feed

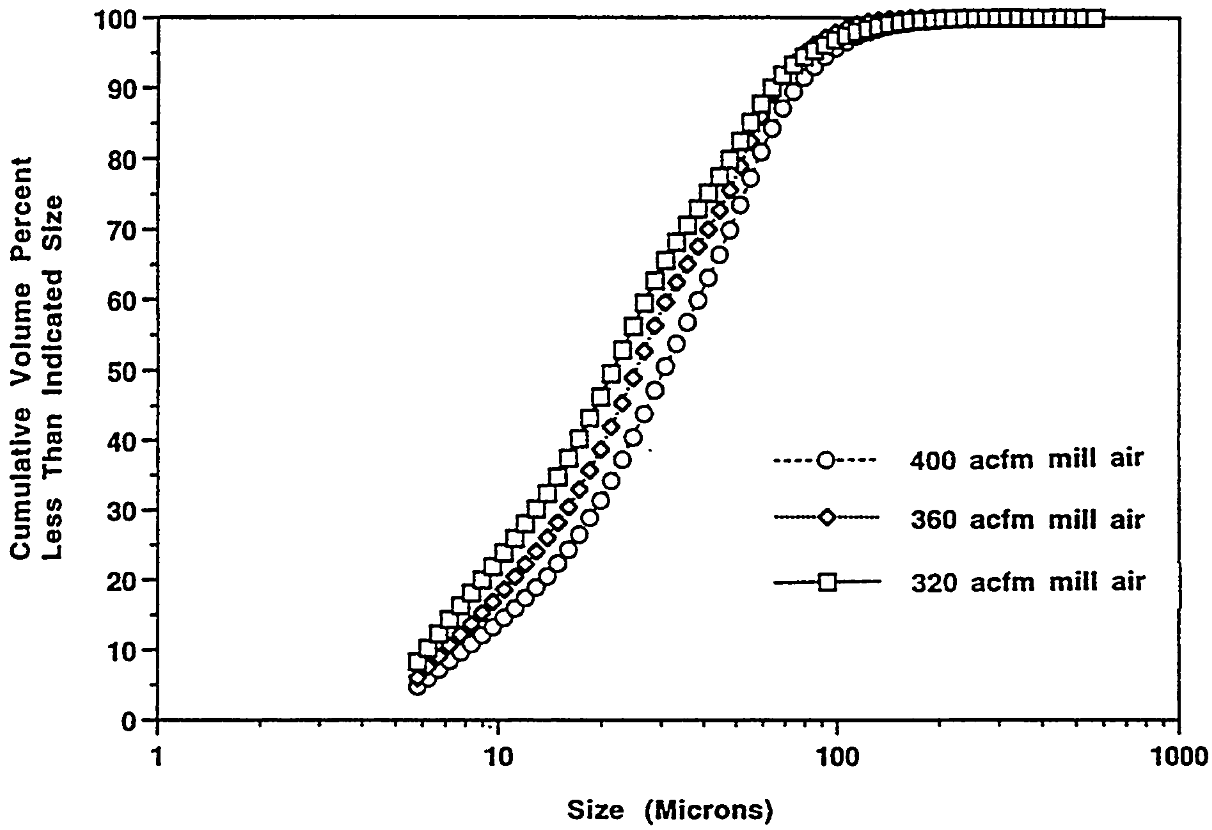

Figure C16 Brookville Coal PSDs at a 9.4 lb/m Coal Feed Rate and Low Mill Speed

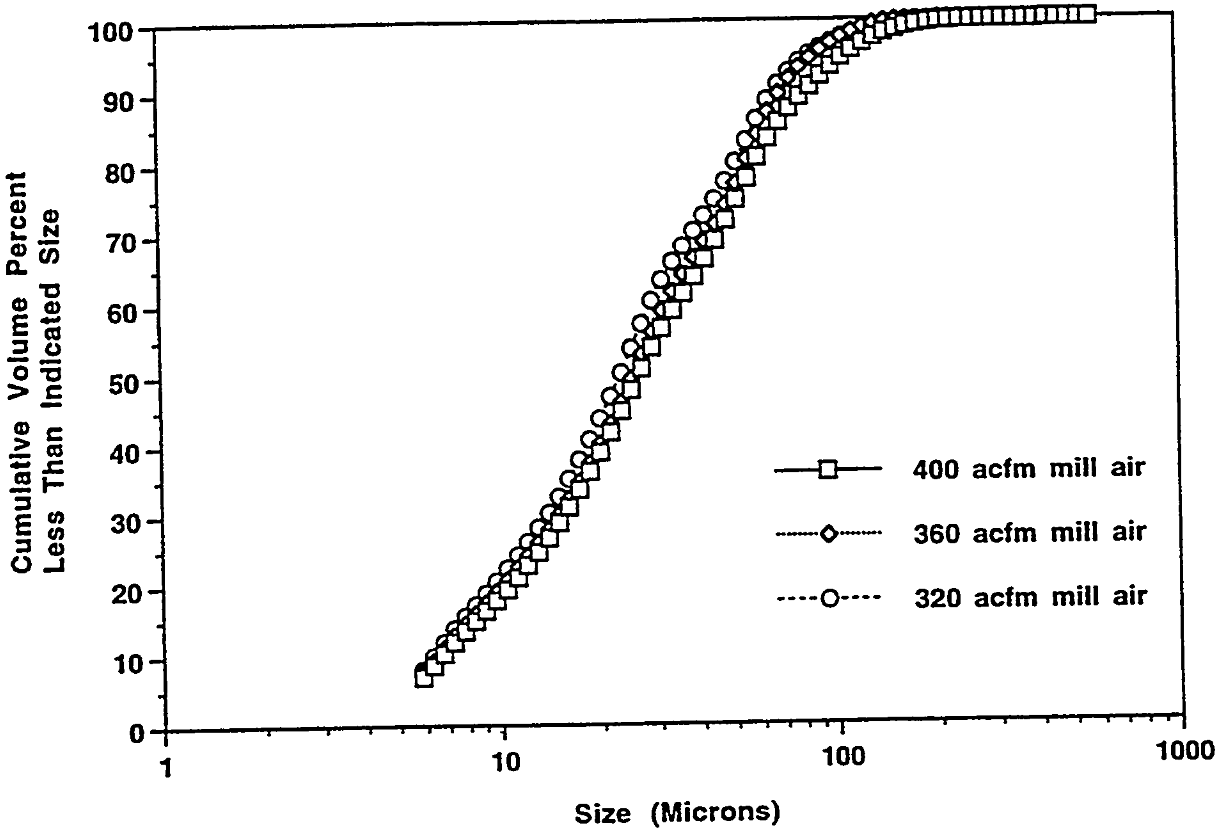

Figure C17 Brookville Coal PSDs at a 13.9 Coal Feed Rate and Low Mill Speed

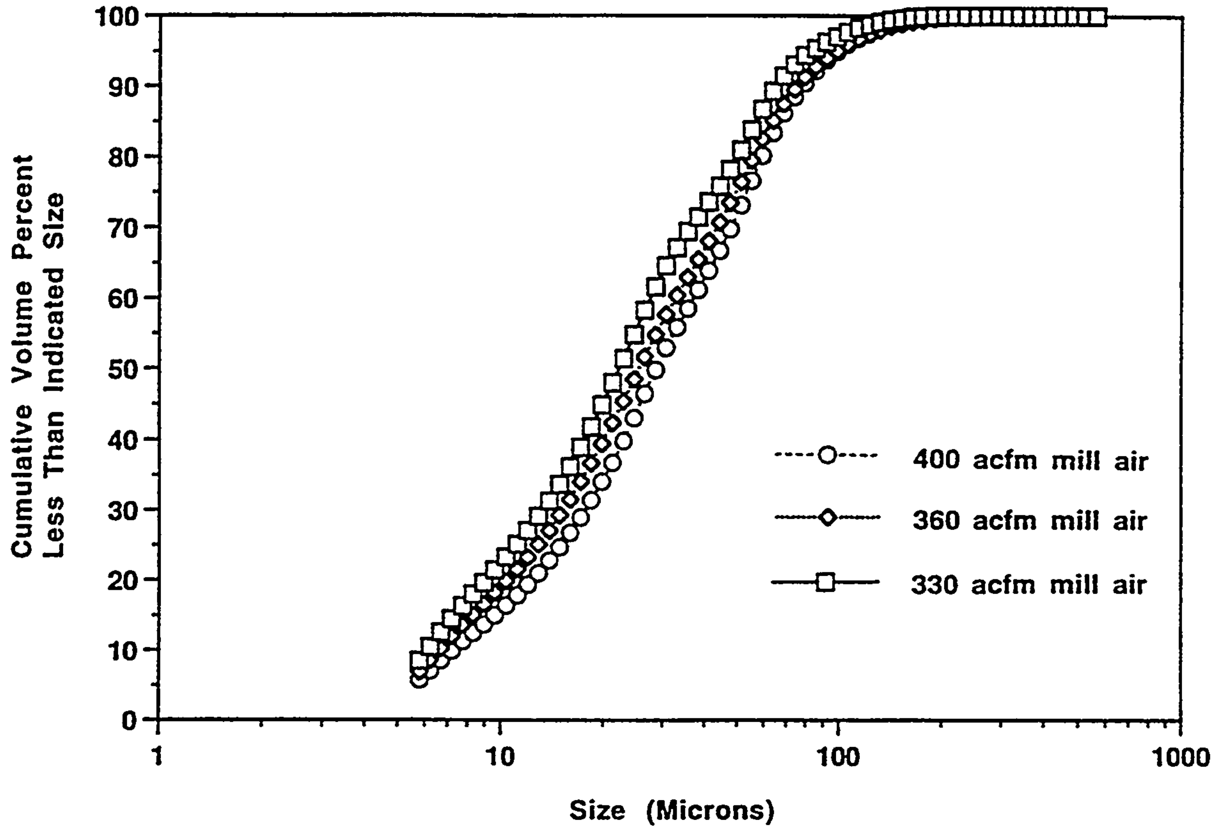

Figure C18 Brookville Coal PSDs at a 16.5 lb/m Coal Feed Rate and Low Mill Speed

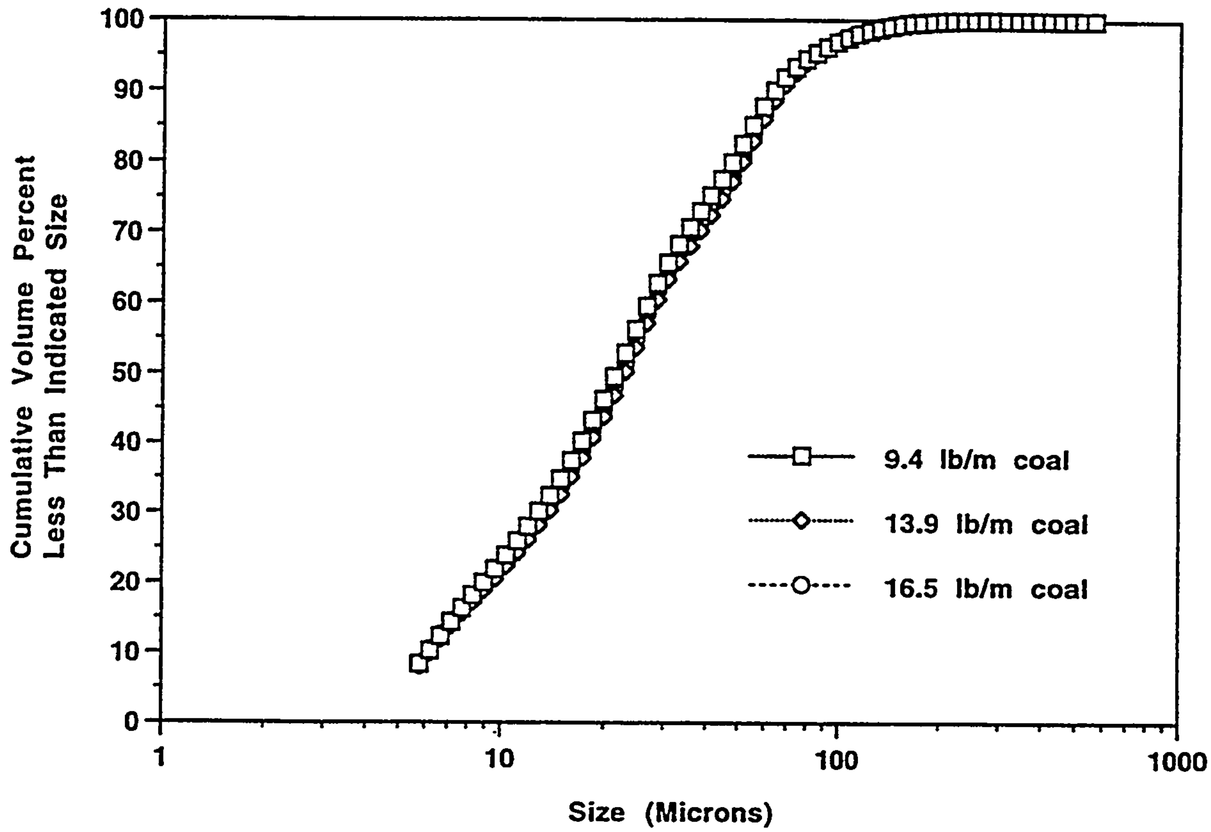

Figure C19 **Brookville Coal PSDs at a Mill Air Flow Rate of 320 acfm, Low Mill Speed**

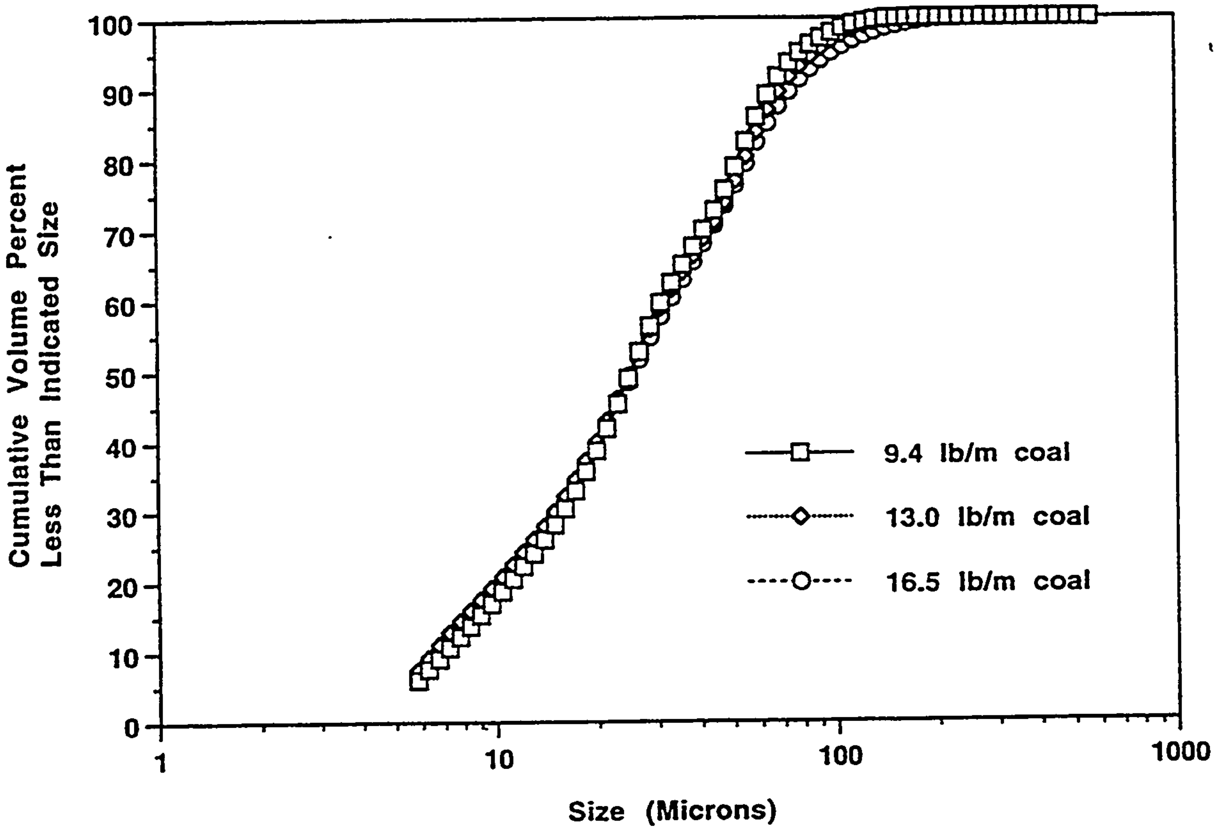

Figure C20 Brookville Coal PSDs at a Mill Air Flow Rate of 360 acfm, Low Mill Speed

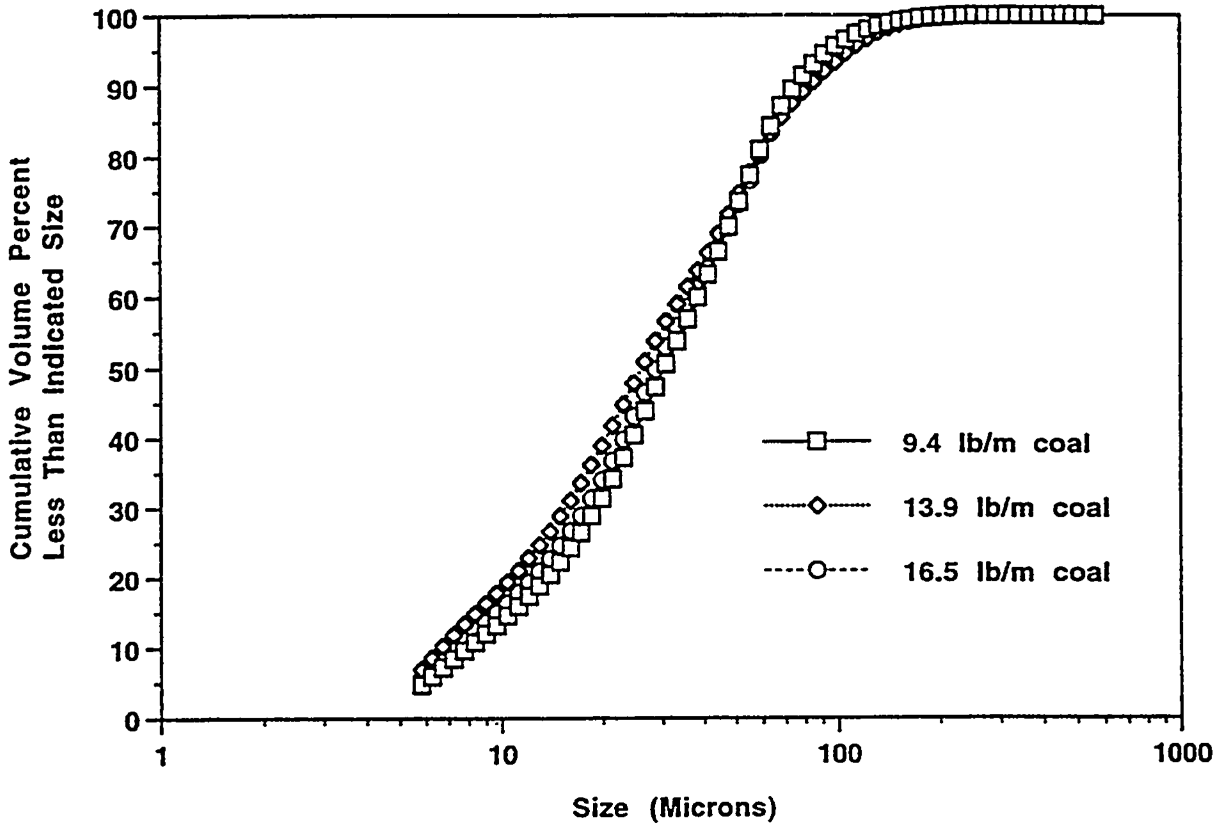

Figure C21 Brookville Coal PSDs at a Mill Air Flow Rate of 400 acfm, Low Mill Speed

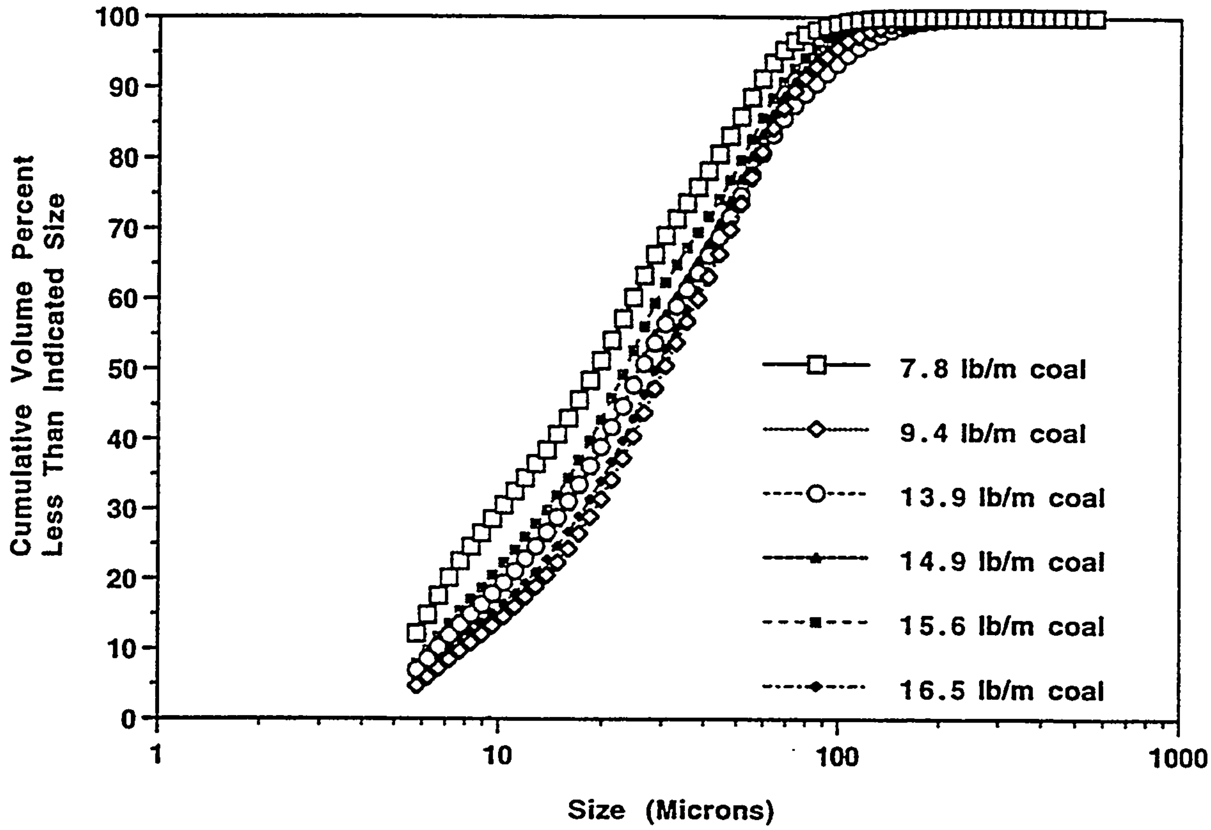

Figure C22 **Brookville Coal PSDs at a Mill Air Flow Rate of 400 acfm, Various Coal Feed Rates and a Low Mill Speed**

rate, 7.8 lb/m; however, there is variability in the results and no specific conclusions can be reached. The general ordering of the coal feed rates, from the finest to coarsest PSD at a cumulative volume percent less than 60% is: 7.8 < 15.6 < 14.9, 13.9 < 16.5 < 9.4. Above approximately ~60 cumulative volume percent the graphs exhibit much overlap and crossing.

B) Brookville Seam Coal - High Mill Speed (April 28, 1994)

One test was conducted on April 28, 1994 where coal samples were collected at 9.6, 13.9, and 16.5 lb/m coal and 370-384 acfm mill air. There was minimal effect of coal feed rate on the coal PSD as shown in Figure C23.

C)Comparison of Milling Brookville Seam Coal at Two Mill Speeds

Figure C24 shows the coal PSDs when operating the mill at 16.5 lb/m and mill air flow rates of 360-370 acfm for both low and high mill speeds. The PSD is finer for the high mill speed.

Summary of Results When Milling Brookville Seam Coal at Two Mill Speeds

A) For a given coal feed rate, 9.4, 13.9, or 16.5 lb/m, the coal PSD distribution became coarser as the mill air flow was increased when operating the mill at the low speed (Figures C16, C17, and C18).
B) There was no effect on coal PSD when varying the coal feed rate from 9.4 to 16.5 lb/m at mill air flows of 320 and 360 acfm when operating the mill at the low speed. Similarly, there was minimal affect on coal PSD when varying the coal feed rate from 9.6 to 16.5 lb/m and operating the mill at 370-384 acfm and high speed (Figures C19, C20, and C23).
C) The coal PSD tended to be slightly finer in the smaller particle size range at 13.9 and 16.5 lb/m when operating the mill at 400 acfm and the low speed (Figure C21).
D) At the high coal feed rate (16.5 lb/m) and mill air flows of 360-370 acfm, the coal PSD was coarser for the lower mill speed (Figure C24).

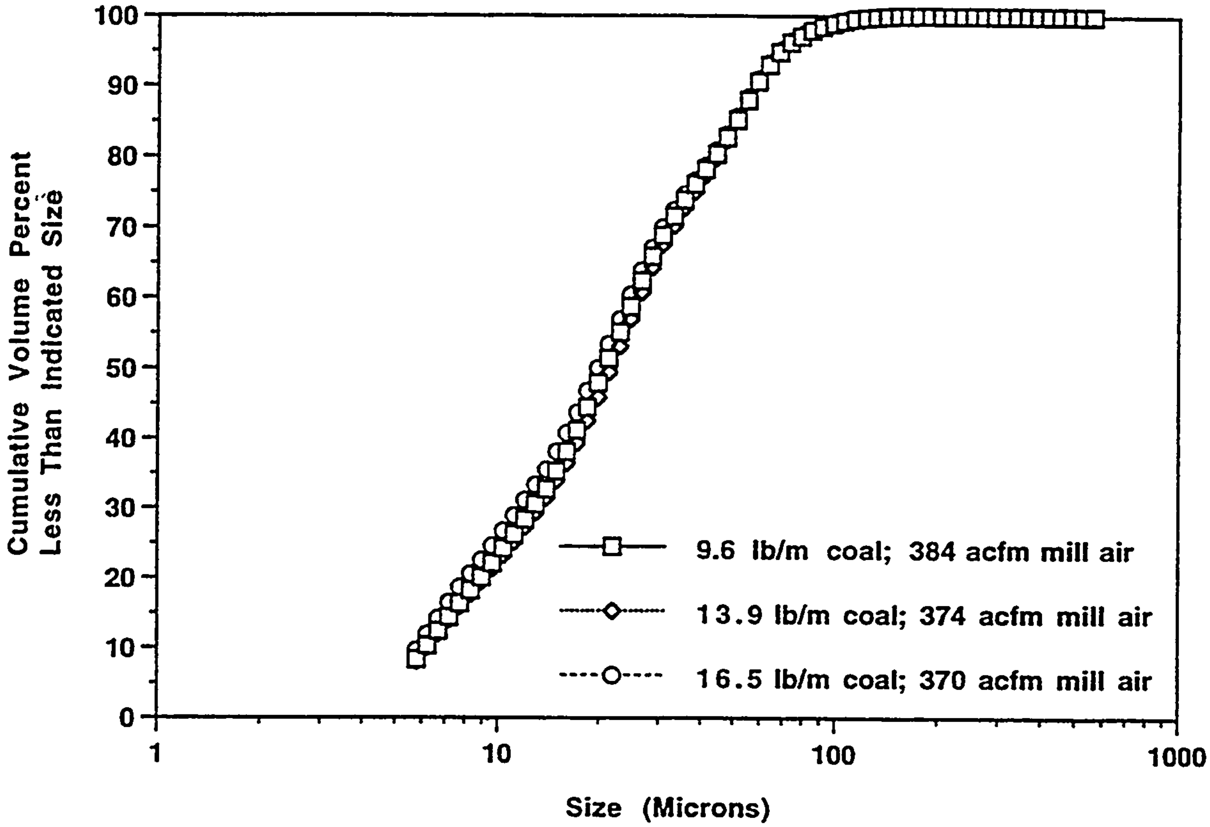

Figure C23 **Brookville Coal PSDs at a Mill Flow Rates of 370-384 acfm, Coal Feed Rates of 9.6, 13.9, and 16.5 lb/m and High Mill Speed**

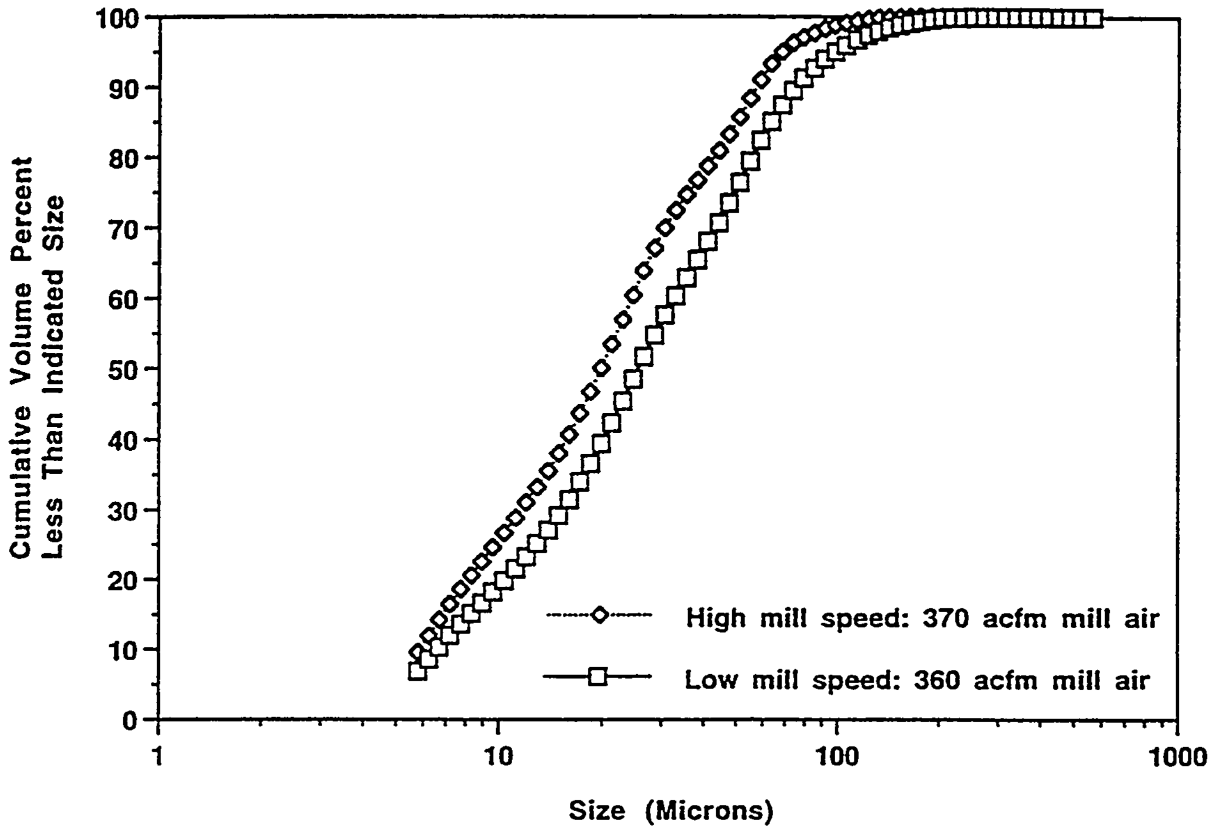

Figure C24 Brookville Coal PSDs at a Coal Feed Rate of 16.5 lb/m and Mill Air Flow Rates of 360-370 acfm for Low and High Mill Speeds

5) Comparison of Milling Performance of Brookville Seam and Kentucky Coals

A) Comparison of PSDs

As observed in the previous subsections, the two coals behaved differently during milling. This section compares the coal PSDs produced when operating the mill with 370-400 acfm air (which is the typical flow necessary for coal entrainment and flame stability), 16.5 lb coal/s (typical full load coal feed rate), and high and low mill speeds. Figure C25 shows the results from this comparison with general observations as follows:

- As noted from previous figures (Figures C15, C16, and C24), the coal PSD is finer for the Brookville Seam coal at the high mill speed and 370 acfm mill air than at the low mill speed regardless of mill air flow (360 or 400 acfm).
- Similarly, the coal PSDs are finer for the Kentucky coal at the high mill speed than for those at the low mill speeds.
- At the high mill speed and 360-370 acfm, PSDs are identical for the Brookville Seam and Kentucky coal. PSD for the Kentucky coal at 400 acfm mill air is coarser than at 360 acfm (see also Figure C4). This PSD is similar to the finest PSD produced at a low mill speed which occurred with the Brookville Seam coal at 360 acfm mill air. The Brookville Seam coal tended to be slightly coarser at the larger particle sizes. This Brookville Seam coal PSD was the finest PSD produced when operating the mill at the low speed.
- The next finest PSDs were those using Brookville Seam coal at 400 acfm mill air and Kentucky coal at 360 acfm mill air (both when the mill was operating at low mill speed). The PSDs were similar with the Kentucky coal PSD being coarser at the larger particle sizes.
- The coarsest PSD was produced from the Kentucky coal at 400 acfm mill air and low mill speed.

B) Comparison of Top Coal Particle Size

As previously mentioned, the objectives of the mill characterization were to determine the milling conditions necessary to reduce the coal PSD and top size in order to achieve >98% coal combustion efficiency and to evaluate the feasibility for external classification to reduce the coal top size. This section discusses the effect of mill air flow rate and coal feed rate on coal top size.

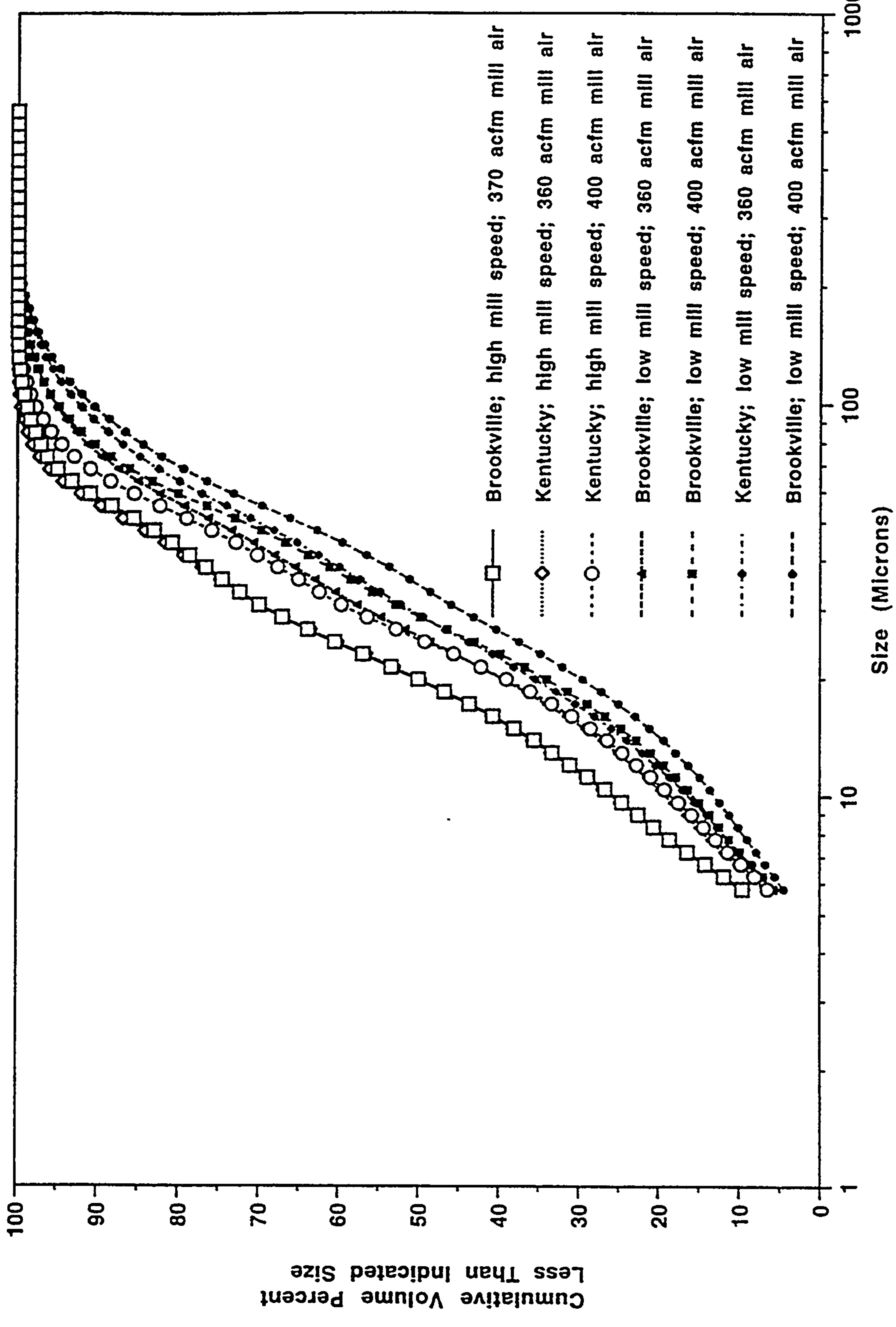

Figure C25 Comparison of Brookville Seam and Kentucky Coal PSDs at a Coal Feed Rate of 16.5 lb/m

The coal, mill air flow rate, coal feed rate, and mill speed influence the coal PSD produced in the TCS Mill. Although the influence of each parameter cannot be easily delineated, Figures C26 AND C27 show the Brookville Seam and Kentucky coal top size as a function of coal feed rate and mill air flow rate, respectively.

(1) Brookville Seam and Kentucky Coal Top Size as a Function of Coal Feed Rate

Figure C26 shows the Brookville Seam and Kentucky coal top size as a function of coal feed rate at low and high mill speeds for mill air flow rates ranging from 280 to 450 acfm. The results are summarized below by coal and mill speed. For each coal and each mill speed, the coal feed rates were divided into intervals (see below) for evaluation.

<u>Brookville Seam Coal - Low Mill Speed</u>

- At a coal feed rate of 7.8 lb/m, the coal top size was the largest at the lowest mill air flow rate and decreased as the mill air flow rate increased.
- At coal feed rates of ~9.5, 14-15, 15.5-16.5, and 18-19 lb/m, the coal top size exhibited much variability.

<u>Brookville Seam Coal - High Mill Speed</u>

- The coal top size increased slightly with increasing coal feed rate; however, there were a limited number of data points.

<u>Kentucky Coal - Low Mill Speed</u>

- At coal feed rates of 9.5, 14-15, and 16.5 lb/m, the coal top size decreased as the mill air flow rate was increased.

<u>Kentucky Coal - High Mill Speed</u>

- At a coal feed rate of 9.5 lb/m, the coal top size was the smallest at the highest mill air flow rate.
- At a coal feed rate of 14.0 lb/m, the coal top size was variable.
- At a coal feed rate of 16.5 lb/m, the coal top size was the largest at the highest mill air flow rate.
- There was only one data point at 19 lb/m, therefore, no conclusions can be drawn.

At Brookville Seam coal feed rates which are typical of normal load operation, ~15.0 lb/m or greater, and low mill speed, the resultant coal top size exhibited much variability. The coal top size ranged from 175 to 425 µm. The Kentucky coal however,

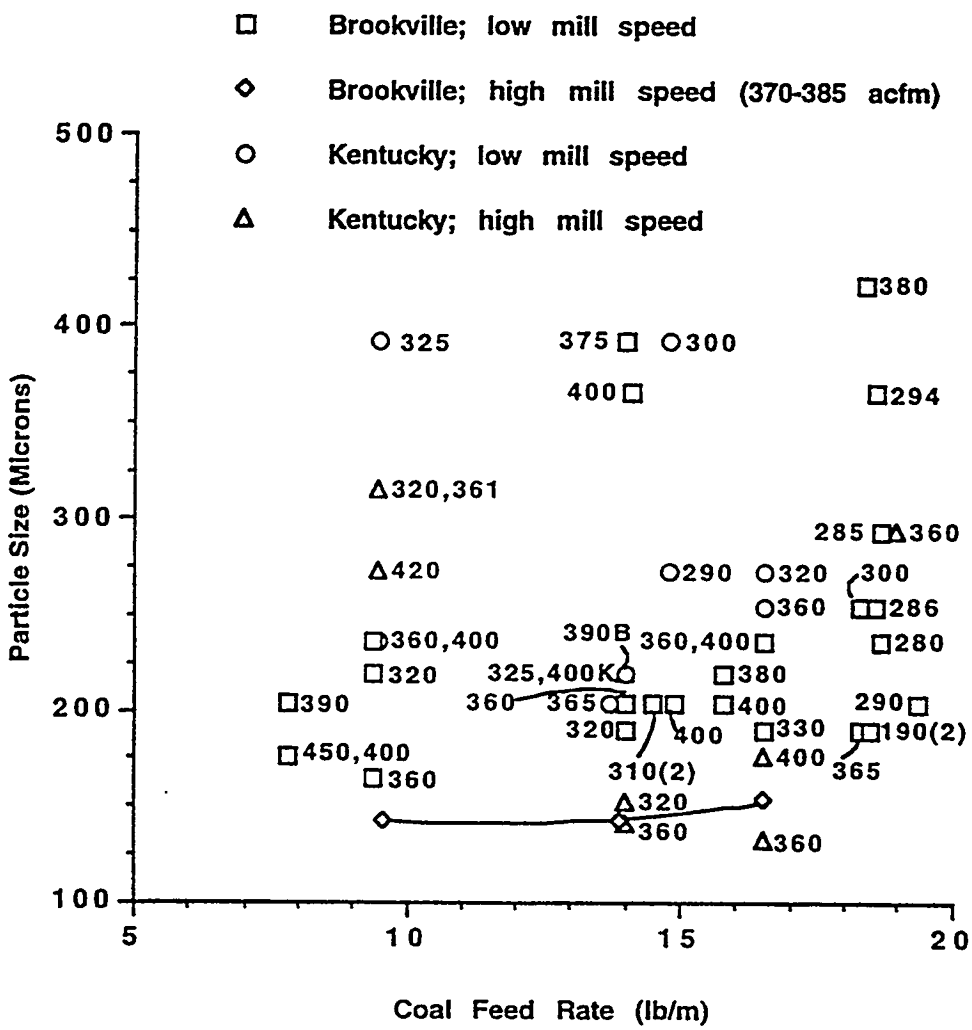

Figure C26 Brookville Seam and Kentucky Coal Top Size as a Function of Coal Feed Rate at Low and High Mill Speeds for Varying Mill Air Flow Rates

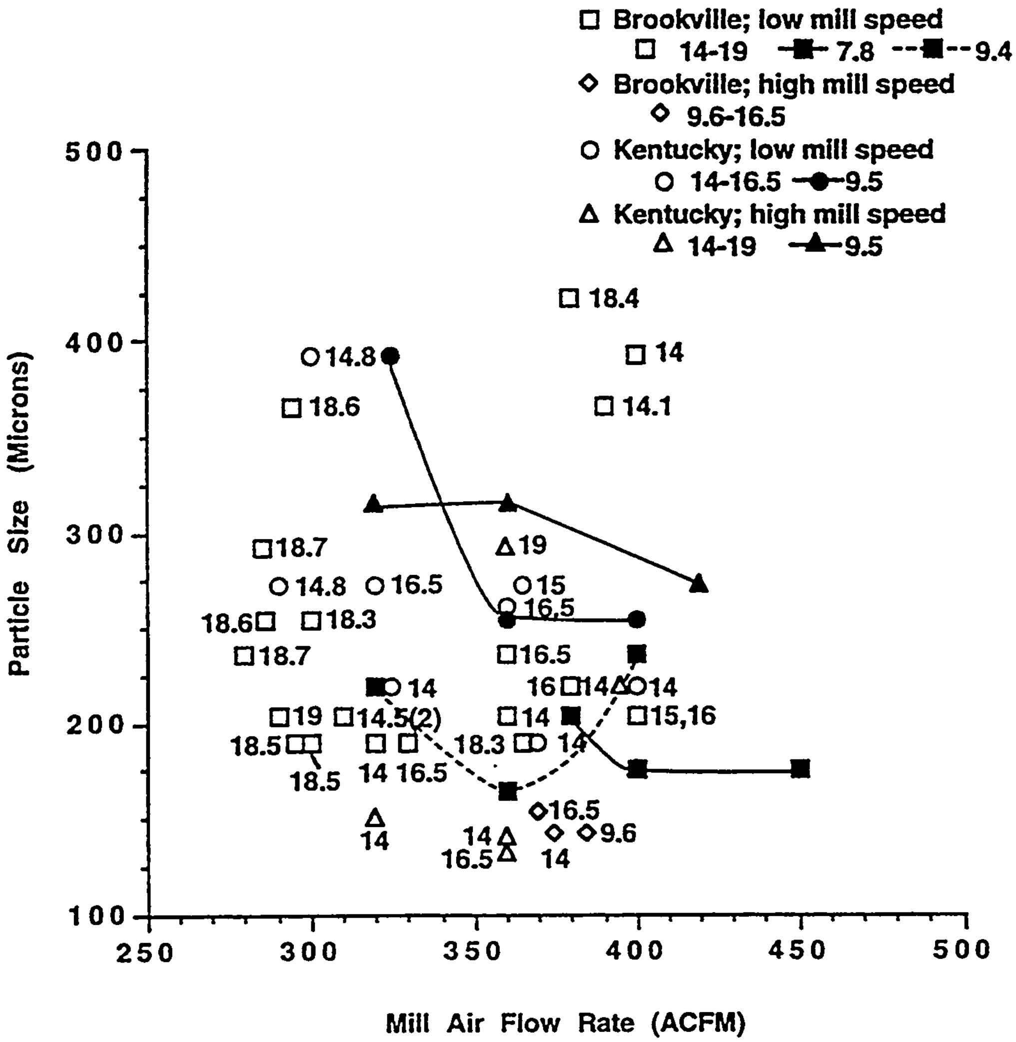

Figure C27 Brookville Seam and Kentucky Coal Top Sizes as a Function of Mill Air Flow at Low and High Mill Speeds for Varying Coal Feed Rates exhibited a decrease in the top size of the coal produced as the mill air flow rate increased when operating the mill at low speed. The coal top size decreased from ~400 to 250 μm.

(2) Brookville Seam and Kentucky Coal Top Size as a Function of Mill Air Flow Rate

Figure C27 shows the Brookville Seam and Kentucky coal top size as a function of mill air flow rate at low and high mill speeds for coal feed rates ranging from 7.8 and 19.4 lb/m. The results are summarized below by coal and mill speed. For each coal and mill speed, the coal feed rates were divided into intervals for comparison.

<u>Brookville Seam Coal - Low Mill Speed</u>

- At a coal feed rate of 7.8 lb/m, the coal top size was the largest at the lowest mill air flow rate which is a typical flow rate used. The top size decreased slightly, then leveled off as the air flow rate was increased over 400 acfm. The mill is not typically operated over 400 acfm.
- At a coal feed rate of 9.4 lb/m, the coal top size exhibited a minimum at ~360 acfm mill air as the mill air flow was varied from 320 to 400 acfm.
- The coal top size varied significantly at coal feed rates from 14.0-19.0 lb/m.

<u>Brookville Seam Coal - High Mill Speed</u>

- There was limited testing conducted with the mill at high speed. The testing that was conducted resulted in similar coal top sizes.

<u>Kentucky Coal - Low Mill Speed</u>

- At a coal feed rate of 9.5 lb/m, the coal top size decreased from ~400 μm at 320 acfm mill air to a levelized size of ~250 μm at mill air flow rates of 350 acfm and higher.
- At coal feed rates of 14-16.5 lb/m, there was much variability in the coal top size, but the scatter was less than that observed with the Brookville Seam coal.

<u>Kentucky Coal - High Mill Speed</u>

- At a coal feed rate of 9.5 lb/m, the coal top size was fairly constant with a slight decrease as the mill air flow rate increased.
- The coal top size was variable at coal feed rates of 14-19 lb/m.

At Brookville Seam and Kentucky coal feed rates which are typical of normal load operation, ~15 lb/m or greater, and low mill speed, the resultant coal top size was very variable and ranged from ~180 to 425 μm and from 225 to 275 μm for the Brookville Seam and Kentucky coals, respectively.

6) Concluding Statements

The results presented in the sections above show much variability. It should be noted that these were obtained under a variety of operating conditions. Samples collected prior to April, 1994, were obtained when there were operational problems encountered on a daily basis (see Appendix B) and system parameters were being changed in an attempt to improve coal combustion efficiency. Consequently, some of these results may not be representative of those obtained during normal operation.

One parameter that was varied was the mill air flow rate. Several of the tests were conducted where the mill air flow was reduced as low as possible. By the end of Task 3, the mill was typically operated with ~370 to 400 acfm air flow, ~16.5 to 18.5 lb coal/m (18.5 lb/m is full rate), and the low mill speed. At these conditions, the coal top size ranged from ~190 to 300 μm and from ~250 to 275 μm for the Brookville Seam and Kentucky coals, respectively. One Brookville Seam coal had a top size of 422 μm; however, it is likely that this sample is not representative because 99.8% of the particles were less than 293 μm with the distribution then increasing to 99.9% of the particles less than 422 μm. The D_{50} ranged from ~25 to 30 μm for both the Brookville Seam and Kentucky coals. Similarly, the D_{80}, which is the target specification and is to be less than 325 mesh (44 μm), varied from approximately 50 to 70 μm for the two coals.