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PROGRAM FOR REDUCTION OF NO_X FROM TANGENTIAL COAL-FIRED BOILERS PHASE II

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PROGRAM FOR REDUCTION OF NO_X FROM TANGENTIAL COAL-FIRED BOILERS PHASE II

by

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ABSTRACT

This report presents the findings of the Phase II "Program For Reduction of NO_x From Tangentially Coal Fired Boilers" performed under the sponsorship of the Office of Research and Development of the Environmental Protection Agency (Contract 68-02-1367). Phase I of the program consisted of selecting the Alabama Power Company, Barry Station #2 steam generator which was modified for the studies performed under Phase II. The Phase I results were presented in final report EPA-650/2-73-005, dated August, 1973.

The work accomplished under Phase II included the design, fabrication, and delivery of an overfire air system for the test unit, the installation of test equipment, planning, and the conducting of baseline, biased firing and overfire air studies for NO_x emission control while burning a Kentucky bituminous coal type.

These test programs included an evaluation of the effect of variations in excess air, unit slagging, load and overfire air on unit performance and emission levels. Additionally, the effect of biasing combustion air through various out of service fuel nozzle elevations was also evaluated. The effect of biased firing and overfire air operation on waterwall corrosion potential was evaluated during three thirty (30) day baseline, biased firing and overfire air corrosion coupon tests.

Unit loading and waterwall slag conditions exhibited minimal effects on NO_x emission levels while reductions in excess air levels and overfire air operation were found to be effective in reducing NO_x emission levels.

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ACKNOWLEDGMENTS

The author wishes to acknowledge the constructive participation of Mr. D. G. Lachapelle, EPA Project Officer, in providing the program direction necessary for its successful completion.

The cooperation and active participation of Alabama Power Company and, in particular, the personnel of the Barry Steam Plant were essential to successfully modifying the test unit and conducting the various test program phases.

The results presented in this report represent the effort of many Combustion Engineering, Inc. personnel whose participation was required for its successful completion and in particular the technical contributions made by Messrs. W. A. Stevens, R. F. Swope, M. S. Hargrove, R. W. Robinson, R. W. Borio, R. M. Kantorak and E. R. LePage.

CONCLUSIONS

Normal Operation

1. Under normal unit operation without overfire air, excess air variation was found to have the greatest single effect on NO_x emission levels, increasing NO_x with increasing excess air. An average increase of 0.014 g $NO_2/10^6$cal for each 1% change in excess air was observed over the normal operating range.
2. Unit loading and variation in furnace slag conditions were found to have the least effect on NO_x and CO emission levels and the percent carbon in the flyash.
3. Under normal unit operation, the percent carbon loss in the fly ash and CO emission levels increased with decreasing excess air with the increases becoming greater below a level of approximately 20 to 25 percent excess air. CO levels in excess of 0.1 g/10^6cal were considered unacceptable for the purposes of this program.

Overfire Air Operation

1. NO_x reductions of 20 to 30% were obtained with 15 to 20 percent overfire air when operating at a total unit excess air of approximately 15 percent as measured at the economizer outlet. This condition would provide an average fuel firing zone stoichiometry of 95 to 100 percent of theoretical air. Stoichiometries below this level did not result in large enough decreases in NO_x levels to justify their use. Biased firing, while potentially as effective, necessitates a reduction in unit loading and is therefore less desirable as a method of NO_x control.
2. When using overfire air as a means of decreasing the theoretical air (TA)* to the fuel firing zone the percent carbon in the fly ash and CO emission levels were less affected than when operating with

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* See Appendix I.

low excess air. This is due to the ability to maintain acceptable total excess air levels during overfire air operation.

3. Furnace performance as indicated by waterwall slag accumulations, visual observations and absorption rates were not significantly affected by overfire air operation.
4. On the test unit, where the overfire air port could not be installed as a windbox extension, test results indicated that the centerline of the overfire air port should be kept within 3 meters of the centerline of the top fuel elevation. Distances greater than 3 meters did not result in decreased NO_x levels. Changes in distance less than 3 meters did affect NO_x levels to a limited extent with the NO_x level increasing with decreasing distance.
5. Optimum overfire air operation was obtained with the test unit when the overfire air nozzles were tilted with the fuel nozzles. From a standpoint of NO_x control, emission levels increased when the nozzles were directed toward each other, and flame stability decreased when they were directed away from each other by more than 20-25°. With the overfire air tilts fixed in a horizontal position, acceptable unit operation was obtained, however, NO_x levels varied with fuel nozzle position.
6. The results of the 30 day baseline, biased firing and overfire air corrosion coupon runs indicate that the overfire air operation for low NO_x optimization did not result in significant increases in corrosion coupon degradation. Additional studies will be required to verify these observations over long-term operation.
7. Variables normally used to control normal boiler operation should not be considered as NO_x controls with coal firing. These variables include unit load, nozzle tilt, pulverizer fineness, windbox dampers and total excess air.
8. Overall unit efficiency was not significantly affected by overfire air operation.

RECOMMENDATIONS

This program investigated the effects of employing biased firing and overfire air, as incorporated on a specially modified unit, as methods for controlling NO_x emission levels in existing steam generating units.

These control methods were studied using an Eastern United States bituminous coal type. Due to the location of the test site it was not, however, within the scope of this program to investigate coal types located in the western areas of the United States.

1. As these western coal types are becoming a more predominate source of fuel for electric generating stations, it was recommended in the Task V interim report that studies be undertaken to include their evaluation. EPA Contract 68-02-1486 was subsequently awarded to Combustion Engineering, Inc. to study western coal fuels. In this program new units being designed with overfire air systems as an extension to the windbox will be utilized eliminating the need for unit modifications while expanding the experimental studies to include test data for larger current design steam generating units.
2. Additionally, the results of the corrosion probe evaluations indicate that the coupon weight losses encountered during a 30 day evaluation are small and consideration should be given to studies of up to one year duration to verify short term test results. These studies should include evaluation of actual fireside waterwall tube wastage rates as well as corrosion probe wastage rates.

INTRODUCTION

Purpose and Scope

This program encompassed the work to be performed under the second phase of a two phase program to identify, develop and recommend the most promising combustion modification techniques for the reduction of NO_x emissions from tangentially coal-fired utility boilers with a minimum impact on unit performance.

Phase I (performed under EPA Contract 68-02-0264) consisted of selecting a suitable utility field boiler to be modified for experimental studies to evaluate NO_x emission control. Phase I also included the preparation of preliminary drawings, a detailed preliminary test program, a cost estimate and detailed schedule of the program phases and a preliminary application economic study indicating the cost range of a variety of combustion modification techniques applicable to existing and new boilers. [1]

Phase II consisted of modifying and testing the utility boiler selected in Phase I to evaluate overfire air and biased firing as methods for NO_x control. This phase also included the completion of detailed fabrication and erection drawings, installation of analytical test equipment, updating of the preliminary test program, analysis and reporting of test results and the development of control technology application guidelines for existing and new tangentially coal-fired utility boilers.

This program was conducted at the Barry Steam Station, Unit No. 2 of the Alabama Power Company. This unit is a natural circulation, balanced draft design, firing coal through four elevations of tilting tangential fuel nozzles. Unit capacity at maximum continuous rating (MCR) is 408,000 kg/hr main steam flow with a superheat outlet temperature and pressure of 538°C and 131.8 kg/cm^2. Superheat and reheat temperatures are controlled by fuel nozzle tilt and spray desuperheating. A side elevation of the unit prior to modification is shown on Figure 1.

Throughout this report NO_x emission levels are expressed as $g/10^6 cal\ NO_2$.

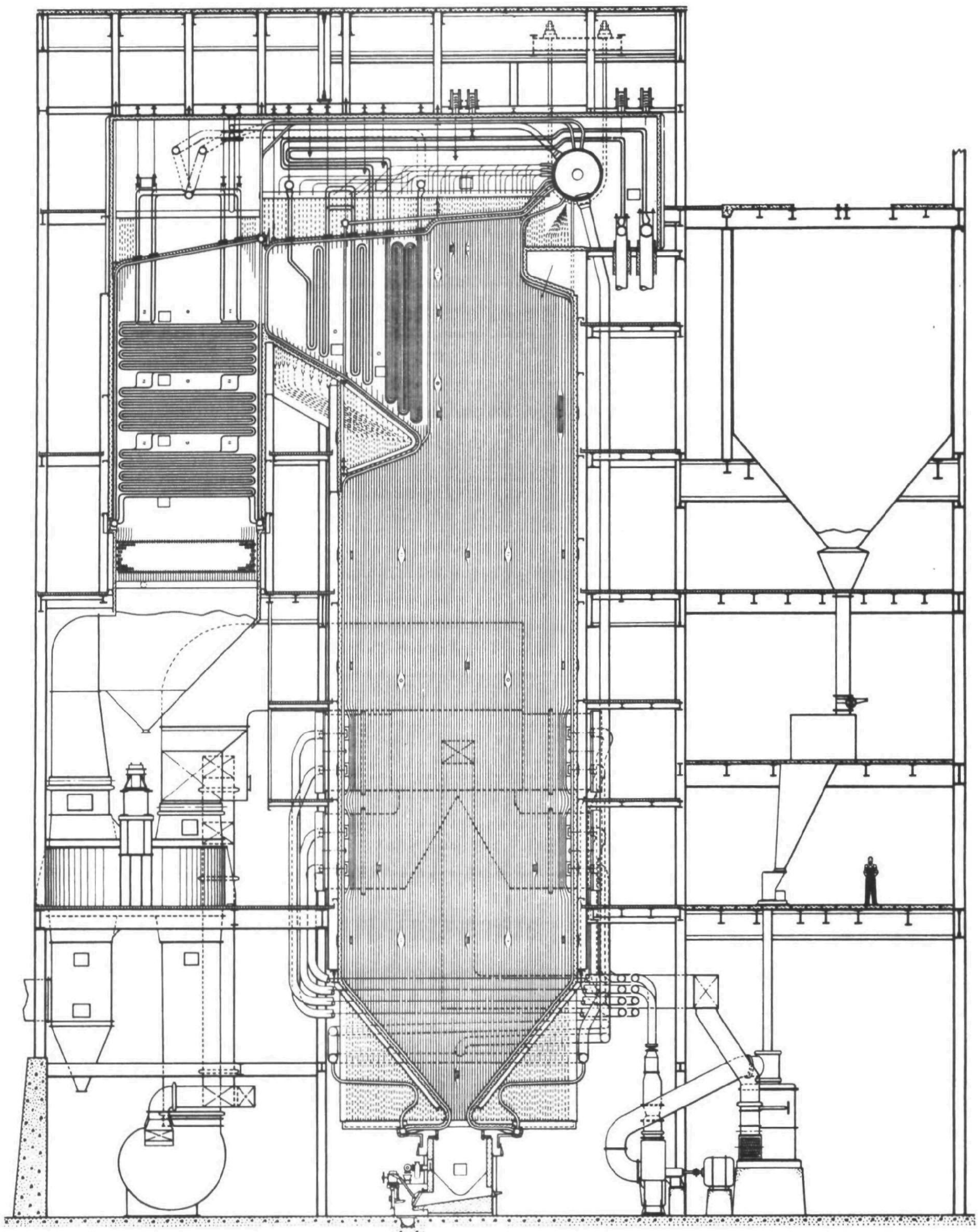

Figure 1. Unit Side Elevation, Alabama Power Company, Barry No. 2

OBJECTIVES

The objective of program Phase II was to complete the design of the overfire air system, modify the Barry 2 unit accordingly, perform baseline, biased firing and optimization tests and based on the results of this program, prepare an application guideline for the NO_x control technology generated.

Specifically these objectives are defined as follows:

Task I - Prepare the design, detailed fabrication and erection drawings necessary for modification of Barry No. 2 to incorporate an overfire air system. The system design provides for:

a. Introducing a maximum of 20% of the total combustion air above the fuel admission nozzles.
b. Overfire air introduction through the top two existing windbox compartments (thereby prohibiting the use of one elevation of fuel nozzles).
c. Introduction of hot overfire air only with consideration for air preheat control.

An updated schedule for Tasks II and IV were also prepared under Task I.

Task II - Complete the purchasing and fabrication of all equipment necessary for modification of the Barry No. 2 unit.

Task III - Install all necessary instrumentation required to measure flue gas constituents and characterize the effects of combustion modifications on unit performance. Specifically the following determinations were made:

a. Flue gas constituents: NO_x, SO_x, CO, HC, O_2
b. Unit Performance Effects:

Fireside corrosion
Furnace heat absorption
Sensible heat leaving furnace
Superheater, reheater and air heater performance

Task IV - Conduct a baseline test program to establish the effect of unit load, wall slagging and excess air variation on baseline emission levels, thermal performance and operating ranges. A baseline corrosion coupon test of 30 day duration was also conducted.

Task V - Conduct a biased firing baseline test program to establish the effect on unit emission levels while operating with various fuel elevations out of service. These tests were performed specifically to evaluate the maximum emission control at full load and throughout the normal load range. In addition, the degree of control required to meet and maintain emission standards throughout the normal control range was also evaluated. A biased firing corrosion coupon test of 30 days duration was also conducted.

Task VI - Install all equipment required for modification of the test unit and functionally check equipment to determine that proper operation is obtained. (See Figure 1A)

Task VII - Complete final preparations for conducting the overfire air test program to be conducted in Task VIII including the following:

a. Finish installation of the furnace waterwall thermocouples.
b. Check out all necessary test instrumentation for proper installation and operation.
c. Review test program with EPA project officer and util-

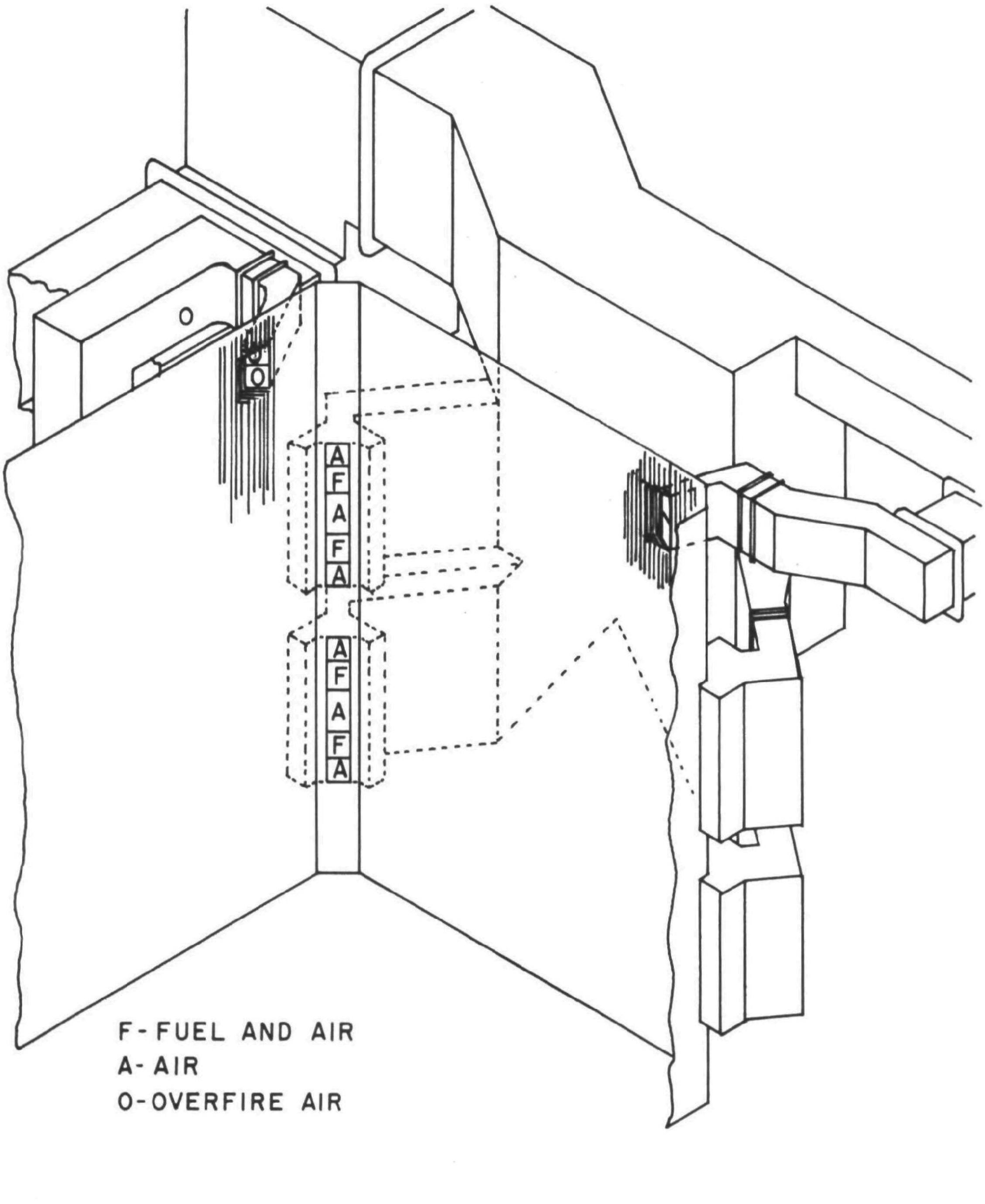

Figure 1A: Schematic Overfire Air System, Barry No. 2

ity company.*

d. Perform a final inspection of the test unit to assure proper operation.

Task VIII- Conduct the overfire air test program, analyze the data generated and compare this data with that obtained during Task V. The program investigated the effect of overfire air location and rate at various unit loadings and evaluated operating conditions considered as optimum from the standpoint of NO_x control and unit operation. The final report was also generated under this Task.

Task IX - Prepare a program outlining the application of the technology developed under this study to existing and new design tangentially coal-fired utility boilers. These application guidelines will be submitted as a separate final report.

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* The test program for this study was originated during the Phase I study, Contract 68-02-0264 and was included as part of the Phase I report.

DISCUSSION

Task I - Prepare the Design, Detailed Fabrication and Erection Drawings

Engineering Drawings

The drawings necessary for the design and installation of the overfire air system were completed by the end of the eighth program month and were submitted to the EPA for review and approval as they were completed. The design provides for the introduction of 20% of the total combustion air as overfire air above the existing fuel admission zone. These compartments are located approximately 2.4 meters above the existing windbox. In addition overfire air can be introduced through the top two compartments of the existing windbox. The current design provides for the introduction of hot overfire air only.

Updated Time Schedule

The Phase II program schedule was reviewed and updated relative to the coordination of Tasks II, IV and V with the test unit outage.

The scheduling of the unit outage was coordinated with Alabama Power Company and reviewed periodically to assure that the unit modification would occur as scheduled. The final program schedule presenting the actual periods of performance for Phase II is shown on Figure 2.

Task II - Purchase and Fabricate Equipment

The equipment for modification of the Barry No. 2 unit to incorporate overfire air as an NO_x control was assembled and ready to be shipped to the test site by the end of the eighth program month. Completion of equipment fabrication by this date permitted necessary time for delivery of the equipment to the job site and performing any possible pre-outage erection which would be accomplished prior to the unit outage.

In addition, instrumentation required for the baseline and optimization test phases of the program was calibrated, fabricated and prepared for shipment to the job site. This effort included fabrication of corrosion

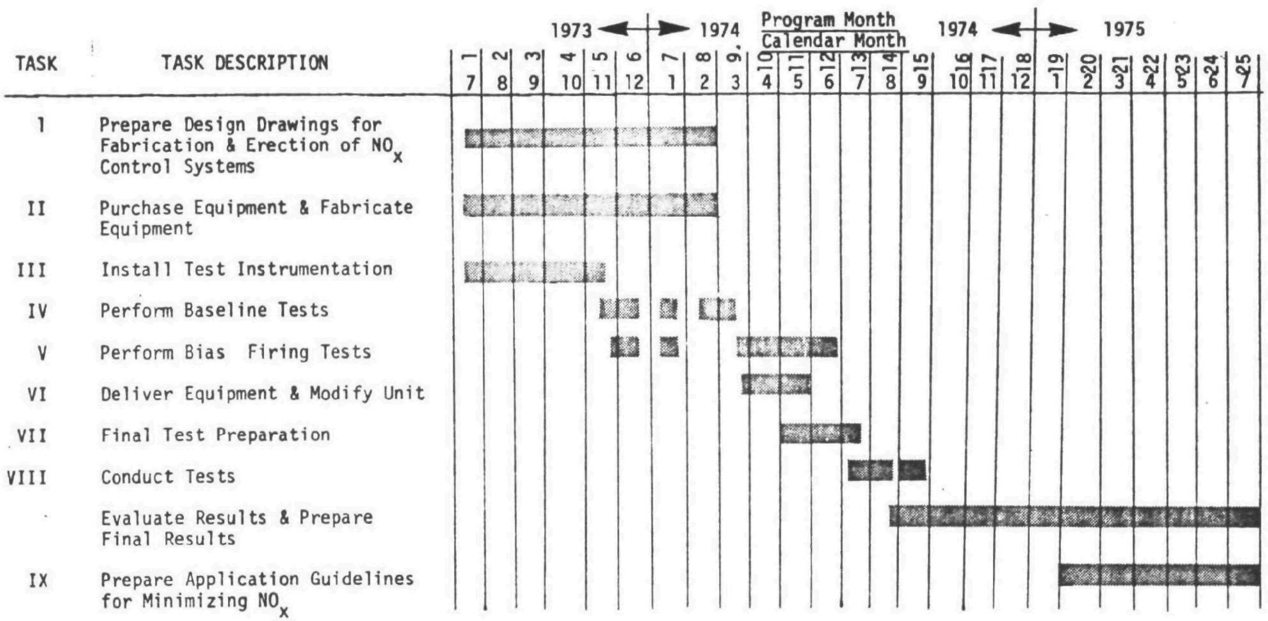

Figure 2: Program Schedule for Evaluation of Biased and Overfire Air Firing and Existing Process Variables

probes, probe control systems, and gas sampling probes, and calibration of thermocouples, analyzers and transducers. The emissions monitoring system is shown in Figure 3.

Task III - Test Instrumentation Installation

The analytical test instrumentation necessary for the measurement of flue gas constituents and unit performance were installed by the fifth program month with the exception of the waterwall absorption thermocouples which were installed during the unit outage for installation of the overfire air modification.

The instrumentation and analytical methods used were as follows:

Measurement	Instrument/Analytical Procedure
Flue Gas Constituents	
NO_x	Chemiluminescence Analyzer
SO_2	Wet Chemistry
CO & Hydrocarbons	Infrared Analy. and Flame Ionization Analyzer
Carbon Loss	Dust Collector
Oxygen	Paramagnetic Analyzer
Fuel Analysis	ASTM Procedures
Ash Analysis	ASTM Procedures
Flow Rates	
Steam & Water	
Feedwater Flow	Flow Orifice
Reheat and Superheat Desuperheat Spray	Heat Balance (°F & PSIG) Around Desuperheater
Reheat Flow	Heat Balance Around Superheat Extractions and Estimated Turbine Gland Seal Losses

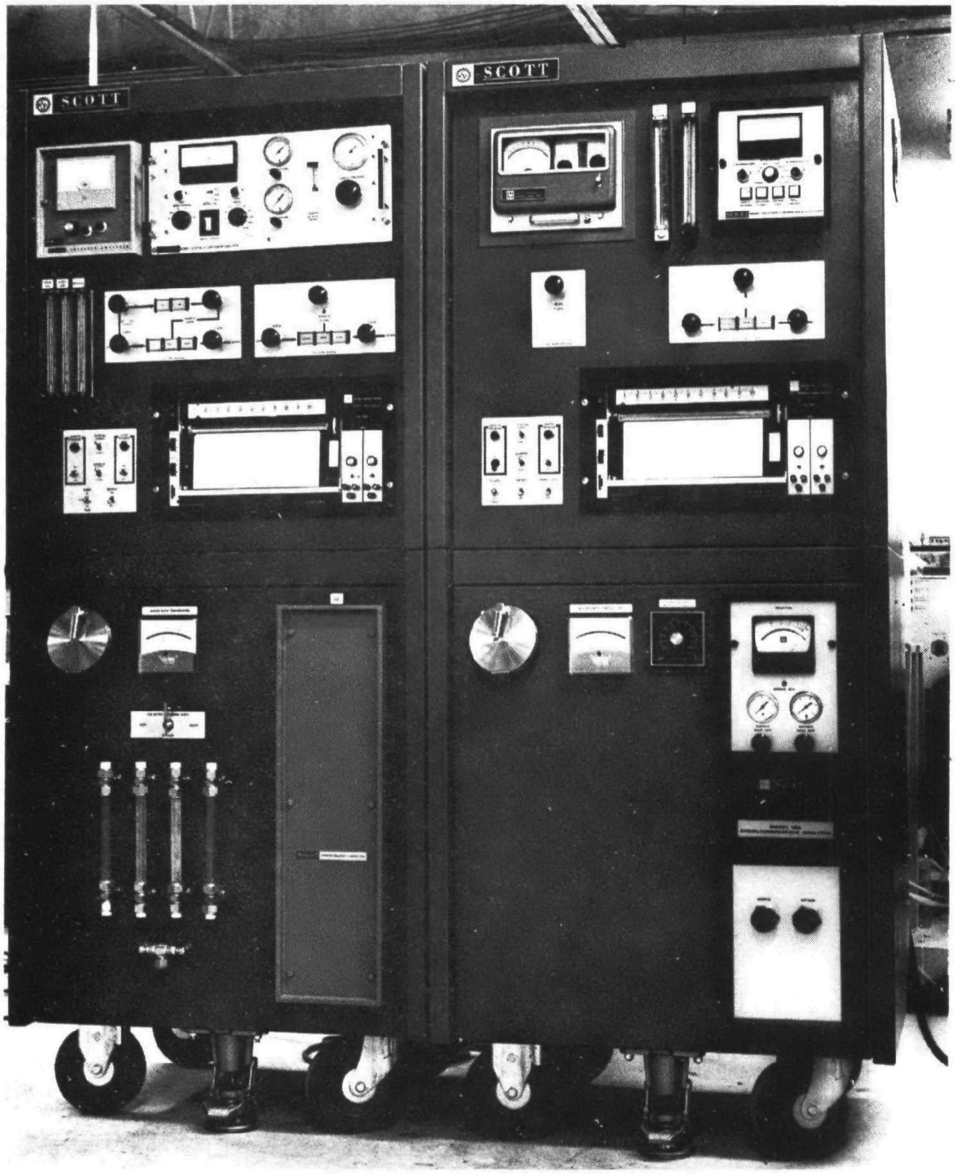

Figure 3. Gaseous Emissions Test System

Measurement	Instrument/Analytical Procedure
Air & Gas	
Total Air & Gas Weight	Calculated
Overfire Air*	Pitot Traverse
Air Heater Leakage	Paramagnetic O_2 Analyzer
Temperatures	
Steam & Water °F	
Unit Absorption Rates	Calibrated Stainless Steel Sheathed CR-C Well & Button TC's
Waterwall Absorption*	Calibrated Stainless Steel Sheathed Cr-C Chordal WW TC's
Air & Gas °F	Cr-C TC's Water Cooled Probes Pt/Pt-10% Rh TC's
Pressures	
Steam and Water PSIG	
Unit Absorption Rates	Pressure Gauges and/or Transducers
Unit Draft Loss	Water Manometers
Temperature and Pressure Logging, °F & PSI	C-E Data Logger Capacity: 400 temperatures, 50 pressures

Tasks IV & V Baseline & Biased Firing Test Programs

Test Data Acquisition and Analysis

The flue gas samples for determination of NO_x, O_2, CO, SO_2 and HC emission levels were obtained at each of the two economizer outlet ducts.

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* Installed during Task VI

The flue gas samples were drawn from a twenty-four (24) point grid arranged on centroids of equal area in each duct with the exception of the SO_2 sample which was drawn from a single average point using a heated sample line. Fly ash samples for carbon loss analysis and dust loading were obtained at a single point in each duct.

The percent O_2 leaving the air preheaters was also determined using a twenty-four (24) point grid arranged in centroids of equal area for the determination of air preheater leakage and unit efficiency.

The following instrumentation was used in determining the emission concentrations:

1. NO_x: Chemiluminescence Analyzer
2. O_2: Paramagnetic Analyzer
3. CO: Nondispersive Infrared Analyzer
4. HC: Flame Ionization Analyzer
5. SO_2: Wet Chemistry
6. Carbon Loss & Dust Loading: ASME Particulate Sampling Train

A summary of the NO_x emission test data is tabulated on Data Sheets 1, 2, 3 and 4.

Unit steam and gas side performance was monitored using calibrated thermocouples, pressure gauges, transducers and manometers as required.

Coal samples were obtained during each test for later analysis. The samples were obtained from each feeder and blended to form a composite sample. Fuel analyses, unit steam flow rates, absorption rates, gas and air weights and efficiencies were calculated for each test run. Unit efficiency was determined using the heat losses method (based on ASME power test code 4.1-1964). The measured and calculated unit performance test data is presented on Data Sheets 5, 6, 7 and 8. A complete set of unit board data was obtained for each test run and is presented on Data Sheets 9, 10, 11 and 12. While Data Sheets 1 through 8 are reported in metric units, the board data (Sheets 9 through 12) are reported in the engineering units as taken. The 30 day waterwall corrosion coupon evaluation was conducted using a specially designed probe consisting of four individual coupons shown in Figure 4. Individual probes were exposed at five locations on the front furnace wall as shown on Figure 5. A typical trace of the control temperature range for each of the twenty coupons is shown on Figure 6. The control temperature ranges were the same for the baseline, biased firing and overfire air studies.

Task IV Baseline Test Study

Load and Excess Air Variation

Tests 1 through 7 were conducted to determine the effect of varying excess air at three unit loads on unit emission levels and performance. These tests were conducted with clean furnace conditions.

As shown in the following table, NO_x emission levels increased with increased excess air but did not change significantly with changes in unit loading. An average increase of 0.014 g $NO_2/10^6$ cal was noted for each 1% change in excess air over the normal unit operating range.

Load & Excess Air Variation

Test No.	Main Steam Flow 10^3 kg/hr	NO_2 g/10^6cal	CO g/10^6cal	EA %	Theo. Air to Firing Zone %	Unit Eff. %	WW Slag
1	219	1.337	0.032	35.5	130.6	88.3	Clean
2	224	1.030	0.182	17.5	117.1	88.2	Clean
3	214	1.519	0.010	58.9	151.3	87.6	Clean
4	316	0.90	0.050	12.6	109.2	89.3	Clean
5	404	1.041	0.040	22.7	117.9	89.0	Clean
6	407	0.761	0.198	11.7	107.2	89.1	Clean
7	405	1.403	0.042	30.8	125.3	89.5	Clean

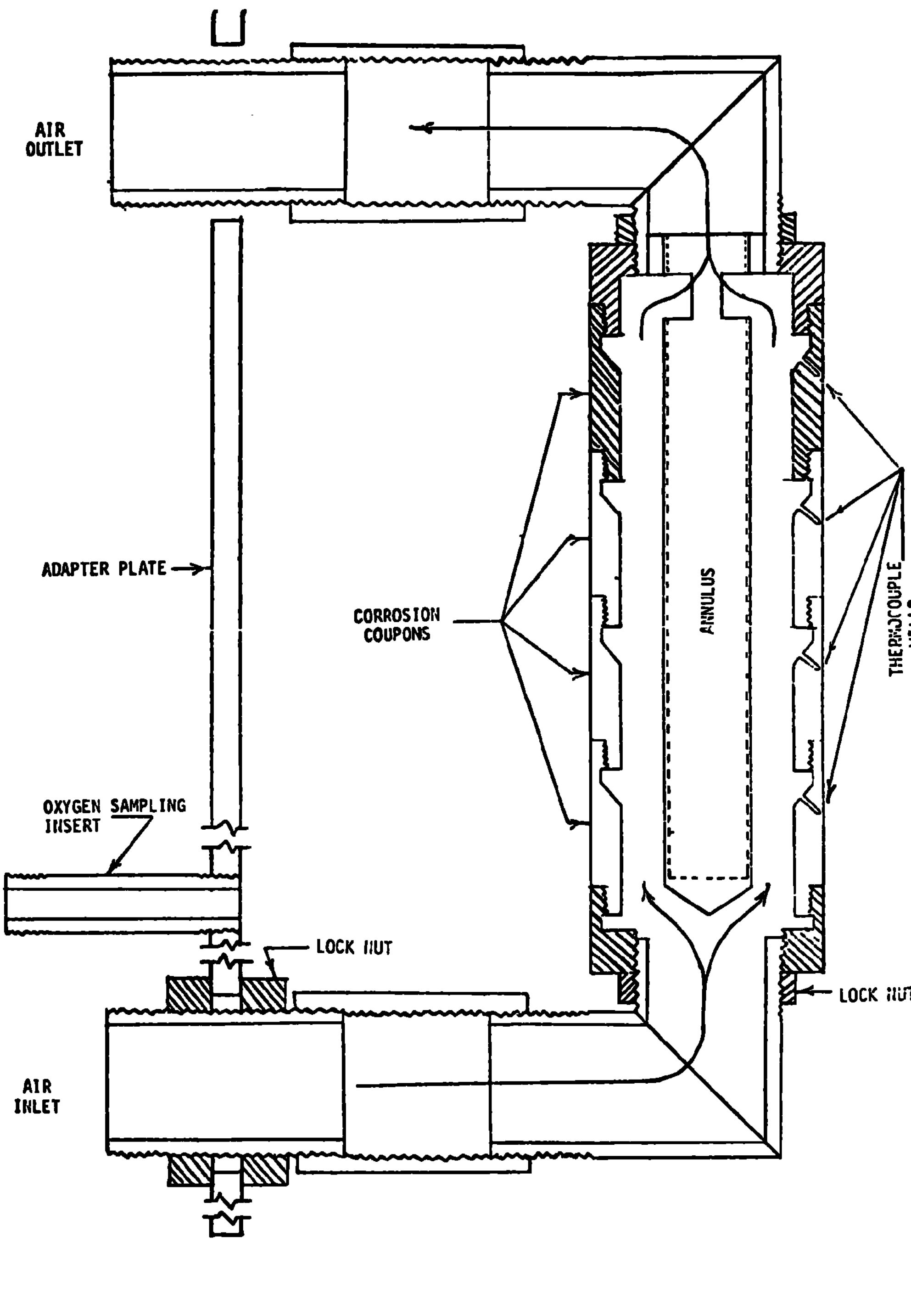

Figure 4: Corrosion Probe Assembly Drawing

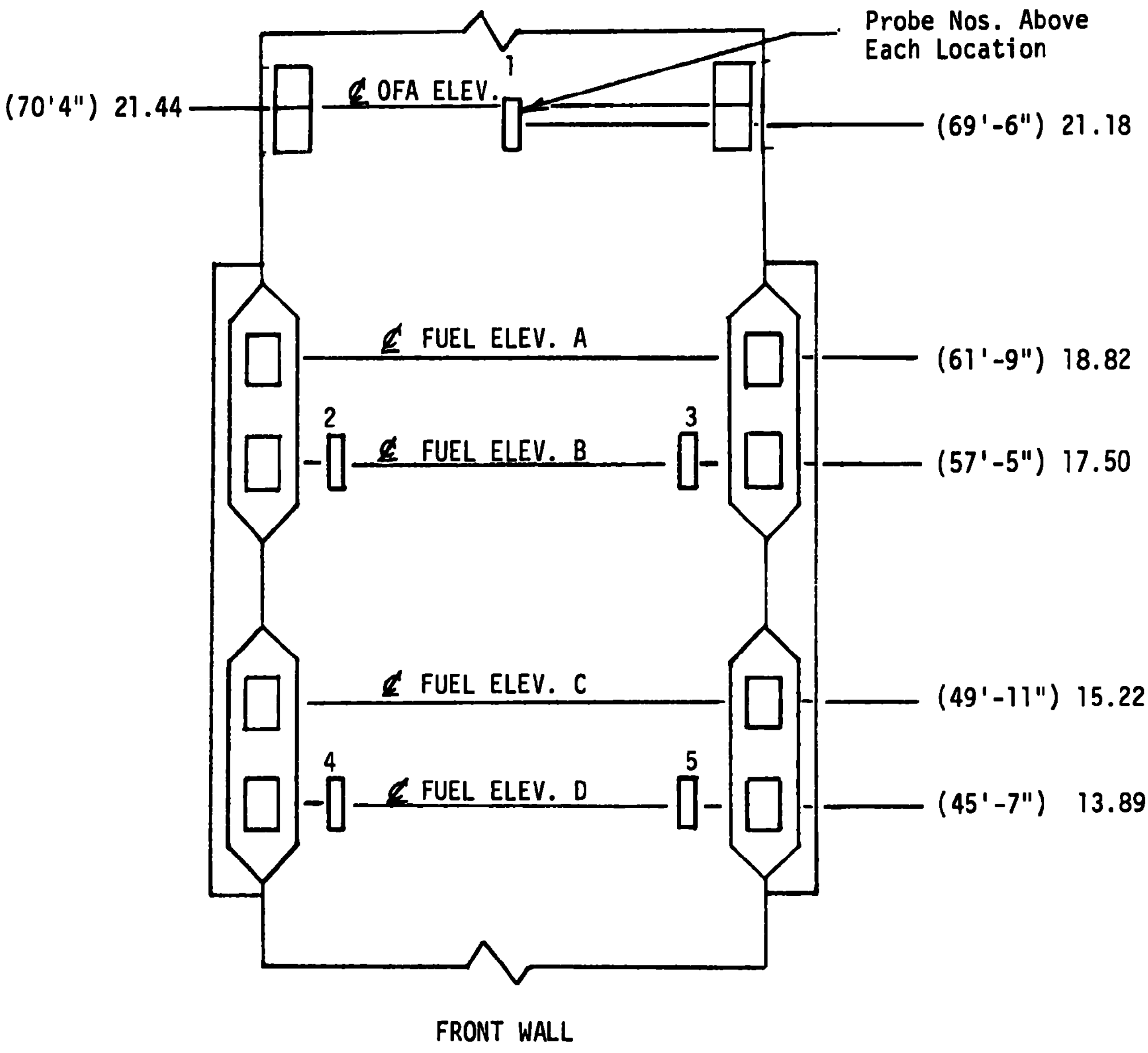

Figure 5. Waterwall Corrosion Probe Locations, Alabama Power Company Barry No. 2

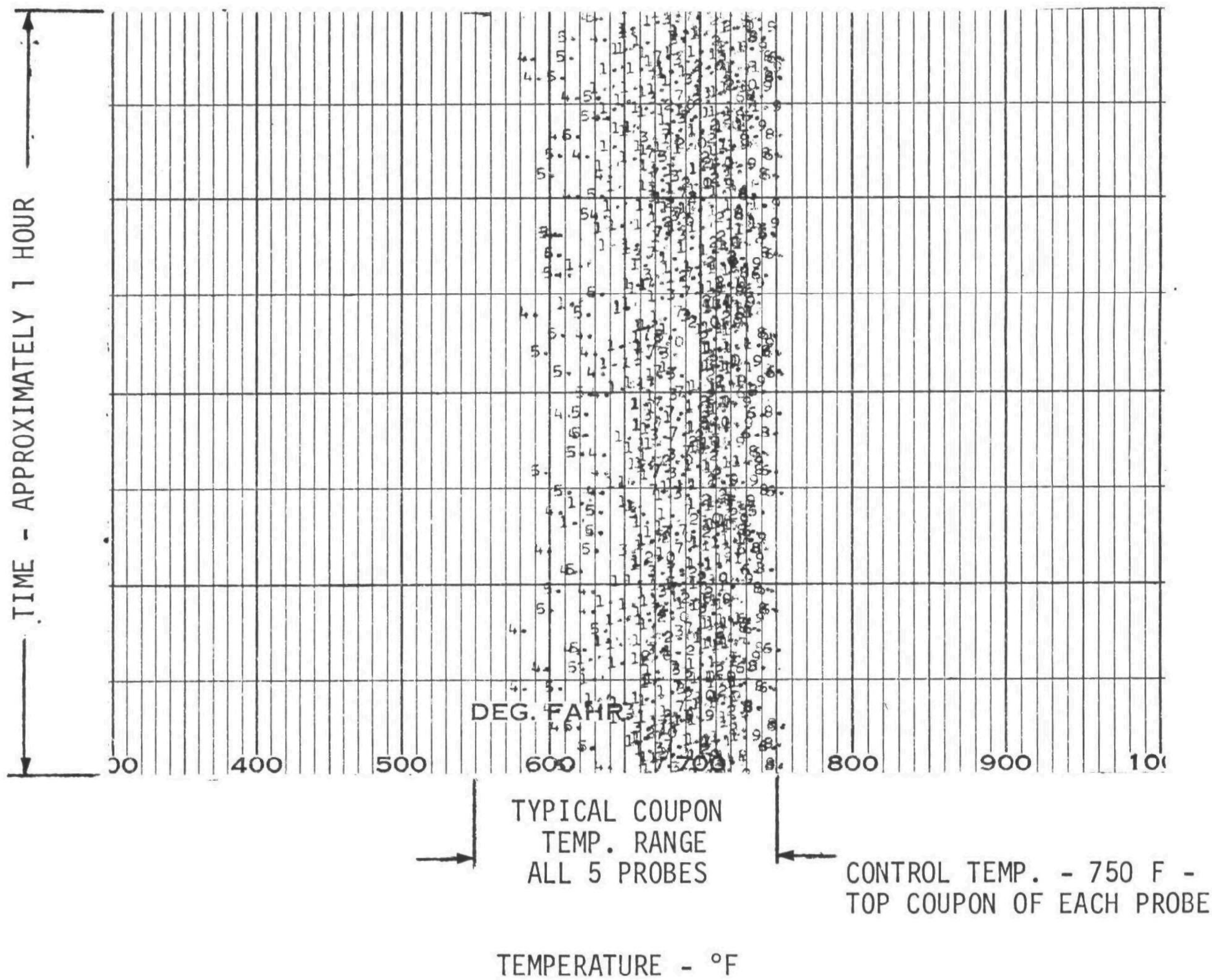

Figure 6: Typical Corrosion Probe Temperature Range

A maximum excess air limit of 30.8 and 58.9 percent was obtained at full and half load conditions respectively due to ID fan capacities.

Minimum excess air limits of 20 to 25 percent were determined as those at which acceptable CO emission levels could be maintained. Reduction of NO_2 emission levels using excess air reduction was therefore limited to approximately 1.04 g/10^6cal as obtained during Test 5.

The changes in NO_2, CO, percent carbon loss in the fly ash and unit efficiency versus theoretical air to the fuel firing zone are shown on Figures 7, 8, 9 and 10, respectively. The theoretical air (TA) to the firing zone is used in this case as it accounts for variations in position and leakage in the compartment dampers above the top active fuel compartment and thereby presents a more accurate determination of the actual air available for combustion in the fuel firing zone than does the total excess air. As seen on Figure 7 for clean furnace conditions the NO_2 correlates well with TA with little variation due to unit load. As shown on Figures 8 and 9 carbon loss in the fly ash and CO emission levels increased with decreased TA levels. Unit load does not appear to have a discernable effect. Figure 10 is a plot of Unit Efficiency versus Unit Excess Air measured at the economizer outlet.

During this portion of the test program total hydrocarbon levels (HC) were monitored and were found to be present in only trace quantities as shown on Data Sheets 1 and 2. The SO_2 levels measured are also shown on Data Sheets 1 and 2.

Furnace Wall Deposit Variation

Tests 8 through 14 were conducted to determine the effect on unit performance and emission levels of varying furnace waterwall deposits from a clean condition to the maximum possible slagging condition obtainable. The maximum slagging condition was obtained after operation in excess of twenty-four hours without operating any wall blowers. During this

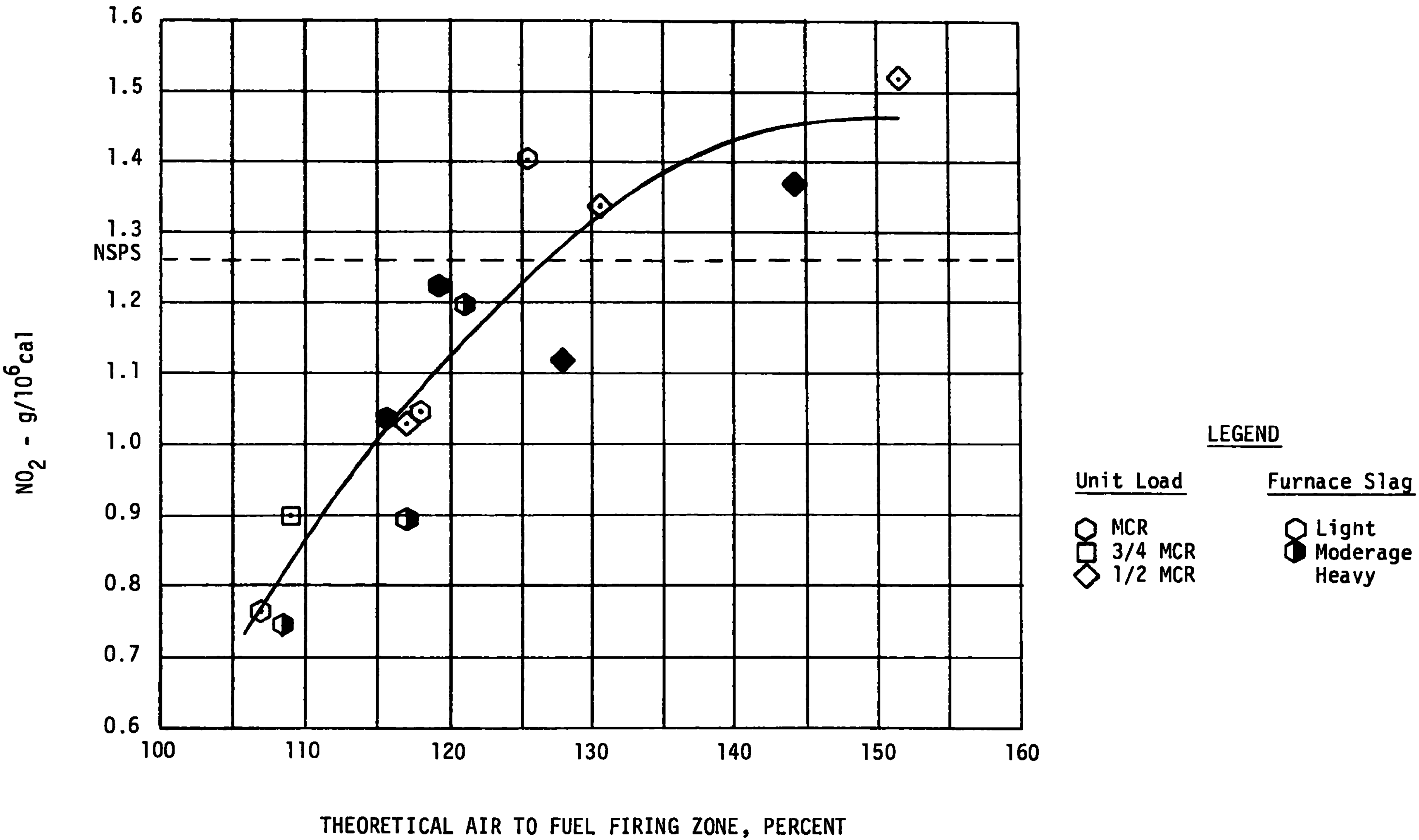

Figure 7: NO_2 Vs. Theoretical Air to Fuel Firing Zone, Baseline Study, Tests 1-14

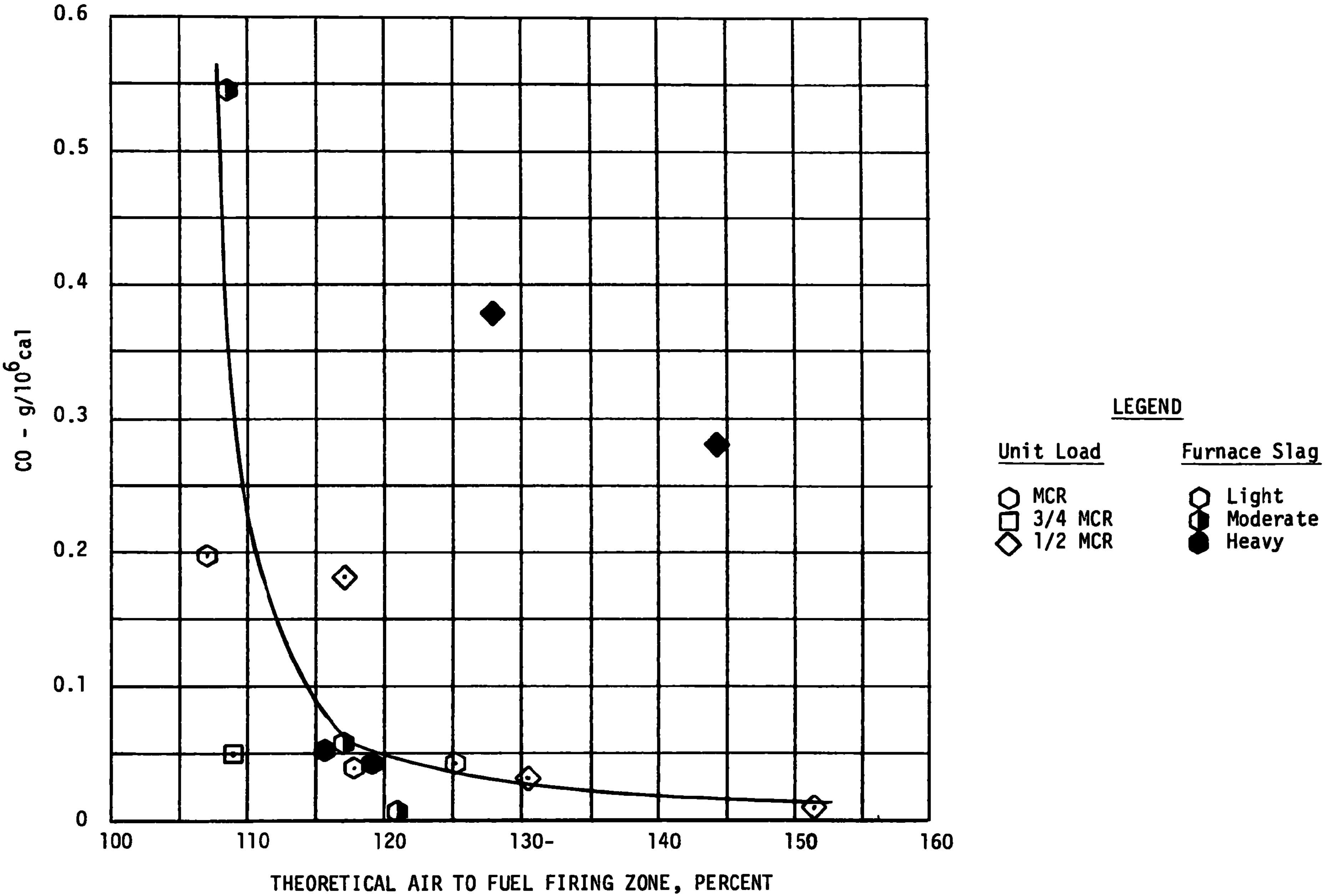

Figure 8: CO Vs. Theoretical Air to Fuel Firing Zone, Baseline Study, Tests 1-14

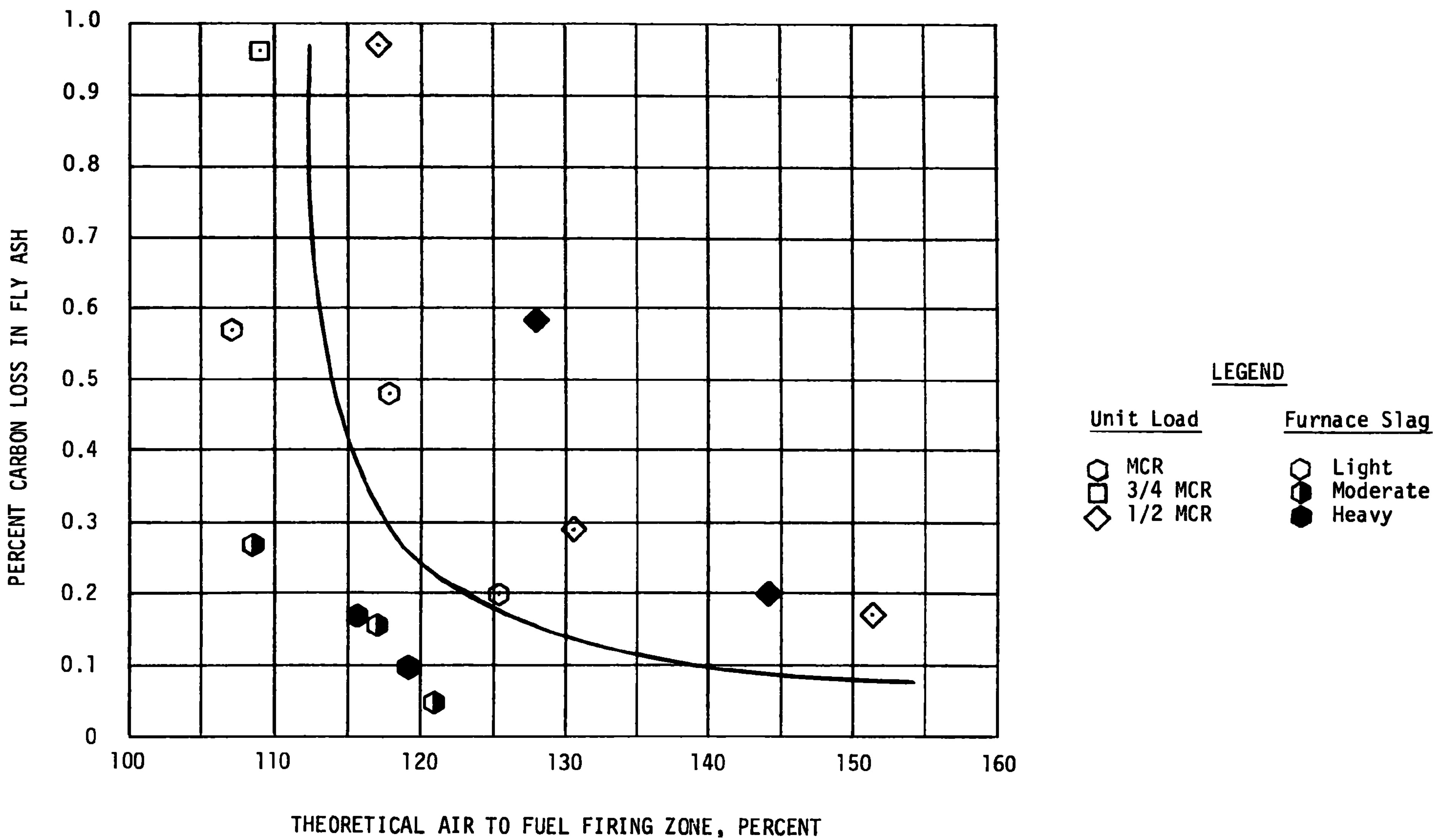

Figure 9: Percent Carbon Loss Vs. Theoretical Air to Fuel Firing Zone, Baseline Study, Tests 1-14

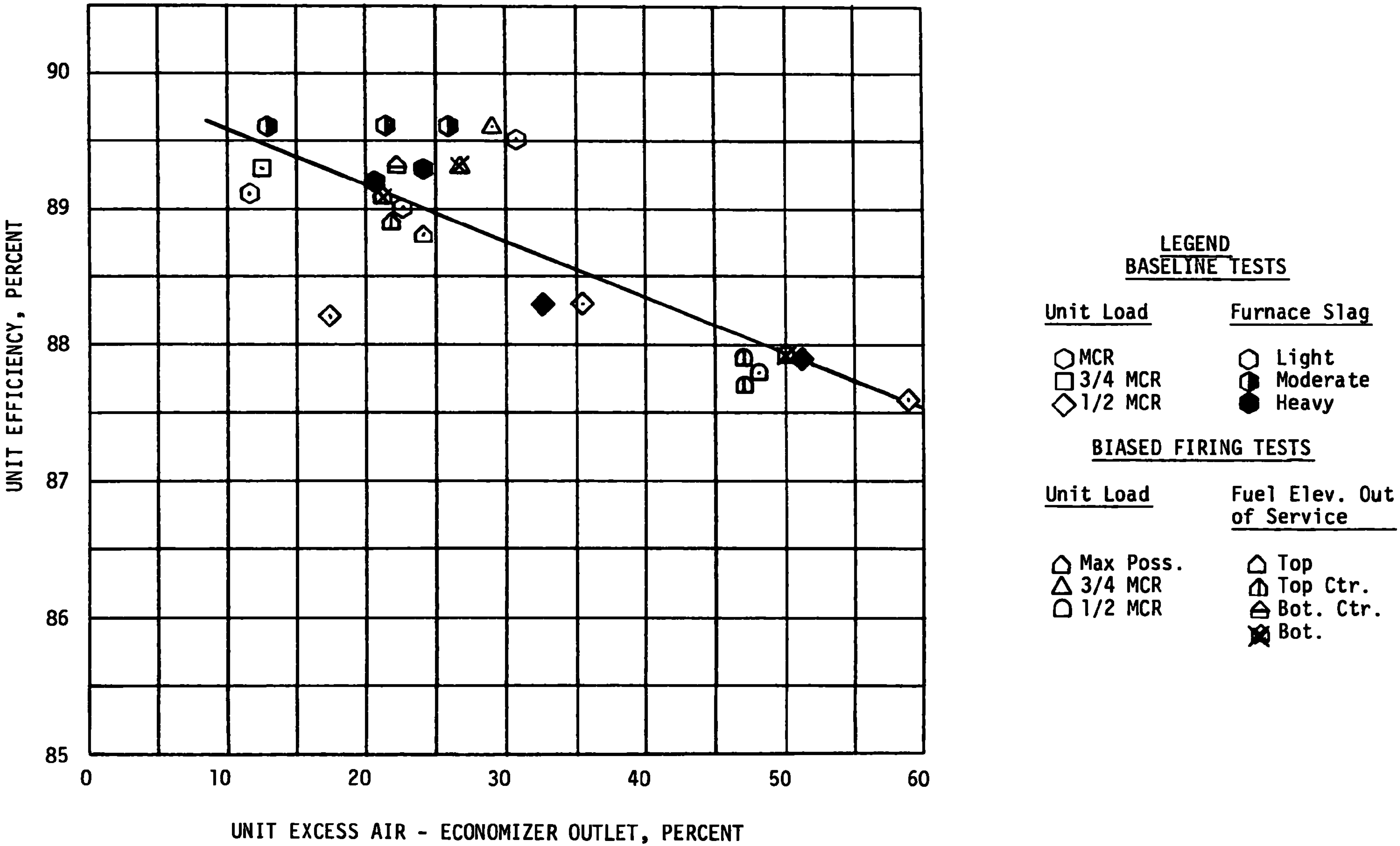

Figure 10: Unit Efficiency Vs. Unit Excess Air

time period slag deposits of up to 4 inches in thickness could be obtained in and above the fuel firing zone.

Furnace Wall Deposit Variation

Test No.	Main Steam Flow 10^3kg/hr	NO_2 g/10^6cal	CO g/10^6cal	EA %	Theo. Air to Firing Zone %	Unit Eff. %	WW Slag
8	411	0.894	0.059	21.5	116.9	89.6	1/2 Max Dep
9	403	0.748	0.545	13.0	108.5	89.6	1/2 Max Dep
10	405	1.198	0.007	26.0	120.8	89.6	1/2 Max Dep
11	211	1.118	0.378	32.7	128.0	88.3	Max Dep
12	206	1.370	0.280	51.2	144.1	87.9	Max Dep
13	412	1.037	0.052	20.7	115.7	89.2	Max Dep
14	406	1.225	0.043	24.3	119.2	89.3	Max Dep

As can be seen from Figure 7 furnace slagging did not exhibit a discernable effect on NO_x emission levels. As shown in Figures 8 and 9 this condition was also found to be true for carbon loss in the fly ash and CO emission levels with the exception of the half load Tests 11 and 12 where CO levels higher than those obtained with clean furnace conditions were observed. The high CO levels may have been due to slag build-up at or near the fuel and air nozzles which could have contributed to poor combustion. The higher CO levels were not observed under full load with heavy slag operation. Figure 10 indicates that furnace cleanliness did not exhibit any discernable effect on unit efficiency.

Slag patterns taken during clean, moderate and heavy slagging conditions at full load operation are shown on Figures 11, 12 and 13.

Task V - Biased Firing Study - Fuel Elevations Out of Service Variation

Tests 15 through 24 were conducted to determine the effect on NO_x emission levels of taking various fuel elevations out of service (biased firing) at various unit loadings. As shown on the following table the

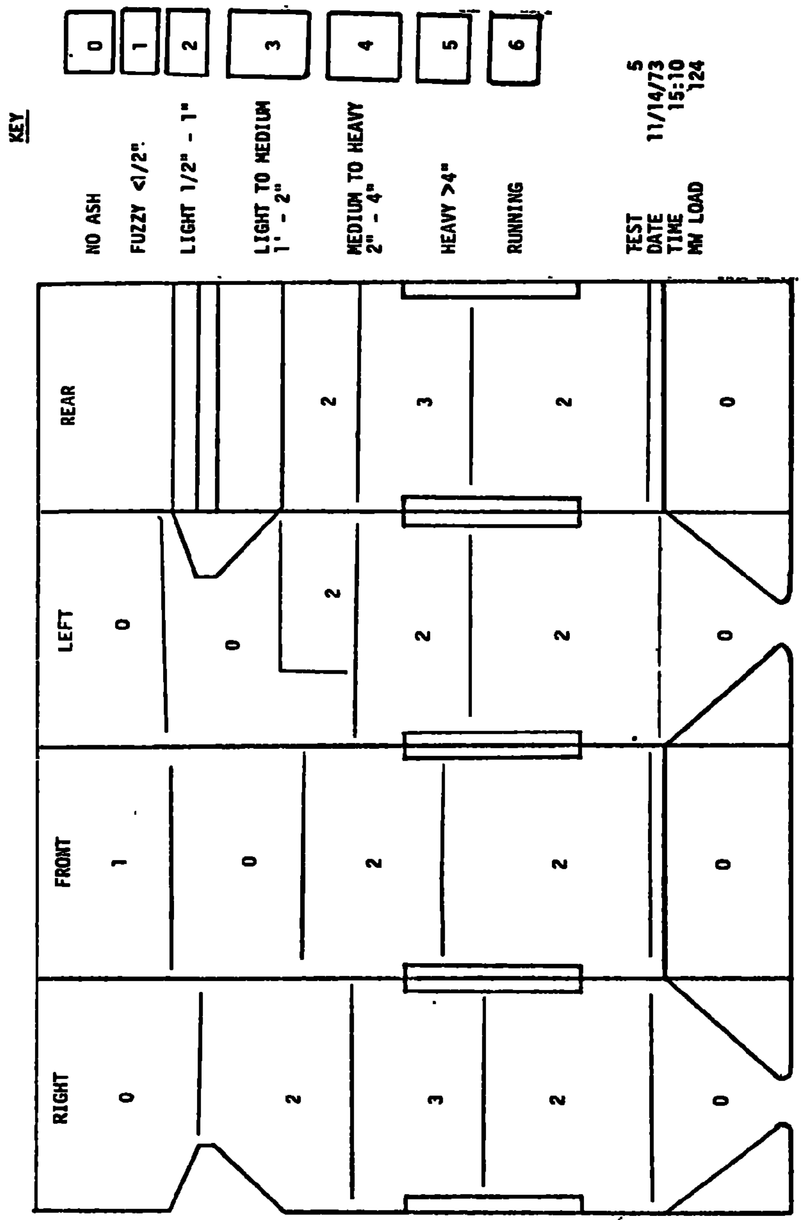

Figure 11: Furnace Slag Pattern, Clean Furnace

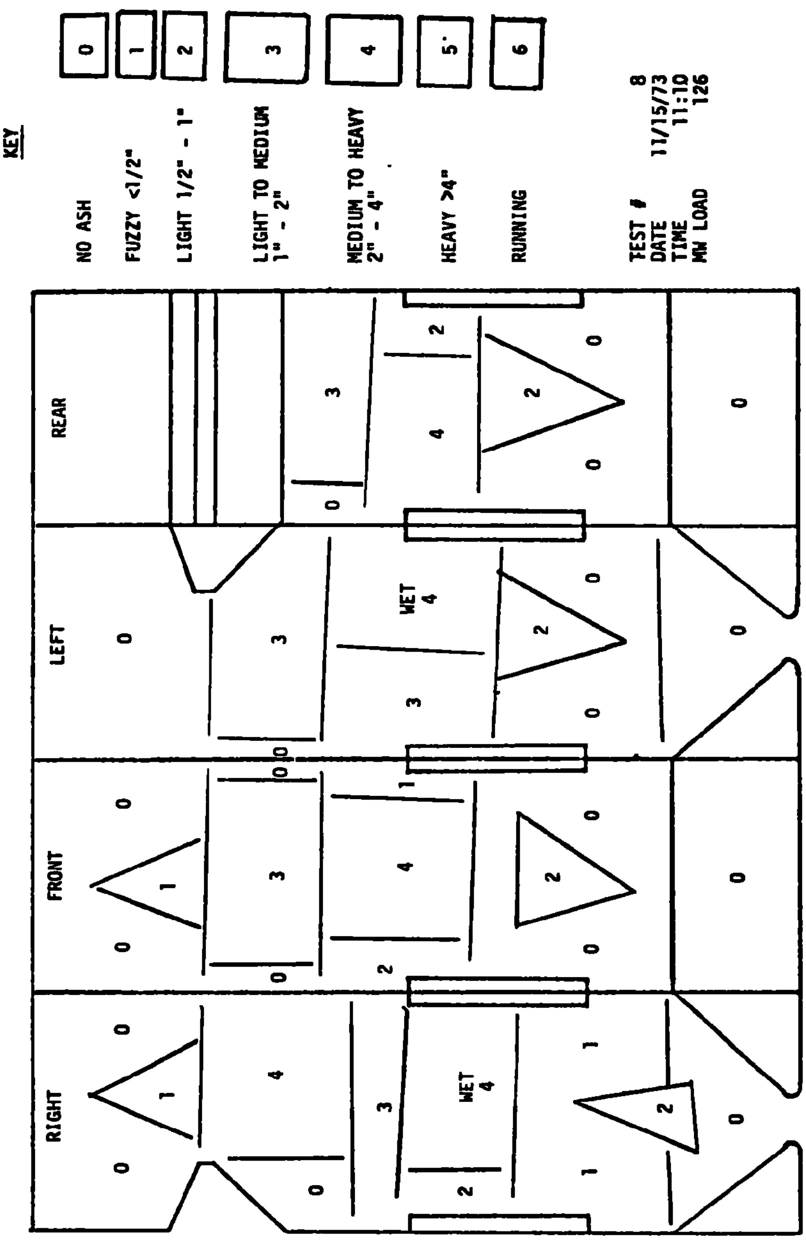

Figure 12: Furnace Slag Pattern, Moderate Slag Furnace

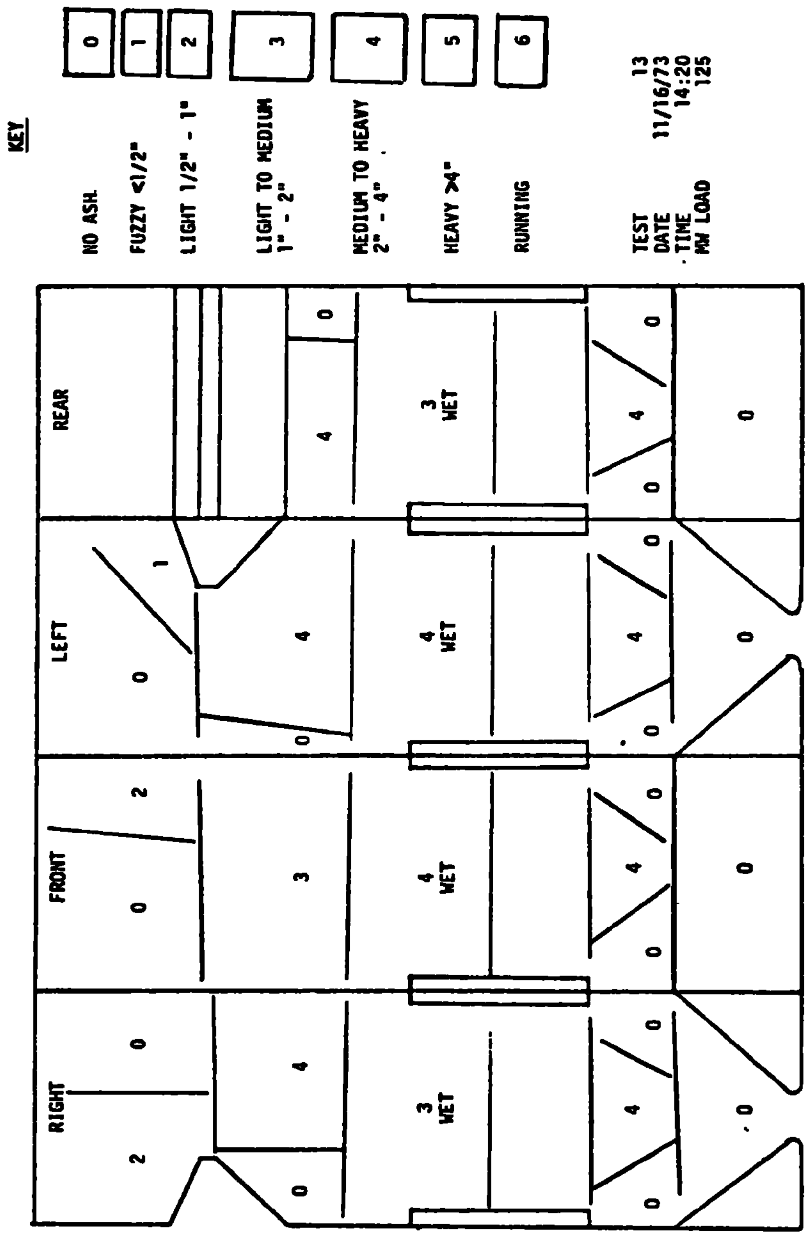

Figure 13: Furnace Slag Pattern, Heavy Slag Furnace

maximum NO_x emissions control was obtained with the top elevation of fuel nozzles out of service at maximum and 75 percent maximum loading (Tests 20 and 21). At 50 percent maximum loading (Test 23) the high excess air levels required to maintain unit steam temperatures appeared to negate any NO_x reductions obtained by biasing the top fuel nozzle elevation, however, the emissions level obtained was below the current EPA limit for coal fired units of 1.26 $g/10^6cal$.

Biased Firing - Fuel Elevations Variation

Test No.	Main Steam Flow $10^3kg/hr$	NO_2 $g/10^6cal$	CO $g/10^6cal$	EA %	Theo. Air to Firing Zone %	Unit Eff %	Fuel Nozzle Elevation Out Of Service
15	199	1.206	0.041	50.1	105.8	87.9	Bottom
16	297	1.142	0.037	26.7	121.7	89.3	Bottom
17	315	0.840	0.059	21.1	116.5	89.1	Bottom
18	321	0.792	0.050	22.2	117.5	89.3	Bot. Ctr.
19	321	0.795	0.044	21.8	117.2	88.9	Top Ctr.
20	314	0.599	0.034	24.2	94.7	88.8	Top
21	308	0.696	0.040	29.0	97.3	89.6	Top
22	208	1.124	0.038	48.0	112.5	87.8	Top
23	211	1.043	0.029	47.0	141.4	87.9	Top Ctr.
24	202	1.282	0.035	47.0	141.3	87.7	Bot. Ctr.

As can be seen from Figure 14 biasing the center two and bottom fuel elevations did not have a discernable effect on NO_x emission levels although the emission level tended to be higher at reduced unit loadings for given TA levels.

Figures 15 and 16 indicate that with biased firing, low TA levels to the fuel firing zone were obtained without increasing either CO emission levels or the carbon loss in the fly ash. Figure 10 shows that biased firing operation did not significantly affect unit efficiency. This condition is due to the ability to maintain acceptable total unit excess air levels during biased firing operation.

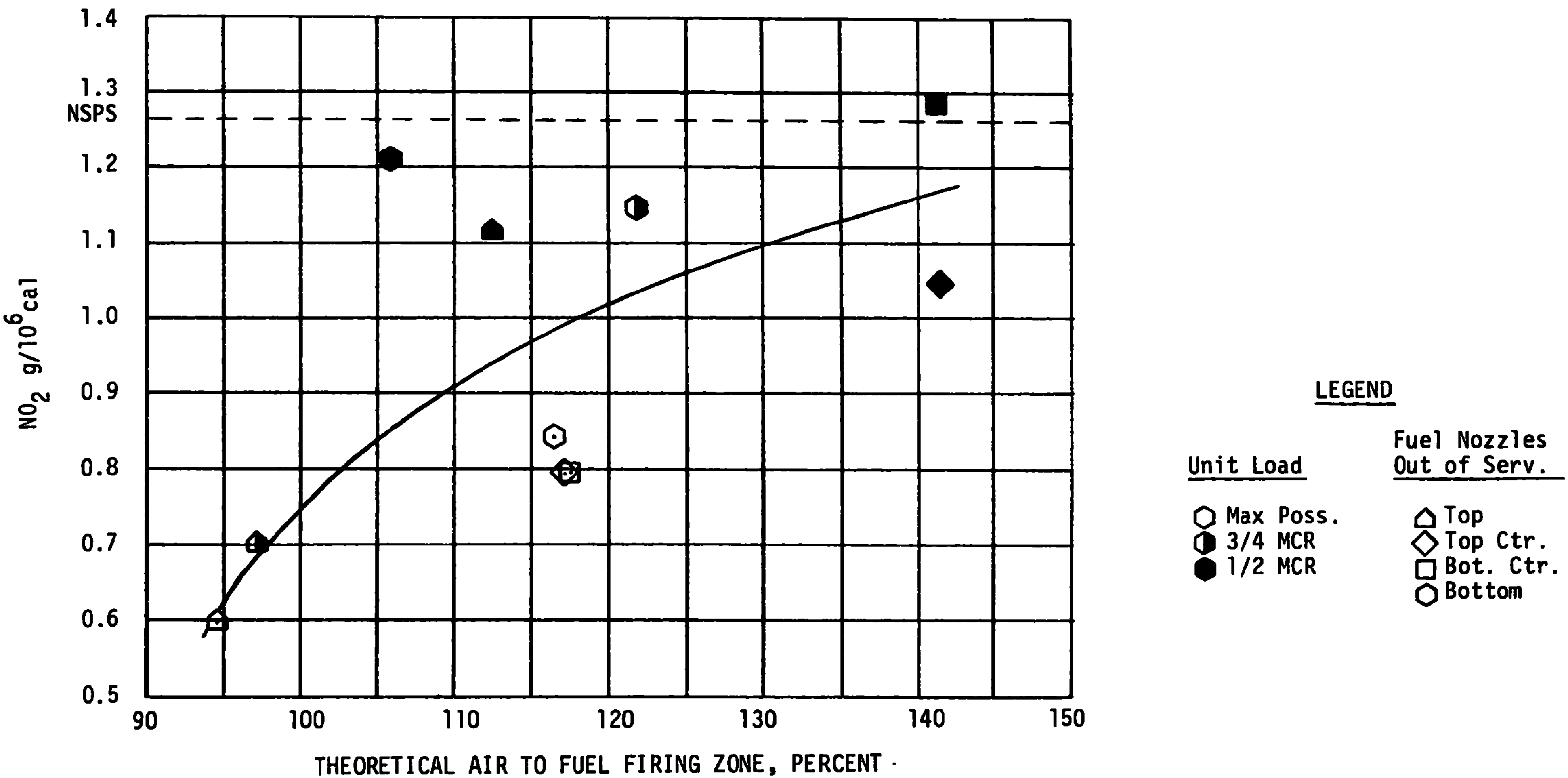

Figure 14: NO_2 Vs. Theoretical Air to Fuel Firing Zone, Biased Firing Study, Tests 15-24

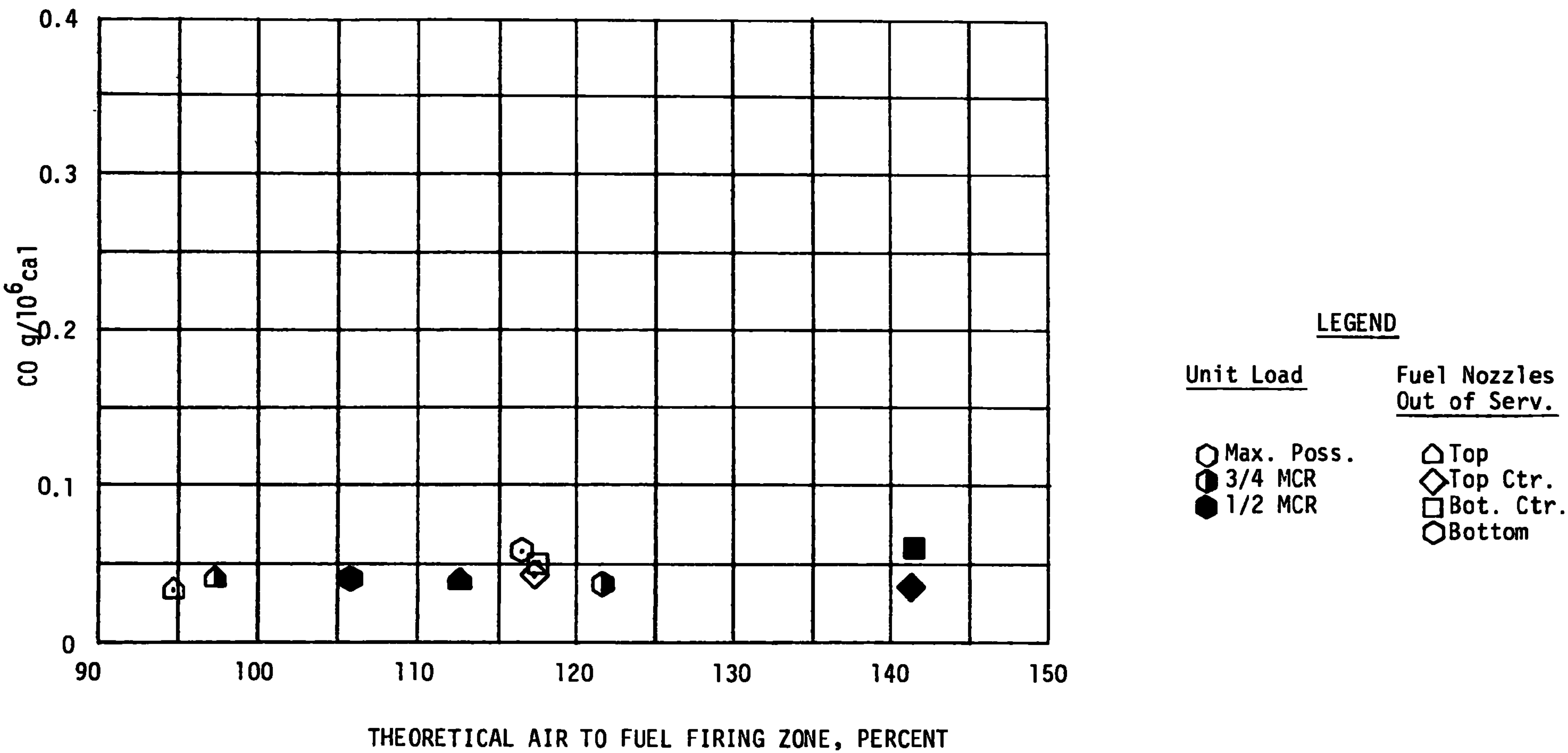

Figure 15: CO vs. Theoretical Air to Fuel Firing Zone, Biased Firing Study, Tests 15-24

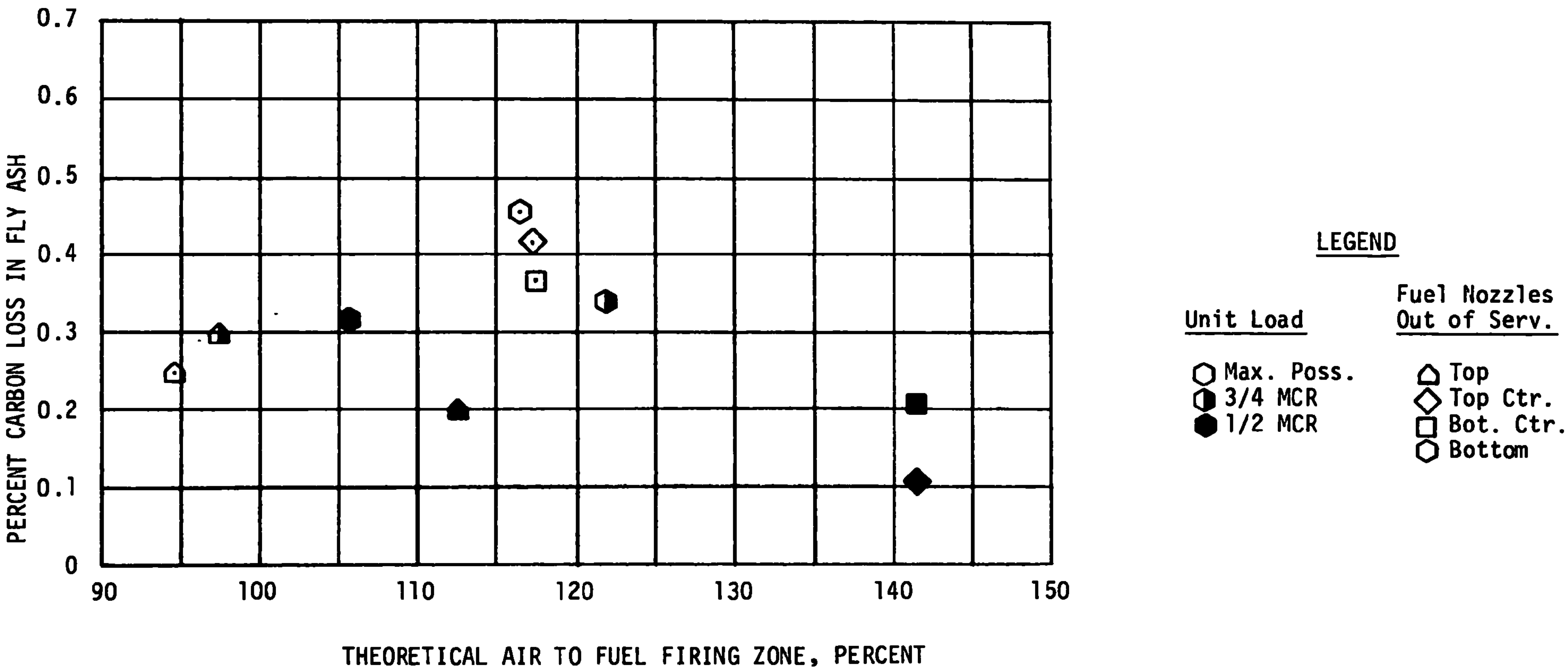

Figure 16: Percent Carbon Loss Vs. Theoretical Air to Fuel Firing Zone, Biased Firing Study Tests 15-24

Task VIII - Unit Optimization Study

Load and Excess Air Variation (After Modification)

Load & Excess Air Variation

Test No.	Main Steam Flow 10^3kg/hr	NO_2 g/10^6cal	CO g/10^6cal	EA %	Theo. Air Firing Zone %	Unit Eff. %	WW Slag
1	219	0.929	0.035	33.5	127.1	88.4	Clean
2	213	0.701	0.479	16.0	113.4	88.8	Clean
3	217	1.339	0.044	64.7	155.4	87.4	Clean
4	315	0.684	0.140	15.5	111.0	89.8	Clean
5	450	0.846	0.037	21.0	115.3	89.4	Clean
6	441	0.692	0.162	12.4	107.1	89.2	Clean
7	423	1.000	0.028	25.4	119.5	89.5	Clean

Tests 1 through 7 were performed with unit conditions closely approximating those of Baseline Tests 1 - 7 under Program Task IV. A clean furnace was maintained as the excess air was varied at three unit loads.

The effect of these operating conditions on emission levels and performance can be seen in the Table above.

As witnessed in the previous baseline tests, NO_x emissions levels increased with increased excess air.*

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* In general, NO_2 values were slightly lower after modification for the same test conditions. This resulted from an updated firing system installed between the sets of tests along with an average percent nitrogen in fuel decrease of 0.15 percent (1.21 to 1.06 percent). Also, fuel higher heating values and furnace outlet temperatures tended to be lower for Tests 1 - 7 after modification.

ID fan capacities limited excess air to a maximum of 64.7 and 33.5 percent at half and full load conditions respectively. Acceptable minimum excess air limits were established at 20-25 percent to control CO emission levels. Thus, NO_x emission levels could only be reduced to approximately 0.90 $g/10^6 cal$ through excess air reduction. The effect of theoretical air to the firing zone on NO_x, CO, and percent carbon loss in the fly ash (% CL) can be seen in Figures 17, 18 and 19. In agreement with the original baseline tests, theoretical air to the firing zone (TA) was used for comparison in place of total excess air (EA). TA is determined by location and means of admission as well as quantity, and consequently better defines that air actually available for initial combustion.

Figure 17 indicates a definite increase in NO_x emission levels with increasing TA for clean furnace conditions. CO emission levels and percent carbon loss in the fly ash can be seen to increase with decreased TA without overfire air. Reasonable control of CO and % CL can only be maintained at TA levels above 120%. No definite relationship can be observed between unit load and CO emission levels. Percent CL can be seen to be greater at higher unit loads for given TA levels.

Changes in unit efficiency versus excess air at the economizer outlet are presented in Figure 20. Overall, unit efficiency decreases as the excess air increases.

Hydrocarbon emission levels appeared only in trace quantities for this portion of the test program. HC and SO_2 levels are presented on Data Sheets 3 and 4.

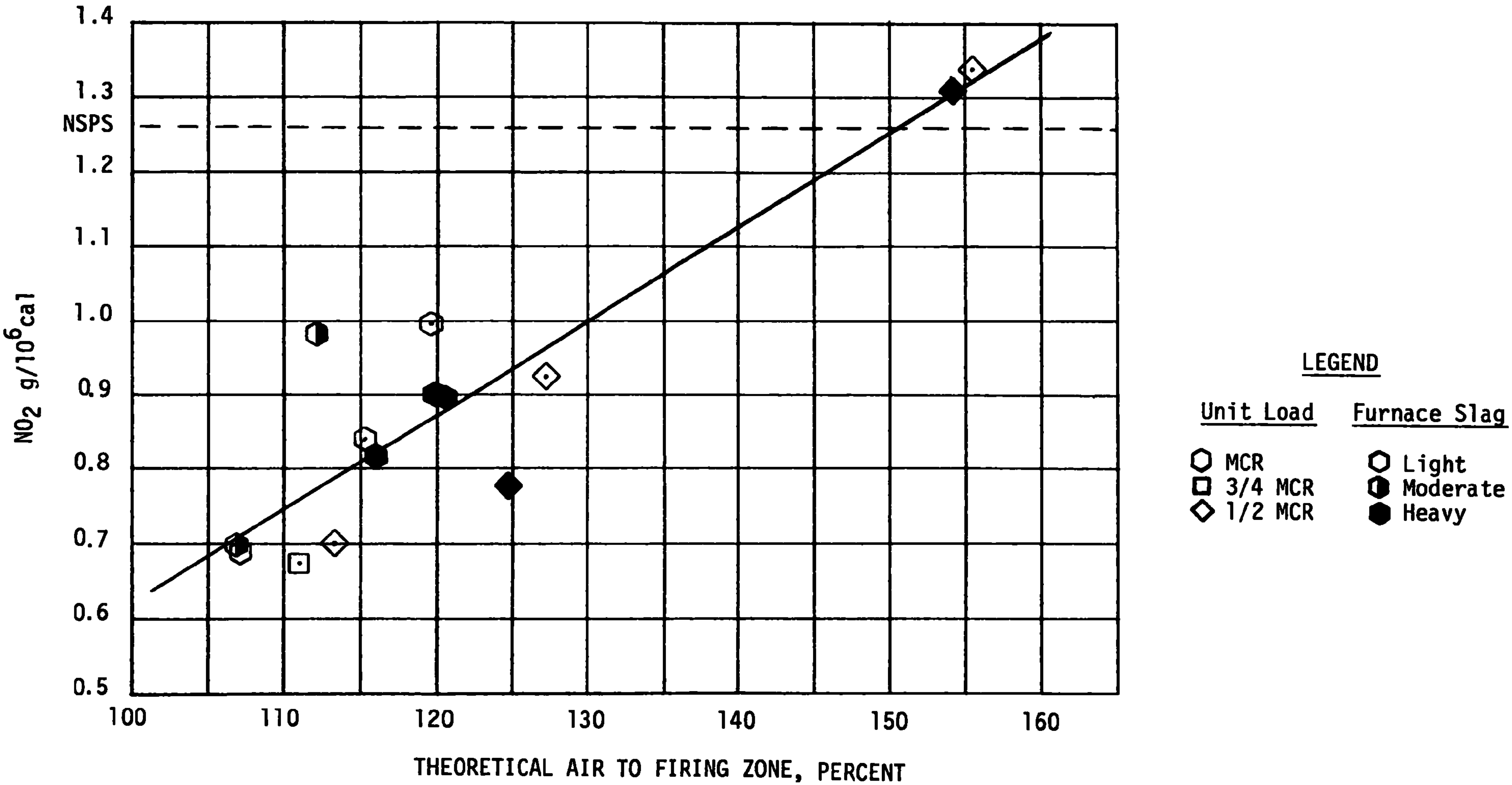

Figure 17: NO_2 Vs. Theoretical Air to Firing Zone, Overfire Air Study, Load and Excess Air Variation, Tests 1-14

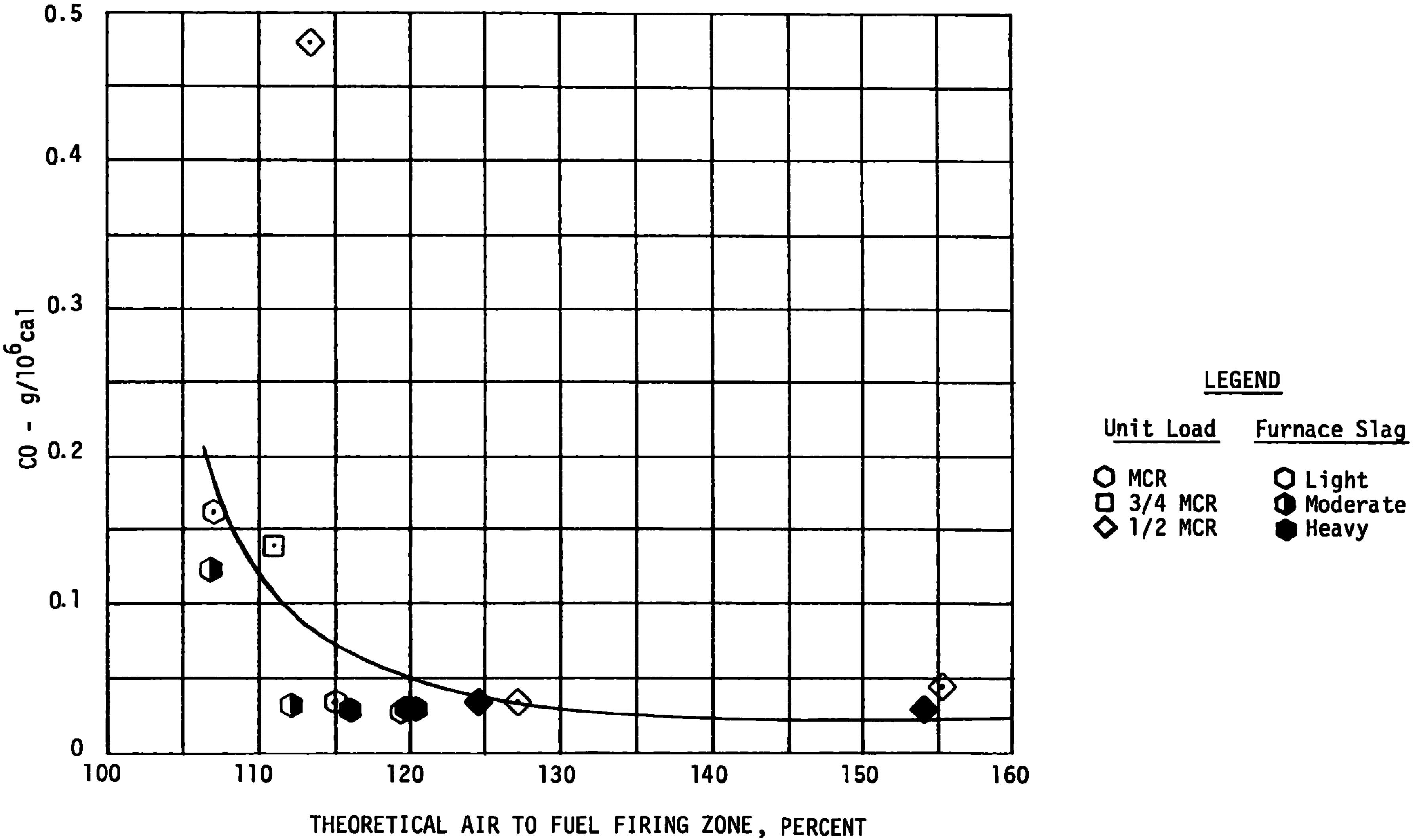

Figure 18: CO Vs. Theoretical Air to Firing Zone, Overfire Air Study, Load and Excess Air Variation, Tests 1-14

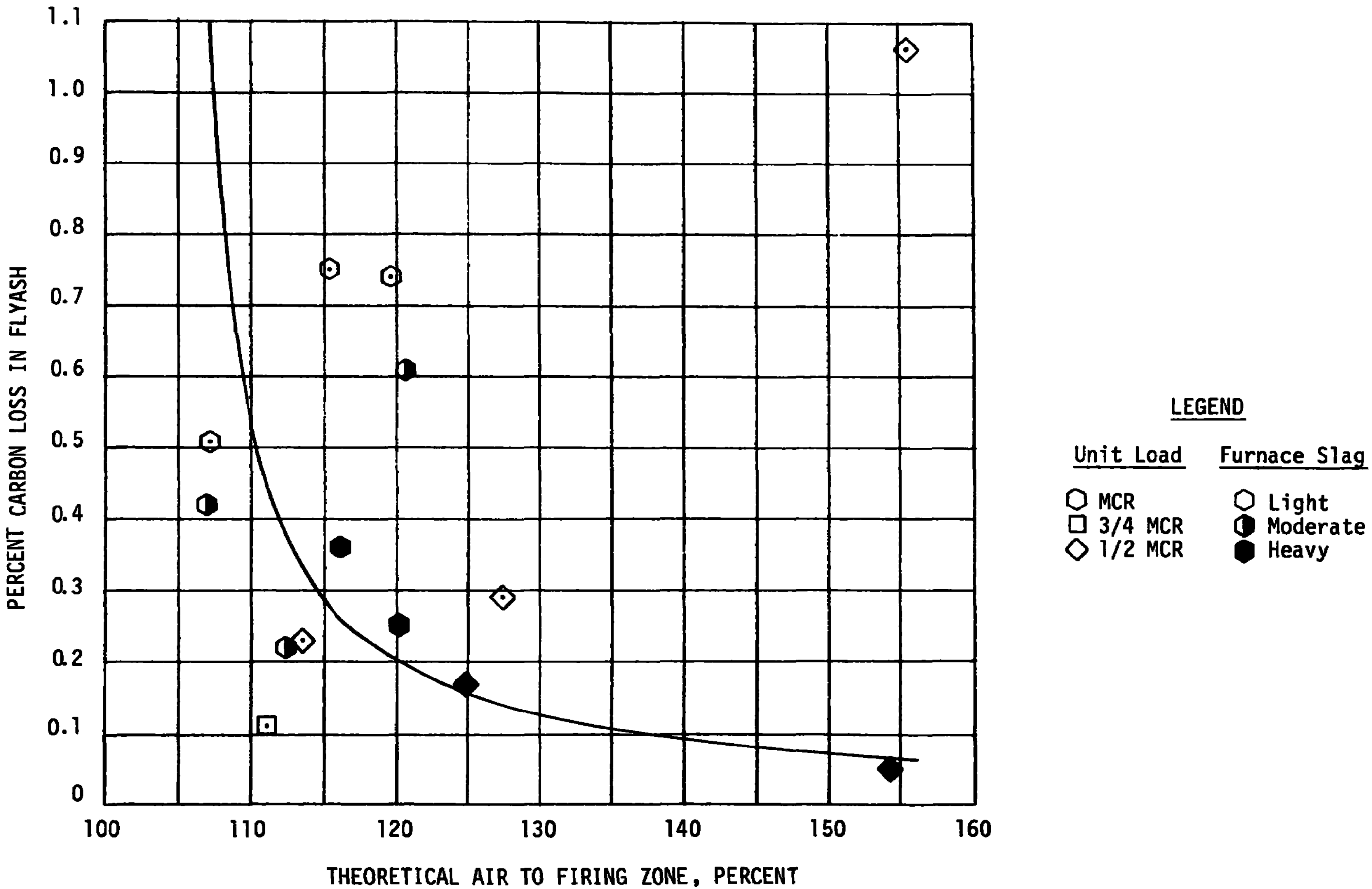

Figure 19: Percent Carbon Loss Vs. Theoretical Air to Firing Zone, Overfire Air Study Load and Excess Air Variation, Tests 1-14

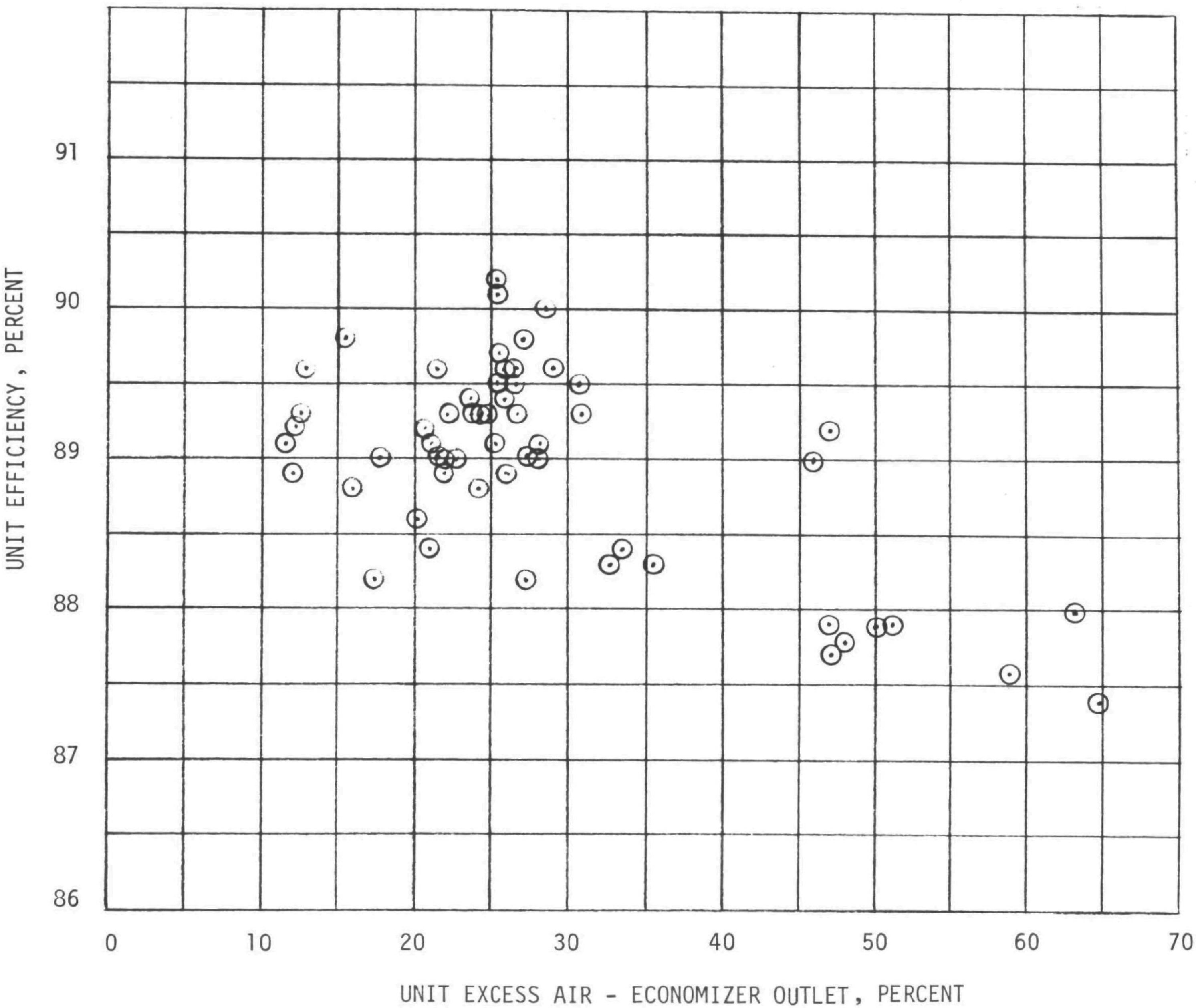

Figure 20: Unit Efficiency Vs. Excess Air - Economizer Outlet, All Tests (Before & After Modification)

Furnace Wall Deposit Variation (After Modification)

Test No.	Main Steam Flow 10^3kg/hr	NO_2 g/10^6cal	CO g/10^6cal	EA %	Theo. Air Firing Zone %	Unit Eff. %	WW Slag
8	440	0.985	0.0310	17.8	112.3	89.0	1/2 Max
9	446	0.699	0.1239	12.1	106.9	88.9	1/2 Max
10	428	0.902	0.0300	26.6	120.5	89.5	1/2 Max
11	246	0.782	0.0335	30.9	124.6	89.3	Max
12	218	1.310	0.0304	63.1	154.0	88.0	Max
13	432	0.819	0.0298	22.0	116.2	89.0	Max
14	425	0.902	0.0292	25.9	119.9	89.4	Max

The effect of furnace waterwall deposits on unit performance and emission levels was studied in Tests 8 through 14 (Clean Condition - Maximum Slagging Conditions). Dirty conditions were established after a minimum of 24 hours of no operation of wall blowers. Deposits of up to four inches in thickness could subsequently be found in and above the fuel firing zone.

Figures 17, 18 and 19 reveal no observable effect of furnace cleanliness on NO_x or CO emission levels along with percent carbon loss in the fly ash.*

Slag patterns taken during full load operation for clean, moderate and heavy slagging furnace conditions can be viewed in Figures 21, 22 and 23.

---

* Again, NO_x values were generally slightly lower after modification. Nitrogen in fuel decreased an average of 0.19 percent from 1.23 percent. Furnace outlet temperatures were somewhat lower for Tests 8 through 14 after modification although fuel higher heating values showed no definite change.

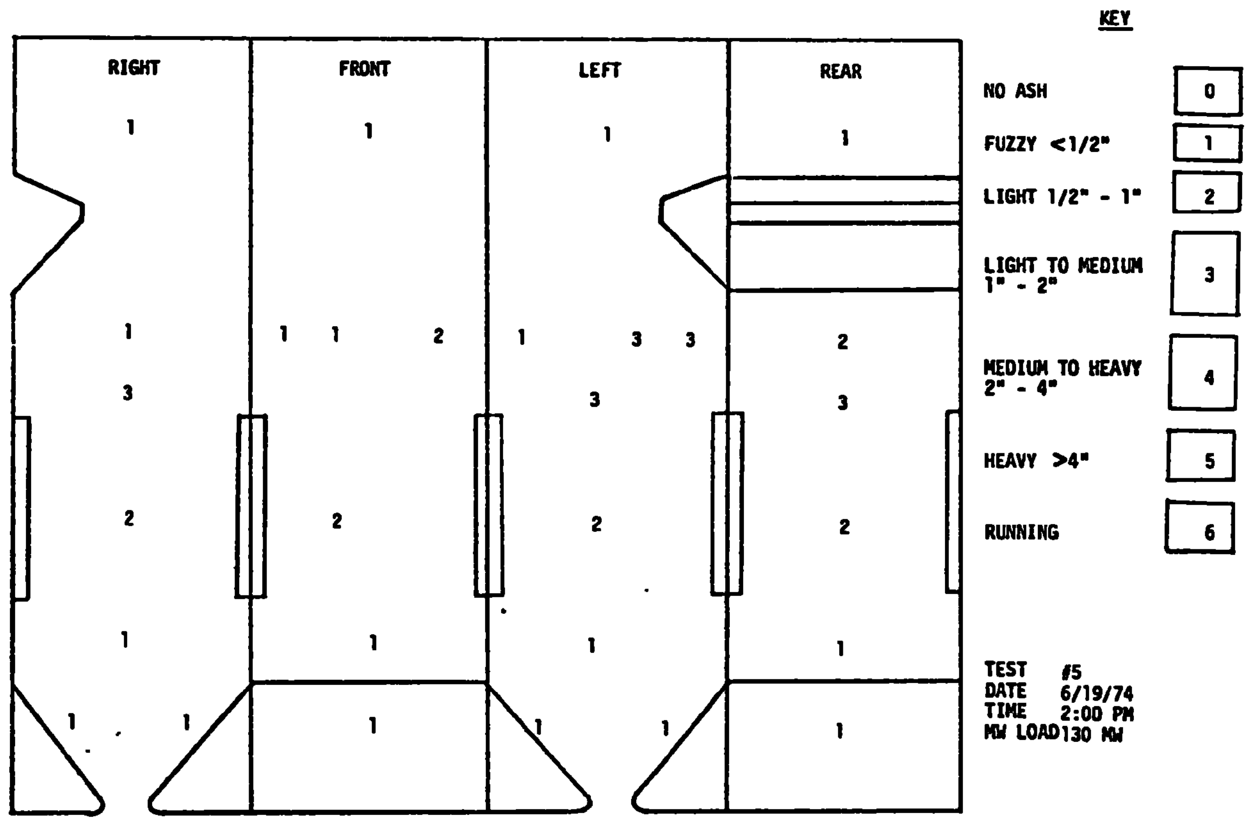

Figure 21: Furnace Slag Pattern, Clean Furnace

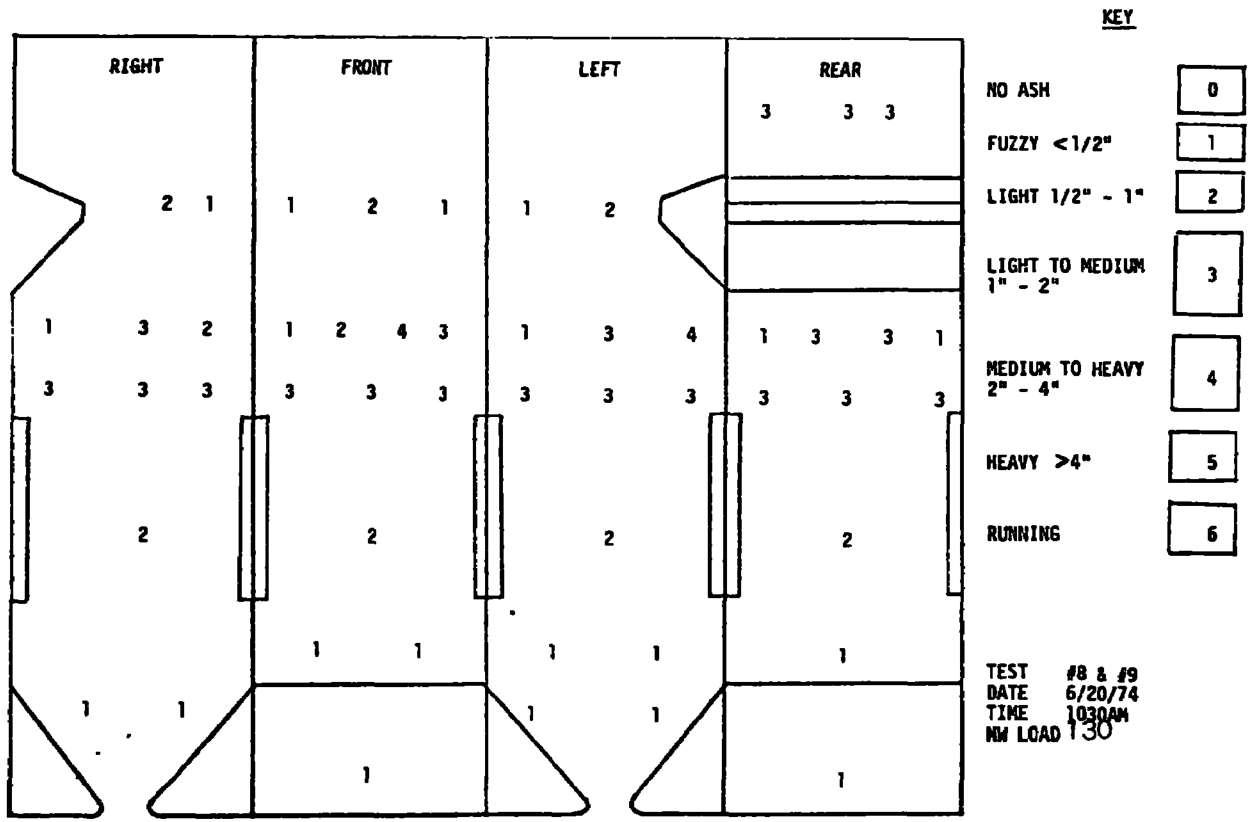

Figure 22: Furnace Slag Pattern, Moderate Slag Furnace

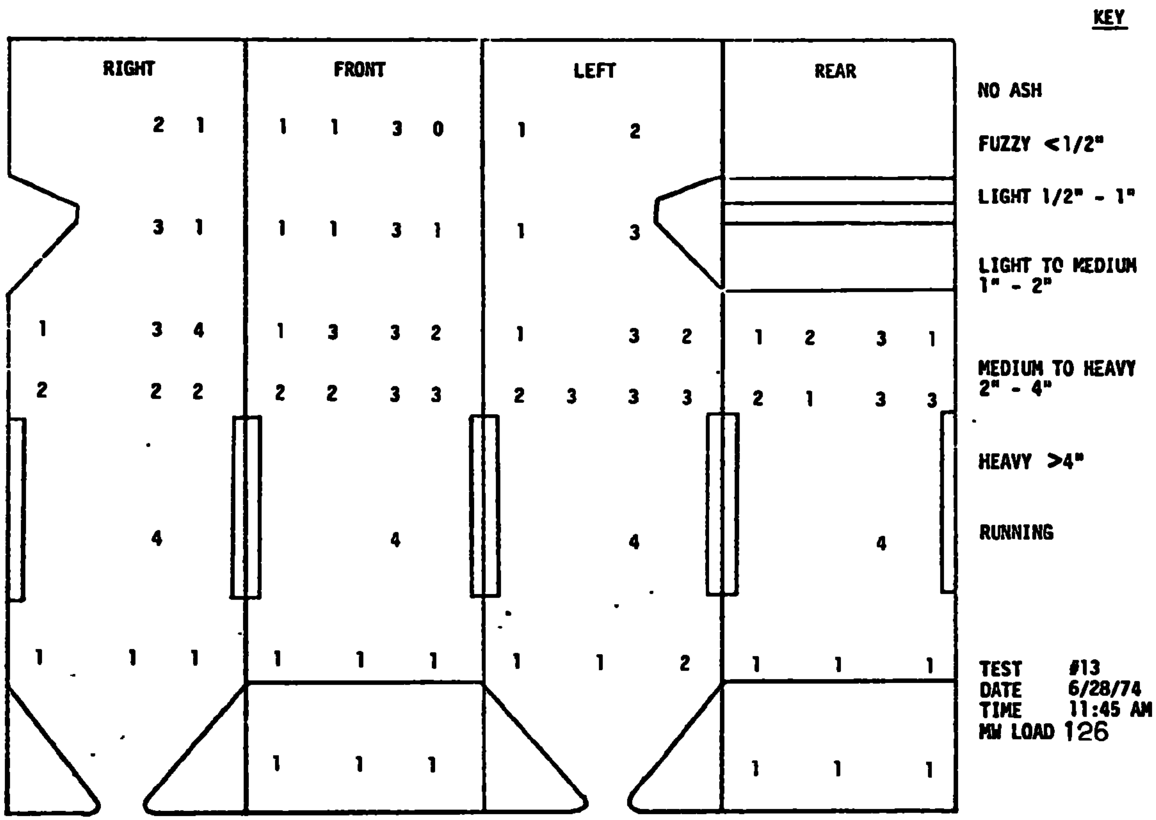

Figure 23: Furnace Slag Pattern, Heavy Slag Furnace

This set of tests also confirms the results found in Tests 1 through 7. NO_x emission levels increase with increased excess air. NO_x cannot be decreased through excess air reductions below 20 percent excess air while maintaining an acceptable CO emission level without overfire air.

OFA Location, Rate, and Velocity Variation

Test No.	Main Steam Flow 10^3kg/hr	NO_2 g/10^6cal	CO g/10^6cal	Theo. Air Firing Zone %	Unit Eff. %	Mills In Serv.	Adm. Pts.*	Adm. Rate
15	336	0.723	0.0358	114.5	90.0	BCD	0-1	0
16	340	0.533	0.0382	96.7	89.8	BCD	0-1	Max
17	338	0.533	0.0413	95.8	89.7	BCD	0-2	Max
18	344	0.479	0.0613	84.8	89.6	BCD	0-1,0-2	Max
19	338	0.486	0.0500	89.3	89.3	BCD	0-1,0-2	1/2 Max
20	344	0.677	0.0367	100.5	90.2	BCD	0-3	Max
21	342	1.012	0.0321	117.4	90.1	ABC	0-1	0
22	341	0.689	0.0329	90.4	89.0	ABC	0-1,0-2	Max
23	346	0.704	0.0322	96.9	89.1	ABC	0-1,0-2	1/2 Max

Tests 15 through 23 were performed to establish the effect of overfire air admission on NO_x emission levels. The unit load and excess air remained constant for moderately dirty furnace conditions. Location of air admission to the furnace was varied.

As shown in Figure 24, this set of tests shows a tendency of NO_x emission levels to decrease with decreased theoretical air to the firing

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* OFA Admission Points:

0-1: Top overfire air compartment.

0-2: Bottom overfire air compartment.

0-3: Top fuel elevation out of service.

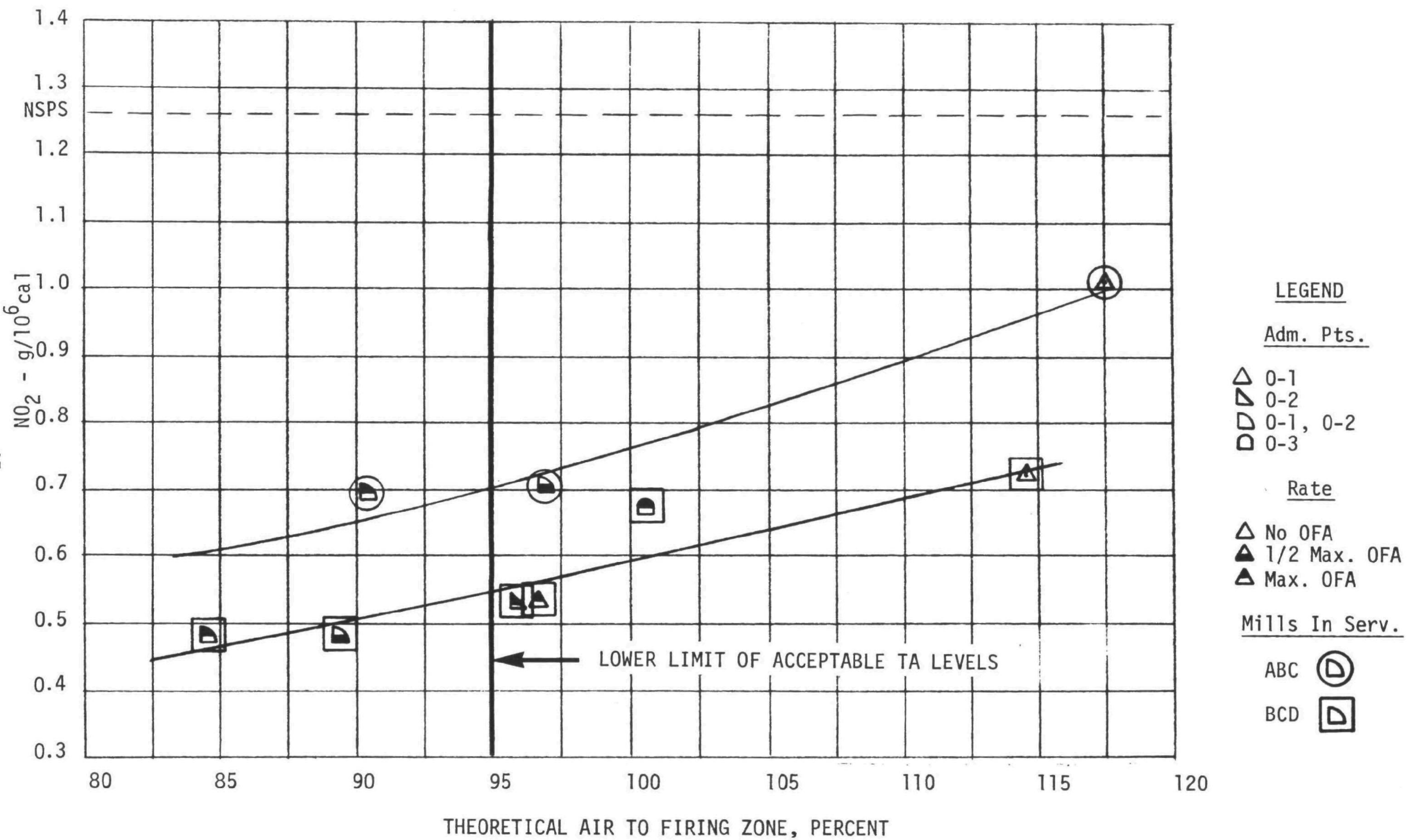


Figure 24: NO_2 Vs. Theoretical Air to Firing Zone, Overfire Air Location, Rate & Velocity Variation, Tests 15-23

zone. NO_x levels are generally higher with ABC mills (top 3 elevations) in service than with BCD mills (bottom 3 elevations). Both operating conditions support the premise of reducing NO_x emission levels by reducing the air input to the fuel firing zone and admitting downstream of that point. The fire is thereby spread out over more of the furnace reducing its intensity. The above factors are limited by flame stability which became very lazy in Test 18. By using the bottom 3 elevations in place of the top 3 elevations, the distance between the overfire air and the firing zone was increased. (The mean firing elevation is also slightly decreased.) Comparison of Tests 18 and 19 with Tests 22 and 23 reveals lower NO_x levels obtained with increased distance between the overfire air and the firing zone. Operation at TA levels below 95% did not result in significant reductions in NO_x emission levels.

CO emission levels remained acceptable for the entire set of tests where the total excess air was approximately 27 percent as shown on Figure 25.

OFA admission location or rate variation exhibited no significant change in percent carbon loss in the fly ash as shown on Figure 26.

Unit efficiencies were not significantly affected by fuel elevations in service, or by overfire air location and rate variation. This is explained by the fact that essentially constant total excess air levels were maintained during this study.

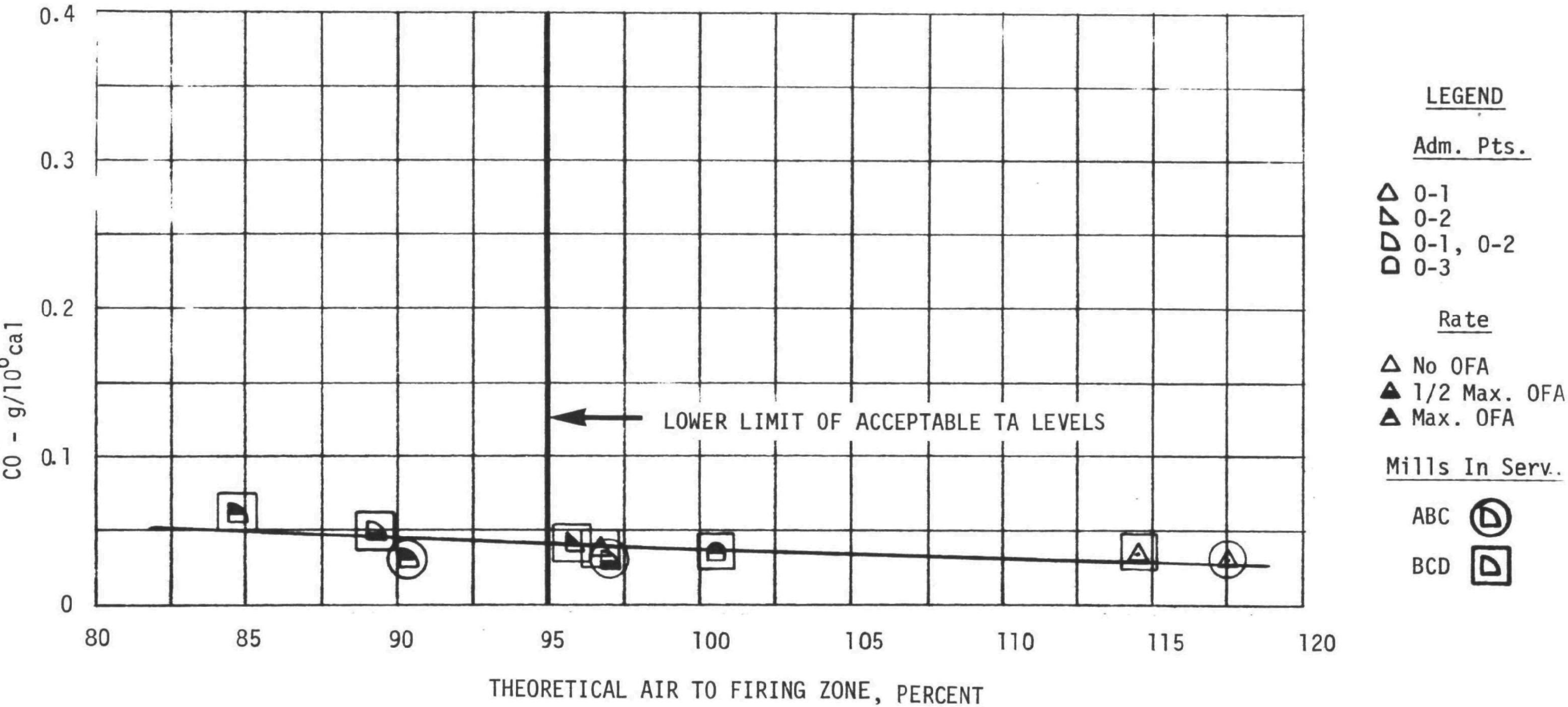


Figure 25: CO Vs. Theoretical Air to Firing Zone, Overfire Air Location, Rate & Velocity Variation, Tests 15-23

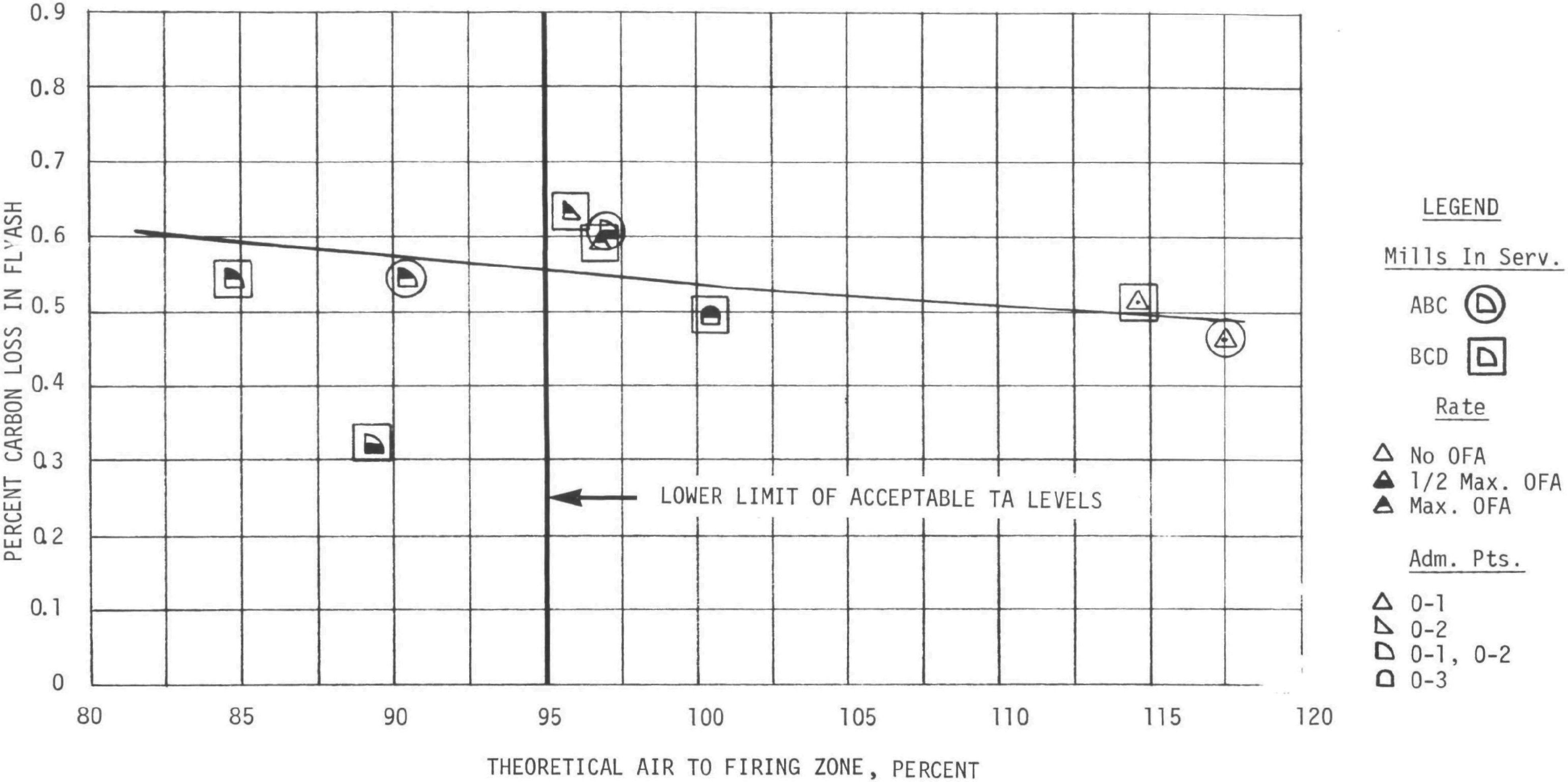


Figure 26: Percent Carbon Loss Vs. Theoretical Air to Firing Zone, Overfire Air Location Rate & Velocity Variation, Tests 15-23

OFA Tilt Variation

Test No.	Main Steam Flow 10^3kg/hr	NO_2 g/10^6cal	CO g/10^6cal	EA %	Theo. Air Firing Zone %	Unit Eff. %	Fuel Nozz Tilt °	OFA Tilts °
24	407	0.710	0.0324	25.9	94.2	89.6	-5	0
25	418	0.609	0.0346	23.7	92.4	89.3	-23	0
26	412	0.770	0.0406	25.1	93.2	88.9	+19	0
27	407	0.721	0.0282	22.3	91.5	89.3	-5	-30
28	414	0.846	0.0360	20.2	89.6	88.6	+22	-30
29	418	0.596	0.0630	23.7	92.6	89.4	-21	+30
30	416	0.710	0.0333	21.6	90.7	89.0	-4	0
33	409	0.697	0.0316	27.4	94.6	89.0	-22	-22

Tests 24 through 30, and 33, were conducted at full unit load with excess air and theoretical air levels to the firing zone of approximately 24 percent and 92 percent, respectively. With moderate slagging conditions on the waterwalls the fuel nozzle tilts and OFA tilts were varied. This essentially moves the firing zone both in the furnace and in its relative position to the overfire air. Fuel nozzle tilts that are maximum minus combined with OFA tilts of maximum plus increase the distance between the overfire air and the firing zone. As with previous methods of increasing this distance, the NO_x emission levels are decreased. Figure 27 shows that as the tilts are moved toward one another (fuel nozzle tilts up; OFA tilts down), the OFA - firing zone separation is decreased and the NO_x levels are increased.

When the OFA tilts are maximum minus and the fuel nozzle tilts maximum plus, the term overfire air becomes ambiguous. The actual overfire air is less than the reported value, because the air is being forced down into the raised firing zone. At this point where the combined fuel nozzle and OFA tilt differential is 52 degrees toward each other, the NO_x emission level reaches a maximum of 0.846 g/10^6cal.

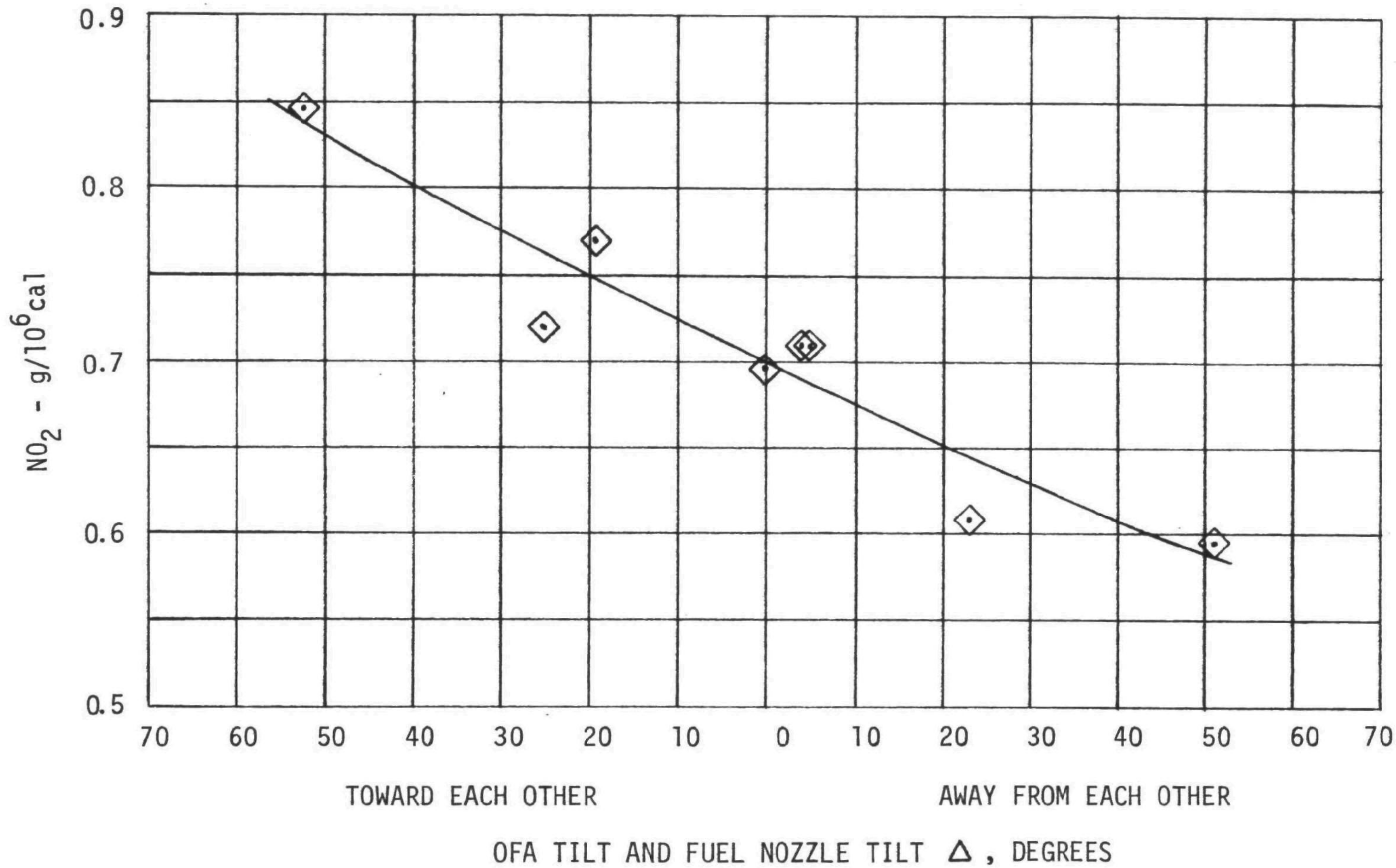


Figure 27: NC_2 Vs. OFA Tilt and Fuel Nozzle Tilt Differential, OFA Tilt Variation Tests 24-33

Percent carbon loss in the flyash exhibits a definite increase as the fuel nozzle tilts and OFA tilts move away from each other. This can be witnessed in Figure 28.

CO emission levels also show an increase as the tilt differential increases, yet there is enough total excess air to maintain an acceptable emission level as shown in Figure 29.

Flame stability arises as a limiting factor in variation of the tilts. As the tilts move substantially away from each other, the fire becomes unstable and pulsing may result. Test 29 was performed with a fuel nozzle and OFA tilt differential of 51 degrees away from each other. NO_x emission levels decreased to 0.596 g/10^6cal, yet the CO emission levels began to increase and the fire appeared less stable. Maintaining the fuel nozzle tilts and OFA tilts at approximately equal tilt angles resulted in acceptable flame stability as well as reduced NO_x emission levels.

For all OFA tilt variation tests the NO_x emissions level obtained was below the EPA limit of 1.26 g/10^6cal.

Load Variation at Optimum Conditions

Tests 30 through 35 were conducted to evaluate unit performance and emission levels at optimum operating conditions as determined during Tests 15 through 29. Tests were conducted over the unit load range at varying furnace waterwall slagging conditions. The NO_x emission level results of this series of tests versus unit loading, expressed as main steam flow, are shown on Figure 30.

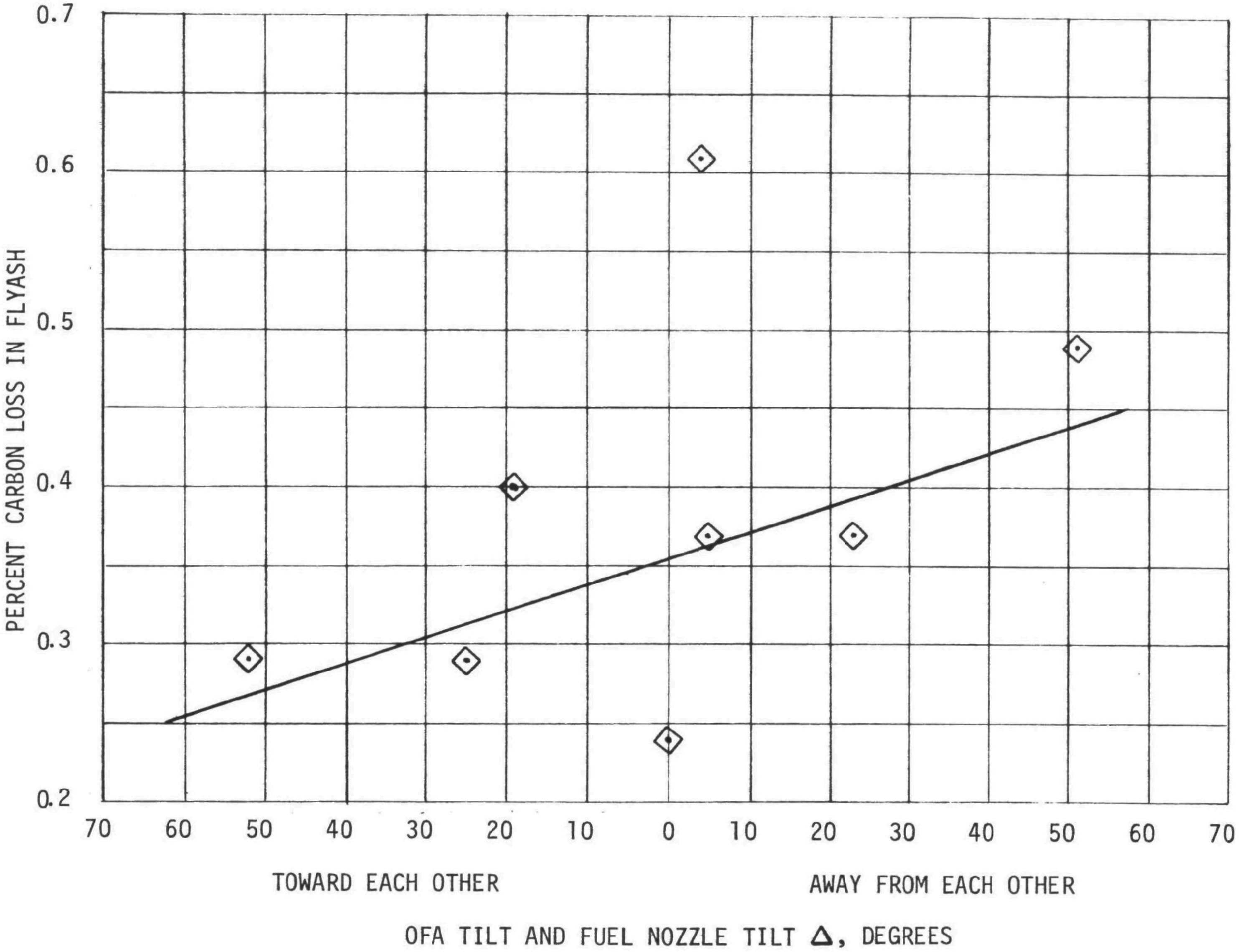


Figure 28: Percent Carbon Loss Vs. OFA Tilt and Fuel Nozzle Tilt Differential, OFA Tilt Variation, Tests 24-33

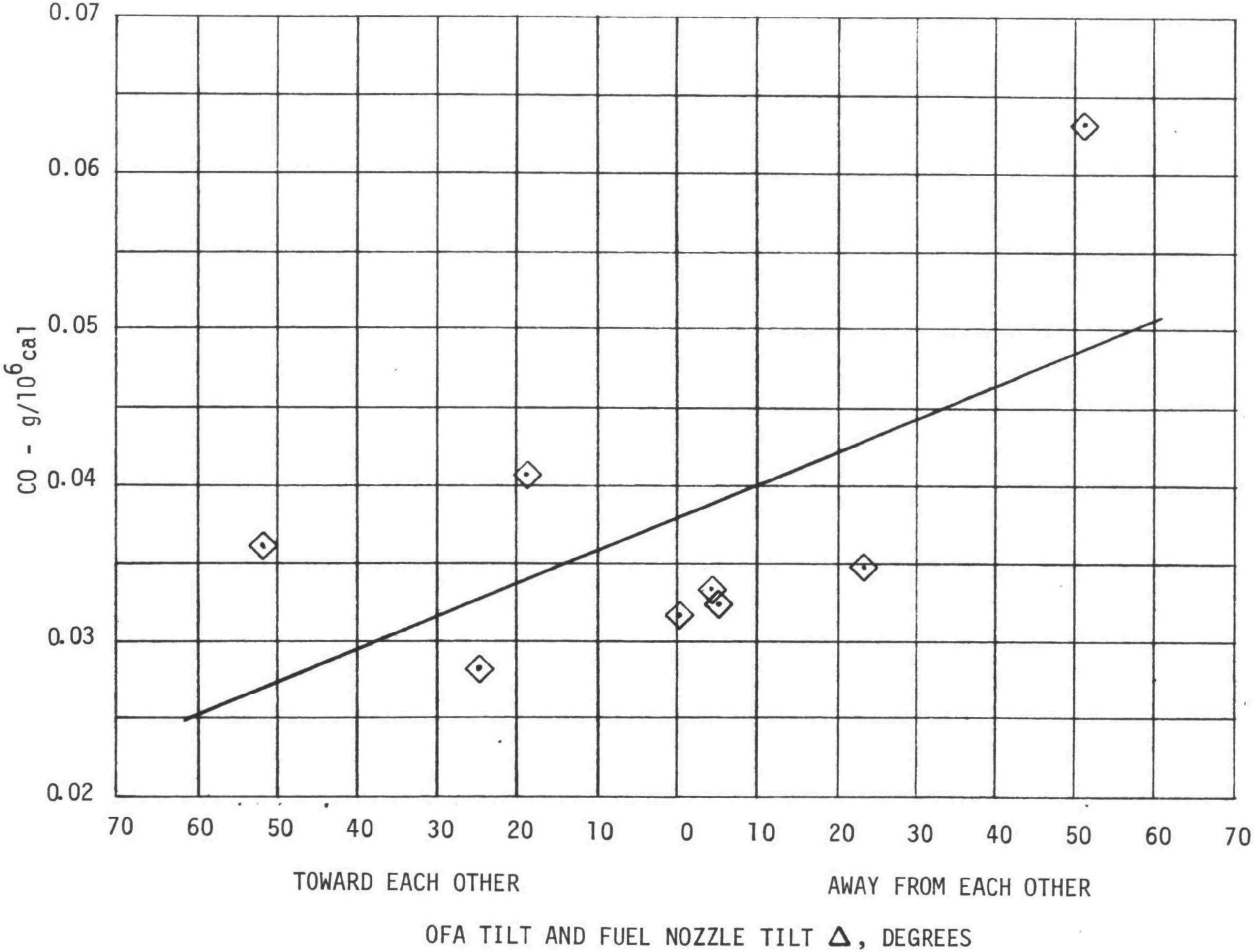


Figure 29: CO Vs. OFA tilt and Fuel Nozzle Tilt Differential, OFA Tilt Variation Tests 24-33

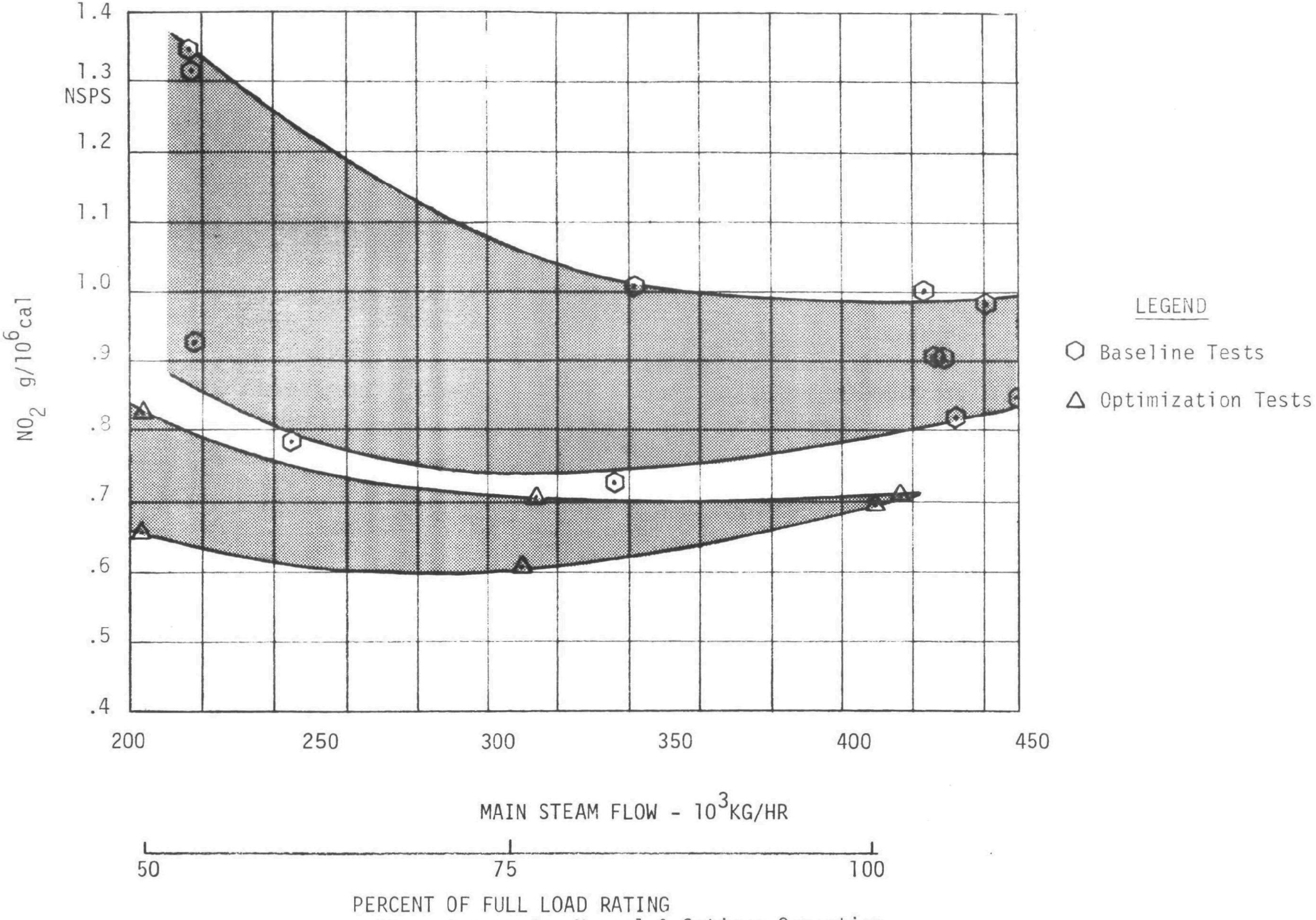


Figure 30: NO_2 Vs. Main Steam Flow, Ranges for Normal & Optimum Operation

Load Variation at Optimum Conditions

Test No.	Main Steam Flow 10^3kg/hr	NO_2 g/10^6cal	CO g/10^6cal	EA %	Theo. Air Firing Zone %	Unit Eff. %	WW Slag
30	416	0.710	0.033	21.6	90.7	89.0	Clean
31	314	0.708	0.033	25.2	89.4	89.1	Clean
32	204	0.828	0.031	46.9	88.5	89.2	Clean
33	409	0.697	0.032	27.4	94.6	89.0	Max.
34	310	0.608	0.034	27.4	90.6	88.2	Max.
35	204	0.655	0.032	45.9	88.5	89.0	Max.

This figure illustrates the range of NO_2 levels obtained both during baseline (after modification) and optimum unit operations. Not all the baseline tests are included as in some cases unit operation was felt to depart excessively from normal operations. Low excess air operation can be cited as an example.

The wide range of NO_2 levels obtained, particularly during the baseline tests are due to variations in unit operating parameters such as excess air level. During the optimization tests total excess air at the unit economizer outlet was maintained between 20 and 28% at full and 3/4 load and 45 to 47% at 1/2 load and fuel nozzle tilts raised or lowered as required to maintain acceptable reheat and superheat outlet temperatures. Also minimum excess air levels were established on the basis of maintaining acceptable CO emission levels and flame stability.

Tests 30, 31 and 32 were conducted as a series and no problems were encountered while changing load with optimum operation.

Furnace Performance

During the test program furnace performance was monitored by use of chordal thermocouples installed in the furnace waterwalls. A schematic of the thermocouple locations is shown in Figure 31 and a tabulation of

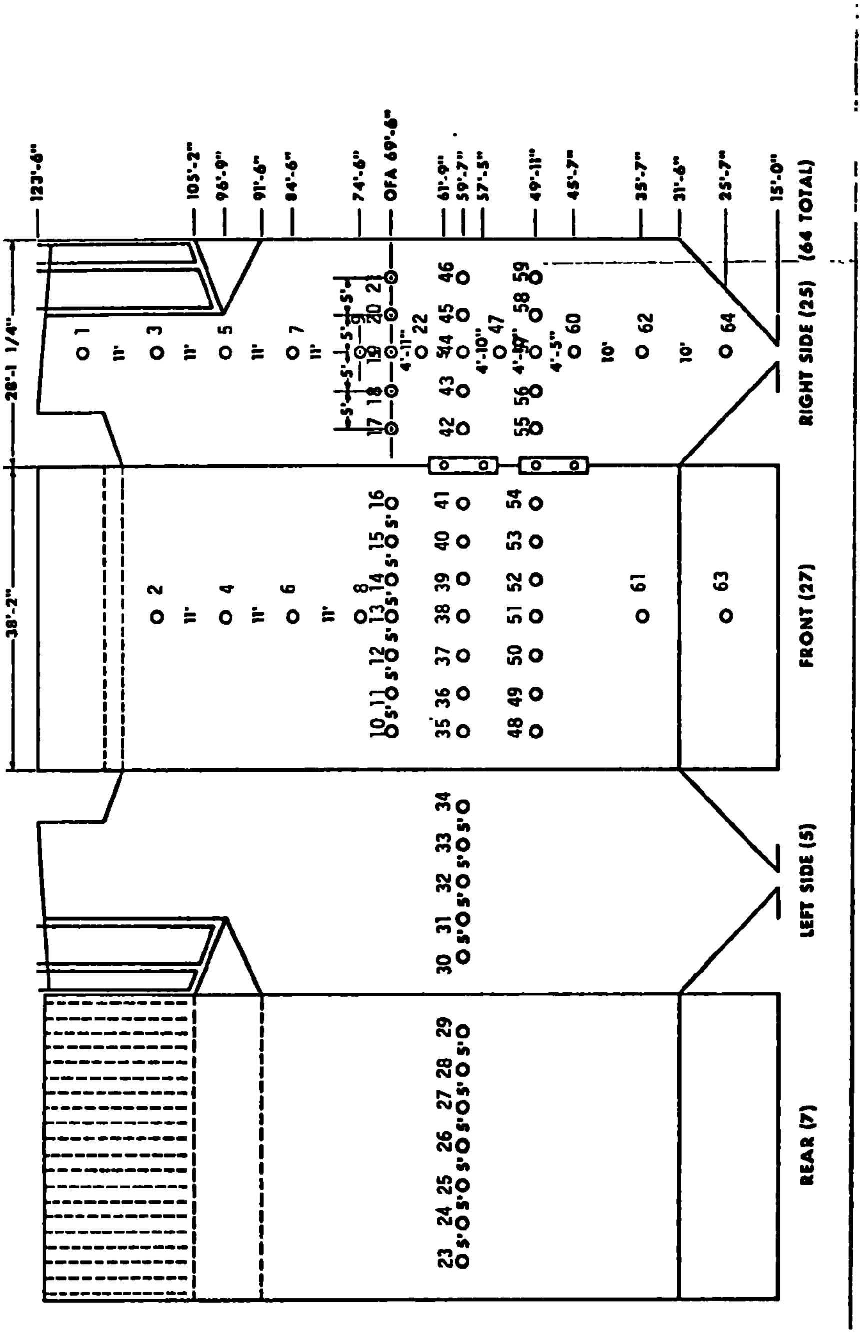


Figure 31: Chordal Thermocouple Locations on the Furnace Waterwalls

the absorption rates obtained is presented on Sheets 13A, 13B and 13C. The temperatures and corresponding absorption rates were found to vary significantly with wall slag conditions making data interpretation difficult. The method finally arrived at as representing an accurate indication of furnace performance is as follows:

The front and right side wall centertube profiles were plotted as shown in Figure 32 and the average of these profiles determined. It should be noted that the maximum and minimum profiles shown do not represent individual walls in every case, i.e., at given furnace elevations the maximum rate shown may switch from wall to wall.

For comparison of optimum and normal unit operation with respect to furnace performance, three full load tests with similar furnace slagging conditions, etc., were selected for comparison. The average centerline profiles for these tests (14, 24, 33) were determined, as shown on Figures 32, 33 and 34, and then plotted together as shown on Figure 35. As shown, furnace performance remained essentially unchanged when furnace slagging effects are taken into account.

It should be noted here that obtaining desired slag conditions proved to be difficult and somewhat unpredictable during overfire air operation. This situation was most pronounced in the firing zone where slag accumulations would normally shed themselves before appreciable accumulations could be built up.

<u>Waterwall Corrosion Coupon Evaluation</u>

Following completion of the steady state phases of the baseline, biased firing and overfire air test programs, thirty (30) day waterwall corrosion coupon evaluations were performed. The purpose of these evaluations was to determine whether any measurable changes in coupon weight losses could be obtained for the various firing modes studied.

The corrosion probes used in the evaluations were previously shown on

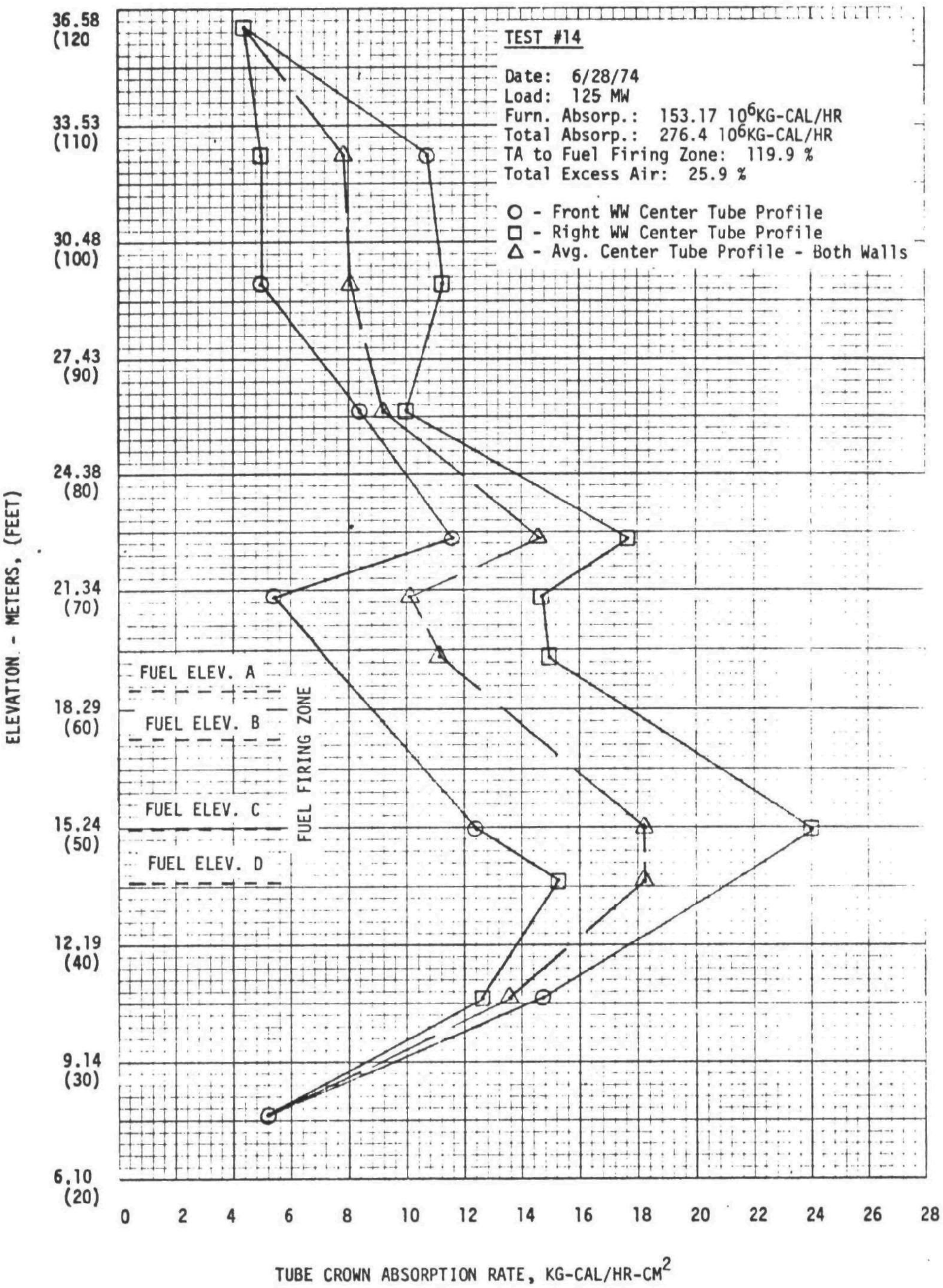


Figure 32: Average Centerline Absorption Profile, Test 14

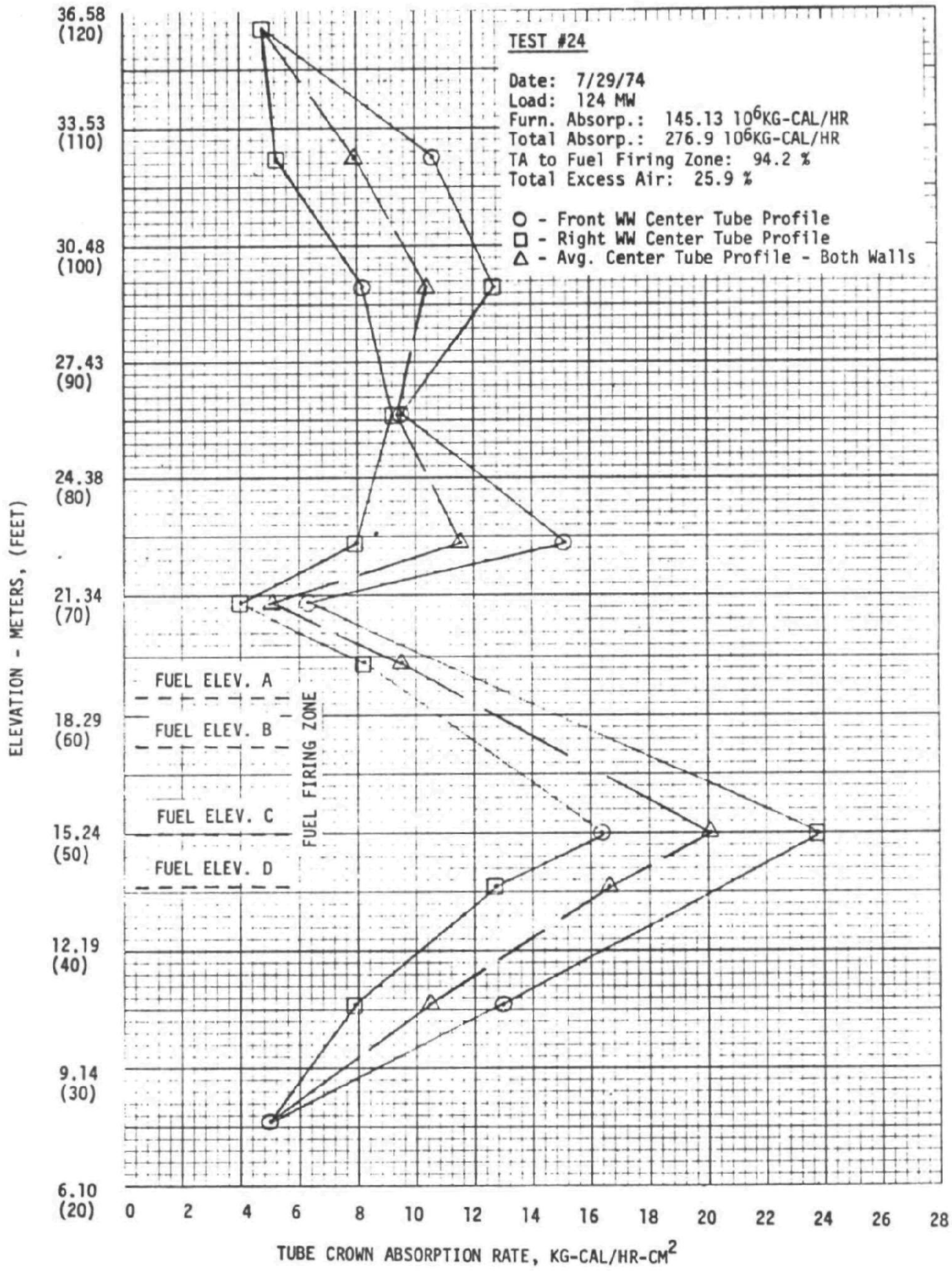


Figure 33: Average Centerline Absorption Profile, Test 24

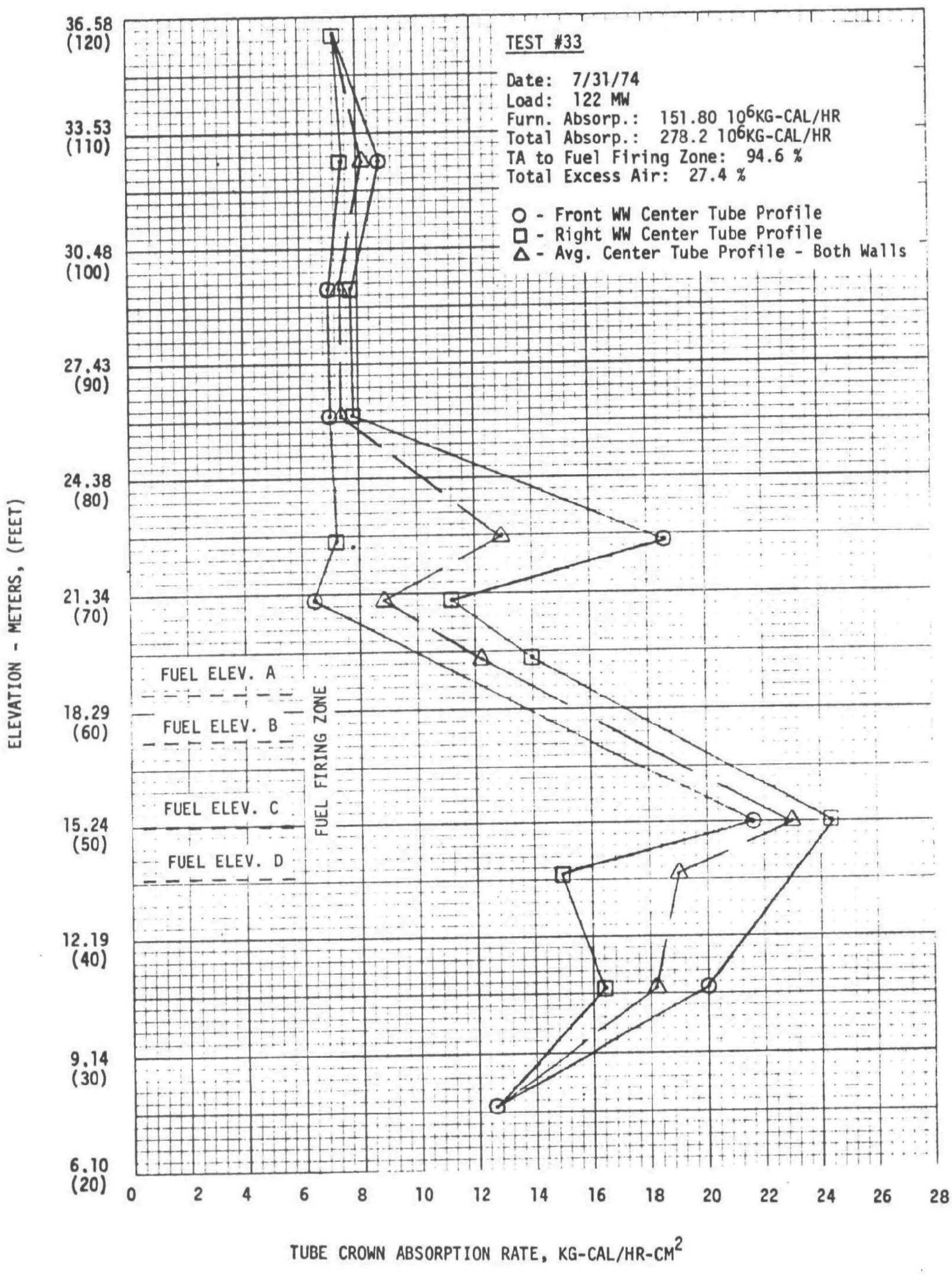


Figure 34: Average Centerline Absorption Profile, Test 33

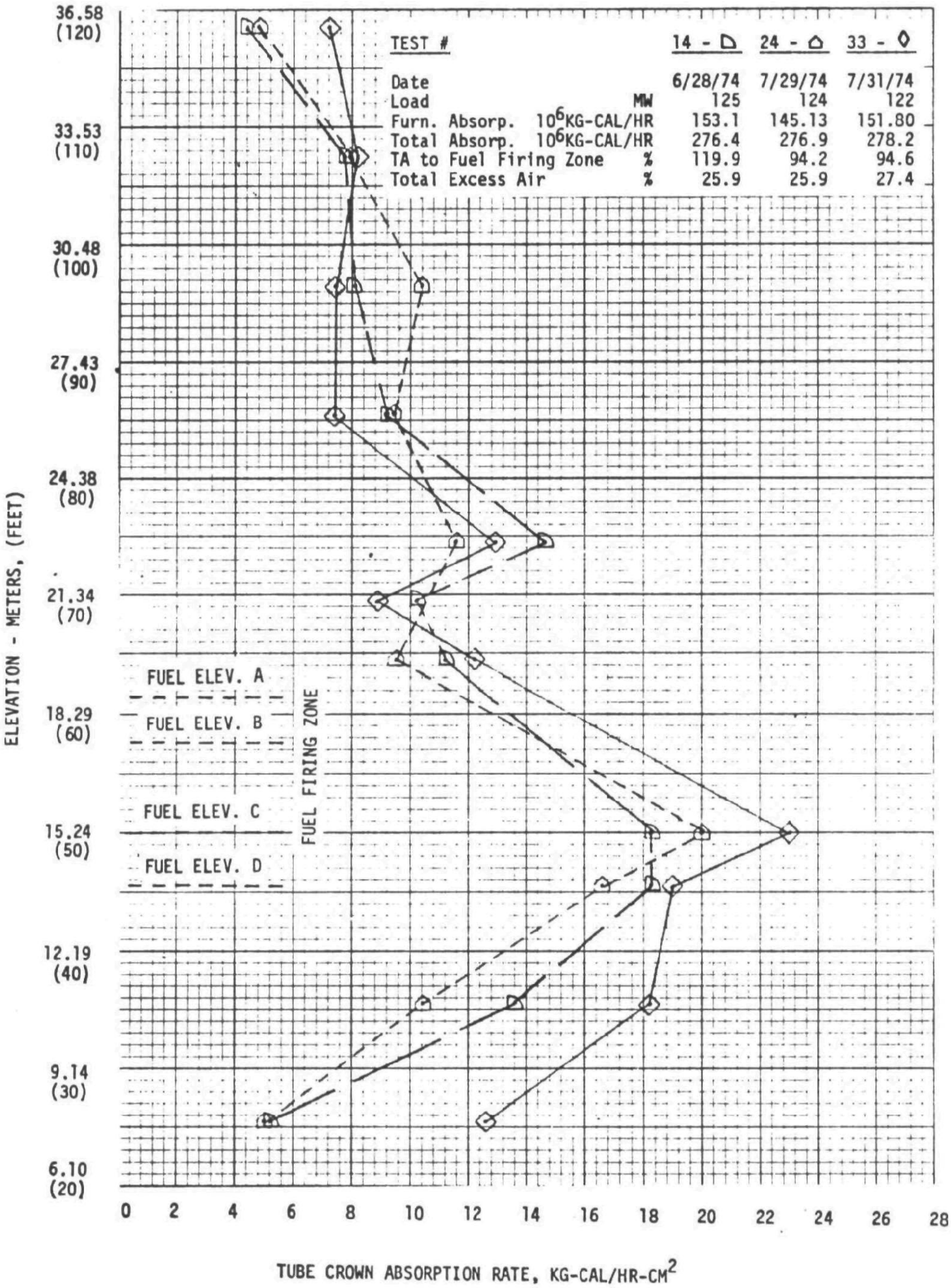


Figure 35: Average Centerline Absorption Profile, All Tests

Figure 4. The individual probes were exposed at five locations on the furnace front wall as shown on Figure 5. The coupon temperatures were maintained at the same levels for each 30 day run and a typical trace of the control temperature range for each of the twenty coupons is shown on Figure 6.

The individual coupon weights were determined before and after each thirty day test and the individual coupon and average probe weight losses are shown on Sheets 14A, 14B, and 14C. The weight losses are calculated as mg/cm^2 of coupon surface area. Of the sixty coupons exposed, three were damaged during disassembly and were therefore not included in the weight loss determinations. The affected coupons were as follows: Coupon K-1, baseline study, and coupons 2-1 and 2-4 overfire air study. In addition, five coupons from probes T and N of the overfire air study resisted disassembly and were therefore weighed as single units and average weight losses were determined.

Figures 36, 37 and 38 show the unit load schedules for each of the 30 day test periods.

The biased firing study was conducted with the top fuel firing elevation out of service as this operating condition was shown during steady state biased firing tests to produce the lowest NO_x emission level of the biasing modes studied. The overfire air study was conducted using an "optimized" operating mode as determined during the overfire air steady state tests.

Throughout each study the following damper positions were maintained over the load ranges indicated.

At unit loadings below 204,000 kg/hr steam flow, with two elevations of mills in service, damper positions were maintained as follows:

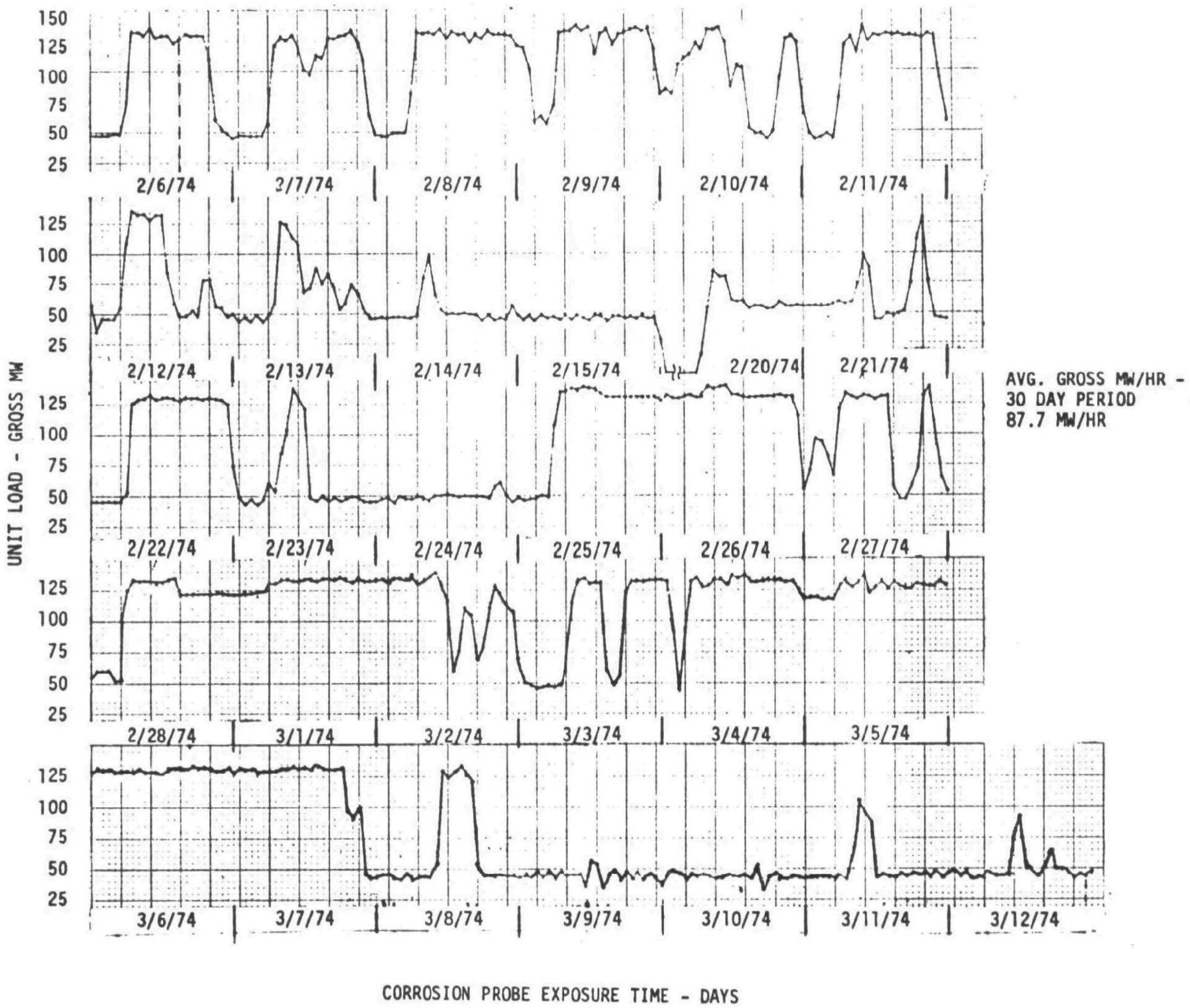


Figure 36: Gross MW Loading Vs. Time - Baseline Corrosion Probe Study

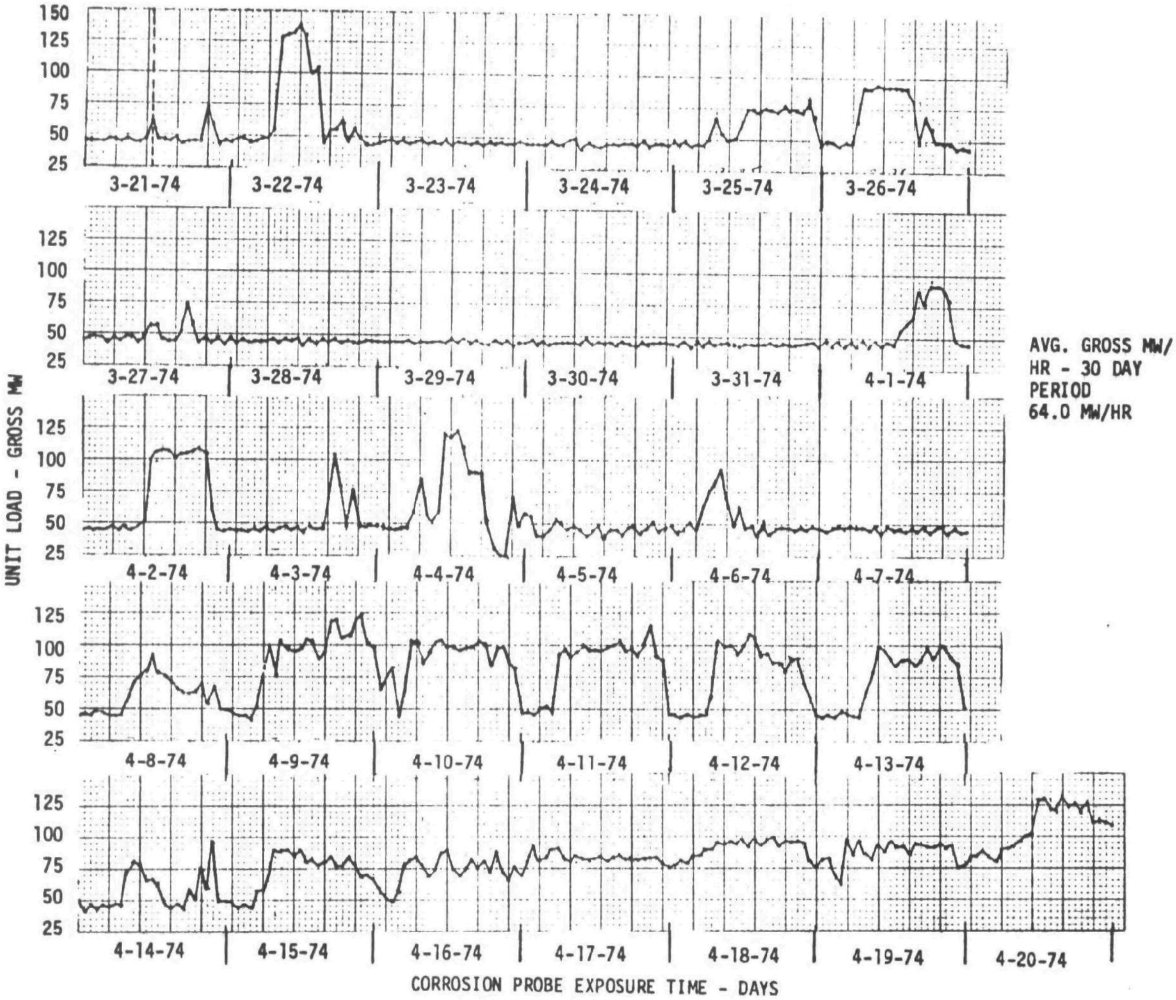


Figure 37: Gross MW Loading Vs. Time - Biased Firing Corrosion Probe Study

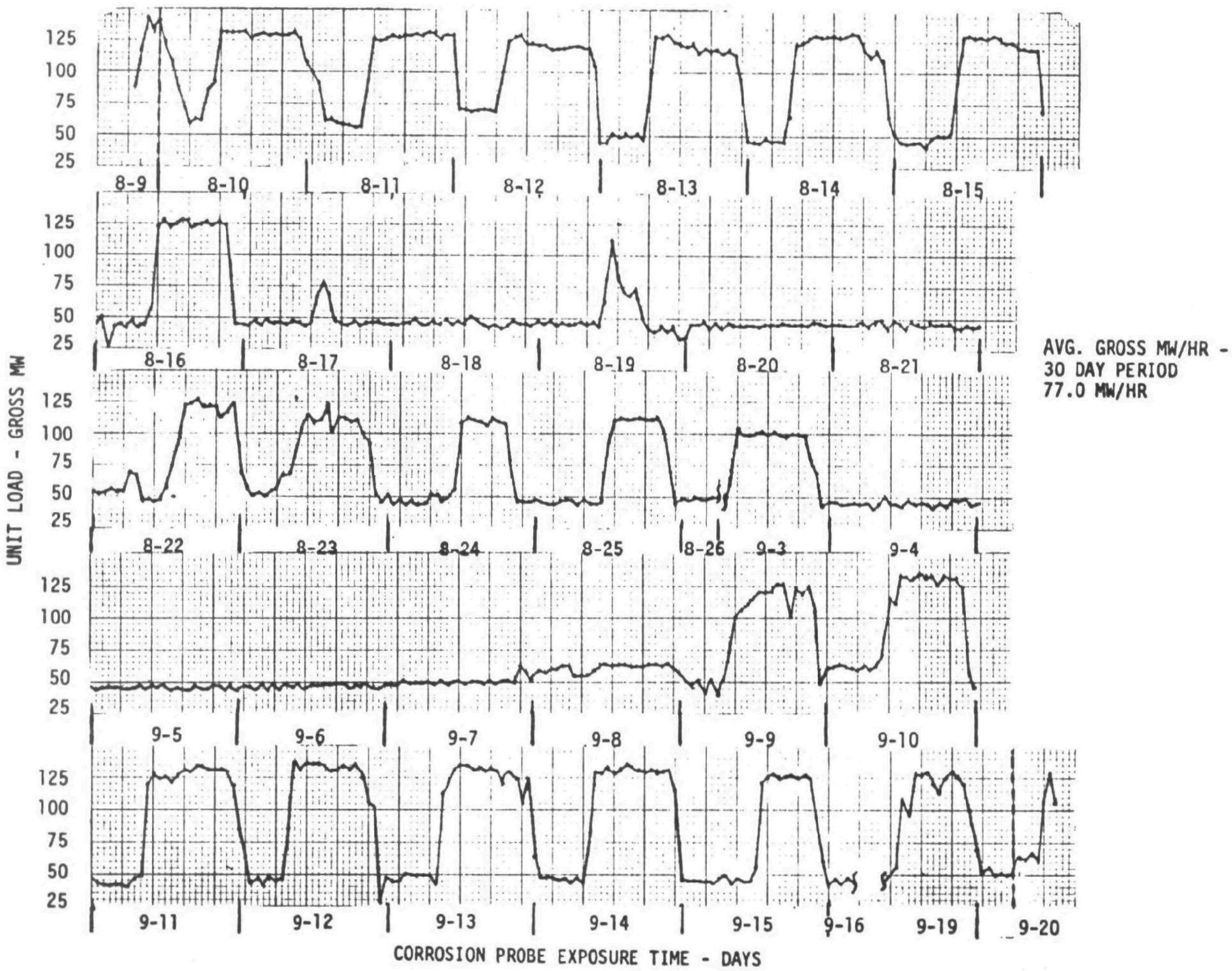


Figure 38: Gross MW Loading Vs. Time - Overfire Air Corrosion Probe Study

Biased Firing Operation

Coal	Auxiliary
	0
0	
	0
0	
	100 ⎤ Combustion
	100 ⎦ Air Only
30	
	50
30	

Overfire Air Operation

OFA Dampers 100
100

Coal	Auxiliary
	100
100	
	50
30	
	50
	0
0	
	0
0	
	0

From 204,000 to 272,000 kg/hr steam flow, with three elevations of mills in service, the damper positions were as follows:

Biased Firing Operation

Coal	Auxiliary
	100 ⎤ Combustion
100	⎦ Air Only
	50
20	
	50
	50
20	
	50
20	
	50

Overfire Air Operation

OFA Dampers 100
100

Coal	Auxiliary
	100
100	
	50
30	
	50
	50
30	
	50
0	
	0

At unit loadings above 272,000 kg/hr to the maximum steam flow with the maximum elevations of mills in service, the following damper positions were maintained.*

Biased Firing Operation		Overfire Air Operation	
		OFA Dampers	100 100
Coal	Auxiliary	Coal	Auxiliary
	100 Combustion Air Only		100
100		100	
	50		50
30		30	
	50		50
	50		50
30		30	
	50		50
30		30	
	50		50

The percent oxygen was monitored daily during each thirty day study at each probe location and was found to be essentially the same for the various test conditions ranging between 16 and 19 percent O_2.

The weight losses calculated for the biased and overfire air portion of the test program were found to be greater than those for the baseline tests. The average weight losses for all five probes were as follows:

---

* At no time during the biased firing study was the top elevation coal pulverizer placed in service. Maximum unit loading was therefore limited to the maximum with the lower three mills in service.

Baseline	Biased Firing	Overfire Air
2.6381 mg/cm^2	4.6429 mg/cm^2	4.4419 mg/cm^2

These values are within the range of losses which would be expected for oxidation of carbon steel for a 30 day period. To verify this premise control studies were conducted in C-E's Kreisinger Development Laboratory using probes exposed during the biased firing study. These probes were cleaned and prepared in an identical manner to those used for furnace exposure and placed in a muffle furnace for 30 and 60 day exposures at 750 F with a fresh air exchange. The test results were as follows:

Probe	Wt. Loss mg/cm^2 - 30 Days
M (30 day)	4.7999
Q (30 day)	4.7741
R (60 day)	5.1571/2 = 2.5785
B (60 day)	8.3493/2 = 4.1746

These results indicate that the test coupons oxidized more rapidly during the first 30 days exposure with average weight losses decreasing in the second thirty days. Based on these results, it appears that the differences in weight losses observed during the test program are within the ranges to be expected from oxidation alone.

Chemical analysis of deposits taken during the test program does not, in itself, show that molten phase attack has occurred. The composition of the deposits does show some differences, primarily in the iron content as noted on Figure 39. The deposit collected during the biased firing and overfire air tests show 50 and 35 percent iron, respectively, versus 30 percent in the baseline test. Higher iron is normally indicative of lower melting temperatures. However a certain quantity of CaO is necessary to flux the iron if it is to result in a low melting mixture. The CaO content is considerably less in the biased firing and overfire air tests as compared to that of the baseline test. According-

	Waterwall Slag Sample Baseline Test	Coal Ash (As-Fired)	Waterwall Slag Sample Biased Firing Test	Waterwall Slag Sample Overfire Air Test
Ash Fusibility				
IT	1930	2150	2060	1930
ST	2090	2410	2170	2090
HT	2200	2500	+2700	2250
FT	2500	2620	+2700	----
Ash Composition				
SiO_2	46.2	45.8	38.4	38.5
Al_2O_3	18.4	30.7	10.3	18.1
Fe_2O_3	29.9	13.9	50.0	35.4
CaO	3.9	1.8	1.0	1.8
MgO	0.8	1.3	0.3	0.9
Na_2O	0.32	0.4	0.1	0.4
K_2O	0.61	1.4	0.7	1.9
TiO_2	N.R.	0.8	N.R.	1.0
P_2O_5	N.R.	0.5	N.R.	N.R.
SO_3	0.34	1.2	0.8	0.4
	100.4	97.8	101.5	98.4

Figure 39. Ash Analysis

ly the fusibility temperatures are higher for the biased firing test and slightly higher for the overfire air tests. This agrees with observations made during the tests, i.e., deposits during biased firing were more friable and easily removed than in the baseline tests with the overfire air tests falling closer to baseline operation.

For comparison fusibilities and compositions have been given in Figure 39 for the coal ash as fired. This points out the selective deposition of certain constituents in the coal ash, like iron, and also shows that resultant fusibility temperatures of deposits can be significantly different than the coal ash as fired.

Overfire Air Evaluation - Alternate Coal Types

The evaluation of alternate coal types with respect to their effect on unit performance and NO_x emissions optimization was originally proposed as part of this study. However, due to coal supply problems encountered after the start of work, these evaluations proved to be not feasible and were therefore not performed. Tests of a similar nature evaluating Alabama and Midwestern coals were performed during 1973 by Esso Research and Engineering Co. under EPA Contract 68-02-0227 at the Alabama Power Co., Barry No. 4 unit. A discussion of those test results has therefore been included in this report.[2]

Unit Description

Barry No. 4 is a controlled circulation, radiant, reheat, single cell pressurized design firing coal through five elevations of tilting tangential fuel nozzles. Maximum continuous rating is 1,164,969 kg/hr superheat steam flow at 538°C/176 kg/cm^2 and 1,024,566 kg/hr reheat steam flow at 538°C/44 kg/cm^2. Control load rating is 582,485 kg/hr main steam flow.

Alabama and Midwest coals plus petroleum coke were fuels being burned at the time of the test program. The petroleum coke was fired exclusively through the center fuel nozzle (Elevation C) and normally represented one-quarter to one-fifth of the heat input.

Test Objectives

The objectives of the Esso test program were as follows:

1. A series of short (thirty minutes) tests for optimizing NO_x reduction by varying the following:
   A. Excess Air
   B. Nozzle Tilt
   C. Overfire Air
   D. Primary/Auxiliary Air Damper Settings
   E. Unit Load
   F. Pulverizer Coal Fineness
   G. Firing Alabama Coal, Alabama + Coke and Midwest + Coke

2. A two or three day sustained operation at optimum NO_x reduction operating conditions for checking possible short term unit operating problems.

3. A three hundred hour operating period at optimum NO_x reduction conditions for determining possible long term operating problems.

Discussion

Test Data Acquisition

Esso Research measured all gas emission levels with instrumentation located in a specially designed mobile van. The van was located at ground level and had the following instrumentation:

NO Thermo Electric Chemiluminescence

NO_2 Beckman Ultraviolet, Thermo Electric Chemiluminescence

CO_2 ⎤
SO_2 ⎬— Beckman Infrared
CO ⎦

O_2 Beckman Paramagnetic

Esso also employed a remote recorder readout of CO, NO_2 and O_2 in the control room for convenience in observing emission levels during testing.

There were no conveniently located test inserts available for gas sampling at the gas duct entering the air heater. Esso, therefore, had to set up a twelve point sampling grid after the air heater. The flue gas sampling rate from each point was proportioned to a gas flow previously determined by velocity traverse. All gas sample lines were heated until the particulate filters, then all condensables are removed by a 32°F ice bath. The gas sample is then blended to one sample per probe location and pumped under 5 pounds pressure to the sample analytical van.

C-E instrumented Corners #1 and 2 windbox compartments to determine the amount of overfire air and the air flow to each compartment. A static pressure tap was installed in each compartment and the pressure differential to the furnace measured.

Petroleum coke, Alabama coal and Midwest coal are normally available at this plant. Normally the coals are fired as mixed in the coal pile. For the test series Alabama and Midwest coals were supplied directly to the bunker. The petroleum coke is burned in a separate Nozzle "C" with coal firing in surrounding Coal Nozzle B and D to insure stable ignition.

Normal coal fineness as taken before the tests was 72 percent thru the 200 mesh screen. Coal fineness was changed to approximately 60 percent thru the 200 mesh screen on several tests to investigate the possible effect on NO_x emission levels.

Esso Research obtained pulverizer coal and coke samples from the feeder belts of each mill on every test. Typical analysis for the coals and coke is presented on Sheet 17.

Unit Performance

Boiler operation as reported on Sheet 15 and 15A was based on board instrumentation. The NO_x, CO, CO_2 and SO_2 PPM values represent data as averaged from Esso data sheets using the appropriate instrument calibration tables.

Test Emission Data

Overfire Air

The greatest effect on NO_x emission levels was obtained by use of overfire air which decreases the amount of air to the firing zone. Figure 40 presents the NO_x emission levels versus percent excess air to the firing zone for all tests. Emission levels are reduced from 525 PPM to approximately 327 PPM in reducing theoretical air from 134 to approximately 95 percent at 0° tilt.

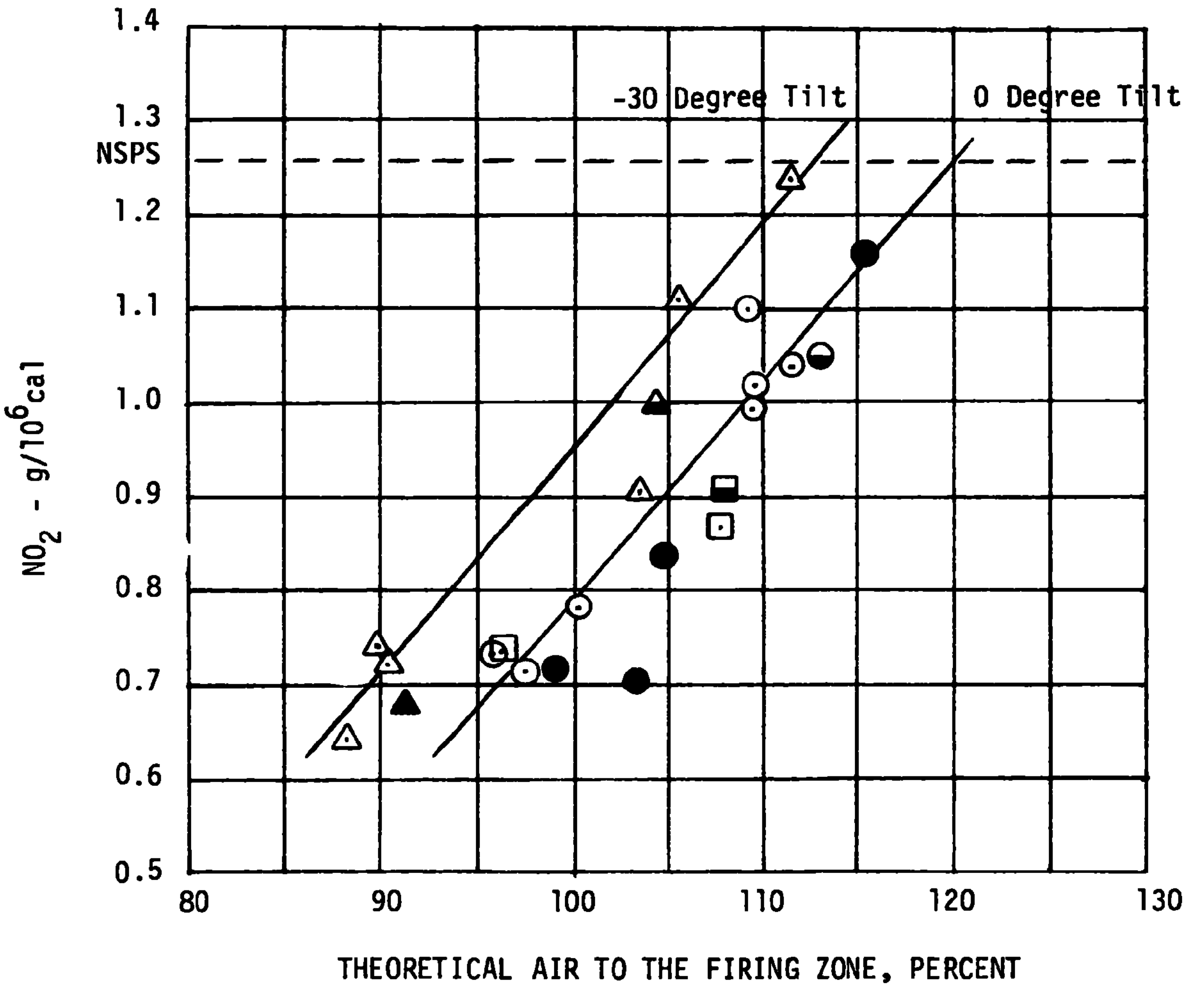
Excess Air

Unit operating excess air as determined at the air heater inlet had no significant effect on NO_x emission levels (corrected to 0 percent excess air when maintaining a constant theoretical air to the firing zone. Figure 41 shows that with this type of operation the unit operating excess air level could be varied from 6 percent to 26 percent with essentially constant NO_x emission; unit excess air was important, however, in keeping CO emissions at low values (Figure 42).

CO Emissions

Figure 42 indicates that CO emissions are a function of percent excess air at the air heater inlet and also the amount of overfire operation. The test data indicates that at 15 percent excess air unit operation and no overfire air the CO emission was 33 PPM which increased to 93 PPM

Alabama Power Company
Barry #4



LEGEND

Degrees Tilt	Symbol
-20 to -30	△
0	○
+15 to +20	□

SYMBOL	COAL
Open	Alabama + C
Solid	Midwest + C
1/2 Solid	Alabama

Figure 40: NO_2 Vs. Percent Theoretical Air to Firing Zone, All Tests at Unit Loads of 290 to 360 MW

Alabama Power Company
Barry #4

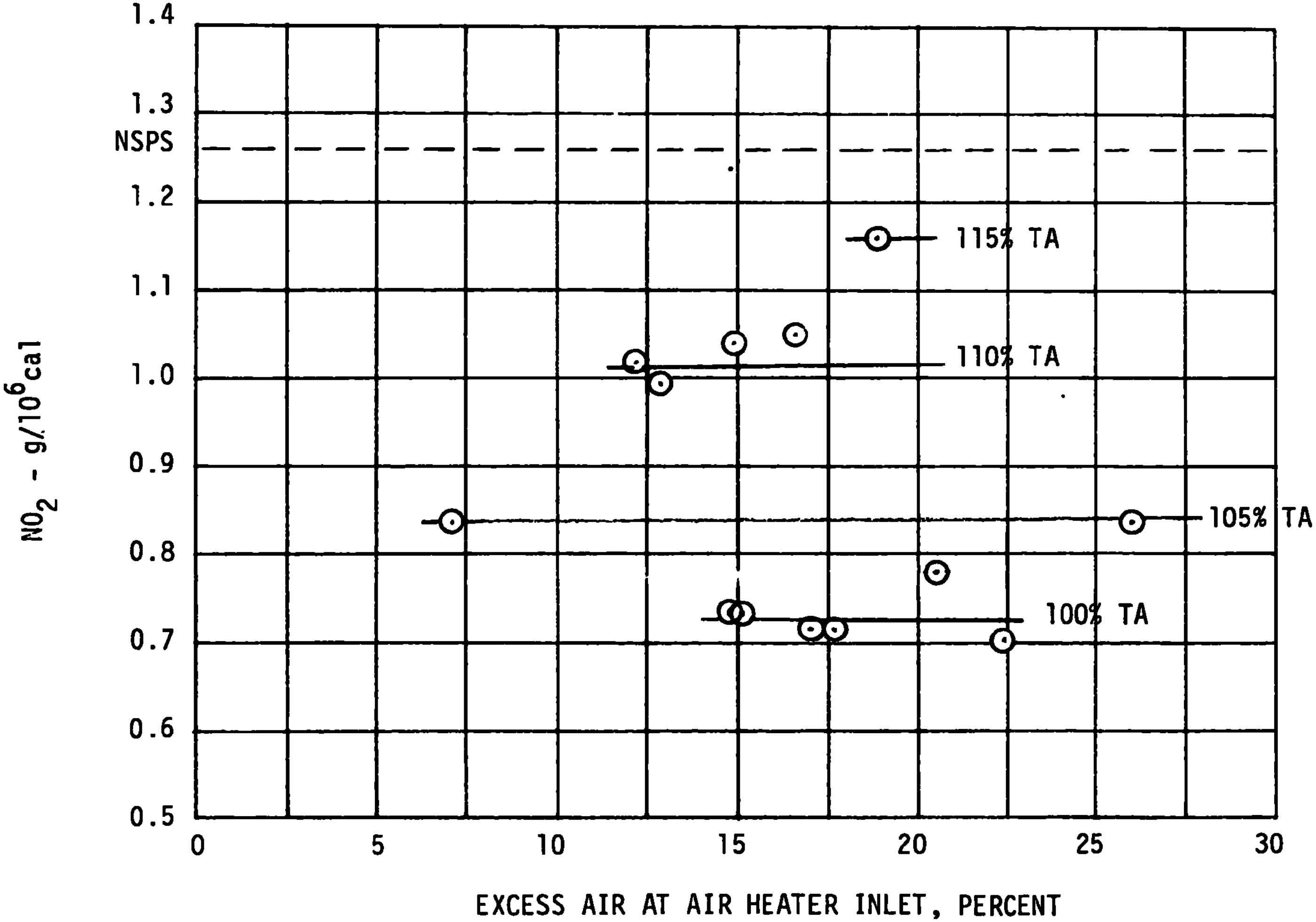


Figure 41: NO_2 Vs. Percent Excess Air at Air Heater Inlet
All Tests at Horizontal Tilt, Unit Load 290 to 360 MW

Alabama Power Company
Barry #4

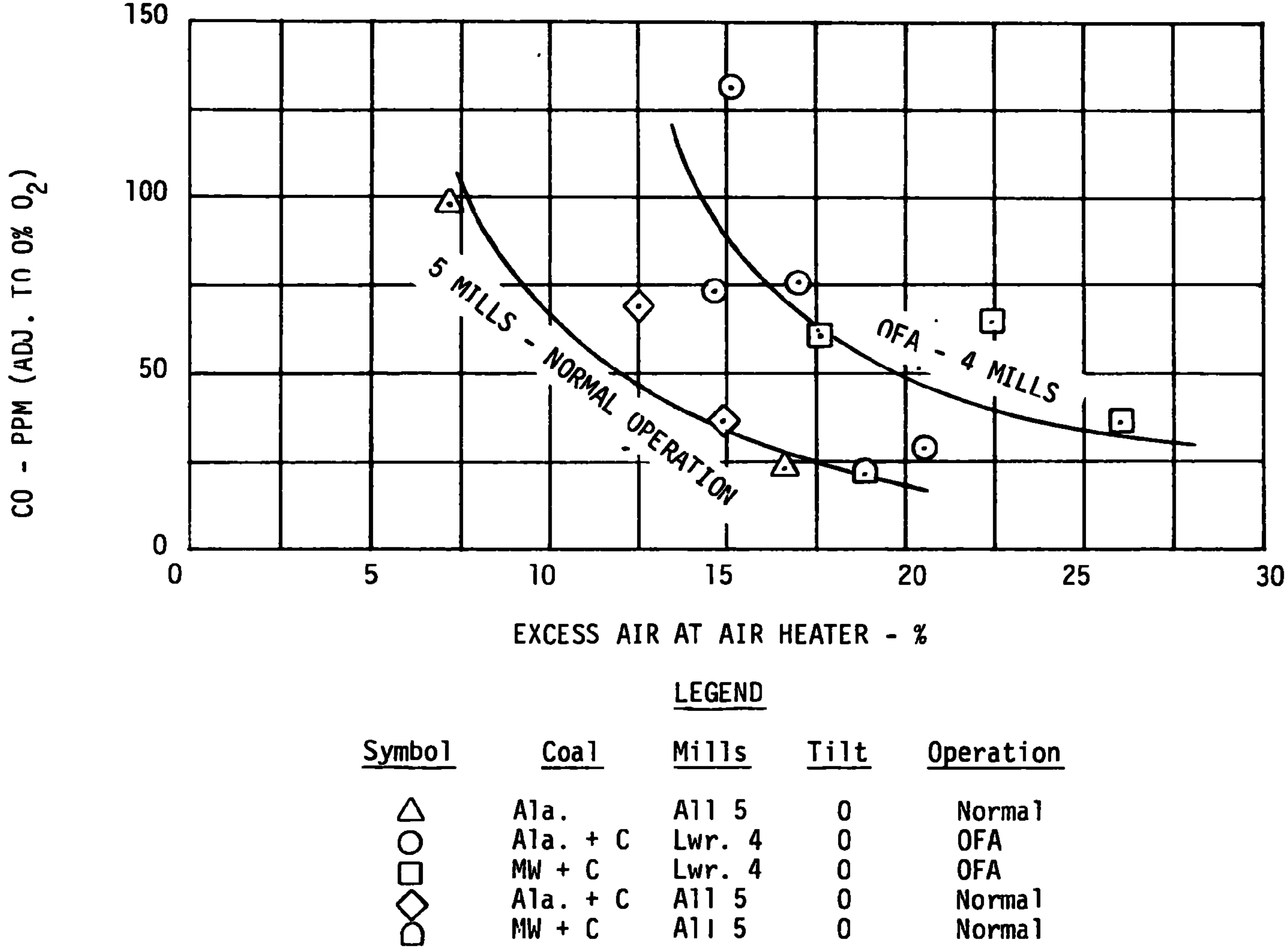


Figure 42: CO Vs. Excess Air, Normal and Overfire Air Operation

with overfire air (90 to 100 percent theoretical air to burner zone). In coal firing 15 percent excess air would seem to be the lowest practicable limit of operation.

Nozzle Tilt

Operating at -30° fuel nozzle tilt increased the NO_x emission approximately 87 PPM over that obtained at 0° tilt. The limited testing with plus tilts of +15° and +20° produced no effect on the measured NO_x emission levels.

Effects of Other Operating Variables

The variation of primary/secondary air dampers (Figure 43) unit load and the pulverized coal fineness had minor effects on NO_x emission levels. This substantiates previous test results and indicates that these operating variables should continue to be used to control normal boiler operation and should not be considered as NO_x controls with coal firing.

Type of Coal

During the test series the following combinations of fuel were fired:

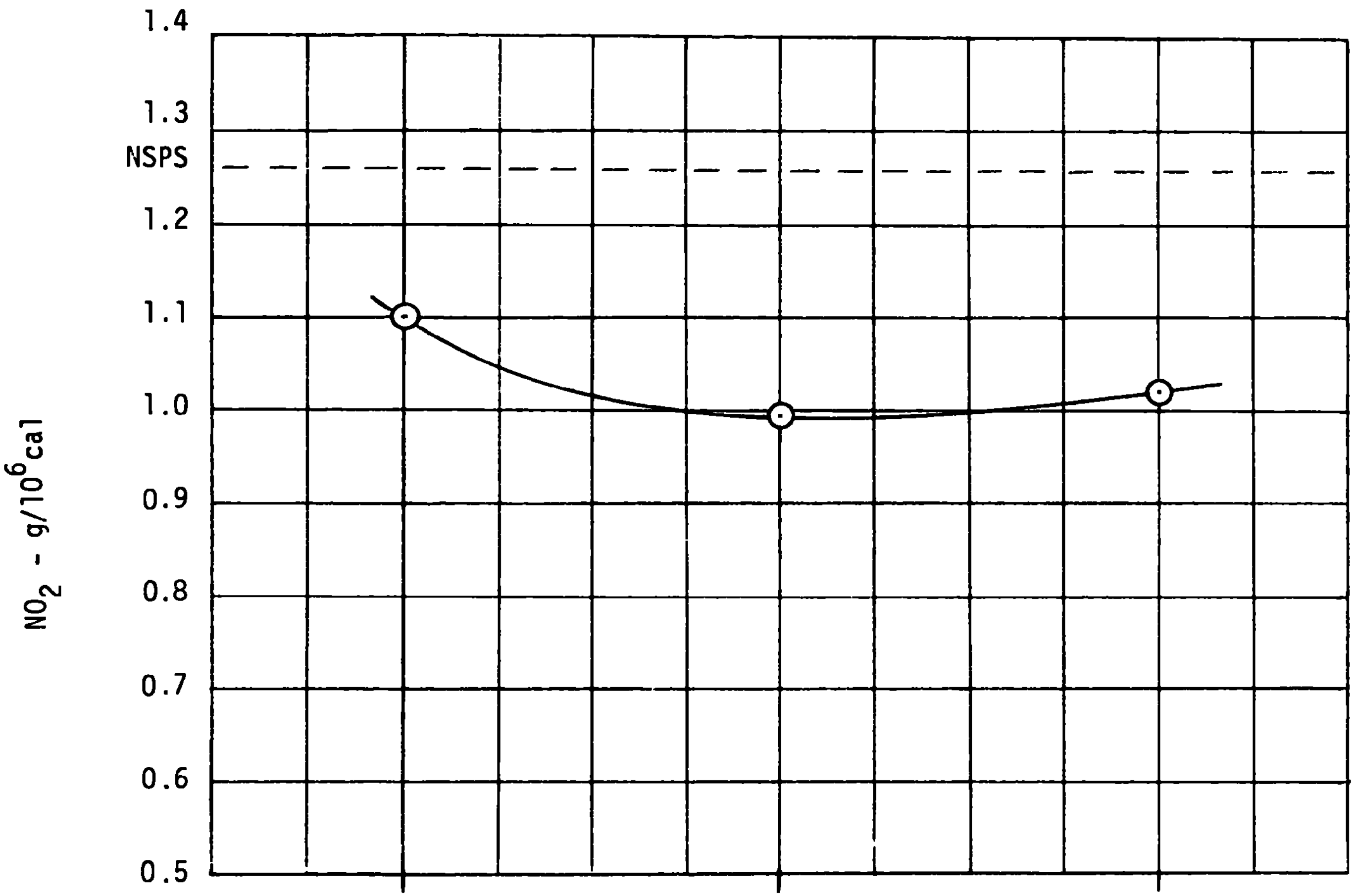
	Fuel	No. of Tests
1.	Alabama Coal	4
2	Alabama Coal + Coke	15
3.	Midwest Coal + Coke	5

Figure 40 plots all tests and identifies the firing combinations and indicates no change in emission levels with fuel change.

Unit Operation

Superheat-reheat outlet temperature of 538/538°C could be maintained at 90 percent MCR horizontal tilt and 95 percent theoretical air to the burner zone which was the optimum NO_x reduction conditions. The overfire

Alabama Power Company
Barry #4



AUX./PRIM. DAMP. - % OPEN	100/20	100/50	50/100
TEST NO.	37	2	35
LOAD - MW	348	348	360
O_2 - %	2.4	2.4	2.4
TILT - DEG.	0	0	0
% THEORETICAL AIR TO FIRING ZONE	109.1	109.4	109.5

Figure 43: Auxiliary/Primary Damper Positions Vs. NO_2

operation maintains the gas weight thru the unit which results in unchanged superheat-reheat performance.

No adverse furnace slagging was noted during the short term tests with low theoretical air to the firing zone. The three hundred hour, long term test with approximately 95 percent theoretical air to the firing zone and 15 percent excess air at air heater inlet was also completed without excessive furnace slag buildup.

300 Hour Corrosion Probe Test Results

Corrosion probes were installed in the furnace of the test boiler by inserting them through available viewpoints in the furnace firing zone as shown on Figure 44. Prior to installing the probes in the test furnace, the probes were prepared by mild acid pickling, preweighing the coupons, and screwing them onto the probes along with the necessary thermocouples. Each probe was then exposed to the furnace atmosphere prevailing for the particular type of operation desired for approximately 300 hours at coupon temperatures of about 468°C in order to accelerate corrosion. After exposure, furnace slag was cleaned off and saved for future analyses, and the coupons were carefully removed from the probes. In the laboratory the coupons were cleaned ultrasonically with fine glass beads to the base metal, and reweighed to determine the weight loss.

Total weight loss data was converted to corrosion rates on a mils per year basis, using the combined inner and outer coupon rates, coupon material density, and exposure time.

Corrosion rates have been determined for 8 coupons installed on 4 probes (2 coupons/probe), in four different locations on the furnace wall. The corrosion data obtained is tabulated on Sheet 16.

Although there is some scatter in the data obtained, Esso concluded "that

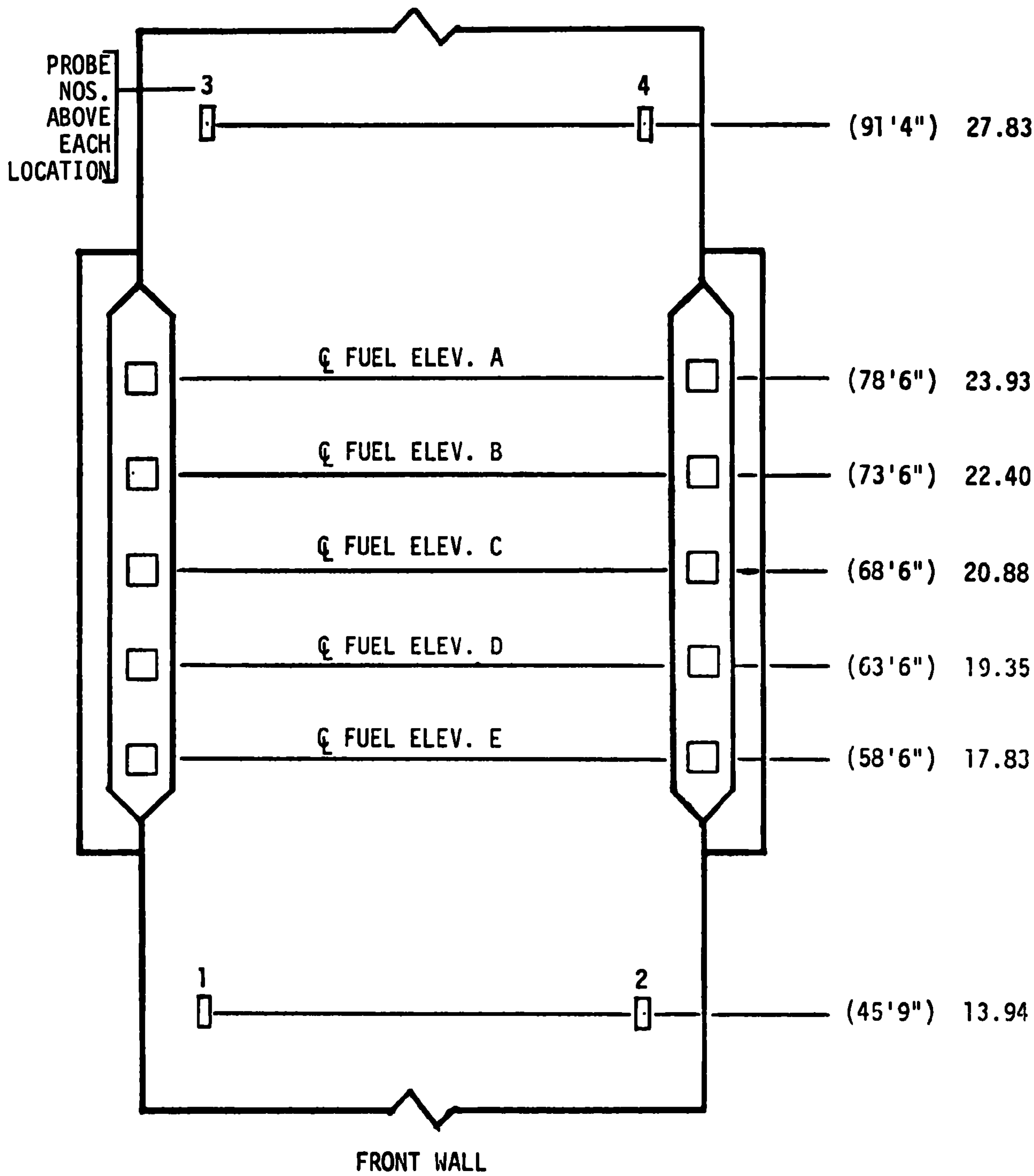


Figure 44: Waterwall Corrosion Probe Locations, Barry No. 4

no major differences in corrosion rates have been observed for coupons exposed to 'low NO_x' conditions compared to those subjected to normal operation."

Esso further concluded that "since corrosion rates were deliberately accelerated in this study in order to develop 'measurable' corrosion rates in a short time period, measured rates, as expected, are much higher than the normal wastage of actual furnace wall tubes."

Task IX - Application Guidelines

The program outlining the application of the technology developed under this study to existing and new tangentially coal fired utility boilers will be presented in the Task IX report and is therefore not discussed as part of this report.

BASELINE STUDY

NO_x TEST DATA SUMMARY

Test No.		1	2	3	4	5	6	7
Purpose of Test		Excess Air Var. - Clean Furn. Cond.						
		1/2 Load			3/4 Load		Full Load	
Date		11-30-73	11-30-73	11-30-73	1-18-74	11-14-73	11-28-73	11-28-73
Load	MW	66	65	67	93	124	123	123
Main Steam Flow	10^3 Kg/Hr	219	224	214	316	404	407	405
Excess Air Econ. Outlet	%	35.5	17.5	58.9	12.6	22.7	11.7	30.8
Theo. Air To Fuel Firing Zone	%	130.6	117.1	151.3	109.2	117.9	107.2	125.3
Fuel Elev. In Serv.		ABC	ABC	ABC	ABC	ALL	ALL	ALL
Fuel Nozzle Tilt	Deg.	+3	+7	+3	+8	+3	0	0
Nozzle Comp. Damper Pos. % Open — Aux.		20	0	50	30	60	100	100
"A" Fuel		30	30	30	20	20	30	30
Aux.		20	0	50	60	100	100	100
"B" Fuel		30	30	30	20	20	30	30
Aux./Aux.		20/20	20/10	50/50	80/80	100/100	100/100	100/100
"C" Fuel		30	30	30	20	20	30	30
Aux.		20	10	50	50	100	100	100
"D" Fuel		0	0	0	0	20	30	30
Aux.		0	0	0	0	100	100	100
SHO Temperature	°C	529	498	548	500	539	539	538
RHO Temperature	°C	488	446	517	499	514	524	524
Unit Efficiency	%	88.3	88.2	87.6	89.3	89.0	89.1	89.5
Gas Weight Ent. A.H.	10^3 Kg/Hr	352	360	412	386	554	578	592
NO_x	PPM - 0% O_2	631	489	718	429	494	357	664
NO_x	Gr/10^6 Cal	1.337	1.030	1.519	.900	1.041	.761	1.403
SO_2	PPM - 0% O_2	2298	2318	1644	1635	1641	1434	1455
SO_2	Gr/10^6 Cal	6.770	6.794	4.841	4.769	4.815	4.254	4.278
CO	PPM - 0% O_2	24.51	142.26	8.05	39.09	31.16	152.88	32.91
CO	Gr/10^6 Cal	.0316	.182	.0104	.0499	.0400	.198	.0423
HC	PPM - 0% O_2	.144	.160	0.0	0.0	.509	0.0	0.0
O_2	% A.H. In	5.59	3.20	7.89	2.40	3.96	2.26	5.02
O_2	% A.H. Out	7.28	5.61	9.09	5.14	6.24	4.63	6.87
Carbon Loss in Flyash	%	.29	.97	17	.96	.48	.57	.20
Dust Loading	Gr/SCM					4.19		

Test No.		8	9	10	11	12	13	14
Purpose of Test		E.A. Var. Mod. Dirty Furn.			E.A. Var. Dirty Furn.			
		Full Load			1/2 Load		Full Load	
Date		11-15-73	11-19-73	11-19-73	12-5-73	12-4-73	11-16-73	11-16-73
Load	MW	126	122	124	66	74	125	125
Main Steam Flow	10^3 Kg/Hr	411	403	405	211	206	412	406
Excess Air Econ. Outlet	%	21 5	13.0	26.0	32 7	51.2	20 7	24.3
Theo. Air To Fuel Firing Zone	%	116.9	108.5	120.8	128.0	144.1	115.7	119.2
Fuel Elev. In Serv.		ALL	ALL	ALL	ABC	ABC	ALL	ALL
Fuel Nozzle Tilt	Deg.	+8	-22	-22	0	0	-22	-22
Nozzle Comp. Damper Pos. % Open — Aux.		60	100	100	20	50	100	100
"A" Fuel		30	30	30	30	30	30	30
Aux.		100	100	100	20	50	100	100
"B" Fuel		30	30	30	30	30	30	30
Aux./Aux.		100/100	100/100	100/100	20/20	50/50	100/100	100/100
"C" Fuel		30	30	30	30	30	30	30
Aux.		100	100	100	20	50	100	100
"D" Fuel		30	30	30	0	0	30	30
Aux.		100	100	100	0	0	100	100
SHO Temperature	°C	548	533	544	518	548	539	543
RHO Temperature	°C	533	510	531	476	508	522	529
Unit Efficiency	%	89.6	89.6	89.6	88.3	87.9	89.2	89.3
Gas Weight Ent. A.H.	10^3 Kg/Hr	567	502	565	323	369	556	567
NO_x	PPM - 0% O_2	421	361	581	536	658	499	586
NO_x	Gr/10^6 Cal	.894	.748	1.198	1.118	1.370	1.037	1.225
SO_2	PPM - 0% O_2	1171	2052	2179	2348	2164	1917	1370
SO_2	Gr/10^6 Cal	3.458	5.922	6.251	6.821	6.267	5.538	3.985
CO	PPM - 0% O_2	45.75	431.8	5.48	297.59	220.56	40.85	33.61
CO	Gr/10^6 Cal	.0591	.545	.0069	.378	.280	.052	.043
HC	PPM - 0% O_2	61	.128	1.54	0.0	0.0	.513	.397
O_2	% A.H. In	3.78	2.47	4 41	5.26	7.20	3.66	4.18
O_2	% A.H. Out	5.31	4.60	6.64	6.99	8.63	6.01	6.42
Carbon Loss in Flyash	%	.16	.27	.05	.58	.20	.17	.10

BIASED FIRING STUDY

NO_x TEST DATA SUMMARY

Test No.		15	16	17	18	19
Purpose of Test		Biased Firing - 1 Fuel Elev. Out of Service - Air Dampers Open				
		1/2 Load	3/4 Load	←	Max Load	→
Date		1-19-74	1-18-74	12-3-73	12-4-73	12-5-73
Load	MW	66	96	100	103	99
Main Steam Flow	10^3 Kg/HR	199	297	315	321	321
Excess Air Econ. Outlet	%	50.1	26.7	21.1	22.2	21.8
Theo. Air to Fuel Firing Zone	%	105.8	121.7	116.5	117.5	117.2
Fuel Elev. In Serv.		ABC	ABC	ABC	ABD	ACD
Fuel Nozzle Tilt	Deg.	-9	0	-15	-15	-10
Nozzle Comp. Damper Pos. % Open: Aux.		50	50	50	50	50
"A" Fuel		20	20	30	30	30
Aux.		50	50	50	50	100
"B" Fuel		20	20	30	30	100
Aux./Aux.		50/50	50/50	50/50	50/100	50/50
"C" Fuel		20	20	30	100	30
Aux.		50	50	50	50	50
"D" Fuel		100	100	100	30	30
Aux.		100	100	100	50	50
SHO Temperature	°C	546	539	529	543	523
RHO Temperature	°C	496	506	501	520	486
Unit Efficiency	%	87.9	89.3	89.1	89.3	88.9
Gas Weight Ent. A.H.	10^3 Kg/HR	341	430	439	455	428
NO_x	PPM - % O_2	594	543	397	373	387
NO_x	GR/10^6CAL	1.206	1.142	.840	.792	.795
SO_2	PPM - % O_2	1721	1682	2422	2553	2292
SO_2	GR/10^6CAL	4.861	4.922	7.137	7.536	6.543
CO	PPM - % O_2	33.38	29.10	45.63	38.51	35.48
CO	GR/10^6CAL	.0412	.0372	.0588	.0497	.0443
HC	PPM - % O_2	0.0	0.0	0.0	.012	.012
O_2	% A.H. In	7.10	4.55	3.72	3.885	3.825
O_2	% A.H. Out	8.54	7.19	6.08	5.80	6.30
Carbon Loss in Flyash	%	.32	.34	.46	.37	.42

Test No.		20	21	22	23	24
Purpose of Test		Biased Firing - 1 Fuel Elev. Out of Service - Air Dampers Open				
		Max Load	3/4 Load	←	1/2 Load	→
Date		12-6-73	1-18-74	1-19-74	1-19-74	1-19-74
Load	MW	102	94	64	64	66
Main Steam Flow	10^3 Kg/HR	314	308	208	211	202
Excess Air Econ. Outlet	%	24.2	29.0	48.0	47.0	47.0
Theo. Air to Fuel Firing Zone	%	94.7	97.3	112.5	141.4	141.3
Fuel Elev. in Service.		BCD	BCD	BCD	ACD	ABD
Fuel Nozzle Tilt	Deg.	-5	+10	0	0	-15
Nozzle Comp. Damper Pos. % Open: Aux.		100	100	100	50	50
"A" Fuel		100	100	100	20	20
Aux.		50	50	50	100	50
"B" Fuel		30	20	20	100	20
Aux./Aux.		50/50	50/50	50/50	50/50	50/100
"C" Fuel		30	20	20	20	100
Aux.		50	50	50	50	50
"D" Fuel		30	20	20	20	20
Aux		50	20	50	50	50
SHO Temperature	°C	544	512	501	507	544
RHO Temperature	°C	515	469	448	454	513
Unit Efficiency	%	88.8	89.6	87.8	87.9	87.7
Gas Weight Ent. A.H.	10^3 Kg/HR	451	435	360	361	356
NO_x	PPM - % O_2	285	331	520	485	609
NO_x	GR/10^6CAL	.599	.696	1.124	1.043	1.282
SO_2	PPM - % O_2	2277	1566	1861	2245	1807
SO_2	GR/10^6CAL	6.661	4.578	5.593	6.710	5.288
CO	PPM - % O_2	26.61	31.28	29.10	22.41	27.54
CO	GR/10^6CAL	.0341	.0400	.0382	.0293	.0353
HC	PPM - % O_2	0.0	0.0	0.0	0.0	0.0
O_2	% A.H. In	4.165	4.76	6.93	6.85	6.79
O_2	% A.H. Out	7.31	8.37	8.40	8.58	6.87
Carbon Loss in Flyash	%	.25	.30	.20	.11	.21
Dust Loading	GR/SCM	8.65				

NO_X TEST DATA SUMMARY
BASELINE STUDY AFTER MODIFICATION

TEST NO		1	2	3	4	5	6	7
Purpose of Test		Excess Air Var. - Clean Furnace Cond.						
		← 1/2 Load →		← 3/4 Load →		← Maximum Load →		
Date		6/25/74	6/25/74	6/25/74	6/27/74	6/19/74	6/27/74	6/27/74
Load	MW	62	62	64	92	131	127	125
Main Steam Flow	10^3KG/HR	219	213	217	315	450	441	423
Excess Air Econ Outlet	%	33.5	16 0	64 7	15 5	21.0	12.4	25.4
Theo. Air to Fuel Firing Zone	%	127 1	113.4	155.4	111.0	115.3	107 1	119.5
Fuel Elev. In Serv.		ABC	ABC	ABC	ABC	ALL	ALL	ALL
OFA Nozzle Tilt	DEG	0	0	0	0	0	0	0
Fuel Nozzle Tilt	DEG.	3	6	-14	2	-13	-3	-22
Nozzle Comp. Damper Pos % Open: OFA		0	0	0	0	0	0	0
OFA		0	0	0	0	0	0	0
Aux		20	0	50	30	80	100	100
"A" Fuel		30	30	30	20	30	30	35
Aux		20	0	50	60	100	100	100
"B" Fuel		30	30	30	20	30	30	35
Aux /Aux.		20/20	10/10	50/50	80/80	100/100	100/100	100/100
"C" Fuel		30	30	30	20	30	30	35
Aux.		20	10	50	50	100	100	100
"D" Fuel		0	0	0	0	30	30	35
Aux.		0	0	0	0	100	100	100
SHO Temperature	°C	492	468	536	504	528	524	518
RHO Temperature	°C	435	402	499	466	488	487	480
Unit Efficiency	%	88.4	88.8	87.4	89.8	88.4	89.2	89.5
Gas Weight Ent. A.H	10^3KG/HR	335	270	413	398	593	546	559
NO_X	PPM - 0% O_2	444	335	640	327	404	330	477
NO_2	GR/10^6CAL	.929	.701	1 339	.684	.846	.692	1.000
SO_2	PPM - 0% O_2	3678	3621	2611	2634	2251	2677	2707
SO_2	GR/10^6CAL	10.718	10.551	7 606	7.674	6.559	7.800	7.889
CO	PPM - 0% O_2	27.54	375 77	34.66	109.70	26.37	127 2	21.74
CO	GR/10^6CAL	.0351	4790	.0442	1398	0336	.1622	.0277
HC	PPM - 0% O_2	0	0	0	0	0	0	0
O_2	% A.H. In	5.36	2.95	8.36	2.87	3.71	2 36	4.34
O_2	% A.H Out	7.35	5.52	9.70	5 5	7.36	5 75	7.02
Carbon Loss In Flyash	%	.29	.23	1 06	.11	.75	.51	.74

TEST NO.		8	9	10	11	12	13	14
Purpose of Test		E.A. Var. - Mod. Dirty Furnace			E A Var. - Dirty Furnace			
		← Maximum Load →			1/2 Load		Maximum Load	
Date		6/20/74	6/20/74	6/28/74	6/26/74	6/26/74	6/28/74	6/28/74
Load	MW	130	129	125	65	68	126	125
Main Steam Flow	10^3KG/HR	440	446	428	246	218	432	425
Excess Air Econ Outlet	%	17.8	12 1	26.6	30.9	63.1	22.0	25.9
Theo Air to Fuel Firing Zone	%	112.3	106 9	120 5	124.6	154 0	116 2	119 9
Fuel Elev. In Serv		ALL	ALL	ALL	ABC	ABC	ALL	ALL
OFA Nozzle Tilt	DEG	0	0	0	0	0	0	0
Fuel Nozzle Tilt	DEG	-21	-17	-6	-16	-16	-6	-6
Nozzle Comp. Damper Pos. % Open: OFA		0	0	0	0	0	0	0
OFA		0	0	0	0	0	0	0
Aux.		80	80	100	20	50	100	100
"A" Fuel		30	30	30	30	30	30	30
Aux.		100	100	100	20	50	100	100
"B" Fuel		30	30	30	30	30	30	30
Aux /Aux.		100/100	100/100	100/100	20/20	50/50	100/100	100/100
"C" Fuel		30	30	30	30	30	30	30
Aux.		100	100	100	20	50	100	100
"D" Fuel		30	30	30	0	0	30	30
Aux.		100	100	100	0	0	100	100
SHO Temperature	°C	526	528	524	507	531	524	529
RHO Temperature	°C	486	483	480	457	498	496	499
Unit Efficiency	%	89 0	88.9	89 5	89.3	88 0	89.0	89.4
Gas Weight Ent. A.H	10^3KG/HR	565	542	584	363	419	575	583
NO_X	PPM - 0% O_2	470	334	431	373	626	391	431
NO_2	GR/10^6CAL	.985	.699	902	782	1.310	819	.902
SO_2	PPM - 0% O_2	1941	2482	2500	2558	2461	2564	2629
SO_2	GR/10^6CAL	5 655	7.232	7.283	7 453	7.171	7.470	7.661
CO	PPM - 0% O_2	24 31	97.16	23 55	26.28	23.85	23 4	22.92
CO	GR/10^6CAL	.0310	.1239	0300	.0335	0304	0298	.0292
HC	PPM - 0% O_2	0	0	0	0	0	0	0
O_2	% A.H. In.	3 24	2.31	4 5	5 04	8 23	3.86	4.4
O_2	% A H. Out.	6.8	6 19	7 48	7 55	10.75	7.3	7.15
Carbon Loss in Flyash	%	22	42	61	17	05	.36	.25

NO_x TEST DATA SUMMARY
OVERFIRE AIR LOCATION, RATE & VELOCITY VARIATION

TEST NO.		15	16	17	18A	19
Purpose of Test		OFA Damper Position Variation				
		← 3/4 Load →				
Date		7/10/74	7/10/74	7/10/74	7/12/74	7/11/74
Load	MW	97	98	100	100	100
Main Steam Flow	10^3KG/HR	336	340	338	344	338
Excess Air Econ. Outlet	%	28.5	27.1	25.6	26.6	24.8
Theo. Air to Fuel Firing Zone	%	114.5	96.7	95.8	84.8	89.3
Fuel Elev. In Serv.		BCD	BCD	BCD	BCD	BCD
OFA Nozzle Tilt	DEG.	0	0	0	0	0
Fuel Nozzle Tilt	DEG.	-5	-5	-5	-4	-4
Nozzle Comp. Damper Pos. % Open: OFA		0	100	0	100	50
OFA		0	0	100	100	50
Aux.		0	0	0	0	0
"A" Fuel		0	0	0	0	0
Aux.		50	50	50	50	50
"B" Fuel		30	30	30	30	30
Aux./Aux.		50/50	50/50	50/50	50/50	50/50
"C" Fuel		30	30	30	30	30
Aux.		50	50	50	50	50
"D" Fuel		30	30	30	30	30
Aux.		50	50	50	50	50
SHO Temperature	°C	518	510	514	524	521
RHO Temperature	°C	457	452	457	476	486
Unit Efficiency	%	90.0	89.8	89.7	89.6	89.3
Gas Weight Ent. A.H.	10^3KG/HR	458	447	442	466	468
NO_x	PPM - 0% O_2	345	254	254	229	232
NO_2	GR/10^6CAL	.723	.533	.533	.479	.486
SO_2	PPM - 0% O_2	1892	1973	2092	2397	2684
SO_2	GR/10^6CAL	5 512	5.750	6.097	6.984	7.821
CO	PPM - 0% O_2	28.10	29.96	32.4	48.08	39.20
CO	GR/10^6CAL	.0358	.0382	.0413	.0613	0500
HC	PPM - 0% O_2	0	0	0	0	0
O_2	% A.H. In.	4.74	4.55	4.36	4.5	4.25
O_2	% A.H. Out.	6.51	6.49	6.08	6.32	6.05
Carbon Loss In Flyash	%	.51	.59	.63	.54	.32

TEST NO.		20	21	22	23
Purpose of Test		OFA Damper Position Variation			
		← 3/4 Load →			
Date		7/11/74	7/12/74	7/12/74	7/12/74
Load	MW	100	102	102	102
Main Steam Flow	10^3KG/HR	344	342	341	346
Excess Air Econ. Outlet	%	25.4	25 4	27.9	28.1
Theo. Air to Fuel Firing Zone	%	100 5	117.4	90 4	96.9
Fuel Elev. In Serv.		BCD	ABC	ABC	ABC
OFA Nozzle Tilt	DEG.	0	0	0	0
Fuel Nozzle Tilt	DEG	-4	-4	-4	-4
Nozzle Comp. Damper Pos. % Open: OFA		0	0	100	50
OFA		0	0	100	50
Aux.		100	100	100	50
"A" Fuel		0	100	100	50
Aux.		50	50	50	50
"B" Fuel		30	30	30	30
Aux./Aux.		50/50	50/50	50/50	50/50
"C" Fuel		30	30	30	30
Aux.		50	50	50	50
"D" Fuel		30	0	0	0
Aux.		50	0	0	0
SHO Temperature	°C	524	532	524	521
RHO Temperature	°C	479	498	491	485
Unit Efficiency	%	90 2	90.1	89.0	89.1
Gas Weight Ent. A.H.	10^3KG/HR	468	476	494	492
NO_x	PPM - 0% O_2	323	483	329	336
NO_2	GR/10^6CAL	.677	1.012	.689	.704
SO_2	PPM - 0% O_2	1821	1814	2259	2417
SO_2	GR/10^6CAL	5.308	5.284	6.583	7.042
CO	PPM - 0% O_2	28.79	25.16	25.79	25.28
CO	GR/10^6CAL	.0367	.0321	.0329	.0322
HC	PPM - 0% O_2	0	0	0	0
O_2	% A.H. In.	4 33	4.33	4.67	4.69
O_2	% A.H. Out.	6.14	6.05	6.46	6.72
Carbon Loss in Flyash	%	.49	.46	.54	.60

NO_x TEST DATA SUMMARY
OFA TILT VARIATION

TEST NO.		24	25	26	27	28	29
Purpose of Test		OFA & Fuel Nozzle Tilt Variation					
		Full Load					
Date		7/29/74	7/29/74	7/29/74	7/29/74	7/29/74	7/29/74
Load	MW	124	124	124	125	125	124
Main Steam Flow	10^3KG/HR	407	418	412	407	414	418
Excess Air Econ. Outlet	%	25.9	23.7	25.1	22.3	20.2	23.7
Theo. Air to Fuel Firing Zone	%	94.2	92.4	93.2	91.5	89.6	92.6
Fuel Elev. In Serv.		ALL	ALL	ALL	ALL	ALL	ALL
OFA Nozzle Tilt	DEG.	0	0	0	-30	-30	+30
Fuel Nozzle Tilt	DEG.	-5	-23	+19	-5	+22	-21
Nozzle Comp. Damper Pos. % Open: OFA		100	100	100	100	100	100
OFA		100	100	100	100	100	100
Aux.		100	100	100	100	100	100
"A" Fuel		100	100	100	100	100	100
Aux.		50	50	50	50	50	50
"B" Fuel		30	30	30	30	30	30
Aux./Aux.		50/50	50/50	50/50	50/50	50/50	50/50
"C" Fuel		30	30	30	30	30	30
Aux.		50	50	50	50	50	50
"D" Fuel		30	30	30	30	30	30
Aux.		50	50	50	50	50	50
SHO Temperature	°C	538	521	524	527	524	521
RHO Temperature	°C	532	508	527	533	535	505
Unit Efficiency	%	89.6	89.3	88.9	89.3	88.6	89.4
Gas Weight Ent. A.H.	10^3KG/HR	548	566	585	557	586	544
NO_x	PPM - 0% O_2	339	290	368	344	404	285
NO_2	GR/10^6CAL	.710	.609	.770	.721	.846	.596
SO_2	PPM - 0% O_2	2450	2920	3310	3160	3370	3240
SO_2	GR/10^6CAL	7.140	8.511	9.647	9.208	9.820	9.443
CO	PPM - 0% O_2	25.4	27.1	31.8	22.1	28.2	49.4
CO	GR/10^6CAL	.0324	.0346	.0406	.0282	.0360	.0630
HC	PPM - 0% O_2	0	0	0	0	0	0
O_2	% A.H. In.	4.4	4.1	4.3	3.9	3.6	4.1
O_2	% A.H. Out.	5.9	6.0	6.2	6.0	5.8	6.4
Carbon Loss In Flyash	%	.37	.37	.40	.29	.29	.49

LOAD VARIATION AT OPTIMUM CONDITIONS

TEST NO.		30	31	32	33	34	35
Purpose of Test		Load Variation at Optimum Conditions					
		Max. Load	3/4 Load	1/2 Load	Max. Load	3/4 Load	1/2 Load
Date		7/30/74	7/31/74	7/31/74	7/31/74	7/31/74	8/1/74
Load	MW	125	97	65	122	95	64
Main Steam Flow	10^3KG/HR	416	314	204	409	310	204
Excess Air Econ. Outlet	%	21.6	25.2	46.9	27.4	27.4	45.9
Theo. Air to Fuel Firing Zone	%	90.7	89.4	88.5	94 6	90.6	88.5
Fuel Elev In Serv.		ALL	ABC	AB	ALL	ABC	AB
OFA Nozzle Tilt	DEG	0	-12	0	-22	-22	-10
Fuel Nozzle Tilt	DEG.	-4	-16	-5	-22	-22	-15
Nozzle Comp. Damper Pos. % Open: OFA		100	100	100	100	100	100
OFA		100	100	100	100	100	100
Aux.		100	100	100	100	100	100
"A" Fuel		100	100	100	100	100	100
Aux.		50	50	50	50	50	50
"B" Fuel		30	30	30	30	30	30
Aux./Aux.		50/50	50/50	50/0	50/50	50/50	50/0
"C" Fuel		30	30	0	30	30	0
Aux.		50	50	0	50	50	0
"D" Fuel		30	0	0	30	0	0
Aux.		50	0	0	50	0	0
SHO Temperature	°C	538	525	535	521	506	512
RHO Temperature	°C	536	514	514	521	493	493
Unit Efficiency	%	89.0	89.1	89.2	89 0	88.2	89.0
Gas Weight Ent. A.H.	10^3KG/HR	574	456	341	584	472	329
NO_x	PPM - 0% O_2	339	338	396	333	291	313
NO_2	GR/10^6CAL	.710	.708	.828	.697	.608	.655
SO_2	PPM - 0% O_2	1680	1730	1740	2430	2490	2420
SO_2	GR/10^6CAL	4.896	5.043	5.070	7.083	7.256	6.960
CO	PPM - 0% O_2	26.1	26.1	24.4	24.8	26.4	25.0
CO	GR/10^6CAL	.0333	.0333	.0311	0316	.0337	.0319
HC	PPM - 0% O_2	0	0	0	0	0	0
O_2	% A.H. In.	3.8	4.3	6.8	4.6	4.6	6.7
O_2	% A.H. Out.	5.3	5.7	8.2	6.3	6.8	8.4
Carbon Loss In Flyash	%	.61	.39	.32	.24	.33	.15
Dust Loading	GR/SCM	8.64					

BASELINE STUDY
TEST DATA

Test No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Date	11-30-73	11-30-73	11-30-73	1-18-74	11-14-73	11-28-73	11-28-73	11-15-73	11-19-73	11-19-73	12-5-73	12-4-73	11-16-73	11-16-73
Time	01 55	00 00	02·45	16 00	15·10	13·21	10:37	11·10	13.04	10:00	01·40	23·30	14:20	9:50
Unit Load - MW	66	65	67	93	124	123	123	126	122	124	66	74	125	125
Flows - 10^3 Kg/Hr														
Feedwater	217	222	206	309	400	401	393	399	391	384	210	204	390	385
SH Spray (Heat Balance)	2.31	1.67	8.3	2.5	4.13	5.90	11.8	11.5	12.11	20.14	1.09	1.81	21.86	20.77
Main Steam	219	224	214	316	404	407	405	411	403	405	211	206	412	406
Turbine Leakage	9.98	10.2	9.52	14	17.83	17.92	17.6	17.83	17.55	17.24	9.66	9.39	17.46	17.24
RH Extraction	13.79	14.56	12 70	23	31.62	31.62	31.0	31.39	31.07	29.89	13.52	12.79	30.84	30.3
RH Spray (Heat Balance)	18	.09	18	0.0	.907	.907	1.32	1.13	.907	.907	.09	.18	.73	.907
RH Flow (Calc.)	195	199	192	279	355	358	357	363	355	358	188	184	364	359
Air & Gas Flows - 10^3 KG/HR														
Gas Ent. A.H.	352	300	412	386	554	518	592	567	502	565	323	369	556	567
Gas Lvg A.H.	392	343	451	445	631	587	663	618	561	645	360	408	635	646
Air Ent A.H.	369	320	427	414	590	546	623	375	520	603	351	385	592	604
Air Lvg. A.H.	328	278	389	355	512	478	552	524	461	523	301	346	513	524
A.H. Leakage	40 18	42 6	38.74	59	77.88	67.90	71	49.89	58.88	80.0	36.51	39.42	79.11	79 38
Unit Absorption - 10^6 Kg-Cal/Hr														
Econ.	8.32	7.03	9 65	8.8	12.20	10 99	12.8	12.19	11.16	12.7	7 66	8.85	12.87	12.7
Furn.	85 53	89.06	79 05	110	145	148	143	142.5	143.6	138.9	83.6	79.53	138	137.5
Drum - Desup.	24	18 5	29.2	31.2	54	52	57.6	59.0	52.7	59.4	20.2	25.45	61.4	60.9
Desup. - S.H. Out.	16 9	18.62	16 08	22	24.5	27.32	24.1	29.18	28 22	28.68	16.78	14.97	31.25	28.53
RH	19.8	18 85	20.6	24.8	33 67	35.56	35.9	36.29	33 94	36.16	18.9	19.05	35.73	36.04
Total	154.6	152	154.6	207	270	274	273	279	279	275.8	147.1	147.8	275.7	141 5
Pressures														
Steam & Water - Kg/CM^2														
Econ. In	134.1	134 3	134	140.5	142 2	136.7	136.8	149.6	139.9	141.0	131.3	131.5	150.6	146.5
Drum	132.8	133.0	132.6	139	140.5	134.9	135	147.8	138.1	139.3	130.0	130 2	148.9	144.8
SH - Desup. In	130.9	131 1	131.1	133.6	134.3	132.2	132.3	137.4	133.3	134.1	129.5	129.7	137.7	136.1
SH Out	129.8	129.8	130.0	130.8	130.7	130.7	130.7	131.2	130.5	131.0	129.1	129.4	131.1	131.0
RH In	15.04	15 25	15 11	22.43	29.38	29.46	29.46	30.09	29.24	29.53	14.69	14.76	29.74	29.81
RH Out	14.27	14.41	14.34	21.09	27.98	28 05	28	28.68	27.84	28.12	13.92	13.99	28.33	28.40
Air & Gas - Cm Wg														
F.D. Fan Out	3.56	3.048	4.064	5.08	10.67	7.112	15.24	10.16	7.62	13.335	3.048	3.302	10.668	12.70
"B" A.H. Air Out	1.524	1.016	2.032	1.016	3.81	1.016	5.588	3.048	1.905	6.35	1.27	.508	4.318	5.08
"B" A H. Gas Out	-12.192	-15.24	-16.256	-15.24	-26.416	-28.86	-27.686	-25 908	-24.384	-27.94	-10.668	-14.224	-27.432	27.94
"D" Elev. Left Rear Fuel Air Comp.	-3 81	-3 175	-3.175	-3.048	1.905	-.381	5.08	1.905	.635	5.08	-3.556	-3.302	2.54	4.445
"A" Elev. Left Rear Fuel Air Comp.	-2 54	-3.175	-3 175	-1.524	.635	-.508	3 81	.254	0	3.81	-3 048	-1.524	2.54	4.445
Left Mill Duct at Windbox	1.016	1.016	.508	.508	2.032	-3.81	3.81	1.778	.508	4.445	.508	-.254	22.86	3.81
Mill Air Duct at "B" Elev. Mill	-.762	-.762	-1.016	-1.27	-.508	-1.905	2.032	.635	-1.016	3.175	-.508	-1.524	.508	2.54
Upper Furnace	-1 524	-1.778	-1.524	-2 032	-1.524	-1.778	-.635	-15.24	-2.032	-1.016	-1.778	-1 524	-1.27	-1.016
Temperatures - °C														
Steam & Water														
SH Out	529	498	548	500	539	539	538	548	533	544	518	548	539	543
SH Desup In	426	393	470	409	458	452	475	468	456	484	409	446	481	486
SH Desup. Out	418	389	435	404	449	440	447	444	431	440	405	438	436	440
RH Out	488	446	517	449	514	524	524	533	510	531	476	508	522	529
RH Desup In	295	267	311	286	342	343	342	351	337	347	339	310	343	347
RH Desup Out	294	267	310	286	339	340	339	348	335	344	283	309	340	344
Econ In	198	198	198	217	230	230	230	231	229	229	197	199	230	230
Econ Out	233	227	242	242	257	254	259	258	254	259	231	239	259	259

BASELINE STUDY
TEST DATA

Test No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14
#5 HP Heater In	167	166	168	183	194	193	193	195	193	194	167	168	194	194
#5 HP Heater Out	199	198	199	217	231	230	230	232	231	231	199	199	232	231
#5 HP Heater Ext In	286	260	300	282	336	337	337	346	331	341	275	300	337	341
#5 HP Heater Drain	195	195	196	214	226	225	225	227	226	226	195	195	227	226
Spray Water	134	134	134	148	157	156	157	157	156	156	134	134	157	157
Air & Gas														
A.H Gas In	282	273	295	298	325	321	298	325	320	328	277	288	329	330
A.H. Gas Out	145	150	142	150	154	153	150	153	156	153	153	152	153	149
A H Air In	29.4	30.6	24.4	43 3	41.0	33.3	43.3	39	37 8	41.0	33.3	30 0	36 7	35 6
A.H Air Out	263	261	269	269	280	282	269	281	283	276	262	268	282	278
Furnace Outlet (Avg.)	1096	1127	1045	1202	1226	1295	1206	1314	1274	1278	1122	1096	1323	1302
Air Heater Leakage - %	11 41	14.19	9 41	15.33	14 07	13.08	12.03	8 87	11.72	14.16	11.29	10.69	14.22	14 00
A.H. Gas Side Efficiency - %	49 5	44 5	53 0	52.3	55 1	53.8	53.5	57.0	53.6	57.9	48.3	51.1	55 4	56.7
Unit Efficiency - %	88 3	88.2	87.6	89.3	89.0	89 1	89.5	89.6	89.6	89.6	88.3	87 9	89.2	89.3
Products of Combustion - Gr/10^6Cal.														
AH Inlet														
Dry Air	1852	1589	2173	1343	1665	1554	1784	1663	1514	1678	1782	2030	1615	1678
Wet Air	1877	1611	2200	1512	1944	1775	1807	1685	1534	1699	1805	2057	1636	1699
Dry Prod.	1911	1649	2232	1532	1190	1595	1843	1728	1577	1741	1845	2092	1678	1739
Wet Prod.	2012	1744	2333	1575	1825	1687	1939	1822	1669	1838	1942	2192	1775	1836
AH Outlet														
Dry Air	2079	1834	2389	1667	1919	1751	2014	1822	1706	1933	2000	2061	1863	1931
Wet Air	2106	1858	2419	1766	1944	1775	2039	1845	1728	1958	2025	2291	1888	1957
Dry Prod.	2138	1894	2448	1787	1982	1811	2074	1886	1771	1998	2061	2324	1926	1926
Wet Prod.	2241	1991	2552	1827	2081	1906	2171	1984	1865	2097	2160	2426	2027	2092
Excess Air - %														
A.H. In	35.5	17.5	58.9	12 6	22 7	11.8	30.8	21.5	13.0	26 0	32.7	51.2	20.7	24.3
A.H Out	52.1	35.6	74.8	31 4	41.4	27.6	47.6	33.2	27.5	45.3	48.8	68.4	39.3	43.1
Fuel Analysis - %														
Carbon	65.1	65.2	65 6	64 9	65.1	66	66.3	66.8	65 4	64.0	63 5	64.2	64.6	64.7
Hydrogen	4.4	4 4	4.4	4 1	4.3	4.4	4.4	4.3	4.3	4.3	4.2	4.2	4.3	4.4
Nitrogen	1.2	1.2	1.2	1.2	1 3	1.2	1.2	1.3	1.3	1.3	1.1	1.1	1.3	1 2
Oxygen	5 6	5.6	5.6	5 5	6.9	5.6	5.6	6.9	7.4	7.4	5.9	5.9	7.4	6 9
Sulfur	2.1	2 2	1.8	2 3	3.1	1.4	1.7	2.3	2.3	3.0	2.9	2.5	2.7	2 3
Moisture	8 8	8 7	7 6	9 8	8 8	7 0	7.4	9 1	8.8	9.9	9.5	9.6	10.7	8.3
Ash	12.8	12 7	13.8	12.2	10.5	14.4	13.4	9.3	10.1	10.1	12.9	12.5	9.6	12.2
HHV - Cal/g	6455	6499	6499	6449	6460	6466	6560	6538	6555	6494	6382	6449	6494	6477

BIASED FIRING STUDY
TEST DATA

TEST NO.	15	16	17	18	19	20	21	22	23	24
Date	1/19/74	1/18/74	12/3/73	12/4/73	12/5/73	12/6/73	1/18/74	1/19/74	1/19/74	1/19/74
Time	09:10	18:24	11:07	01:30	23:50	02:30	20:30	15:45	13:30	11:30
Unit Load MW	66	96	100	103	99	102	94	64	64	66
FLOWS - 10^3KG/HR										
Feedwater	199	296	304	310	314	307	307	203	209	194
SH Spray (Heat Balance)	0	1.77	10.85	11.15	5.54	7.08	1.50	2.18	1.77	7.62
Main Steam	199	297	315	321	321	314	308	208	211	202
Turbine Leakage	9.06	13.4	13.7	13.9	14.2	13.7	13.8	9.5	9.6	9.1
RH Extraction	12.1	20.9	22.0	22.2	23.1	22.2	22.2	13.3	13.6	11.9
RH Spray (Heat Balance)	.091	.272	.408	.272	.091	.408	.045	0.0	0.0	.091
RH Flow (Calc.)	178	264	280	284	282	278	272	185	188	181
AIR & GAS FLOWS - 10^3KG/HR										
Gas Ent. AH	341	430	439	455	428	451	435	360	361	356
Gas Lvg. AH	377	505	502	499	479	511	507	400	403	404
Air Ent. AH	356	475	467	465	446	477	476	376	380	382
Air Lvg. AH	350	398	405	421	396	418	405	337	338	334
AH Leakage	35.5	76.8	62.8	43.1	50.6	59.8	72.8	39.6	42.5	42.8
UNIT ABSORPTION - 10^6KG-CAL/HR										
Economizer	8.88	10.05	10.01	10.045	9.4	9.8	9.55	8.45	8.65	9.13
Furnace	76.4	110	115	116	120.5	116.5	105.8	80.0	80.8	73.9
Drum - DESH	27.2	36.6	39.8	43.1	35.4	39.2	34.8	23.3	24.2	28.2
DESH - SH Out.	11.5	21.0	22.4	22.9	23.9	24.0	19.4	12.1	12.7	14.5
RH	17.5	26.2	28.1	29.4	26.9	28.1	25.2	17.6	17.8	19.4
Total	141.5	204	216	222	216	218	205	141.5	144	145
PRESSURES										
STEAM & WATER - KG/CM^2										
Economizer In.	138.5	139.9	132.2	132.9	133.6	133.9	139.5	138.7	138.4	138.4
Drum	137.2	138.4	130.7	131.3	132	132.4	138	137.3	137	137
SH - DESH In.	132.8	133.1	129.4	130	130.3	130.8	132.8	133.1	132.5	133.1
SH Out.	130.3	130.2	128.6	129.4	129.4	129.7	129.9	130.2	130.1	130.2
RH In.	14.84	22.26	22.89	23.24	21.98	22.75	22.4	14.98	14.84	14.77
RH Out.	14.0	21.0	21.7	22.05	21.49	21.56	21.14	14.14	14	13.93
AIR & GAS - CM. WG										
FD Fan Out.	2.03	7.87	7.37	7.11	4.06	6.1	7.87	2.29	2.03	2.29
"B" AH Air Out.	-.508	2.03	2.03	2.03	.762	1.27	2.29	-.254	-.254	-.508
"B" AH Gas Out.	-14.73	-18.8	-18.8	-19.81	-17.78	-18.8	-18.8	-14.22	-14.22	-14.73
"D" Elev. Left Rear Fuel Air Comp.	-.762	1.27	1.27	-1.52	-1.52	-1.78	-.508	-2.03	-2.03	-2.03
"A" Elev. Left Rear Fuel Air Comp.	-1.27	-.762	1.02	-1.02	-1.78	.254	.76	-.76	-2.03	-2.03
Left Mill Duct at Windbox	-.762	1.016	1.27	1.016	-.508	.508	1.27	-.762	-1.016	-1 016
Mill Air Duct at "B" Elev. Mill	-2.29	-.762	-.508	-1.016	-1.27	-2.03	-.254	-2.29	-1.52	-2.29
Upper Furnace	-2.03	-1.78	-2.03	-2.03	-2.03	-2.03	-1.78	-1.78	-2.03	-1.78
TEMPERATURES - °C										
STEAM & WATER										
SH Out.	546	539	529	543	523	544	512	501	507	544
SH DESH In.	459	456	454	466	429	449	427	427	431	472
SH DESH Out.	452	435	425	436	416	431	423	420	424	438

BIASED FIRING STUDY
TEST DATA

TEST NO.		15	16	17	18	19	20	21	22	23	24
TEMPERATURES - °C											
STEAM & WATER (Cont.)											
RH Out.		496	506	501	520	486	515	469	448	454	513
RH DESH In.		307	320	315	327	308	327	297	268	274	307
RH DESH Out.		307	319	313	326	308	326	297	268	274	307
Economizer In.		200	218	218	219	217	217	217	199	199	200
Economizer Out.		241	450	248	450	244	247	245	237	237	243
#5 HP Heater In.		169	185	184	185	182	183	183	169	169	169
#5 HP Heater Out.		200	219	219	220	218	218	217	200	201	201
#5 HP Heater Ext. In.		297	313	308	321	302	321	291	261	266	297
#5 HP Heater Drain		197	214	215	216	213	213	214	197	197	196
Spray Water		135	149	149	150	147	147	148	136	136	136
AIR & GAS											
AH Gas In.		298	311	307	311	301	305	312	293	293	298
AH Gas Out.		154	147	145	147	140	136	143	147	146	150
AH Air In.		28.3	44.4	38.4	37.8	23.3	17.2	44.0	37.2	32.2	30.0
AH Air Out.		273	271	271	274	268	269	265	268	268	268
Furnace Outlet (Avg.)		1036	1197	1246	1253	1171	1195	1129	999	873	827
Air Heater Leakage	%	10.4	17.89	14.32	9.46	11.8	13.24	16.73	11.02	11.77	13.46
AH Gas Side Efficiency	%	51.1	55.4	55.3	56.8	53.4	53.8	56.3	52.7	51.8	49.9
Unit Efficiency	%	87.9	89.3	89.1	89.3	89.0	88.8	89.6	87.8	87.9	87.8
PRODUCTS OF COMBUSTION - GR/10⁶CAL.											
AH INLET											
Dry Air		1962	1720	1650	1670	1610	1685	1745	2060	2036	1990
Wet Air		2000	1740	1670	1690	1632	1705	1770	2084	2060	2016
Dry Prod.		2010	1780	1715	1732	1670	1745	1810	2130	2100	2060
Wet Prod.		2120	1875	1815	1830	1765	1840	1900	2230	2205	2150
AH OUTLET											
Dry Air		2180	2050	1910	1841	1816	1925	2060	2300	2295	2280
Wet Air		2210	2080	1935	1865	1840	1950	2090	2330	2320	2310
Dry Prod.		2240	2115	1970	1905	1880	1990	2125	2370	2355	2345
Wet Prod.		2340	2210	2080	2010	1970	2085	2190	2480	2460	2445
EXCESS AIR - %											
AH In.		50.1	26.7	21.1	22.2	21.8	24.2	29.0	48.0	47.0	47.0
AH Out.		66.7	51.1	39.9	34.7	37.3	42.0	52.2	65.4	65.5	68.1
FUEL ANALYSIS - %											
Carbon		63.5	64.8	64.3	64.7	62.5	64.8	65.2	63.1	65.5	65.4
Hydrogen		4.1	4.1	4.2	4.2	4.2	4.2	4.2	4.1	4.1	4.1
Nitrogen		1.1	1.2	1.1	1.1	1.1	1.1	1.2	1.1	1.1	1.1
Oxygen		6.4	5.5	5.9	5.9	5.9	5.9	5.5	6.4	6.4	6.4
Sulfur		2.3	2.2	2.9	2.8	2.7	2.5	2.1	2.4	2.6	2.2
Moisture		9.7	10.4	11.6	11.4	10.0	9.4	9.0	11.9	12.2	9.2
Ash		12.9	11.8	10.0	9.9	13.6	12.1	12.9	11.0	10.1	11.6
HHV - CAL/G		6510	6416	6360	6383	6399	6438	6455	6088	6332	6444

TEST DATA
BASELINE STUDY AFTER MODIFICATION

TEST NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14
DATE	6/25/74	6/25/74	6/25/74	6/27/74	6/19/74	6/27/74	6/27/74	6/20/74	6/20/74	6/28/74	6/26/74	6/26/74	6/28/74	6/28/74
TIME	2 30	4·25	6:38	9·30	13:24	11·18	3·05	9·41	12:25	14:45	1:23	4:05	11:25	9·20
UNIT LOAD - MW	62	62	64	92	131	127	125	130	129	125	65	68	126	125
FLOWS - 10^3KG/HR														
FEEDWATER	219	212	216	315	450	441	412	435	446	421	244	200	423	421
SH SPRAY (HEAT BALANCE)	1.05	.818	1.0	0	0	.546	10.64	4.95	.227	6.14	1.91	18.14	8.46	4.0
MAIN STEAM	219	213	217	315	450	441	423	440	446	428	246	218	432	425
TURBINE LEAKAGE	10 1	9.82	10.0	14 18	20.09	19.82	19.0	19.68	19.95	19.18	12.27	10.0	19.27	19.0
RH EXTRACT	13.64	13.77	13.0	23.27	37.55	36.05	35.27	37.09	36.91	33.23	18.55	15.55	33.09	33.55
RH SPRAY (HEAT BALANCE)	818	091	091	.318	.182	.591	.364	1.409	.591	1.227	2.364	1.227	.818	.818
RH FLOW (CALC.)	196	189	194	278	393	386	369	385	390	376	218	193	380	373
RH FLOW (TEST)	187	198	189	279	393	385	371	394	389	377	194	189	378	375
AIR & GAS FLOWS - 10^3KG/HR														
GAS ENT. AH	335	270	413	398	593	546	559	565	542	584	363	419	575	583
GAS LVG. AH	379	311	459	459	737	655	657	694	670	702	425	515	706	688
AIR ENT. AH	355	289	436	427	691	611	616	650	624	661	399	491	665	645
AIR LVG. AH	311	248	390	366	547	502	518	522	497	543	337	395	533	539
AH LEAKAGE	44.6	40.5	45.8	60.9	144.0	109.3	97.6	128.5	127.7	117.8	61.9	96.3	131.6	105.4
UNIT ABSORPTION - 10^6KG-CAL/HR														
ECONOMIZER	7.79	6.78	9.98	8.59	18.60	11.49	12.57	18.24	14.94	13.71	5.09	10.16	12.73	12.63
FURNACE	87 8	86.18	84.22	122.19	160.95	162.91	150.89	155.53	158.18	153.17	98.36	74.01	153.42	153.17
DRUM - DESH	17.16	12.37	25.86	26.69	51.66	47.43	50.85	51.84	51.23	51.21	22.5	29.08	51.03	51.71
DESH - SH OUT.	15.8	16.51	13.63	23.49	25.45	30.79	26.79	24.70	27.67	25.12	19.38	18.27	27.49	24.97
RH	19.20	17.26	19.78	26.13	36.19	35.38	34.90	36.31	35.00	33.24	23.13	22.38	33.97	33.89
TOTAL	147.8	139.1	153.5	207.1	292.9	288.0	276.0	286.6	287.0	276.4	168.5	153.9	278.6	276.4
PRESSURES														
STEAM & WATER - KG/CM^2														
ECONOMIZER IN.	130.6	129.6	139.5	132.1	137	135.5	135.9	136.5	136.2	134.3	129.6	127.7	134.4	135
DRUM	128.9	129.5	132.6	132.9	134 9	135.5	136 1	135.8	135.5	133.7	135.5	129.6	135.5	135.4
SH - DESH IN.	127 7	128.4	131.4	131.1	132.0	132.7	133.9	133	132.5	131.1	134.2	128.5	132.8	133.1
SH OUT.	127	127.7	130.8	130.1	130.1	131.0	132.1	131.3	130.8	129.6	133.4	127.9	131.2	131.7
RH IN.	14.27	14.76	14.97	22.29	32.13	31.42	30.23	32.20	31.78	30.72	15.54	15.40	30.72	30.72
RH OUT.	13.50	13.99	14.20	21.02	30.58	29.95	28.82	30.72	30.23	29.24	14.55	14.62	29.24	29.24
AIR & GAS - CM. WG														
FD FAN OUT.	6.10	2.79	7.37	4.83	13.21	5.33	13.46	11.68	8.89	12.70	3.05	6.86	9.40	12.7
"B" AH AIR OUT.	1.78	1.52	2.03	1.02	5.08	1.52	4.57	4.32	2.54	5.08	1.52	2.54	2.03	4.32
"B" AH GAS OUT.	-10.67	-11.68	-16.26	-15.24	-28.19	-24.64	-25.4	-28.45	-24.13	-26.16	-11.43	-16.51	-26.16	-26.16
"D" ELEV LEFT REAR FUEL AIR COMP	1.27	1 27	1.27	-1.27	1.27	.254	1.27	1.27	.508	1.27	-1.27	.254	.762	1.27
"A" ELEV. LEFT REAR FUEL AIR COMP.	1.91	.254	.38	1.52	2.54	.508	2.54	2.03	1.016	2.54	-3.05	1.27	1.016	2.54
LEFT MILL DUCT AT WINDBOX	508	.254	.508	0	2.54	0	2.54	2.03	.762	3.05	.508	0	1.016	3.05
MILL AIR DUCT AT "B" ELEV. MILL	.254	-.254	0	-.762	.762	-.762	2.03	.762	-.762	2.03	0	1.016	0	1.78
UPPER FURNACE	-1.27	-1.27	-1.27	-1.52	-.508	-1.52	-.508	-1.27	-1.27	-.762	-1.27	-1 52	-1.52	-.762
TEMPERATURES - °C														
STEAM & WATER														
SH OUT.	482	461	530	502	516	523	515	510	523	516	508	524	518	522
SH DESH IN	390	369	441	397	433	423	444	438	433	442	405	479	441	444

TEST DATA
BASELINE STUDY AFTER MODIFICATION

TEST NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14
TEMPERATURES - °C														
STEAM & WATER														
SH DESH Out	387	368	437	399	433	422	424	430	432	431	400	404	425	436
RH Out.	436	401	487	455	496	495	493	493	496	486	466	514	485	494
RH DESH In	255	232	292	283	332	330	321	329	333	329	278	299	324	331
RH DESH Out.	250	232	291	282	328	328	321	322	331	325	265	292	322	328
Economizer In	195	194	196	214	229	231	230	228	238	232	205	210	235	233
Economizer Out	229	224	239	240	265	254	257	265	268	261	224	257	261	259
#5 HP Heater In	164	163	165	180	190	193	193	189	194	196	163	164	195	194
#5 HP Heater Out	194	194	195	214	229	231	229	228	232	232	200	203	232	231
#5 HP Heater Ext In	246	227	282	277	331	324	316	323	329	321	268	289	318	323
#5 HP Heater Drain	193	193	193	211	221	226	225	226	227	228	194	201	229	228
Spray Water	128	130	129	143	163	158	157	163	165	159	126	128	157	156
AIR & GAS														
AH Gas In	269	262	287	290	320	314	320	322	320	320	273	294	320	322
AH Gas Out	136	142	132	144	143	149	145	144	151	148	138	135	153	147
AH Air In	31.7	29 4	32.8	42 2	36.1	44.4	53 3	34 4	42.2	53.3	40.5	41.1	47.2	51 1
AH Air Out	248	248	252	261	268	268	263	270	273	266	253	258	272	265
Furnace Outlet (Avg)	1010	1010	988	1149	1238	1232	1182	1266	1271	1199	1043	1049	1238	1199
Air Heater Leakage - %	13.34	14.97	11 07	15 31	24.30	20.01	17.45	22.73	23.55	20.17	17 06	22 97	22 91	18 09
AH Gas Side Efficiency - %	50 7	45 0	56 9	53 3	54.0	54 3	60.1	54.0	52 4	57.8	51.7	55.2	53.0	58.7
Unit Efficiency - %	88 4	88 8	87 4	89.8	88.4	89 2	89 5	89.0	88.9	89 5	89.3	88 0	89.0	89 4
PRODUCTS OF COMBUSTION - GR/10^6CAL.														
AH HOT SIDE														
Dry Air	1834	1563	2191	1566	1630	1533	1659	1598	1519	1734	1763	2228	1680	1722
Wet Air	1858	1583	2219	1586	1652	1553	1680	1619	1539	1757	1786	2256	1702	1744
Dry Products	1897	1625	2250	1625	1691	1593	1716	1659	1580	1794	1822	2288	1741	1783
Wet Products	2002	1725	2354	1724	1789	1691	1814	1755	1679	1890	1923	2395	1835	1885
AH COLD SIDE														
Dry Air	2098	1818	2448	1826	2059	1867	1979	1992	1909	2111	2087	2771	2095	2059
Wet Air	2125	1842	2480	1850	2086	1892	1997	2018	1934	2138	2114	2807	2122	2085
Dry Products	2161	1880	2507	1886	2120	1927	2028	2052	1970	2171	2146	2831	2156	2120
Wet Products	2269	1983	2615	1988	2223	2030	2131	2154	2075	2271	2252	2946	2255	2226
EXCESS AIR - %														
AH In.	33.5	16.0	64.7	15.5	21.0	12.4	25.4	17.8	12.1	26.6	30.9	63 1	22.0	25.9
AH Out	52.7	34.9	84.1	34.7	52 8	36.8	49.1	46.8	40 9	54.1	54.9	102.9	52.1	50 5
FUEL ANALYSIS - %														
Carbon	60.7	60 0	61 3	64 2	63.5	64.0	62.9	63.3	63 6	68.4	64.3	64.7	64.9	63.3
Hydrogen	4.3	4.3	4 4	4.6	4.2	4.6	4.5	4.3	4 4	4.9	4.6	4.6	4.4	4.5
Nitrogen	.9	1.0	1.0	1.3	1.1	1.1	1.0	1.1	1.1	1.1	1.0	.9	1.1	1.0
Oxygen	7 5	7.4	7 5	7.1	5.7	7.0	6.9	6 2	6.8	7.9	7.4	7.4	6.4	7.3
Sulfur	3.2	4.2	3.2	3.0	2.4	3.1	3.0	1.9	2.8	2.9	3.0	3.0	1 5	3 1
Moisture	10.1	9.8	7 7	9.4	10.9	9.1	9.3	9.1	11.0	5.2	9.6	9.2	6.5	9.9
Ash	13.3	13.3	14.9	10.4	12.2	11.1	12.4	14.1	10.3	9.6	10 1	10 2	15.2	10.9
HHV - CAL/G	6011	6106	6250	6478	6350	6406	6478	6311	6367	6783	6517	6467	6350	6311

TEST DATA
OVERFIRE AIR LOCATION, RATE & VELOCITY VARIATION

TEST NO.	15	16	17	18	19	20	21	22	23
Date	7/10/74	7/10/74	7/10/74	7/12/74	7/11/74	7/11/74	7/12/74	7/12/74	7/12/74
Time	0:00	2:15	4:00	7:25	4:35	23:10	1:24	3:30	4:45
Unit Load - MW	97	98	100	100	100	100	102	102	102
FLOWS - 10^3KG/HR									
Feedwater	336	340	338	343	325	337	330	326	330
SH Spray (Heat Balance)	.046	.682	.409	.909	13	6.95	11.5	15.55	15.45
Main Steam	336	340	338	344	338	344	342	341	346
Turbine Leakage	15.18	15.31	15.22	15.5	15.23	15.5	15.4	15.4	15.59
RH Extract	27.18	27.41	27.55	28.09	26.14	25.18	24.86	24.36	25.59
RH Spray (Heat Balance)	.682	2.409	3.273	.682	1.14	.136	0	0	0
RH Flow (Calc.)	295	300	299	301	298	304	301	302	305
RH Flow (Test)	299	300	303	300	295	298	297	299	299
AIR & GAS FLOWS - 10^3KG/HR									
Gas Ent. AH	458	447	442	466	468	468	476	494	492
Gas Lvg. AH	509	501	489	519	519	521	526	550	556
Air Ent AH	477	470	457	486	484	488	493	515	521
Air Lvg. AH	426	415	410	433	433	436	443	460	457
AH Leakage	51.2	54.7	46.5	52.8	52.8	52.2	50.1	55.7	64.0
UNIT ABSORPTION - 10^6KG-CAL/HR									
Economizer	9.88	7.23	6.15	10.31	10.16	10.33	10.53	10.61	10.74
Furnace	127.89	131.64	131.9	129.78	122.93	122.99	124.49	122.75	124.41
Drum - DESH	34.62	34.37	34.78	36.87	38.86	37.27	39.56	40.24	40.17
DESH - SH Out.	20.92	21.24	21.39	22.81	24.97	24.95	26.06	25.60	25.58
RH	25.93	27.44	26.91	28.80	30.64	30.79	32.05	31.55	31.75
Total	219.2	221.9	221.1	228.6	227.6	226.3	232.7	230.7	232.6
PRESSURES									
STEAM & WATER - KG/CM^2									
Economizer In.	133.5	133.3	133.1	133.3	133.1	133.1	133.2	133.1	133.1
Drum	132.6	133.3	132.7	133.6	133.6	133.4	133.1	133	133.2
SH - DESH In.	130.7	131.3	130.7	131.5	131.7	131.4	131.3	131.2	131.4
SH Out.	129.6	130.2	129.6	130.4	130.7	130.3	130.1	130.1	130.3
RH In.	23.76	23.83	24.04	24.32	23.97	24.25	24.46	24.46	24.32
RH Out.	22.50	22.57	22.78	23.06	22.71	22.99	23.20	23.20	23.06
AIR & GAS - CM. WG									
FD Fan Out.	7.11	6.35	6.86	6.60	5.33	8.13	9.40	6.60	6.86
"B" AH Air Out.	4.57	2.03	1.52	1.78	1.78	3.05	3.56	2.03	2.03
"B" AH Gas Out	-18.80	-18.80	-18.29	-19.30	-19.81	-19.56	-19.56	-19.81	-19.81
"D" Elev. Left Rear Fuel Air Comp.	1.016	0	-.254	-.762	-.762	-.254	-3.56	-3.05	-.762
"A" Elev. Left Rear Fuel Air Comp.	-3.05	-3.05	-2.54	-3.30	-2.29	1.78	.254	1.27	3.56
Left Mill Duct at Windbox	3.81	1.52	1.27	.508	.762	2.03	2.79	.762	2.03
Mill Air Duct at "B" Elev. Mill	2.29	.254	.254	-1.27	-1.016	.254	1.52	-1.52	-1.16
Upper Furnace	-1.52	-1.52	-1.52	-1.52	-1.52	-1.52	-1.52	-1.52	-1.52
TEMPERATURES - °C									
STEAM & WATER									
SH Out.	509	502	507	518	514	518	523	516	512
SH DESH In.	418	416	418	424	440	429	440	445	443

TEST DATA
OVERFIRE AIR LOCATION, RATE & VELOCITY VARIATION

TEST NO.	15	16	17	18	19	20	21	22	23
TEMPERATURES - °C									
STEAM & WATER									
SH DESH Out.	420	414	418	422	410	414	414	409	408
RH Out.	458	455	457	481	492	492	510	501	494
RH DESH In.	298	295	302	305	304	304	311	305	301
RH DESH Out.	295	287	292	303	302	304	311	306	301
Economizer In.	220	220	220	220	219	220	220	220	220
Economizer Out.	247	240	237	244	244	249	249	250	250
#5 HP Heater In.	180	181	181	181	182	183	184	185	184
#5 HP Heater Out.	218	219	220	220	220	219	219	220	220
#5 HP Heater Ext. In.	293	290	295	298	298	298	305	299	295
#5 HP Heater Drain	215	213	213	217	215	216	217	216	217
Spray Water	143	140	140	146	145	148	148	149	149
AIR & GAS									
AH Gas In.	300	299	301	301	302	301	303	302	304
AH Gas Out.	141	140	139	141	139	142	143	142	143
AH Air In.	47.2	36.7	35.0	38.4	31.7	43.9	44.4	37.2	39.5
AH Air Out.	260	262	262	261	263	261	263	259	263
Furnace Outlet (Avg.)	1121	1099	1105	1132	1188	1154	1221	1216	1199
Air Heater Leakage - %	11.19	12.24	10.53	11.32	10.96	11.15	10.53	11.25	13.01
AH Gas Side Efficiency - %	59.1	56.3	57.2	57.0	56.5	58.1	58.3	56.6	56.3
Unit Efficiency - %	90.0	89.8	89.7	89.6	89.3	90.2	90.1	89.0	89.1
PRODUCTS OF COMBUSTION - GR/10^6CAL.									
AH HOT SIDE									
Dry Air	1725	1657	1644	1675	1677	1679	1694	1751	1729
Wet Air	1748	1679	1665	1697	1699	1700	1716	1774	1751
Dry Products	1787	1717	1704	1733	1739	1737	1752	1810	1787
Wet Products	1880	1806	1794	1828	1837	1826	1843	1908	1884
AH COLD SIDE									
Dry Air	1933	1876	1830	1879	1876	1880	1885	1963	1971
Wet Air	1958	1900	1854	1904	1900	1904	1910	1989	1996
Dry Products	1994	1936	1891	1938	1938	1938	1943	2022	2029
Wet Products	2091	2028	1893	2034	2038	2030	2037	2123	2129
EXCESS AIR - %									
AH In.	28.5	27.1	25.6	26.6	24.8	25.4	25.4	27.0	28.1
AH Out.	44.0	43.8	39.9	42.1	39.6	40.4	39.5	43.4	46.0
FUEL ANALYSIS - %									
Carbon	65.9	66.6	65.4	65.2	64.3	69.3	67.5	65.4	66.0
Hydrogen	4.4	4.4	4.3	4.5	4.4	4.6	4.6	4.6	4.6
Nitrogen	1.1	1.1	1.1	1.4	1.1	.9	1.1	1.4	1.4
Oxygen	6.7	6.8	6.7	6.1	7.1	5.6	5.9	6.1	6.2
Sulfur	2.3	2.1	2.4	3.0	3.0	2.1	2.1	2.5	2.6
Moisture	7.4	6.7	7.3	8.0	9.6	5.8	5.4	7.8	7.9
Ash	12.2	12.3	12.8	11.8	10.5	11.7	13.4	12.2	11.3
HHV - CAL/G	6606	6844	6706	6711	6483	6994	6772	6511	6650

TEST DATA

OVERFIRE AIR TILT VARIATION — LOAD VARIATION AT OPTIMUM CONDITIONS

TEST NO.	24	25	26	27	28	29	30	31	32	33	34	35
DATE	7/29/74	7/29/74	7/29/74	7/29/74	7/29/74	7/29/74	7/30/74	7/31/74	7/31/74	7/31/74	7/31/74	8/1/74
TIME	9·40	11·05	13:30	15·00	16:30	18·07	21:05	12·22	2:35	21·50	23:35	1:38
UNIT LOAD - MW	124	124	124	125	125	124	125	97	65	122	95	64
FLOWS - 10^3KG/HR												
FEEDWATER	398	415	391	394	384	416	399	301	200	400	305	202
SH SPRAY (HEAT BALANCE)	9.05	2 68	21.09	13.5	30.32	1.82	17.77	12.32	4.05	8.59	5.05	1 27
MAIN STREAM	407	418	412	407	414	418	416	314	204	409	310	204
TURBINE LEAKAGE	18.23	18.73	18.5	18.23	18.55	18.68	18 64	14.18	10 45	18.27	14.0	9.41
RH EXTRACT	31.07	33.14	30.73	--	31.59	36.04	31.5	20.91	10.[illegible]5	39.5	23.82	13.23
RH SPRAY (HEAT BALANCE)	.909	.364	.727	2.05	3.41	3.27	0	2.59	1.64	9.5	3.41	1.86
RH FLOW (CALC.)	358	367	364	--	367	366	366	281	185	360	276	183
RH FLOW (TEST)	355	363	363	359	357	359	353	273	185	355	275	187
AIR & GAS FLOWS - 10^3KG/HR												
GAS ENT. AH	548	566	585	557	586	544	574	456	341	584	472	329
GAS LVG. AH	597	631	653	628	663	622	624	494	376	645	538	370
AIR ENT. AH	559	589	610	586	618	582	582	461	355	602	504	349
AIR LVG. AH	509	524	542	515	541	504	532	423	320	541	437	308
AH LEAKAGE	49.7	65.2	68.4	70.9	77.0	78.2	49.9	38.1	34.6	61.6	66.7	41.1
UNIT ABSORPTION - 10^6KG-CAL/HR												
ECONOMIZER	12.93	12.22	12.98	12.02	9.78	10.33	8.62	9.35	8.27	4.21	3.70	5.44
FURNACE	145.13	152.59	142.53	144.47	142.08	154.17	150.04	1$5.87	78.80	151.80	120.61	81.14
DRUM - DESH	55.72	52.09	55.44	55.59	58.14	53 42	57.86	39.46	26.21	55.72	37.72	23.79
DESH - SH OUT.	27.64	25.20	29.69	28.20	33.24	24.39	32.10	24.72	14.97	26.51	20.20	13.81
RH	35.51	34.27	37.52	37.62	41.23	36.09	41.83	31.68	21.19	39.99	28.68	19.81
TOTAL	276.9	276.4	278.2	277.9	284.5	278.4	290.4	221.1	149.4	278.2	211.0	144.0
PRESSURES												
STEAM & WATER - KG/CM^2												
ECONOMIZER IN.	133.6	134.5	133.4	133.4	133.5	135.3	134.2	132.5	131.2	134.7	132.7	131.7
DRUM	133.2	133.9	133.7	133.2	133	134.6	134.6	132.4	132.4	134.6	132.7	132.2
SH - DESH IN.	131.3	131.8	131.2	131.0	131.0	132.1	132.7	131.5	131.2	132.2	131.3	131.2
SH OUT.	130.2	130.5	129.7	129.7	129.9	130.7	131.7	131.0	130.5	130.8	130.4	130.5
RH IN.	29.67	30.23	29.88	29.88	30.02	29.88	29.95	22.92	15.04	29.24	22.64	14.97
RH OUT.	28 26	28.82	28.47	28.47	28.61	28.47	28.54	21.65	14.27	27.84	21.37	14.2
AIR & GAS - CM. WG												
FD FAN OUT.	10.67	10.67	10.92	11.43	10.92	11.68	8.89	4.83	4.32	10.92	4.32	3.56
"B" AH AIR OUT	3.56	3.05	4.32	3.81	4.32	4.06	2.03	.762	1.016	4.32	.762	.508
"B" AH GAS OUT	-26.42	-25.91	-26.42	-26.42	-26.67	-26.42	-26.92	-19.05	-14.22	-26.67	-18.54	-13.46
"D" ELEV. LEFT REAR FUEL AIR COMP	0	0	0	0	0	.254	.508	1.52	1.52	0	3.81	3.81
"A" ELEV. LEFT REAR FUEL AIR COMP.	-2.54	2.29	2.29	2.03	2.03	3.30	.762	-.254	.254	1.78	0	.254
LEFT MILL DUCT AT WINDBOX	2.03	1.78	2.29	2.03	2.03	4.06	1.016	-.254	.254	1.78	.254	.254
MILL AIR DUCT AT "B" ELEV. MILL	1.27	1.016	1.016	2.03	1.79	3.05	.508	2.03	.762	1.52	1.27	1.27
UPPER FURNACE	-1.52	-1.52	-1.016	-1.52	-1.52	-1.27	-1.52	-1.52	-1.016	-1.52	-1.27	-1.27
TEMPERATURES - °C												
STEAM & WATER												
SH OUT	547	532	535	545	538	536	554	539	549	548	529	533
SH DESH IN.	464	448	474	471	486	451	476	457	456	467	446	438

TEST DATA

OVERFIRE AIR TILT VARIATION — LOAD VARIATION AT OPTIMUM CONDITIONS

TEST NO.	24	25	26	27	28	29	30	31	32	33	34	35
TEMPERATURES - °C												
STEAM & WATER												
SH DESH OUT.	444	442	429	441	421	448	438	423	438	448	432	432
RH OUT.	532	509	529	543	548	516	554	529	528	526	497	498
RH DESH IN.	350	338	340	356	350	343	361	327	317	349	315	301
RH DESH OUT.	348	337	338	349	340	334	346	317	307	322	302	290
ECONOMIZER IN	231	231	231	230	232	232	230	214	197	237	222	203
ECONOMIZER OUT	260	257	261	258	255	254	249	243	235	245	233	228
#5 HP HEATER IN	193	193	193	193	193	191	194	182	169	188	180	165
#5 HP HEATER OUT.	230	230	230	230	232	231	232	216	196	234	217	198
#5 HP HEATER EXT IN	343	332	333	347	341	333	353	320	305	331	299	290
#5 HP HEATER DRAIN	227	227	228	227	226	227	225	210	192	227	211	194
SPRAY WATER	155	156	155	151	148	151	144	136	123	147	144	122
AIR & GAS												
AH GAS IN.	332	320	323	323	326	321	322	302	287	323	302	284
AH GAS OUT.	149	147	148	150	151	143	146	140	129	149	144	135
AH AIR IN.	36.1	37.8	37.8	36.7	30.6	30.0	25.0	22.8	25.0	33.9	33.3	29.4
AH AIR OUT.	274	272	274	275	276	269	274	265	257	273	267	257
FURNACE OUTLET (AVG.)	1238	1221	1293	1232	1310	1188	1288	1238	116	1232	1177	1054
AIR HEATER LEAKAGE - %	9.07	11.54	11.70	12 75	13.15	14.37	8.70	8.36	10.14	10.56	14.14	12.49
AH GAS SIDE EFFICIENCY - %	57.4	57.4	57.2	55.8	54.6	55.9	56.2	54.9	56.5	56.4	53.4	54.0
UNIT EFFICIENCY - %	89.6	89.3	88.9	89 3	88.6	89.4	89.0	89.1	89.2	89.0	88.2	89.0
PRODUCTS OF COMBUSTION - GR/10^6CAL.												
AH HOT SIDE												
DRY AIR	1626	1670	1708	1634	1664	1599	1610	1684	1885	1708	1804	1880
WET AIR	1647	1692	1730	1656	1686	1620	1631	1705	1909	1730	1827	1905
DRY PRODUCTS	1682	1730	1768	1695	1728	1659	1669	1744	1943	1769	1868	1939
WET PRODUCTS	1774	1827	1867	1789	1825	1748	1760	1837	2037	1867	1972	2036
AH COLD SIDE												
DRY AIR	1785	1878	1924	1860	1901	1847	1761	1835	2089	1903	2079	2131
WET AIR	1808	1902	1949	1884	1926	1871	1784	1859	2116	1927	2106	2159
DRY PRODUCTS	1841	1938	1984	1920	1965	1907	1820	1895	2147	1964	2143	2191
WET PRODUCTS	1934	2038	2086	2017	2065	1999	1913	1991	2243	2064	2251	2290
EXCESS AIR - %												
AH IN.	25.9	23.7	25.1	22 3	20.2	23.7	21 6	25.2	46.9	27.4	27.4	45 9
AH OUT.	38 2	39 1	40 9	39.1	37.3	42.9	33.0	36.4	62.8	41.9	46.9	65.3
FUEL ANALYSIS - %												
CARBON	64 4	63 5	63.1	63.8	62.9	64.5	65.2	65.8	64 3	64.3	64.0	65 0
HYDROGEN	4.5	4 4	4 4	4 3	4.2	4.2	4.4	4.4	4.4	4 4	4.4	4.4
NITROGEN	1 0	1.2	1 0	1.1	1.2	1 0	1.0	1 1	1.0	9	1.1	1.0
OXYGEN	6.2	6.1	6.1	5.9	5.7	5.8	6.3	6.4	6.9	6.9	6.9	6.9
SULFUR	3.1	3.4	3.2	3.3	3.5	3.3	2.3	1.9	3.0	3.2	2.9	2.9
MOISTURE	7.5	8.7	9.0	8.4	8.7	8.1	7.1	7.5	7.1	9.6	9.7	9.6
ASH	13.3	12 7	13.2	13.2	13 8	13 1	13.7	12.9	13 3	10.7	11 0	10.2
HHV - CAL/G	6811	6428	6317	6500	6189	6750	6644	6589	6794	6517	6133	6833

BASELINE STUDY
BOARD DATA

Test No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Date	11-30-73	11-30-73	11-30-73	1-18-74	11-14-73	11-28-73	11-28-73	11-15-73	11-19-73	11-19-73	12-5-73	12-4-73	11-16-73	11-16-73
Time	01:55	00·00	02 45	16·00	15:10	13:21	10:37	11·10	13·04	10:00	01:40	23·30	14:20	9:50
Load - MW	66	65	67	93	124	123	123	126	122	124	66	74	125	125
Flows - 10^3 LBS/HR														
BFP 2A	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BFP 2B	260	280	284	350	475	475	480	460	480	480	460	460	460	468
BFP 2C	260	260	278	400	480	485	480	480	470	480	0	0	480	490
Reheat Steam	630	632	640	775	865	865	860	880	870	880	635	635	880	870
Condensate	300	305	300	470	600	600	600	600	599	600	300	300	600	600
Superheat Spray	0	0	12.5	3 0	6.0	4.0	21.5	17.8	17.5	31	2.2	2.3	35	36
Reheat Spray	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feedwater	370	400	350	660	880	800	730	780	780	780	370	330	780	760
Primary Steam Flow	450	460	450	680	900	900	900	905	885	900	447	445	901	901
Air Flow - Relative	470	400	580	620	830	750	950	823	750	925	450	550	850	895
PRESSURES														
Steam & Water - PSIG														
1st Stage Extraction	680	700	680	1000	1320	1310	1310	1340	1310	1310	665	775	1330	1330
8th	212	218	214	318	418	415	415	422	410	415	210	211	420	420
12th	78	80	79	123	166	165	165	170	165	165	77	77	169	169
16th	23	24	24	39	54	54	54	56	54	54	21.5	23	56	56
19th (-In. Hg + PSIG)	-9	-9	-9	0	6.0	6.0	6.0	6.4	6.0	6.0	-8.5	-8.5	6.6	6.4
21st (In. Hg)	-20	-20	-20	-15 2	-13.3	-13.0	-13.0	-13.0	-13.0	-13.0	-20.0	-20.0	-13.0	-13.0
Feedwater Regulator Inlet	1950	1960	1950	1990	2020	2010	2005	2020	2005	2005	1930	1940	2020	2015
Feedwater	1890	1900	1900	1910	1950	1950	1950	1950	1950	1950	1890	1900	1950	1950
Drum	1890	1900	1900	1900	1940	1920	1940	1940	1940	1940	1900	1900	1940	1940
Turbine Throttle	1825	1825	1825	1830	1825	1820	1820	1825	1820	1820	1825	1825	1820	1820
Reheat Inlet	200	205	200	308	410	410	408	418	405	409	197	200	415	415
Reheat Bowl	194	195	195	286	380	377	375	386	375	376	198	190	382	382
Exhaust (In. Hg)	-29 0	-29.0	-29.0	-28.4	-28.5	-27.8	-28.0	-28.4	-28.0	-28.1	-28.4	-28.4	-28.1	-28.1
Main Steam	1850	1850	1850	1850	1850	1850	1840	1850	1850	1850	1850	1850	1850	1850
Reheat Outlet	200	209	200	297	385	390	388	398	385	388	200	200	397	395
Light Oil Upper Burners	0	0	0	0	0	0	0	0	0	0	26	26	0	0
Light Oil Lower Burners	0	0	0	0	0	0	0	0	0	0	26	26	0	0
PRESSURES														
Air & Gas - In. Wg														
2A FD Fan Discharge	1.8	1.5	1.9	2.1	4.5	3.0	6.8	4.2	4.1	6.0	1.5	1.5	4.9	5.8
2B FD Fan Discharge	1.2	1.0	1.5	2.0	4.0	2.8	6.0	4.0	4.0	5.2	1.1	1.2	4.2	5.2
2A Preheater Outlet Air	.7	.7	.5	.8	1.5	.5	2.5	1.5	0.9	2.5	.7	.4	1.5	2.2
2B Preheater Outlet Air	.8	.8	.5	.8	1.5	.8	2.5	1.5	1.0	2.5	.8	.5	1.5	2.2
Furnace Pressure	-.5	-.5	-.5	-.45	-0.5	-.48	-0.5	-.45	-.5	-.05	-.5	-.5	-.50	-.35
Superheater Cavity	1.0	-.9	-1.0	-1.0	-1.4	-1.5	-1.4	-1.4	-1.5	-1.4	-1.0	-1.1	-1.7	-1.5
Econ Inlet	-2.7	-2.2	-3.4	-2.4	-5.5	-4.8	-5.4	-5.6	-5.4	-6.1	-2.6	-3.2	-6.0	-5.9
Economizer Outlet R.H.	-3.7	-3.2	-4 5	-4.4	-6.75	-6.2	-7.2	-6.8	-6.7	-7.4	-3.5	-4.1	-7.5	-7.5
Economizer Outlet L.H.	-3.5	-3.0	-4.4	-4.2	-6.80	-6.2	-7.4	-7.0	-6.7	-7.0	-3.3	-4.0	-7.7	-7.6
No. 2A Preheater Diff. Gas	1.9	1.6	2.4	2 6	4.0	3.5	4.2	3.9	3.6	4.3	1.9	2.3	4.1	4.2
No. 2B Preheater Diff Gas	1.6	1 2	2.0	1.9	3.5	3.1	3.9	3.5	3.2	3.7	1.3	1.8	3.6	3.8
No. 2A I D. Fan Suction	-6.4	-5.6	-8.1	-8.2	-13 8	-12.0	-15.0	-13.6	-12.5	-15.0	-6.0	-7.6	14.5	15.0
No. 2B I.D. Fan Suction	-6.2	-5.0	-8.2	-8.0	-13.8	-12.2	-14.8	-13.8	-13.0	-14.5	-5.8	-7.2	14.5	14.8
Pulverizer 2A Inlet Air	-1.5	-1.5	-1.5	-1.3	-1.3	-1.4	-1.1	-1.2	-1.4	-1.2	-1.2	-1.4	-1.3	-1.2
Exhauster 2A Discharge	13.2	13.4	13.3	12.0	14.3	12.8	13.5	11.5	12 5	13.5	12.3	12.4	13.5	13.7
Pulverizer 2B Inlet Air	-1.6	-1.7	-1.7	-1.3	-1.4	-1.7	-1.5	-1.4	-1.6	-1.4	-1.6	-1.8	-1.4	-1.4
Exhauster 2B Discharge	12.7	12.9	12.8	13 2	13.0	12.2	13.0	11.5	12 2	13.0	12.8	12.7	12 8	13.2
Pulverizer 2C Inlet Air	-2.0	-2 0	-2.0	-1.5	-1.8	-1.5	-1.0	-1.8	-1 8	-1.5	-2.4	-2 3	-1.8	-1 7
Exhauster 2C Discharge	12.5	12.5	12.5	12 5	12.0	12.0	12.0	12.1	12.5	12.5	12.0	12.1	12.2	12.2
Pulverizer 2D Inlet Air	-1.1	-1 2	-1 1	-1.2	-2.4	-2.4	-1.8	-2.3	-2.4	-2.0	-1 2	-1.2	-2.4	-2.0
Exhauster 2D Discharge	0	0	0	0	10.5	12.0	10.2	11.8	12.0	13.0	0	0	12.0	12.2

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Test No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Temperatures														
Air & Gas - °F														
Boiler Outlet Gas L.H.	627	619	641	632	660	661	678	662	656	669	621	631	667	669
Boiler Outlet Gas R.H	638	631	652	643	671	670	681	672	662	678	632	645	678	679
Economizer Out Gas L H	546	532	569	575	620	619	640	622	613	632	540	558	632	635
Economizer Out Gas R.H	547	529	570	570	622	618	632	622	611	625	531	555	628	630
Preheater 2A Outlet Gas	300	328	292	320	312	311	298	311	320	302	313	310	315	308
Preheater 2B Outlet Gas	299	294	289	291	311	310	300	311	318	305	291	289	315	308
Preheater 2A Inlet Air	80	75	71	108	102	92	120	100	94	102	92	87	100	100
Preheater 2B Inlet Air	90	90	79	102	108	90	128	99	98	109	90	81	100	100
Preheater 2A Outlet Air	502	500	511	517	538	540	525	539	540	529	502	511	540	532
Preheater 2B Outlet Air	505	495	511	505	530	540	528	535	537	529	499	508	539	532
Pulverizer 2A Inlet Air	460	460	463	470	479	480	460	472	480	460	480	480	480	465
Pulverizer 2A Internal	140	140	143	155	150	142	160	145	142	159	158	141	142	159
Pulverizer 2B Inlet Air	462	460	462	475	482	480	465	480	483	462	465	495	495	472
Pulverizer 2B Internal	160	159	159	140	150	160	160	160	150	160	150	150	155	159
Pulverizer 2C Inlet Air	455	441	458	460	470	483	470	479	480	475	440	445	485	422
Pulverizer 2C Internal	165	159	158	140	160	140	160	160	141	160	160	142	150	160
Pulverizer 2D Inlet Air	80	70	80	110	480	490	480	485	490	485	90	90	495	490
Pulverizer 2D Internal	80	70	80	110	159	135	158	155	140	150	90	90	138	159
Temperatures														
Steam & Water - °F														
Feedwater	412	412	412	447	470	465	465	470	469	470	412	414	470	470
Economizer Water Outlet - L H	452	445	470	468	492	491	500	497	490	500	450	451	500	500
Economizer Water Outlet - R H	455	446	470	468	495	492	500	499	490	500	449	460	500	501
RH Desuph in L H	565	502	580	535	632	639	637	660	628	649	532	578	640	650
RH Desuph out L H	565	502	580	532	632	639	637	660	628	646	532	578	640	650
RH Desuph. in R.H.	565	502	580	535	631	639	637	659	628	646	532	578	640	648
RH Desuph out R H.	565	502	580	535	631	639	637	659	628	646	532	578	640	648
Superheat Out L H	980	917	1020	950	992	999	989	1021	981	997	960	1013	995	1002
Superheat Out.R.H.	979	920	1003	938	991	999	999	1000	979	1008	951	1006	999	1004
Throttle Steam L H.	975	920	1008	940	986	992	989	1005	980	998	951	1003	990	999
Throttle Steam R.H	975	920	1007	938	986	990	989	1005	980	998	951	1005	990	999
Reheat Outlet L.H	902	821	951	862	932	970	972	980	948	982	888	939	959	978
Reheat Outlet R.H.	879	809	930	848	946	930	922	979	898	941	832	905	965	926
Superheater Outlet	967	911	998	899	975	972	975	1003	965	989	935	990	980	989
Reheater Outlet	900	829	948	831	940	959	964	985	938	976	874	932	960	975
Upper Valve Chest	958	900	978	899	917	970	969	990	962	988	940	984	971	980
Lower Valve Chest	89	85	90	101	101	95	99	100	100	98	99	100	100	98
H P. Exhaust	551	501	578	531	632	639	638	659	628	649	535	580	640	649
Reheat Bowl	901	835	938	845	941	949	950	980	931	970	879	927	960	972
Intermediate Exhaust	429	376	458	370	452	461	461	483	445	475	409	450	470	480
Condensate Temp.	95	95	95	107	110	115	115	110	112	110	96	96	115	110
S.H Desuph. in L H	800	740	878	771	846	849	891	870	865	911	775	834	900	900
S H Desuph out L H	782	730	811	762	838	833	852	821	822	836	765	819	822	832
S H Desuph In R.H	795	738	879	770	856	840	877	878	831	889	765	829	895	904
S.H. Desuph Out R.H	789	734	826	762	839	815	812	839	791	801	755	820	808	820
Miscellaneous														
I D Fan 2A RPM	420	400	480	480	660	600	680	660	620	683	420	480	680	670
I D Fan 2B RPM	420	400	480	480	660	600	680	660	640	680	420	480	680	680
F D Fan 2A RPM	360	340	365	440	510	440	660	505	450	600	330	370	540	590
F D. Fan 2B RPM	340	340	380	450	547	450	650	540	460	600	320	380	540	582
Fan Damper Position - (0-12)														
ID Fan 2A	8 0	4 8	8.0	5.6	12.0	7.4	11.4	12.0	12.0	12.0	5.6	6 5	12.0	12.0
ID Fan 2B	8 4	5 3	8 4	5 6	12.0	7.4	11.2	12.0	12 0	12.0	5.7	6 3	12.0	12.0
FD Fan 2A	3.2	2 5	3.8	4 0	11.6	5.6	10.9	11.6	5.8	11.6	3.2	3 4	11.6	11.6
FD Fan 2B	3 2	2 6	3 8	4.0	11.6	6.0	10.9	11.6	6 0	11.6	3.2	3.4	11.6	11.6
Drum Level In. ± Norm H_2O Level	-1 0	-1 0	-1 0	-2.0	-0.8	-1 0	-1.0	0	-0.8	-0.5	-2.5	-1.0	-0.25	-0 25

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Test No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14
A Mill AMPS	40	40	38	36	44	44	40	43	38	40	40	38	40	39
B Mill AMPS	38	39	40	37	44	42	40	45	40	41	38	34	42	44
C Mill AMPS	32	33	34	38	38	42	42	40	42	45	30	33	39	40
D Mill AMPS	0	0	0	0	36	43	43	41	41	42	0	0	42	42
Exhauster Damper Position - % Open														
0 - 12 Scale														
Mill 2A	11 4	11 2	11.3	5 7	7.9	6.0	8.0	5.3	6.0	9.0	7 0	7.0	8.0	8 0
Mill 2B	11.0	11.6	11.4	8.1	7.8	6.0	7.3	5.3	5.8	8.0	7.1	7.0	8.1	8.0
Mill 2C	11.5	11.5	11.5	5.6	5.5	4.4	4.5	5.6	8.2	8.4	6.0	6.0	5.8	5.8
Mill 2D	0	0	0	0	4.2	5 9	6.2	5.5	5.8	8.0	0	0	5.8	5.8
Pulverizer Feeder Cap - % Open														
0 - 12 Scale														
Mill 2A	4.3	4.4	4.4	5.7	5.5	4.4	4.6	5.3	5.1	5.2	4.7	4.5	5.2	5.3
Mill 2B	3.8	3.7	3.7	5.7	5.4	3.9	4.0	5.1	4.5	4.6	4.3	3.7	5.2	5.2
Mill 2C	3.0	3.0	3.0	5.6	5.4	4.1	4.4	5.5	5.8	5.8	2 6	3.4	5.8	5.6
Mill 2D	0	0	0	0	4.5	5.0	5.1	5.6	6.0	6.0	0	0	6.0	6.0
Spray Valve Positions - % Open														
SH Spray L	16	0	39	0	29	30	48	40	44	68	0	16	66	72
SH Spray R	16	0	39	0	0	0	32	40	36	52	0	16	54	56
RH Spray L	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RH Spray R	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burner Tilt Position - Degrees														
LR	+2	+2	+2	0	+3.5	+4	+4	+10	-22	-22	-9	+2	-22	-22
RR	+6	+13	+6	+8	+2.0	+4	+4	+5	-22	-22	-9	+4	-22	-22
LF	+6	+13	+6	+10	+5.0	+4	+4	+10	-22	-22	-9	+4	-22	-22
RF	+6	+13	+6	+10	+3.0	+4	+4	+7	-22	-22	-10	+4	-22	-22
Feedwater Valve - % Open (0-12 Scale)	8.1	8.1	8.1	8.0	12.0	11.4	11.4	12.0	12	12	12	12	9.8	9.8
Air Htr. 2A Recirc. Damper - % Open	37	38	39	39	31	44	40	34	32	32	35	35	34	34
Air Htr. 2B Recirc. Damper - % Open	50	51	50	52	38	43	42	36	36	27	36	36	36	36

BIASED FIRING STUDY

BOARD DATA

Test No.	15	16	17	18	19	20	21	22	23	24
Date	1-19-74	1-18-74	12-3-73	12-4-73	12-5-73	12-6-73	1-18-74	1-19-74	1-19-74	1-19-74
Time	09:10	18:24	11:07	01:30	23:50	02:30	20:30	15:45	13 30	11:30
Load - MW	66	96	100	103	99	102	94	64	64	166
Flows - 10^3LBS/HR										
BFP 2A	0	0	0	0	0	0	0	0	0	0
BFP 2B	220	324	360	360	360	360	350	240	250	240
BFP 2C	230	382	384	385	403	403	400	210	200	210
Reheat Steam	635	770	770	790	770	770	760	650	640	640
Condensate	330	460	470	470	470	460	460	340	341	325
Superheat Spray	3.1	10.0	17.5	17.5	4.9	8.3	3.0	2.9	2.5	10.0
Reheat Spray	0	0	0	0	0	0	0	0	0	0
Feedwater	390	660	600	600	---	---	660	440	440	400
Primary Steam Flow	450	675	690	700	690	690	675	450	450	442
Air Flow - Relative	580	750	700	705	660	705	750	580	590	575
PRESSURES										
Steam & Water - PSIG										
1st Stage Extraction	1680	1000	1020	1040	1020	1030	1000	680	670	670
8th	210	315	322	328	320	320	315	213	212	210
12th	75	122	125	128	125	125	120	76	77	76
16th	21	39	40	40	38.5	39.5	37.0	20.0	20.5	20.5
19th (-In. Hg· + PSIG)	-11.5	0.0	0.0	0.0	0.0	0.0	0.0	-11.0	-10.5	-11.0
21st (In. Hg)	-21.0	-15.2	-16.0	-16.0	-16.0	-16.2	-15.2	-20.5	-20.2	-21.0
Feedwater Regulator Inlet	2045	2000	1960	1980	1975	2000	1980	2050	2035	2025
Feedwater	1890	1920	1910	1920	1910	1925	1910	1890	1895	1890
Drum	1890	1915	1900	1920	1910	1925	1910	1900	1900	1900
Turbine Throttle	1845	1830	1810	1825	1825	1830	1830	1840	1845	1835
Reheat Inlet	199	308	317	321	316	317	308	200	201	199
Reheat Bowl	188	286	294	300	291	293	286	193	190	190
Exhaust (In. Hg)	-29.4	-28.5	-28.1	-28.2	-28.4	-28.4	-28.5	-29.0	-29 0	-29.2
Main Steam	1850	1850	1840	1850	1850	1850	1850	1850	1850	1850
Reheat Outlet	200	297	305	310	301	302	297	200	200	200
Light Oil Upper Burners	26	0	0	0	26	26	0	26	26	26
Light Oil Lower Burners	26	0	0	0	26	26	0	26	26	26
PRESSURES										
Air & Gas - In Wg										
2A FD Fan Discharge	1.2	3.0	3.2	3 1	2.0	2.5	3.2	1.2	1.2	1.2
2B FD Fan Discharge	0.8	3 0	2.9	2.8	1.8	2.5	3.0	0.8	0.8	0.8
2A Preheater Outlet Air	- 5	1.0	1.0	1.0	4	.6	1.2	- 5	-.5	-.5
2B Preheater Outlet Air	- 2	1.0	1.0	1 0	4	.7	1.2	- 2	- 2	-.2
Furnace Pressure	-.45	-.5	-.47	-.5	-.48	-.5	- 4	-.45	-.5	-.4
Superheater Cavity	-1.0	-1.3	-1.3	-1.4	-1.3	-1.3	-1.2	-1.0	-1.0	-1.0
Econ. Inlet	-3.0	-4.2	-4.1	-4.3	-4.0	-4.2	-4.0	-3 0	-3.0	-3.1
Economizer Outlet R.H.	-4.0	-5.4	-5.3	-5.5	-5.0	-5.3	-5.2	-4.0	-4.0	-4.0
Economizer Outlet L.H.	-4.0	-5.3	-5.3	-5.4	-5.0	-5.3	-5.2	-3.8	-3.9	-4.0
No. 2A Preheater Diff. Gas	2 2	3.2	2.9	3.0	2.8	2.9	3.2	2 3	2.3	2.3
No. 2B Preheater Diff. Gas	2.0	2.4	2.6	2.7	2.3	2.4	2.4	1 9	1.9	1 9
No. 2A I.D. Fan Suction	-7.2	-10.5	-10.0	-10.2	-9.1	-9.8	-10.1	-7.1	-7.1	-7.1
No. 2B I.D Fan Suction	-7.2	-10.0	-10.0	-10 5	-9.5	-10 0	-9.8	-7.2	-7 1	-7.1

BIASED FIRING STUDY

BOARD DATA

Test No.	15	16	17	18	19	20	21	22	23	24
PRESSURES (Cont'd)										
Air & Gas - In. Wg										
Pulverizer 2A Inlet Air	-1.5	-1.2	-1.0	-.8	-1.4	-.7	-.7	-.7	-1.5	-1.4
Exhauster 2A Discharge	11.5	12.0	12.0	13.0	13.0	0	0	0	10.5	11.5
Pulverizer 2B Inlet Air	-1.4	-1.0	-1.5	-1.4	-.75	-1.4	-1.3	-2.0	-.7	-1.5
Exhauster 2B Discharge	11.2	13.2	13.0	12.8	0	12.9	13.2	12.0	0	11.5
Pulverizer 2C Inlet Air	-2.0	-1.0	-1.2	-.9	-1.5	-1.2	-1.0	-1.5	-1.5	-0.8
Exhauster 2C Discharge	10.9	12.0	12.5	0	12.9	12.1	12.3	12.0	11.5	0
Pulverizer 2D Inlet Air	-1.2	-1.2	-1.2	-1.6	-2.5	-1.8	-2.0	-2.3	-2.0	-2.8
Exhauster 2D Discharge	0	0	0	12.0	12.8	11.9	10.5	10.0	10.0	8.8
TEMPERATURES										
Air & Gas - °F										
Boiler Outlet Gas L.H.	640	649	642	649	639	645	646	637	637	646
Boiler Outlet Gas R.H.	651	660	659	661	650	658	650	640	642	651
Economizer Out Gas L.H.	569	598	591	595	579	589	590	561	561	571
Economizer Out Gas R.H.	573	591	590	594	578	585	580	561	561	572
Preheater 2A Outlet Gas	301	312	297	300	290	288	310	298	298	302
Preheater 2B Outlet Gas	301	285	297	300	290	278	278	302	300	302
Preheater 2A Inlet Air	81	109	99	99	71	62	108	85	86	82
Preheater 2B Inlet Air	79	102	98	93	69	62	102	85	85	81
Preheater 2A Outlet Air	511	520	517	520	512	519	515	502	505	515
Preheater 2B Outlet Air	519	503	520	522	518	515	495	510	510	519
Pulverizer 2A Inlet Air	465	478	480	484	480	480	110	110	460	478
Pulverizer 2A Internal	145	160	138	142	137	80	110	110	145	140
Pulverizer 2B Inlet Air	465	480	480	483	100	482	478	460	110	465
Pulverizer 2B Internal	140	160	145	144	100	162	155	150	110	140
Pulverizer 2C Inlet Air	445	462	480	100	475	479	460	460	480	95
Pulverizer 2C Internal	175	162	122	100	130	145	160	160	155	95
Pulverizer 2D Inlet Air	89	95	105	490	479	480	460	470	470	460
Pulverizer 2D Internal	89	95	105	152	125	143	142	180	140	165
TEMPERATURES										
Steam & Water - °F										
Feedwater	388	445	445	449	442	445	425	412	413	413
Economizer Water Outlet - L.H.	462	480	478	480	471	479	472	457	458	468
Economizer Water Outlet - R.H.	466	480	480	481	473	479	472	456	451	468
RH Desuph. In L.H.	574	596	585	609	577	611	551	505	515	575
RH Desuph. Out L.H.	574	596	585	609	577	611	551	505	515	575
RH Desuph. In R.H.	574	596	585	609	577	611	551	505	515	575
RH Desuph. Out R.H.	574	596	585	609	577	611	551	505	515	575
Superheat Out L.H.	1000	986	978	1006	967	996	941	928	939	1000
Superheat Out R.H.	1008	998	970	992	969	1009	937	921	930	998
Throttle Steam L.H.	998	985	970	995	965	1000	938	927	930	998
Throttle Steam R.H.	998	985	970	995	962	1000	938	920	930	998
Reheat Outlet L.H.	886	901	920	955	900	955	849	819	829	922
Reheat Outlet R.H.	941	961	885	989	861	904	867	828	841	946
Superheater Outlet	990	979	955	980	951	990	981	910	923	987
Reheater Outlet	913	930	920	950	895	950	866	879	840	942
Upper Valve Chest	975	965	952	971	939	1019	921	900	908	976
Lower Valve Chest	100	101	100	101	94	90	101	101	100	100
H.P. Exhaust	568	595	589	609	578	632	555	500	509	568
Reheat Bowl	918	937	918	937	885	975	870	830	840	932
Intermediate Exhaust	440	451	435	455	418	470	401	378	385	458
Condensate Temp.	95	105	107	106	104	103	106	97	97	95

BIASED FIRING STUDY

BOARD DATA

Test No	15	16	17	18	19	20	21	22	23	24
S H Desuph in L H.	845	811	848	870	809	850	800	805	805	876
S H Desuph Out L.H	828	800	797	816	796	830	789	790	790	809
S H Desuph in R.H	864	855	840	858	799	831	974	795	800	872
S H Desuph Out R H	851	820	792	809	770	788	786	790	791	821
MISCELLANEOUS										
I D Fan 2A RPM	420	540	550	560	520	540	520	430	420	420
I D Fan 2B RPM	470	540	560	560	520	540	530	490	470	470
F D Fan 2A RPM	360	530	430	430	380	410	530	370	370	360
F D Fan 2B RPM	340	535	440	440	380	420	535	340	350	340
Fan Damper Position - (0-12)										
ID Fan 2A	5.4	6 2	7.7	7 6	7 8	7 9	6.0	5.2	5.2	5.4
ID Fan 2B	5 8	6.0	7.8	7.8	7.8	7.9	5.8	5.2	5.8	5 8
FD Fan 2A	3.7	5.0	6.8	6.8	4.3	4.5	4.8	3.8	3 9	3 7
FD Fan 2B	3.8	4.8	6 8	6.8	4.1	4.4	4.6	3.5	3.7	3 7
Drum Level In ± Norm. H_2O Level	-0 5	-0.5	-2.5	-1.0	-2 0	-1.0	-0.6	-0.5	-0.6	-0 8
A Mill AMPS	35	36	46	46	42	0	0	0	32	36
B Mill AMPS	36	35	39	42	0	42	36	31	0	37
C Mill AMPS	26	38	46	0	42	42	38	35	35	0
D Mill AMPS	0	0	0	43	44	44	39	36	37	26
Exhauster Damper Position - % Open 120" Full Scale										
Mill 2A	52	56	56	80	82	0	0	0	58	50
Mill 2B	54	80	78	82	0	79	78	60	0	52
Mill 2C	32	57	80	0	80	56	53	50	41	0
Mill 2D	0	0	0	63	83	54	49	49	42	28
Pulverizer Feeder Cap - . 120" Full Scale										
Mill 2A	52	56	57	64	54	0	0	0	38	50
Mill 2B	52	56	47	58	0	50	54	35	0	50
Mill 2C	20	55	56	0	52	54	53	49	50	0
Mill 2D	0	0	0	64	54	55	50	50	52	20
Spray Valve Positions - % Open										
SH Spray L	0	40	47	47	37	40	0	0	0	34
SH Spray R	0	40	41	41	17	20	0	0	0	35
RH Spray L	0	0	0	0	0	0	0	0	0	0
RH Spray R	0	0	0	0	0	0	0	0	0	0
Burner Tilt Positions - Degrees										
LR	-10	0	-18	-9	-9	-2	0	0	0	-18
RR	-13	+1	-18	-10	-9	-2	+8	0	0	-19
LF	-11	0	-18	-10	-9	-2	+10	0	0	-17
RF	-10	-1	-18	-10	-10	-2	+10	0	0	-16
Feedwater Valve - % Open (0-12 Scale)	7.8	12 0	12 0	12 0	12.0	8.4	12.0	7.8	7 9	8.0
Air Htr 2A Recirc. Damper - % Open	39	39	32	32	44	20	37	37	38	39
Air Htr 2B Recirc. Damper - % Open	32	41	34	31	42	20	40	32	32	32

BOARD DATA
BASELINE STUDY AFTER MODIFICATION

TEST NO	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Date	6/25/74	6/25/74	6/25/74	6/27/74	6/19/74	6/27/74	6/27/74	6/20/74	6/20/74	6/28/74	6/26/74	6/26/74	6/28/74	6/28/74
Time	2·30	4·25	6·38	9:30	13:24	11 18	3:05	9·41	12·25	14·45	1·23	4·05	11:25	9:20
Load - MW	62	62	64	92	131	127	125	130	129	125	65	68	126	125
FLOWS - 10^3LBS/HR														
BFP 2A	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BFP 2B	600 to 520	600 to 520	600 to 520	335	574	550	525	568	564	530	0	0	530	530
BFP 2C	0	0	0	275	524	480	410	520	520	425	460	490	425	425
Reheat Steam	642	650	650	705	900+	900+	900+	900+	900+	900+	680	680	900+	900+
Condensate	320	400	380	610	770	740	700	741	742	720	400	400	720	720
Superheat Spray	29.0	29.0	29.0	30.0	30.0	30.0	34.0	32.5	30.0	33.0	29.0	34.0	33.0	30.0
Reheat Spray	0.0	0.0	0 0	0	0	0	0	0	0	0	0	0	0	0
Feedwater	440	440	440	640	930	910	860	900	920	880	440	400	880	890
Primary Steam Flow	440	450	440	665	965	945	910	950	960	920	460	460	925	930
Air Flow - Relative	460	390	622	600	980	820	930	960	870	900	480	660	820	930
PRESSURES														
Steam & Water - PSIG														
1st Stage Extraction	650	660	660	990	1440	1420	1350	1440	1440	1370	700	700	1380	1380
8th	210	210	210	311	452	442	427	451	448	430	220	220	436	431
12th	75	76	75	120	183	176	171	183	180	174	79	80	175	175
16th	20	20	20	36	59	57	55	59	59	56	22	22	56	56
19th (-In. Hg + PSIG)	-12	-12	-12	-3	6.9	5.9	5.0	6.9	6.9	5.0	-11	-11	5.2	5.0
21st (In. Hg)	-20 0	-20.0	-20 0	-16.1	-11.0	-12.0	-12.0	-11 0	-11.0	-12.1	-19.5	-20.0	-12.1	-12.2
Feedwater Regulator Inlet	1950	1920	1950	1990	2020	2060	2050	2050	2050	2040	1950	1950	2050	2050
Feedwater	1870	1850	1900	1940	1960	1975	1970	1960	1950	1960	1900	1900	1970	1970
Drum	1870	1860	1890	1910	1950	1950	1940	1950	1950	1940	1880	1880	1940	1940
Turbine Throttle	1825	1850	1835	1840	1825	1825	1840	1825	1825	1825	1825	1825	1830	1835
Reheat Inlet	200	200	197	307	448	438	421	448	441	424	210	215	428	428
Reheat Bowl	197	192	187	284	412	402	388	412	409	390	197	198	392	392
Exhaust (In. Hg)	-27.6	-28.2	-28.2	-28.1	-27	-27.8	-27.8	-27	-27	-28.0	-27.9	-28.1	-28.0	-27.2
Main Steam	1840	1825	1850	1860	1860	1865	1875	1865	1865	1850	1840	1850	1855	1855
Reheat Outlet	195	200	197	295	425	415	402	425	420	404	205	210	402	406
Light Oil Upper Burners	24.0	24 0	24.0	0	23.7	0	0	0	0	0	23.7	23.7	0	0
Light Oil Lower Burners	25.2	25.2	25 2	0	24 8	0	0	0	0	0	24 9	24.9	0	0
PRESSURES														
Air & Gas - In. Wg														
2A FD Fan Discharge	2.0	1 5	2.7	2.0	5.6	3.5	6.0	5.0	4.0	5.5	1.9	3.1	4.2	5.5
2B FD Fan Discharge	1 5	1 0	2.2	1.6	5.2	3.5	5.5	4.9	3.8	5.0	1.2	2.7	4.0	5.0
2A Preheater Outlet Air	1.0	.8	1 1	.5	2.2	1.0	2.2	2.0	1.1	2.0	.9	1.2	1.2	2.0
2B Preheater Outlet Air	1 0	.8	1.2	.6	2.2	1.0	2.2	2.0	1.1	2.0	.9	1.2	1.2	2.0
Furnace Pressure	-.45	-.45	-.45	-.45	-.1	-.45	-.04	-.27	-.45	-.08	- 475	-.475	-.44	-.05
Superheater Cavity	- 8	-.75	-1.0	-1.0	-1.0	-1.5	-1.1	-1.25	-1.4	-1.2	-1.0	-1.0	-1.5	-1.2
Econ. Inlet	-2.5	-2.0	-3 4	-3.4	-5.6	-5.5	-5.7	-5.5	-5.4	-5 7	-2.5	-3.75	-5.7	-5.7
Economizer Outlet R.H.	-3.4	-3.0	-4.5	-4.4	-7.0	-6.8	-7.2	-7.2	-6.7	-7.1	-3.5	-4.8	-7.4	-7.3
Economizer Outlet L.H.	-3.3	-2 8	-4.6	-4.4	-7.1	-7.0	-7.4	-7.4	-6.9	-7.4	-3.4	-4.8	-7.5	-7.4
No. 2A Preheater Diff. Gas	2.0	1 6	2.5	2.5	4.2	3.7	4.1	4.0	3.8	4.1	1.95	2.7	4.0	4.1
No. 2B Preheater Diff Gas	1.2	1 1	2.0	1.8	3.4	3.1	3.3	3.5	3.2	3.4	1.4	2.0	3.2	3.4
No 2A I.D. Fan Suction	6 2	5.1	8.5	8 2	14.5	13.2	14.7	14.5	13.5	14.6	6.2	9.1	14.5	14.8
No 2B I.D. Fan Suction	5.2	4 5	8.5	8.0	14 0	13.0	14.0	14.0	13.4	14.1	5.9	9.0	14.1	14.2
Pulverizer 2A Inlet Air	-1.2	-1.2	-1.2	-1.4	-1.0	-1.4	-1.0	-1.0	-1.1	-1.2	-1.3	-1.3	-1.5	-1.2
Exhauster 2A Discharge	10 7	11.0	10.8	12.0	12 0	12.0	12.7	12.0	12.2	12.5	11.6	11.2	13.2	13.4
Pulverizer 2B Inlet Air	-1.2	-1.2	-1.0	-1.4	-.25	-1.2	-1.0	-.75	-1.0	-1.2	-1.2	-1.2	-1.4	-1.2
Exhuaster 2B Discharge	10 2	9.5	10.7	10 7	14.5	11.2	11 5	14.2	14.0	10.5	10.0	9.9	10.7	11.5
Pulverizer 2C Inlet Air	-3 5	-3 4	-3.4	-3 0	-1.25	-3.0	-1.8	-1 75	-2.0	-2 8	-3.6	-3.25	-3.2	-2.8
Exhauster 2C Discharge	10 5	10 5	10.5	11.5	12.5	12.0	12 0	12.0	12.0	11.5	10.2	10.4	11.5	12.0
Pulverizer 2D Inlet Air	-1.2	-1.2	-1.2	-1 2	-1.75	-1 9	-1.5	-1.9	-2.0	-1 75	-1.2	-1.2	-2.0	-1 6
Exhauster 2D Discharge	0	0	0	0	11.5	12 0	12.3	11.5	11.0	12.0	0	0	12 0	12.3

BOARD DATA

BASELINE STUDY AFTER MODIFICATION

TEST NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14
TEMPERATURES														
AIR & GAS - °F														
BOILER OUTLET GAS L H.	614	607	631	628	660	647	652	662	658	652	619	640	651	652
BOILER OUTLET GAS R.H.	625	618	642	638	669	657	662	669	661	662	628	650	662	663
ECONOMIZER OUT GAS L.H	520	504	548	552	612	594	609	614	606	608	527	561	604	609
ECONOMIZER OUT GAS R H.	515	504	552	558	615	600	611	617	610	612	527	569	610	612
PREHEATER 2A OUTLET GAS	285	290	272	292	290	295	300	290	299	305	282	272	311	300
PREHEATER 2B OUTLET GAS	279	289	279	282	290	305	298	292	299	302	290	285	306	298
PREHEATER 2A INLET AIR	89	82	89	98	100	105	120	99	101	120	98	92	110	113
PREHEATER 2B INLET AIR	89	88	90	98	101	109	122	99	101	122	101	101	108	115
PREHEATER 2A OUTLET AIR	475	471	479	496	509	508	499	516	520	504	480	488	518	501
PREHEATER 2B OUTLET AIR	477	425	485	491	510	512	500	518	520	509	485	496	517	506
PULVERIZER 2A INLET AIR	418	420	420	430	460	430	420	455	460	410	420	410	440	430
PULVERIZER 2A INTERNAL	145	142	160	150	140	140	155	145	140	160	145	155	160	155
PULVERIZER 2B INLET AIR	435	423	435	440	480	450	440	465	470	440	425	425	455	440
PULVERIZER 2B INTERNAL	150	160	155	140	145	140	145	160	140	160	145	155	150	155
PULVERIZER 2C INLET AIR	410	420	420	425	475	442	450	470	475	435	410	420	440	435
PULVERIZER 2C INTERNAL	160	160	165	139	180	135	160	200	240	160	170	180	150	155
PULVERIZER 2D INLET AIR	80	80	80	80	475	455	455	465	475	455	80	80	460	460
PULVERIZER 2D INTERNAL	80	80	80	80	175	155	175	175	175	180	80	80	175	175
TEMPERATURES														
STEAM & WATER - °F														
FEEDWATER	408	408	408	440	472	470	470	472	472	457	411	411	460	460
ECONOMIZER WATER OUTLET - L H	440	430	460	460	492	486	490	494	490	489	447	471	489	490
ECONOMIZER WATER OUTLET - R H	439	429	459	460	492	485	490	492	490	489	441	470	489	490
RH DESUPH. IN L H	495	461	562	547	638	629	610	630	630	621	520	562	621	630
RH DESUPH. OUT L H	495	461	562	547	638	629	610	630	630	621	520	562	621	630
RH DESUPH. IN R H	495	461	562	547	638	629	610	630	630	621	520	562	621	630
RH DESUPH. OUT R.H.	495	461	562	547	638	629	610	630	630	621	520	562	621	630
SUPERHEAT OUT L H.	907	872	992	935	982	979	962	972	970	968	935	980	972	982
SUPERHEAT OUT. R H	915	872	998	941	980	978	961	971	970	968	941	985	968	982
THROTTLE STEAM L H	916	870	998	941	978	977	960	970	970	965	941	982	968	980
THROTTLE STEAM R H	918	862	994	941	980	975	961	970	969	972	941	985	970	982
REHEAT OUTLET L H	821	780	912	858	932	926	920	941	930	932	858	940	938	942
REHEAT OUTLET R.H.	811	760	910	850	925	907	900	928	917	908	850	930	911	919
SUPERHEATER OUTLET	917	875	997	940	982	976	964	978	982	975	945	987	975	985
REHEATER OUTLET	815	755	900	850	924	917	912	925	916	922	855	935	924	930
UPPER VALVE CHEST	860	820	929	870	909	908	897	906	901	896	885	929	891	902
LOWER VALVE CHEST	95	95	90	97	105	99	101	102	108	101	99	98	100	100
H P. EXHAUST	470	439	532	---	600	---	---	595	595	---	491	530	---	---
REHEAT BOWL	801	750	881	820	890	882	880	897	886	875	832	912	875	879
INTERMEDIATE EXHAUST	350	312	411	---	419	---	---	420	412	---	375	431	---	---
CONDENSATE TEMP.	110	107	107	107	127	119	119	127	127	115	107	107	120	119
S H DESUPH. IN L.H	749	701	842	770	835	818	850	850	821	851	771	908	845	842
S H. DESUPH. OUT L H.	738	696	827	760	820	804	808	802	805	811	759	785	808	819
S.H DESUPH. IN. R H.	749	709	842	765	821	810	842	839	815	850	762	899	845	847
S H. DESUPH. OUT R H	740	701	829	757	810	801	800	800	800	820	752	782	811	826
MISCELLANEOUS														
I D FAN 2A RPM	420	380	500	500	685	650	685	685	660	690	420	530	680	690
I D FAN 2B RPM	420	380	500	500	675	650	680	675	660	660	420	520	660	665
F D. FAN 2A RPM	350	320	450	430	630	530	680	600	520	580	350	460	580	660
F D FAN 2B RPM	340	280	440	430	625	530	680	600	540	585	340	460	585	645
FAN DAMPER POSITION - (0-12)														
ID FAN 2A	6 1	5 8	8 0	7 2	12	9 8	12 0	12	12	12.0	7.2	8.2	12	12
ID FAN 2B	6 1	5 8	8 0	7 1	12	10 0	12 0	12	12	12.0	7 0	8.0	12	12
FD FAN 2A	5 9	4 4	6 2	4 3	12	8 4	12 0	12	12	12 0	6 2	8 9	12	12
FD FAN 2B	6 0	4 4	6 0	4 4	12	8 6	12 0	12	12	12 0	6 3	8.9	12	12
DRUM LEVEL IN. ± NORM H_2O LEVEL	-2 5	-4 0	-4 0	-4.0	-3 0	-4	-4	-3 0	-3 0	-2.2	-4.0	-4.0	-4.0	-4.2

BOARD DATA

BASELINE STUDY AFTER MODIFICATION

TEST NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14
2A Mill AMPS	35	36	34	36	40	37	36	42	42	38	35	32	36	36
2B Mill AMPS	35	35	37	36	39	36	36	40	39	34	34	33	36	35
2C Mill AMPS	32	32	31	38	40	37	36	40	41	37	26	30	38	36
2D Mill AMPS	0	0	0	0	36	38	38	34	35	36	0	0	36	36
EXHAUSTER DAMPER POSITION - % OPEN 0 - 12 Scale														
Mill 2A	4.2	4.3	4 0	5 4	5 2	5.4	5.4	5.4	5.3	5.4	4.7	4.4	6 8	6.8
Mill 2B	5.5	5 5	5 5	5.6	7.75	5 6	5 6	8 1	8.0	5 6	4.8	4.5	5.9	5.8
Mill 2C	4.2	4 2	4 2	5.4	5 2	5.4	5 4	5.5	5.4	5 4	3.2	3.8	5.7	5.6
Mill 2D	0	0	0	0	5.2	5 4	5.4	5 6	5.4	5.5	0	0	5.8	5.8
PULVERIZER FEEDER CAP - % OPEN 0 - 12 Scale														
Mill 2A	4.2	4.3	4 0	5 4	5 2	5.4	5.4	5.4	5 3	5.5	4 8	4.4	5.7	5.6
Mill 2B	4.2	4.3	4.0	5.4	7.75	5.4	5.4	8 1	8.0	5.5	4.8	4.4	5.7	5.6
Mill 2C	3 0	3 2	2 9	5 8	5.2	5.8	6.0	5 5	5.4	6.0	2.6	3.7	6.2	6.1
Mill 2D	0	0	0	0	5.2	5.6	5.6	5.6	5.4	5.6	0	0	5.8	5.8
SPRAY VALVE POSITIONS - % OPEN														
SH Spray L	0	0	0	0	0	0	44	40	18	37	0	65	40	30
SH Spray R	0	0	0	0	0	0	40	40	18	39	0	64	38	30
RH Spray L	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RH Spray R	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BURNER TILT POSITION - DEGREES														
LR	0	10	-13	+4	-8	-2	-22	-22	-9	-3	-10	-10	-3	-3
RR	0	9	-13	+4	-6	-2	-26	-25	-11	-3	-12	-10	-3	-3
LF	0	12	-10	+7	-5	+2	-22	-21	-9	0	-9	-8	0	0
RF	0	10	-12	+6	-7	0	-24	-23	-10	-1	-10	-9	-1	-1
Feedwater Valve - % Open (0-12 Scale)	8.8	8.8	8.7	11.5	12+	11.4	11.4	12+	12+	12+	12+	8.5	12+	12+
Air Htr. 2A Recirc. Damper - % Open	32	32	38	52	26	48	48	26	26	46	41	41	46	46
Air Htr 2B Recirc. Damper - % Open	32	32	39	52	25	49	44	26	26	42	41	41	43	43

BOARD DATA
OVERFIRE AIR LOCATION, RATE & VELOCITY VARIATION

TEST NO.	15	16	17	18A	19	20	21	22	23
Date	7/10/74	7/10/74	7/10/74	7/12/74	7/11/74	7/11/74	7/12/74	7/12/74	7/12/74
Time	0 00	2·15	4·00	7:25	4 35	23.10	1·24	3:30	4:45
Load - MW	97	98	100	100	100	100	102	102	102
FLOWS - 10^3LBS/HR									
BFP 2A	0	0	0	0	0	0	0	0	0
BFP 2B	415	415	420	425	410	420	420	420	425
BFP 2C	360	360	360	365	355	360	360	365	365
Reheat Steam	810	810	820	835	805	820	830	830	830
Condensate	525	530	535	535	525	540	535	540	540
Superheat Spray	30.5	30.5	30.0	29.8	36.0	31.9	33.0	34.0	34.0
Reheat Spray	0	0	0	0	0	0	0	0	0
Feedwater	690	690	690	700	650	685	670	670	670
Primary Steam Flow	725	715	720	725	715	725	725	725	725
Air Flow - Relative	700	660	660	675	680	720	720	680	700
PRESSURES									
STEAM & WATER - PSIG									
1st Stage Extraction	1060	1060	1060	1080	1060	1070	1080	1080	1080
8th	334	338	340	340	340	340	342	348	347
12th	131	130	133	135	132	135	136	136	136
16th	40	40	40	41	41	41	42	42	42
19th (-In Hg. +PSIG)	0	0	0	0	0	0	0	0	0
21st (In. Hg)	-15.2	-15.2	-15.1	-15 2	-15.6	-15 2	-15.2	-15.2	-15.2
Feedwater Regulator Inlet	2000	2010	2010	2000	2000	2000	2000	2010	2000
Feedwater	1950	1950	1950	1950	1940	1940	1940	1950	1940
Drum	1930	1930	1935	1930	1920	1915	1920	1925	1925
Turbine Throttle	1850	1850	1850	1845	1835	1835	1835	1840	1835
Reheat Inlet	329	330	330	332	330	330	335	340	339
Reheat Bowl	304	305	306	309	305	308	310	314	313
Exhaust (In. Hg)	-27 3	-27.6	-27.6	-27 3	-27.4	-27.4	-27 3	-27.3	-27.3
Main Steam	1870	1870	1870	1865	1850	1850	1850	1855	1860
Reheat Outlet	315	315	320	321	319	320	322	325	325
Light Oil Upper Burners	0	0	0	23	23	23	23	23	23
Light Oil Lower Burners	0	0	0	25	25	25	25	25	25
PRESSURES									
AIR & GAS - IN. WG									
2A FD Fan Discharge	4 2	3 1	3 1	3.0	3.0	3.9	4 0	3.0	3.4
2B FD Fan Discharge	4.0	2.7	2.9	2.5	2 7	3.3	3 8	2.7	3.0
2A Preheater Outlet Air	2.0	1.0	1.0	.8	1.0	1.5	1.8	1 8	1 0
2B Preheater Outlet Air	2.0	1.0	1 1	.8	1.0	1.5	1 8	1 8	1 1
Furnace Pressure	- 48	-.48	-.48	-.45	-.48	- 45	- 45	- 45	- 45
Superheater Cavity	-1.2	-1.2	-1.2	-1.2	-1 2	-1 2	-1 2	-1 2	-1.3
Economizer Inlet	-4.0	-4.0	-4.0	-4.2	-4.2	-4 1	-4.3	-4 4	-4 4
Economizer Outlet RH	-5.3	-5.2	-5.2	-5.5	-5.5	-5.5	-5 6	-5.8	-5.7
Economizer Outlet LH	-5 3	-5.2	-5.2	-5.5	-5.5	-5 5	-5 6	-5 8	-5 7
No 2A Preheater Diff. Gas	2 9	2.9	2 9	3 0	2.9	3 0	3.0	3 1	3 1
No. 2B Preheater Diff Gas	2.4	2.3	2.35	2.4	2.4	2.4	2 4	2 6	2 6
No 2A ID Fan Suction	10 0	10.0	10.0	10.5	10 4	10.3	10.5	11.0	11 0
No 2B ID Fan Suction	10.0	10.0	10.0	10 5	10 5	10 3	10.7	11 0	11 0
Pulverizer 2A Inlet Air	-.7	- 7	-.7	-1 7	-.7	-.7	-1 1	-1 4	-1 25
Exhaust 2A Discharge	1 0	1 0	9	0	.8	1 0	11 5	12 0	12 0
Pulverizer 2B Inlet Air	- 9	-1.2	-1.2	-1 0	-1 0	- 95	- 8	-.9	- 75
Exhauster 2B Discharge	10.0	10.0	10.0	11.5	10.2	11.5	11.5	11.5	12 0
Pulverizer 2C Inlet Air	-3.2	-3.3	-3.3	-2 5	-2.1	-2 6	-2.4	-2 4	-2 4
Exhauster 2C Discharge	11 0	11.0	11 0	11.0	11.5	11 2	11.5	11 5	12 0
Pulverizer 2D Inlet Air	-1.8	-2.0	-2 0	-1.4	-1 1	-1 75	-1 2	-1 2	-1 2
Exhauster 2D Discharge	11 0	11 0	11 2	11 2	12 0	11.3	0	0	0
TEMPERATURES									
AIR & GAS - °F									
Boiler Outlet Gas LH	639	638	639	640	641	640	645	645	645
Boiler Outlet Gas RH	646	648	649	649	650	648	652	652	652
Economizer Outlet Gas LH	571	571	572	572	577	573	578	580	579
Economizer Outlet Gas RH	572	574	578	579	582	579	583	589	586
Preheater 2A Outlet Gas	292	292	292	289	291	289	290	290	290
Preheater 2B Outlet Gas	292	292	291	290	287	297	299	298	298
Preheater 2A Inlet Air	122	98	92	95	91	105	103	92	98
Preheater 2B Inlet Air	132	98	95	99	91	110	111	98	101
Preheater 2A Outlet Air	489	495	498	492	500	489	492	498	495
Preheater 2B Outlet Air	492	501	501	500	502	500	505	509	507
Pulverizer 2A Inlet Air	100	90	80	80	80	100	410	420	425
Pulverizer 2A Internal	100	90	80	80	80	100	160	140	140
Pulverizer 2B Inlet Air	435	440	440	440	440	440	440	445	445
Pulverizer 2B Internal	140	140	140	150	130	160	160	140	150
Pulverizer 2C Inlet Air	420	420	420	440	440	440	440	450	455
Pulverizer 2C Internal	145	140	140	160	155	160	170	160	155
Pulverizer 2D Inlet Air	440	440	445	450	460	455	100	100	80
Pulverizer 2D Internal	142	140	140	180	155	160	100	100	80

BOARD DATA
OVERFIRE AIR LOCATION, RATE & VELOCITY VARIATION

TEST NO	15	16	17	18A	19	20	21	22	23
TEMPERATURES									
STEAM & WATER - °F									
Feedwater	445	445	445	450	447	450	450	450	450
Economizer Water Outlet - LH	469	469	470	471	472	472	478	478	477
Economizer Water Outlet - RH	469	469	470	470	472	472	477	478	477
RH DESH Inlet LH	572	567	574	585	582	585	600	589	582
RH DESH Outlet LH	572	567	574	585	582	585	600	589	582
RH DESH Inlet RH	572	567	574	585	582	585	600	589	582
RH DESH Outlet RH	572	567	574	585	582	585	600	589	582
Superheat Outlet LH	960	945	952	961	959	961	981	968	960
Superheat Outlet RH	959	942	952	965	962	969	988	968	962
Throttle Steam LH	955	940	950	966	959	965	985	965	961
Throttle Steam RH	950	938	948	968	968	975	990	969	960
Reheat Outlet LH	890	872	889	897	917	905	940	930	921
Reheat Outlet RH	860	848	859	889	907	891	929	912	905
Superheater Outlet	965	950	957	975	970	975	990	975	970
Reheater Outlet	855	845	854	889	907	895	928	915	905
Upper Valve Chest	899	890	898	920	911	905	929	920	910
Lower Valve Chest	101	101	100	101	102	105	105	102	101
HP Exhaust	549	539	545	560	554	555	575	565	557
Reheat Bowl	840	837	845	872	892	870	909	903	890
Intermediate Exhaust	384	375	380	410	419	405	430	422	417
Condensate Temperature	119	119	119	120	120	121	121	120	120
SH DESH Inlet LH	809	800	808	812	840	815	841	843	841
SH DESH Outlet LH	795	789	792	800	781	784	788	772	774
SH DESH Inlet RH	799	790	796	805	832	813	839	842	837
SH DESH Outlet RH	788	780	785	795	779	787	789	778	775
MISCELLANEOUS									
ID Fan 2A RPM	560	550	540	560	560	570	575	580	580
ID Fan 2B RPM	560	540	540	560	560	560	570	580	580
FD Fan 2A RPM	540	450	450	450	460	500	520	450	480
FD Fan 2B RPM	540	460	460	460	470	500	520	460	480
FAN DAMPER POSITIONS (0-12)									
ID Fan 2A	12+	12+	12+	12+	12+	12+	12+	12+	12+
ID Fan 2B	12+	12+	12+	12+	12+	12+	12+	12+	12+
FD Fan 2A	9.8	8.2	8.2	12+	6.2	12	12	12	12+
FD Fan 2B	9.6	8.2	8.2	12+	5.9	12	12	12	12+
Drum Level In. ± Norm. H_2O Level	-4.5	-4.5	-4 5	-4 5	-4.5	-4.5	-4.5	-4.5	-4.5
2A Mill Amps	0	0	0	0	0	0	36	36	36
2B Mill Amps	37	36	36	36	37	37	38	37	37
2C Mill Amps	36	36	36	36	36	36	38	38	38
2D Mill Amps	41	41	42	38	41	40	0	0	0
EXHAUSTER DAMPER POSITION - % OPEN									
0-12 SCALE									
Mill 2A	0	0	0	0	0	0	4.8	5.0	5.3
Mill 2B	4.6	4.5	4.8	8 6	8.4	8.4	8 4	8 4	8 4
Mill 2C	4.4	4.4	4.6	5.2	4.4	4.8	4.8	5.0	5.4
Mill 2D	4.4	4 4	4.6	4.6	4.4	4.4	0	0	0
PULVERIZER FEEDER CAP. - % OPEN									
0-12 SCALE									
Mill 2A	0	0	0	0	0	0	4.8	5.0	5.4
Mill 2B	4.4	4.4	4 6	5.2	5.2	4.3	4.8	5.0	5.4
Mill 2C	4.9	4.8	5.2	5.8	5.7	4.8	5.3	5.5	5 9
Mill 2D	4.5	4.6	4.8	4.8	5.4	4.4	0	0	0
SPRAY VALVE POSITION - % OPEN									
SH Spray L	0	0	0	0	52	36	50	60	60
SH Spray R	0	0	0	0	52	36	50	60	60
RH Spray L	0	0	0	0	0	0	0	0	0
RH Spray R	0	0	0	0	0	0	0	0	0
BURNER TILT POSITION - DEGREES									
LR	-2	-2	-2	0	0	0	0	0	0
RR	0	0	0	0	+1	+2	+2	+2	+2
LF	0	0	0	0	0	+2	+2	+2	+1
RF	-1	-1	-1	0	-1	0	0	0	0
Feedwater Valve - % Open (0-12 Scale)	12+	12+	12+	12+	12+	12+	12+	12+	12+
Air Htr. 2A Recirc. Damper - % Open	40	29	29	32	0	32	32	32	32
Air Htr. 2B Recirc Damper - % Open	40	29	26	35	0	32	34	34	34

BOARD DATA

	OVERFIRE AIR TILT VARIATION							LOAD VARIATION AT OPTIMUM CONDITIONS				
TEST NO	24	25	26	27	28	29	30	31	32	33	34	35
DATE	7/29/74	7/29/74	7/29/74	7/29/74	7/29/74	7/29/74	7/30/74	7/31/74	7/31/74	7/31/74	7/31/74	8/1/74
TIME	9 40	11·05	13 30	15 00	16·30	18:07	21 05	12·22	2·35	21·50	23.35	1 38
LOAD - MW	124	124	124	125	125	124	125	97	65	122	95	64
FLOWS - 10^3 LBS/HR												
BFP 2A	0	0	0	0	0	0	0	0	0	0	0	0
BFP 2B	500	510	500	500	500	510	500	390	270	500	375	275
BFP 2C	410	415	410	410	410	415	410	330	225	400	325	225
REHEAT STEAM	900+	900+	900+	900+	900+	900+	900+	810	665	900+	798	660
CONDENSATE	620	630	625	620	625	630	625	480	350	625	480	350
SUPERHEAT SPRAY	33 0	31.0	40.0	35.0	48.5	31.5	35 0	33 5	31.0	33.5	32.2	31.0
REHEAT SPRAY	0	0	0	0	0	0	0	0	0	0	0	0
FEEDWATER	820	870	800	810	800	860	820	620	400	840	620	300
PRIMARY STEAM FLOW	900	915	885	902	900	900	900	680	455	895	675	445
AIR FLOW - RELATIVE	800	797	800	799	785	810	780	635	540	800	620	510
PRESSURES												
STEAM & WATER - PSIG												
1ST STAGE EXTRACTION	1320	1350	1300	1320	1319	1340	1335	1019	690	1320	1018	680
8TH	420	425	420	420	422	421	422	324	219	419	321	215
12TH	168	170	170	170	172	171	172	129	79	170	127	78
16TH	55	56	55	56	56	55.5	56.0	39	22	55	38	21 5
19TH (-IN HG· + PSIG)	5 9	6.0	6.0	6.0	6.2	6.0	6.0	-1.0	-12	6 0	0.0	-12
21ST (IN HG)	-12 5	-12.2	-12.5	-12.5	-12.4	-12 2	-12.5	-16.0	-20.0	-12 5	-16.0	-20.0
FEEDWATER REGULATOR INLET	2030	2050	2020	2020	2010	2040	2040	2000	1935	2060	2010	1960
FEEDWATER	1950	1950	1950	1950	1940	1950	1960	1925	1925	1960	1950	1910
DRUM	1930	1920	1930	1925	1915	1940	1940	1910	1900	1950	1920	1900
TURBINE THROTTLE	1825	1825	1825	1820	1820	1825	1835	1835	1850	1835	1850	1850
REHEAT INLET	411	420	411	417	418	415	418	315	204	411	311	200
REHEAT BOWL	380	386	380	384	385	381	384	292	195	380	290	191
EXHAUST (IN HG)	-27.2	-27.1	-27 1	-27 1	-27 0	-27 0	-27 0	-27 5	-27.8	-27.0	-27.4	-27 7
MAIN STEAM	1850	1850	1850	1850	1850	1850	1860	1865	1865	1865	1865	1865
REHEAT OUTLET	390	398	393	398	398	395	398	305	200	391	300	200
LIGHT OIL UPPER BURNERS	0	0	0	0	0	0	0	0	24	23.5	23.5	23.5
LIGHT OIL LOWER BURNERS	0	0	0	0	0	0	0	0	25	25 0	25 0	25 0
PRESSURES												
AIR & GAS - IN WG												
2A FD FAN DISCHARGE	4 9	4 9	4 9	4.9	4.5	5.1	4 0	2.5	1 9	4.9	2.5	1 5
2B FD FAN DISCHARGE	4.5	4 8	4 5	4.4	4.2	5.0	3.9	2.0	1.7	4.5	2 0	1 0
2A PREHEATER OUTLET AIR	1 5	1 7	1 9	1 9	1.5	2 0	1.0	5	5	1.5	.5	.2
2B PREHEATER OUTLET AIR	1.5	1 7	1.9	1.9	1.5	2.0	1.0	.5	5	1.5	.5	.2
FURNACE PRESSURE	- 20	- 21	- 175	-.15	- 18	- 05	-.45	- 425	-.425	- 35	-.5	- 45
SUPERHEATER CAVITY	-1 3	-1 2	-1.2	-1.2	-1.2	-1.2	-1.7	-1.2	-1.0	-1.5	-1.1	-1.0
ECON. INLET	-5 6	-5 6	-5 7	-5 7	-5.7	-5.5	-5.6	-3.8	-2.9	-5 4	-3 7	-2.7
ECONOMIZER OUTLET R.H	-7 1	-7.1	-7.2	-7.1	-7.2	-7 1	-7.5	-5 4	-4 1	-7 2	-5.1	-3.9
ECONOMIZER OUTLET L.H	-7 4	-7.4	-7.4	-7.4	-7.4	-7.4	-7 8	-5.4	-4.0	-7.5	-5.1	-3.8
NO 2A PREHEATER DIFF. GAS	3 9	4.0	4.0	4.0	3.9	4.0	3.9	2.8	2.1	4.0	2 8	2.0
NO 2B PREHEATER DIFF. GAS	3 5	3.5	3 4	3.5	3 4	3 4	3 5	2.4	1.7	3.6	2.3	1.6
NO. 2A I.D. FAN SUCTION	14.4	14 4	14.5	14.5	14.5	14.5	14.5	10.0	7.5	14.7	10.0	7.1
NO. 2B I D. FAN SUCTION	14 0	14 0	14 0	14.0	14.0	14.0	14 5	10 1	7.2	14.2	10.0	6.8
PULVERIZER 2A INLET AIR	-1 3	-1 1	-1.2	-1.2	-1.2	-1 0	-1.4	-1.4	-1.25	-1.25	-1.4	-1.4
EXHAUSTER 2A DISCHARGE	12 0	12.5	12.5	12.0	12.0	12.7	12 0	12.0	12.5	12.2	12.5	12.9
PULVERIZER 2B INLET AIR	-1 0	-1 0	-1 0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.1	-1.0
EXHAUSTER 2B DISCHARGE	10.0	10 0	9.5	9.0	9.5	9.4	9 2	9.5	10.0	9.2	10.0	10.2
PULVERIZER 2C INLET AIR	-2.6	-2 5	-2 5	-2 5	-2.7	-2.6	-3.4	-3.5	-1.2	-3.0	-3.5	-1.0
EXHAUSTER 2C DISCHARGE	12.0	12 5	12.0	12.0	12.0	12.5	11.5	11 5	0	12.0	12.0	0
PULVERIVER 2D INLET AIR	-2.0	-1 9	-1 9	-2 0	-1.75	-1.6	-2.0	-1 2	-1 2	-1.5	-1.2	-1.2
EXHAUSTER 2D DISCHARGE	10 5	10 5	10.5	11.0	11 5	11.5	10.0	0	0	11.0	0	0

BOARD DATA

OVERFIRE AIR TILT VARIATION — LOAD VARIATION AT OPTIMUM CONDITIONS

TEST NO	24	25	26	27	28	29	30	31	32	33	34	35
TEMPERATURES												
Air & Gas - °F												
Boiler Outlet Gas L H.	---	651	660	661	661	652	655	639	630	660	635	628
Boiler Outlet Gas R.H.	---	661	669	670	670	661	670	651	641	670	649	638
Economizer Out Gas L H	---	600	609	610	611	602	606	570	542	610	569	540
Economizer Out Gas R H.	---	605	612	615	---	609	611	578	550	615	572	539
Preheater 2A Outlet Gas	---	298	300	303	305	293	302	292	290	302	291	300
Preheater 2B Outlet Gas	---	295	300	302	302	298	298	287	261	298	288	256
Preheater 2A Inlet Air	---	79	95	95	92	92	85	82	88	89	80	80
Preheater 2B Inlet Air	---	80	95	98	95	95	80	78	80	89	86	90
Preheater 2A Outlet Air	---	502	508	512	516	500	510	499	488	511	499	490
Preheater 2B Outlet Air	---	511	519	521	522	514	519	505	480	519	505	475
Pulverizer 2A Inlet Air	460	460	460	460	460	450	465	450	455	465	465	460
Pulverizer 2A Internal	170	150	160	160	160	165	160	155	155	170	155	145
Pulverizer 2B Inlet Air	480	480	480	480	485	465	485	480	460	480	480	460
Pulverizer 2B Internal	135	160	155	160	160	160	155	150	140	150	140	140
Pulverizer 2C Inlet Air	499	495	495	500	500	495	490	475	100	495	480	100
Pulverizer 2C Internal	170	175	175	165	170	175	140	140	100	160	140	100
Pulverizer 2D Inlet Air	495	480	470	470	500	400	480	100	100	380	100	100
Pulverizer 2D Internal	175	160	175	175	175	180	170	100	100	165	100	100
TEMPERATURES												
Steam & Water - °F												
Feedwater	467	467	467	470	470	470	470	449	415	465	447	412
Economizer Water Outlet - L H.	---	482	490	491	491	486	490	470	457	489	462	450
Economizer Water Outlet - R.H.	---	482	490	490	492	485	491	470	456	489	462	449
RH Desuph. In L.H.	668	649	650	668	656	649	695	638	621	680	616	590
RH Desuph. Out L.H.	668	649	650	668	656	649	695	638	621	680	616	590
RH Desuph In R.H.	668	649	650	668	656	649	695	640	621	680	619	590
RH Desuph. Out R H.	668	649	650	668	656	649	695	640	621	680	619	590
Superheat Out L.H.	995	965	975	999	982	970	1009	981	997	975	940	958
Superheat Out R.H.	992	977	988	1001	992	982	1010	977	1000	981	950	959
Throttle Steam L.H.	995	968	972	995	978	977	1002	985	1000	979	940	960
Throttle Steam R.H.	990	968	972	992	972	972	1002	981	995	972	941	965
Reheat Outlet L.H.	958	911	951	978	971	915	975	931	928	932	876	888
Reheat Outlet R.H.	972	930	970	980	982	938	990	943	950	951	905	889
Superheater Outlet	1000	970	975	990	975	970	1000	977	995	970	942	953
Reheater Outlet	990	946	981	992	995	940	997	958	957	970	920	920
Upper Valve Chest	978	959	959	985	970	961	988	960	967	949	922	927
Lower Valve Chest	110	110	111	112	115	111	105	102	105	111	111	110
H.P Exhaust	649	630	630	650	640	631	655	592	570	619	550	530
Reheat Bowl	970	939	969	995	995	945	990	949	935	940	902	890
Intermediate Exhaust	475	447	471	489	490	450	490	460	457	455	410	422
Condensate Temp.	124	125	125	125	126	127	125	120	113	127	125	114
S H. Desuph. In L.H	891	855	905	906	921	858	919	896	895	940	885	880
S.H. Desuph Out L.H.	839	838	815	845	809	841	851	829	849	885	845	860
S.H. Desuph. In R.H.	880	845	900	885	911	851	920	892	900	926	881	869
S.H. Desuph. Out R.H.	841	834	812	830	803	840	860	835	860	884	850	851
MISCELLANEOUS												
I.D. Fan 2A RPM	690	690	690	690	690	690	690	560	480	690	540	460
I D Fan 2B RPM	680	670	675	680	680	680	679	560	480	670	540	460
F D. Fan 2A RPM	560	570	590	565	570	600	540	440	400	570	410	370
F.D. Fan 2B RPM	570	570	590	570	580	600	540	440	400	570	420	370
Fan Damper Position - (0-12)												
ID Fan 2A	12+	12+	12+	12+	12+	12+	12+	7.0	5.8	12+	7.4	6.0
ID Fan 2B	12+	12+	12+	12+	12+	12+	12+	7 0	5.8	12+	7.3	6 0
FD Fan 2A	12+	12+	12+	12+	12+	12+	12+	4.3	3.8	11.8	6.0	3.6
FD Fan 2B	12+	12+	12+	12+	12+	12+	12+	5 2	3.8	11.8	5.8	3 6
Drum Level In ± Norm. H_2O Level	-5.0	-5.0	-4.9	-5 0	-4.9	-5.0	-4.5	-5.0	-5.0	-5.0	-5.2	-5.0

BOARD DATA

	OVERFIRE AIR TILT VARIATION						LOAD VARIATION AT OPTIMUM CONDITIONS					
TEST NO	24	25	26	27	28	29	30	31	32	33	34	35
2A Mill AMPS	38	40	40	40	40	39	36	36	38	36	37	37
2B Mill AMPS	37	37	37	37	37	36	35	36	36	36	36	37
2C Mill AMPS	38	38	38	39	38	38	38	38	0	38	38	0
2D Mill AMPS	39	39	40	39	40	40	40	0	0	41	0	0
EXHAUSTER DAMPER POSITION - % OPEN												
0 - 12 Scale												
Mill 2A	6 0	6 0	6 0	6 1	5.9	5.8	5.5	5 4	5.6	5 4	5 4	6.0
Mill 2B	6 2	6 2	6.1	6.4	6 1	6 0	5.6	5 6	5 7	5.6	5 6	6 2
Mill 2C	6 0	6 0	6 0	6.2	5 9	5 8	5.5	5.4	0	5 4	5.6	0
Mill 2D	4 1	4 0	4 0	4.2	4.8	4 7	4 0	0	0	5 1	0	0
PULVERIZER FEEDER CAP - % OPEN												
0 - 12 Scale												
Mill 2A	6.0	6 0	6.0	6 2	6.0	5 8	5 5	5.5	5.6	5 4	5.5	6.0
Mill 2B	6.0	6.0	6.0	6.2	6.0	5.8	5.5	5.5	5.6	5.4	5 5	6.0
Mill 2C	6 6	6.6	6.5	6 7	6.4	6.3	6.0	6.0	0	5.9	6.0	0
Mill 2D	4 2	4 2	4.2	4 3	4.9	4.8	4.0	0	0	3.1	0	0
SPRAY VALVE POSITIONS - % OPEN												
SH Spray L	39	0	70	49	90	0	52	48	36	37	34	20
SH Spray R	40	0	70	48	88	0	50	48	36	37	33	20
RH Spray L	0	0	0	0	0	0	0	0	0	0	0	0
RH Spray R	0	0	0	0	0	0	0	0	0	0	0	0
BURNER TILT POSITIONS - DEGREES												
LR	0	-30	+30	0	+30	-30	0	-12	0	-22	-22	-10
RR	0	-30	+30	0	+30	-30	0	-12	0	-22	-22	-10
LF	0	-30	+30	0	+30	-30	0	-12	0	-22	-22	-10
RF	0	-30	+30	0	+30	-30	0	-12	0	-22	-22	-10
Feedwater Valve - % Open (0-12 Scale)	12+	12+	12+	12+	10.4	12+	12+	9.4	9.4	9 3	9.4	9.4
Air Htr 2A Recirc Damper - % Open	24	24	24	24	24	24	38	37	37	26	26	26
Air Htr 2B Recirc Damper - % Open	20	20	20	20	20	20	34	33	33	25	25	25

WATERWALL ABSORPTION RATES, KG-CAL/HR-CM^2

RIGHT WALL CENTERLINE TUBE RATES

TC #	1	3	5	7	9	19	22	44	47	57	60	62	64
ELEVATION	118'-6"	107'-6"	96'-6"	85'-6"	74'-6"	69'-6"	64'-7"	59'-7"	54'-9"	49'-11"	45'-7"	35'-7"	25'-7"
TEST 1	2.02	3.56	7.49	8.81	10.93	9.07	1.28	---	---	8.54	4.08	3.30	---
2	2.36	3.64	8.63	12.07	13.13	9.95	.86	---	---	6.51	5.99	3.12	---
3	1.33	2.85	5.18	7.02	8.08	7.55	.83	---	---	9.66	9.93	4.13	---
4	3.01	5.36	12.23	1.25	2.76	14.88	5.10	---	---	13.29	7.73	4.31	---
5	3.78	7.19	10.90	10.90	22.55	7.46	6.93	---	---	18.85	20.96	12.49	---
6	4.41	7.30	13.66	1.83	3.37	16.04	7.83	---	---	20.81	14.45	10.21	---
7	3.73	5.04	10.06	1.19	2.18	7.67	8.73	12.18	---	27.78	11.38	14.56	---
8	4.59	8.28	11.45	8.54	21.78	5.11	4.06	---	---	10.13	13.04	15.70	---
9	6.26	9.96	14.99	15.52	23.46	15.52	6.26	---	---	8.63	12.34	15.26	---
10	5.14	5.66	12.27	7.51	6.45	10.15	9.36	---	---	24.18	6.98	12.80	---
11	4.16	4.95	6.26	6.79	6.53	4.43	6.00	---	---	11.56	6.53	6.53	---
12	4.15	5.46	6.51	6.51	5.98	5.72	5.72	---	---	11.53	7.56	7.83	---
13	4.95	6.53	13.14	9.96	13.94	17.38	15.00	---	---	25.05	10.76	12.61	---
14	4.44	4.96	11.30	9.97	17.66	14.74	15.01	---	---	24.00	15.28	12.62	---
15	4.12	5.17	9.66	.37	3.34	7.80	13.36	---	---	3.34	10.71	10.98	---
16	5.25	5.77	8.15	2.38	7.62	10.26	12.38	---	---	3.42	8.68	9.47	---
17	6.47	7.26	9.90	3.33	6.99	10.96	13.61	---	---	3.84	10.70	12.55	---
18	3.61	4.91	9.92	.16	13.37	13.37	10.45	---	---	18.67	17.34	8.07	---
19	4.39	5.44	10.19	2.32	4.65	9.40	5.17	---	---	14.43	9.92	10.45	---
20	3.14	5.23	10.24	.64	4.18	2.63	12.1	---	---	20.58	18.20	9.72	---
21	4.00	5.31	12.45	.49	2.71	2.20	12.98	---	---	15.10	10.33	4.53	---
22	3.49	5.32	11.40	1.46	2.46	1.96	11.93	---	---	15.11	9.81	3.24	---
23	2.67	5.00	11.87	.91	2.67	1.90	11.87	---	---	15.32	10.02	3.70	---
24	4.76	5.28	12.68	9.24	7.92	3.98	8.18	---	---	23.80	12.68	7.92	---
25	3.00	5.08	10.63	6.66	6.13	2.48	11.95	---	---	32.55	20.43	13.01	---
26	4.61	6.71	14.66	13.07	19.69	2.80	12.80	---	---	15.45	10.15	4.35	---
27	4.22	6.32	8.43	10.02	15.85	10.81	11.34	---	---	18.76	15.05	12.40	---
28	7.16	8.22	11.93	14.04	17.22	11.66	12.72	---	---	13.25	11.93	7.43	---
29	5.42	7.80	8.32	9.91	11.24	9.91	12.03	---	---	27.63	17.33	17.86	---
30	7.55	9.14	9.93	8.08	3.87	6.23	9.14	---	---	4.65	7.02	8.34	---
31	7.07	7.60	8.65	6.80	7.07	11.56	7.07	---	---	18.98	16.07	9.98	---
32	5.21	6.00	7.05	6.00	5.47	8.90	4.42	---	---	14.73	12.87	7.05	---
33	7.27	7.53	7.80	7.80	7.27	11.24	14.15	---	---	24.47	14.95	16.54	---
34	7.52	7.52	8.84	8.05	8.05	9.37	11.22	---	---	15.47	13.35	14.14	---
35	6.60	5.81	6.60	6.33	6.33	8.18	7.92	---	---	10.56	17.45	7.92	---

WATERWALL ABSORPTION RATES, KG-CAL/HR-CM^2

FRONT WALL CENTERLINE TUBE RATES

TC #	2	4	6	8	13	38	51	61	63
Elevation	107'-6"	96'-6"	85'-6"	74'-6"	69'-6"	59'-7"	49'-11"	35'-7"	25'-7"
TEST 1	6.44	7.49	11.99	18.08	10.93	----	10.13	3.04	2.52
2	6.78	8.89	14.72	16.31	11.01	---	8.89	2.88	2.36
3	5.18	4.92	7.55	8.08	8.61	---	13.11	4.66	1.33
4	10.11	11.96	7.46	24.67	9.84	---	14.62	4.05	3.01
5	11.16	9.57	10.37	24.92	10.10	---	19.11	12.75	7.46
6	12.33	12.60	18.69	27.14	12.86	---	20.28	13.39	4.67
7	9.26	8.47	12.44	10.85	6.35	---	23.56	18.55	9.53
8	10.92	7.48	10.66	22.31	16.76	---	7.22	15.70	9.60
9	13.67	9.96	10.48	25.83	14.20	---	7.05	17.38	7.84
10	11.48	4.61	15.98	14.92	7.24	---	5.40	15.72	5.66
11	5.21	4.95	6.79	6.53	4.95	---	7.85	6.26	6.26
12	5.46	5.72	6.77	6.25	5.46	---	8.88	8.09	7.56
13	12.88	6.26	7.84	11.56	6.79	---	7.58	14.47	5.21
14	10.77	4.96	8.39	11.56	5.48	---	12.36	14.74	5.22
15	8.07	5.17	14.16	11.77	2.57	---	2.32	18.13	6.22
16	7.62	5.77	10.79	15.83	4.46	---	2.92	15.83	7.62
17	8.05	6.99	12.29	14.41	5.68	---	4.63	16.26	9.37
18	8.07	5.17	14.16	11.25	7.28	---	10.19	9.92	6.49
19	9.13	4.91	12.84	6.22	8.86	---	9.66	10.98	5.44
20	8.66	9.98	11.30	22.69	9.98	---	9.19	16.07	4.97
21	10.33	11.39	17.22	21.98	8.48	---	3.23	5.58	3.48
22	10.34	10.07	18.29	15.90	4.80	---	2.21	4.80	2.45
23	10.02	7.64	16.91	19.02	13.46	---	2.40	5.00	2.67
24	10.56	8.18	9.51	15.07	6.34	---	16.40	12.95	5.02
25	10.10	8.24	6.66	15.66	10.10	---	19.64	20.43	9.57
26	12.27	10.68	19.96	19.96	7.51	---	12.80	5.40	4.35
27	9.22	7.64	14.26	8.16	7.11	---	8.69	14.26	3.44
28	9.54	9.81	12.99	12.19	9.54	---	6.11	8.75	6.90
29	9.91	8.06	11.24	10.18	10.44	---	18.92	20.77	9.38
30	9.66	9.66	13.38	25.81	13.90	---	8.61	8.87	7.55
31	7.86	8.12	11.56	8.12	7.60	---	7.33	11.56	8.12
32	6.00	5.21	8.10	6.26	5.21	---	5.21	7.84	5.73
33	8.85	7.00	7.00	18.66	6.48	---	21.57	19.98	12.56
34	8.31	6.99	6.99	10.96	5.68	---	22.08	14.94	10.43
35	7.12	5.81	5.54	7.39	3.20	---	7.92	8.18	7.65

Alabama Power Co.
Barry #2

C-E Power Systems
Field Testing and
Performance Results

WATERWALL ABSORPTION RATES, KG-CAL/HR-CM^2

	Right Wall Horizontal Average Tube Rates			Rear Wall Horizontal Average Tube Rates	Left Wall Horizontal Average Tube Rates	Front Wall Horizontal Average Tube Rates		
TC #	17-21	42-46	55-59	23-29	30-34	10-16	35-41	48-54
Elevation	69'-8"	59'-7"	49'-11"	59'-7"	59'-7"	69'-6"	59'-7"	49'-11"
Test 1	8.65	9.54	8.28	5.78	11.67	11.94	10.31	8.24
2	9.53	9.16	5.82	4.97	12.23	12.34	11.11	6.92
3	7.97	9.27	9.58	4.79	10.72	8.56	8.85	11.87
4	13.51	11.84	7.90	6.01	10.20	13.20	15.68	9.39
5	5.67	9.98	10.64	12.22	17.10	16.33	17.34	18.73
6	14.40	15.11	16.75	8.07	14.53	17.01	17.41	12.26
7	7.84	11.96	18.26	8.21	9.04	10.90	16.12	17.13
8	3.66	7.63	7.10	9.22	14.12	13.80	20.10	20.73
9	7.38	10.05	6.53	14.01	14.83	16.45	18.43	17.94
10	8.20	16.31	15.28	12.13	19.48	14.92	18.98	13.86
11	4.84	5.09	9.18	9.10	4.79	6.35	7.59	7.76
12	5.62	5.46	9.16	8.74	6.19	5.72	6.38	8.75
13	10.18	14.34	15.70	13.94	16.06	12.93	17.64	13.27
14	8.34	15.34	17.92	14.06	16.81	13.91	18.09	13.66
15	9.70	11.38	9.41	10.62	18.29	10.77	15.70	8.54
16	11.70	10.93	12.13	10.46	18.37	12.74	16.45	9.09
17	13.77	10.44	11.95	10.44	16.47	13.17	16.88	10.35
18	7.31	12.77	16.73	6.07	14.48	10.81	17.16	16.12
19	6.96	4.61	8.72	7.52	7.50	9.70	14.43	9.54
20	2.89	9.52	13.62	6.42	7.77	10.92	16.25	9.16
21	2.76	10.14	13.51	5.51	13.72	15.85	18.76	8.42
22	2.52	9.36	13.43	6.28	14.85	13.48	17.66	7.74
23	3.19	10.16	13.64	6.04	15.54	19.17	17.12	12.28
24	12.22	12.22	8.55	9.74	15.86	11.89	16.08	9.18
25	9.63	14.00	22.35	9.61	14.18	12.04	16.76	13.81
26	10.54	12.21	10.25	7.53	14.45	14.22	13.95	10.17
27	10.81	12.40	14.70	8.14	13.52	9.88	10.03	8.88
28	12.94	14.44	12.81	9.21	17.60	13.52	14.80	7.26
29	11.34	16.07	20.06	12.18	12.72	12.30	16.76	17.63
30	9.52	10.66	4.48	12.01	11.47	14.00	16.51	10.51
31	7.71	10.38	17.84	10.85	8.85	7.33	16.78	9.14
32	6.32	7.98	14.02	8.53	9.02	5.21	14.51	8.11
33	10.08	17.06	18.21	10.44	10.66	8.33	16.05	16.05
34	8.21	14.67	13.35	9.11	9.27	8.10	13.79	16.57
35	7.65	10.76	10.12	9.05	9.50	7.75	9.20	9.42

WATERWALL CORROSION COUPON
DATA SUMMARY

WEIGHT LOSS EVALUATION

BASELINE TEST

Probe Loc.	Probe No.	Coupon No.	Initial Wt. GR.	Final Wt. GR.	Wt. Loss GR.	Wt. Loss/ Coupon MG/CM^2	Avg. Wt. Loss/ Probe MG/CM^2
1	I	1	199.2937	199.1341	.1596	3.1643	
		2	201.3871	201.2135	.1736	3.4418	2.9392
		3	198.3883	198.2384	.1499	2.9719	
		4	195.8045	195.6946	.1099	2.1789	
2	J	1	199.1977	199.0534	.1443	2.8609	
		2	199.6807	199.5009	.1798	3.5647	2.8088
		3	202.8649	202.7226	.1423	2.8213	
		4	202.3445	202.2442	.1003	1.9885	
3	E	1	199.0122	198.8632	.1490	2.9541	
		2	202.2508	202.1171	.1337	2.6507	2.13475
		3	201.9826	201.8976	.0850	1.6852	
		4	199.6584	199.5954	.0630	1.249	
4	L	1	202.5778	202.5080	.0698	1.3838	
		2	200.8579	200.7484	.1095	2.1769	1.91965
		3	202.7075	202.5924	.1151	2.282	
		4	197.7676	197.6750	.0926	1.8359	
5	K	1	199.5913	---	---	---	
		2	197.4684	197.2730	.1954	3.874	3.38826
		3	194.9513	194.7783	.1730	3.4299	
		4	202.0694	201.9251	.1443	2.8609	

Avg. Wt. Loss/Test 2.6381 MG/CM^2

WATERWALL CORROSION COUPON DATA SUMMARY

WEIGHT LOSS EVALUATION

BIASED FIRING TEST

Probe Loc.	Probe No.	Coupon No.	Initial Wt. GR.	Final Wt. GR.	Wt. Loss GR.	Wt. Loss/ Coupon MG/CM^2	Avg. Wt. Loss/ Probe MG/CM^2
1	B	1	197.9531	197.6484	.3047	6.0411	
		2	202.1660	201.8659	.3001	5.9499	5.8795
		3	198.3393	198.0383	.3010	5.9678	
		4	200.5603	200.2799	.2804	5.5593	
2	Q	1	199.3158	199.1437	.1721	3.4121	
		2	196.2751	196.0480	.2271	4.5026	4.3777
		3	202.8709	202.5541	.3168	6.2810	
		4	200.2327	200.0655	.1672	3.3150	
3	R	1	198.8940	198.7626	.1314	2.6051	
		2	199.8790	199.6842	.1948	3.8622	3.4081
		3	196.0683	195.8721	.1962	3.8899	
		4	199.3342	199.1690	.1652	3.2753	
4	M	1	199.5078	199.3628	.1450	2.8748	
		2	198.7039	198.4853	.2186	4.3341	3.8201
		3	198.3125	198.1121	.2004	3.9732	
		4	200.8838	200.6771	.2067	4.0981	
5	D	1	197.9655	197.7001	.2654	5.2619	
		2	202.9412	202.5809	.3603	7.1435	5.7289
		3	199.1306	198.7976	.3330	6.6022	
		4	198.2205	198.0234	.1971	3.9078	

Avg. Wt. Loss/Test 4.6429 MG/CM^2

WATERWALL CORROSION COUPON

DATA SUMMARY

WEIGHT LOSS EVALUATION

OVERFIRE AIR TEST

Probe Loc.	Probe No.	Coupon No.	Initial Wt. GR.	Final Wt. GR.	Wt. Loss GR.	Wt. Loss/ Coupon MG/CM^2	Avg. Wt. Loss/ Probe MG/CM^2
1	S	1	200.7678	200.5465	.2213	4.3876	
		2	196.0684	195.8121	.2563	5.0815	4.5244
		3	199.6433	199.3849	.2584	5.1235	
		4	197.8187	197.6419	.1768	3.5053	
2	T	1	200.7026	199.1437	.2802	5.5554	
		2	---	---	---	3.3540	3.9044
		3	593.7075	593.2000	.5075	3.3540	
		4	---	---	---	3.3540	
3	F	1	199.1897	198.9156	.2741	5.4344	
		2	199.4476	199.1351	.3125	6.1958	6.0401
		3	199.3119	198.9858	.3261	6.4654	
		4	199.0463	198.7404	.3059	6.0649	
4	N	1	202.8354	202.6125	.2234	4.4292	
		2	201.2249	200.9784	.2465	4.8872	3.7656
		3	---	---	---	2.8729	
		4	397.4898	397.2000	.2898	2.8729	
5	2	1	---	---	---	---	
		2	191.8528	191.6484	.2044	4.0525	3.9752
		3	192.7875	192.5909	.1966	3.8979	
		4	---	---	---	---	

Avg. Wt. Loss/Test 4.4419 MG/CM^2

TEST DATA SUMMARY
BARRY NO. 4

TEST NO		1	2	3	4	5	6	7	8	9	10	11	12	13
Date (1973)		1/23	1/23	1/23	1/23	1/23	1/23	1/23	1/23	1/24	1/24	1/24	1/24	1/19
Time		0830	0922	1022	1120	1238	1319	1413	1510	1245	1337	1440	1524	0930
TEST CONDITIONS														
Load	GROSS MW	348	348	347	334	299	298	294	294	322	237	311	302	325
Main Steam Flow	$X10^3$ KG/HR	1098	1089	1066	1066	925	884	884	909	952	907	939	918	975
SH DESH Spray	$X10^3$ KG/HR	62	56	63	43	61	54	77	43	59	36	36	67	75
Main Steam Outlet	C	520	525	538	518	521	538	531	523	532	528	534	534	529
Hot RH Outlet	C	516	523	538	510	504	527	532	496	521	504	510	523	535
Oxygen AH Inlet	%	2.8	2.4	2.1	1.2	3.7	3.2	2.9	1.2	2.8	1.6	1.6	2.8	3.1
Excess Air AH Inlet	%	14.9	12.8	11.0	6.0	20.5	17.0	15.1	5.7	15.1	8.2	8.2	14.7	16.6
Mill Classifier Settings	POS.	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	2.0	2.0	3.0
Burner Tilt	DEG.	0	0	+15	-25	0	0	+15	-20	0	-30	-30	0	0
Mills in Service	4A	A	A	A	A	-	-	-	-	-	-	-	-	A
* & Type of Fuel	4B	A	A	A	A	A	A	A	A	A	A	A	A	A
	4C	C	C	C	C	C	C	C	C	C	C	C	C	A
	4D	A	A	A	A	A	A	A	A	A	A	A	A	A
Bottom	4E	A	A	A	A	A	A	A	A	A	A	A	A	A
AIR COMPARTMENT DAMPER POSITION - % OPEN														
All Auxiliary (Control Room Ind.)		100	100	100	50	100	100	100	50	50	100	100	50	100
All Primary		50	50	50	100	50	50	50	100	100	50	50	100	50
Theoretical Air to Firing Zone	%	111.4	109.4	107.6	103.4	100.1	97.4	96.1	88.2	95.8	90.3	89.9	95.4	113.0
EMISSION LEVELS (ADJ. TO 3% O_2 DRY BASIS)														
NO_x	PPM	485	465	407	425	366	330	343	302	344	338	349	346	491
SO_2	PPM	2625	2973	3114	3050	2957	3035	3244	1461	3047	3028	2844	2742	1818
CO_2	PPM	37	138	96	126	29	76	125	115	132	132	112	74	23
NO_2	$GR/10^6$ CAL	1.04	.994	.869	.909	.781	.716	.734	.644	.734	.722	.743	738	1.05
SO_2	$GR/10^6$ CAL	7.74	8.82	9.23	9.05	8.77	9.00	9.63	4.34	9.04	8.98	8.44	8.14	5.74
MISCELLANEOUS														
O_2 (At AHO)	%	4.35	3 95	3.56	2.52	5.40	4.76	4.40	2.44	4.39	3.00	2.92	4.32	4.68
CO_2 (At AHO)	%	13.79	13.83	13.84	14.26	11.5	12.19	12.12	15.9	13.1	13.8	14.5	13.3	13.48

* Alabama Coal - A
Petroleum Coke (C Mill Only) - C
Midwest Coal - M
Combination Firing - A + C, M + C

TEST DATA SUMMARY
BARRY NO. 4

TEST NO.		17	18	19	20	29	30	31	32	33	34	35	37
Date (1973)		1/22	1/22	1/22	1/22	1/19	1/19	1/19	1/22	1/24	1/24	1/24	1/24
Time		1340	0857	0905	1203	1145	1245	1400	1103	0945	1000	1055	1145
TEST CONDITIONS													
Load	GROSS MW	290	295	292	281	328	330	330	286	346	345	360	348
Main Steam Flow	$X10^3$ KG/HR	862	880	875	884	1007	975	1020	862	1111	1111	1134	1089
SH DESH Spray	$X10^3$ KG/HR	68	53	54	34	72	72	72	54	45	48	36	63
Main Steam Outlet	C	536	534	538	521	533	537	513	528	527	523	527	535
Hot RH Outlet	C	529	520	532	496	543	541	510	521	516	516	523	541
Oxygen AH Inlet	%	3.4	4.45	3.25	1.73	1.45	2.2	1.5	4.0	2.8	1.75	2.4	2.4
Excess Air AH Inlet	%	18.8	26.0	17.6	8.7	7.2	11.2	7.3	22.4	14.8	8 8	12 2	12.5
Mill Classifier Settings	POS.	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3 0
Burner Tilt	DEG.	0	0	0	-30	0	+20	-30	0	-30	-30	0	0
Mills in Service	4A	M	-	-	-	A	A	A	-	A	A	A	A
* & Type of Fuel	4B	M	M	M	M	A	A	A	M	A	A	A	A
	4C	C	C	C	C	A	A	A	C	C	C	C	C
	4D	M	M	M	M	A	A	A	M	A	A	A	A
Bottom	4E	M	M	M	M	A	A	A	M	A	A	A	A
AIR COMPARTMENT DAMPER POSITION - % OPEN													
All Auxiliary (Control Room Ind.)		100	100	100	50	100	100	50	50	100	100	50	100
All Primary		50	50	50	100	50	50	100	100	50	50	100	20
Theoretical Air to Firing Zone	%	115.3	104.7	99.0	91.2	103.9	107 8	104 3	103.3	111.4	105 5	109 5	109.1
EMISSION LEVELS (ADJ TO 3% O_2 DRY BASIS)													
NO_x	PPM	516	391	337	319	393	426	466	329	580	521	477	515
SO_2	PPM	3805	3470	3340	3531	1939	2008	1715	3866	2946	2994	2755	2931
CO	PPM	22	37	61	49	98	44	49	65	32	28	211	69
NO_2	$GR/10^6$ CAL	1 16	839	.718	.680	.839	909	.994	704	1.24	1 11	1 02	1.10
SO_2	$GR/10^6$ CAL	11.29	9.49	9.90	10.48	5 74	5.96	5 08	11.3	8.73	8.87	8.17	8 69
MISCELLANEOUS													
O_2 (At AHO)	%	5.09	6.30	4.86	3.11	2.78	3.64	2.80	5 70	4.33	3.13	3 83	3 88
CO_2 (At AHO)	%	11 46	12 27	12.51	13.29	15.37	14.52	15 25	12.0	14 45	15.35	14.04	13.73

* Alabama Coal - A
Petroleum Coke (C Mill Only) - C
Midwest Coal - M
Combination Firing - A + C, M + C

ACCELERATED CORROSION RATE DATA

ALABAMA POWER, BARRY NO. 4

Firing Condition	Corrosion Rate*, Mils/Yr
Baseline	34 24
Baseline	17 18
Baseline	11 13
Baseline	16 16
Low NO_x	32 26
Low NO_x	41 52
Low NO_x	77 87
Low NO_x	13 18

* Paired corrosion rate values obtained on two coupons exposed on the same probe.

TYPICAL COAL ANALYSIS

ALABAMA COAL

Obtained From
Peabody Coal Company
Analysis by Pittsburg Testing Laboratory

Proximate Analysis As Received

SAMPLE IDENTIFICATION	ABC	PEABODY WARRIOR	PEABODY TIGER
Date	9/30/72	9/14/72	9/30/72
Moisture - %	8.40	10.1	9.2
Ash - %	13.00	11.36	9.4
Volatile Matter - %	25.92	19.75	28.8
Fixed Carbon - %	52.68	58.79	52.6
Sulfur - %	2.02	2.67	2.55
HHV - BTU/LB	11,897	12,131	12,269

Ultimate As Fired

Date		1/07/72
Moisture - %		9.09
Carbon - %		70.01
Hydrogen - %		3.83
Oxygen - %		3.83
Nitrogen - %		1.28
Sulfur - %		2.21
Ash - %		9.75
HHV - BTU/LB		12,290

MIDWEST BITUMINOUS

Analysis By Alabama Power Co.

Proximate Analysis As Received

SAMPLE IDENTIFICATION	EAGLE 1	EAGLE 2
Date	11/72	11/72
Moisture - %	8.63	10.36
Ash - %	9.75	8.86
Volatile Matter - %	----	----
Fixed Carbon - %	----	----
Sulfur - %	2.75	3.15
HHV - BTU/LB	13,072	13,023

PETROLEUM COKE

Analysis by Gulf Oil Company, Port Arthur, Texas

Proximate Analysis As Received

SAMPLE IDENTIFICATION	A2602
Date	2/17/70
Moisture - %	7.7
Ash - %	.10
Volatile Matter - %	10.80
Fixed Carbon - %	81.40
Sulfur - %	3.53
HHV - BTU/LB	15,700

REFERENCES

1. Blakeslee, C. E. and Selker, A. P.,"Program For Reduction of NO_x From Tangential Coal Fired Boilers - Phase I"
2. Crawford, A. P., Manny, E. H. and Bartok, W., "Field Testing: Application of Combustion Modifications to Control NO_x Emissions From Utility Boilers"

APPENDIX I
COMPFLOW - WINDBOX
COMPARTMENT AIR FLOW DISTRIBUTION COMPUTER PROGRAM

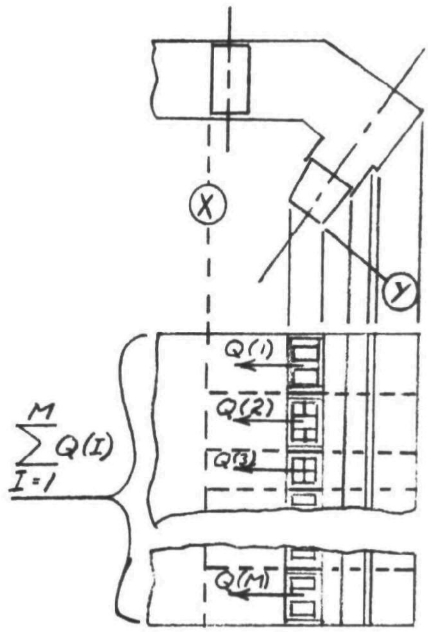
INTRODUCTION

A description of COMPAIR, a computer program which calculates the windbox assembly air flow distribution, was presented in Reference 1. The program has been subsequently found to be deficient; the approach taken in the calculation of the compartment loss coefficient resulted in operational difficulties in certain cases. The program was revised to eliminate this problem.

The revised program, COMPFLOW, is described herein. The basic assumptions and limitations of the calculation method are outlined and discussed. Program runs for two tests conducted at Barry #2 are included.

ANALYSIS

Consideration will be initially focused on those cases where the air flow to each compartment is supplied solely by the windbox.



Assumptions:

1. Constant total pressure at compartment inlet plane, i.e., P_{T_X} = const.

2. Constant density, i.e., R(I) = R = const.

3. Constant static pressure at nozzle exit plane, i.e., P_{s_y} = const.

4. Fully turbulent flow, i.e., Head Loss $\approx$ (Velocity)^2.

Utilizing these assumptions, it follows that

$$2 * \left[\frac{P_{T_X} - P_{s_y}}{R}\right] = K(I) * \left[\frac{Q(I)}{A(I)}\right]^2 = \text{const.} \quad \text{- - - - - - - - - - - -(1)}$$

Where K(I) = loss coef. for Compartment "I"
Q(I) = volume rate of flow for Compartment "I"
A(I) = nozzle exit area of Compartment "I"

Equation (1) yields

$$\frac{\frac{Q(I)}{\sum_{I=1}^{M} Q(I)}}{} = \frac{A(I)/\sqrt{K(I)}}{\sum_{I=1}^{M} A(I)/\sqrt{K(I)}} \text{ ---------------------------------------(2)}$$

By definition

$$P_{T_y}(I) = P_{s_y} + \frac{R}{2} * \left[\frac{Q(I)}{A(I)}\right]^2 \text{ -----------------------------------(3)}$$

Using Equations (1) and (3), we have

$$2 * \left[\frac{P_{T_X} - P_{T_y}(I)}{R}\right] = 2 * \left[\frac{P_{T_X} - P_{s_y}}{R}\right] - \left[\frac{Q(I)}{A(I)}\right]^2 = [K(I) - 1] *$$

$$\left[\frac{Q(I)}{A(I)}\right]^2 \text{ ---(4)}$$

In order to arrive at a relation for K(I), the windbox compartment total pressure loss will be set equal to the sum of its component losses, i.e.,

$$2 * \left[\frac{P_{T_X} - P_{T_y}(I)}{R}\right] = [K_D(I) + K_\beta(I) + K_{90}(I) + K_f(I)] * \left[\frac{Q(I)}{B(I)}\right]^2 +$$

$$K_N(I) * \left[\frac{Q(I)}{A(I)}\right]^2 \text{ ---(5)}$$

Where B(I) = inlet flow area of Compartment "I"

Assumption (5): The values listed below, which allow for no interaction, adequately represent the compartment total pressure loss.

LOSS	VALUE	COMMENT	REFERENCE
Miter bend, $K_\beta(I)$	0.3	Typical, β = 45°	2
90° bend, $K_{90}(I)$	1.2	-----	2
Friction, $K_f(I)$	0.1	$f \approx 0.02, \frac{L}{D} \leq 5; K_f = f\frac{L}{D}$	2
Nozzle, $K_N(I)$	0	$K_N = \frac{1}{C_V} - 1$; Assume $C_V = 1$	3
Damper, $K_D(I)$	Figure 1	Assumed to include inlet loss	4

Using the above values, Equations (4) and (5) yield

$$K(I) = 1 + [1.6 + K_D(I)] * \left[\frac{A(I)}{B(I)}\right]^2 \text{ --------------------------(6)}$$

For coal fired units the mill air must be taken into account. Using Equation (2) for the secondary air flow, it follows that

$$\frac{W(I)}{W1 + W2} = \frac{\left[\frac{A(I)/\sqrt{K(I)}}{\sum_{I=1}^{M} A(I)/\sqrt{K(I)}}\right] * W1 + X(I) * W2}{W1 + W2} \qquad \text{-------------------------(7)}$$

where W(I) = mass rate of flow to Compartment "I"
W1 = total windbox air to corner
W2 = total mill air to corner
X(I) = fraction of mill air to Compartment "I"

Figure 1 and Equations (6) and (7) constitute the basis of COMPFLOW.

Note that if some other source of air were available to the windbox assembly, Equation (7) would yield the flow distribution with adjustments in the definitions of W2 and X(I).

Note also that if there is no corner to corner biasing of compartment dampers, Equation (7) may, to a very good approximation, be regarded on a furnace/elevation basis.

PROGRAM DESCRIPTION

A description of the program input is as follows:

Input

Fuel and Air Compartment Geometry

Number of Compartments
Width of Compartments
Height of Individual Compartments
Number of Dampers per Compartment
Nozzle Exit Area per Compartment

Test Data

Percent Excess Air
Total Air Flow
Compartment Damper Positions
Fuel Elevations in Service

Typical program outputs for Alabama Power Co., Barry #2, tests 5 and 20, are shown on Figure 2. These runs represent both normal and overfire air operation. A definition of the output is shown on Figure 3.

DISCUSSION

A. Development of the Method

The method presented herein, of calculating the windbox assembly flow distribution, is the result of what is obviously a greatly simplified treatment; numerous assumptions were made in the development of the method. The validity of each of these assumptions will now be examined.

Assumption (1): Constant total pressure at the compartment inlet plane.

Air issuing from a duct branches to each of the windbox assemblies; the fluid is moving at a low velocity relative to that at the nozzle exit. It would be reasonable to assume that the total pressure loss between the supply duct exit and the compartment inlet plane is a negligible fraction of the velocity head at the nozzle exit. It is all the more realistic to assume, as is the case herein, that the total pressure distribution in the supply duct and the consequent losses along individual streamlines, are such that the total pressure is uniform at the compartment inlet plane.

Assumption (2): Constant density fluid within the windbox assembly.

The reasoning for this assumption is analagous to that set forth in (1); note that while isothermal flow is not implied between the supply duct and the compartment inlet, it is assumed within the windbox assembly.

Assumption (3): Constant static pressure at the nozzle exit plane.

The static pressure of the jets issuing from the windbox nozzles is equal to the local furnace pressure. The variation in furnace pressure throughout this region should be negligibly small.

Assumption (4): Fully turbulent flow.

This is a valid assumption for the vast majority of cases; unit Reynolds numbers(based on nozzle exit velocity) greater than 10^5 per foot are typical even for small opening of compartment dampers.

Assumption (5): The compartment loss coefficient for existing configurations are adequately represented by the formulations presented herein (i.e. Figure 1 and Equation (6)).

Curves of K versus damper position, as calculated from Figure 1 and Equation (6), are shown in Figure 4 for compartment outlet/inlet area ratios (i.e. A(I)/B(I) of 0.534, 0.322 and 0.136; these values cover the range of our existing compartments. Results obtained from the cold-flow model tests of Reference 5, at area ratios of 0.322 and 0.136, are also shown in this figure; the test results are seen to be in excellent agreement with the predicted values. These test results indicate that nozzle tilt, flow rate, firing angle, the presence of turning vanes and probably compartment inlet interaction, are secondary influences on compartment pressure loss and consequently on compartment flow rate. These results justify the omission of these factors in the development of the method presented herein.

B. Previous Calculations

In the previous method of calculating the windbox assembly flow distribution (Reference 1), the compartment loss coefficient was determined from the equation

$$K(I) = KO + K_D(I) * \left[\frac{A(I)}{B(I)}\right]^2$$

where $K_D(I)$ was specified as herein KO evaluated from test values of the total secondary air flow and windbox/furnace ΔP. Highly closed damper positions result in a very large value of K_D, as is seen in Figure 1, and a small error in this parameter will result in a large variation in KO. Program runs with all compartment dampers at or near the full open position yielded values of KO consistent with the value presented herein, i.e.,

@ 100% open, $K_D \approx 0.1$, K = K/100%

from Equation (6), $K/100\% \approx 1 + 1.7 * \left[\frac{A}{B}\right]^2$

for existing geometries, $0 < \left[\frac{A}{B}\right]^2 < 0.29$

therefore, with $KO \approx K/100\%$, $1 < KO < 1.5$

Program runs with one or more compartment dampers highly closed would sometimes yield values of KO outside this range; in rare cases this would result in operational difficulties.

REFERENCES

1. N. D. Brown, "COMPAIR, Burner-Compartment Air-Flow Distribution Computer Program," Project No. 121029, September, 1971.

2. "Flow of Fluids Through Valves, Fittings, and Pipe," Crane Co., Technical Paper No. 409, May, 1942.

3. R. V. Giles, "Fluid Mechanics and Hydraulics," Schaum Publishing Co., 1962.

4. P. S. Dickey & H. L. Coplan, "A Study of Damper Characteristics," Trans. of the ASME, February, 1942.

5. N. D. Brown, "Windbox Compartment Flow Tests," Test Report 72-6, Project No. 412003, March 2, 1972.

DAMPER LOSS COEFFICIENT
VS.
POSITION

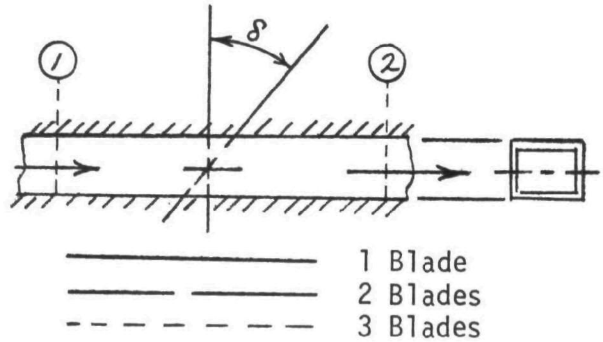
$$K_D = \frac{2(P_{T_1} - P_{T_2})/R}{(Q/A)^2}$$

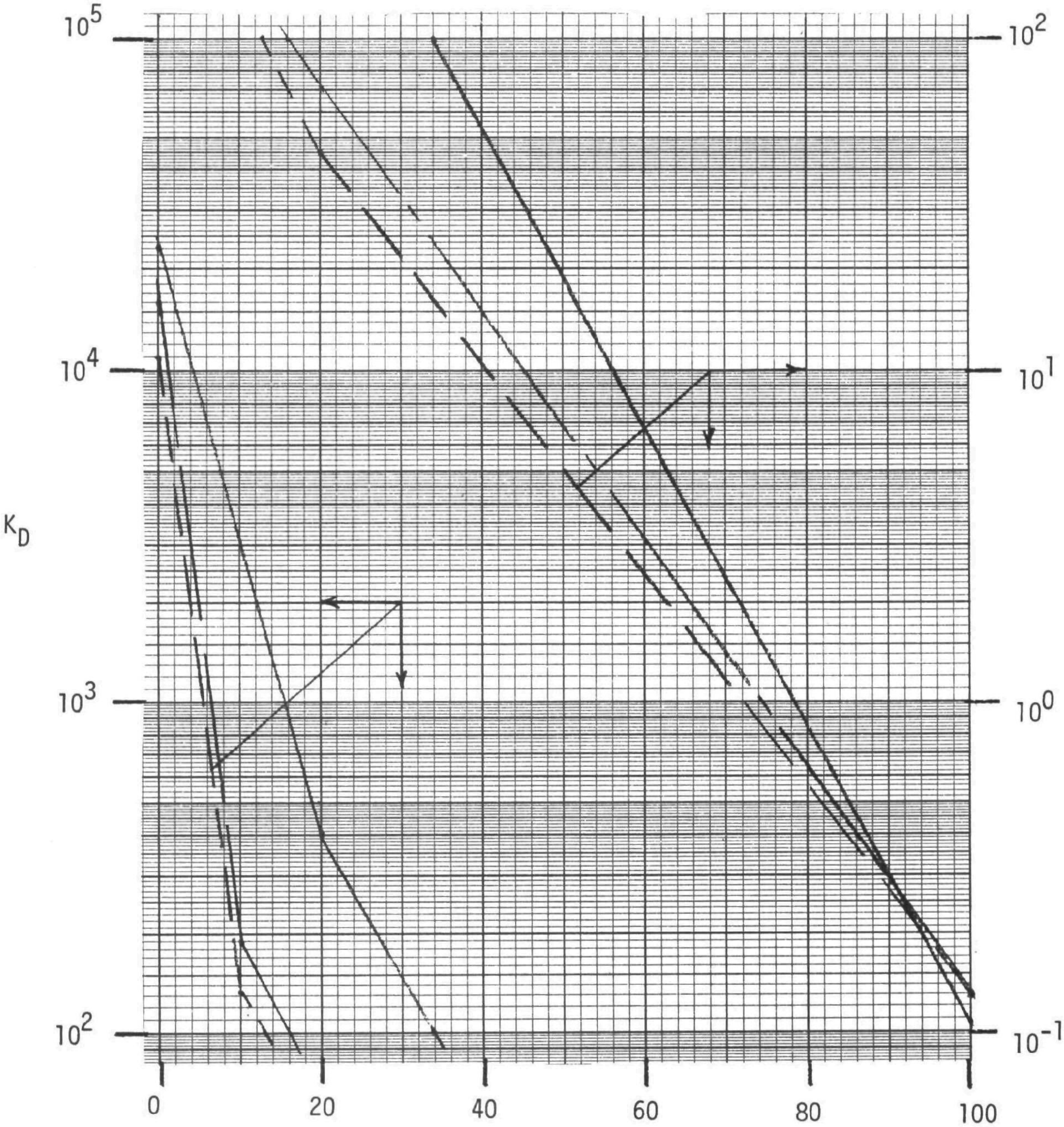
P_{T_1} = Total Pressure @ "1"

P_{T_2} = Total Pressure @ "2"

R = Fluid Density
Q = Volume Rate of Flow
A = Flow Area

% Open = $(\delta/90) \times 100$





AIR FLOW DISTRIBUTION TO WINDBOX COMPARTMENTS
ALABAMA POWER AND LIGHT CO., BARRY #2
EPA '73 - '74 TESTS

FLOW DISTRIBUTION FOR TEST NO. 5

PER CENT EXCESS AIR 22.7

COMPART-MENT (NO.)	FIRING	AREA WT. FLOW (% OF TOTAL)	DAMPERS (% OPEN)	ACTUAL FLOW (% OF TOTAL)
1		9.44	60	7.8
2	Yes	6.55	20	8.39
3		18.03	100	16.37
4	Yes	6.55	20	8.39
5		9.44	100	8.64
6		9.44	100	8.64
7	Yes	6.55	20	8.39
8		18.03	100	16.37
9	Yes	6.55	20	8.39
10		9.44	100	8.64

Firing Fuel Compartment Total Air Flow (%) = 33.55
Air Flow Above Burner Zone (%) = 3.9
Air Flow to Burner Zone (% of Theor. Air) = 117.91

FLOW DISTRIBUTION FOR TEST NO. 20

PERCENT EXCESS AIR 24.2

COMPART-MENT (NO.)	FIRING	AREA WT. FLOW (% OF TOTAL)	DAMPERS (% OPEN)	ACTUAL FLOW (% OF TOTAL)
1		9.44	100	9.42
2		6.55	100	6.85
3		18.03	50	14.93
4	Yes	6.55	30	10.27
5		9.44	50	7.68
6		9.44	50	7.68
7	Yes	6.55	30	10.27
8		18.03	50	14.93
9	Yes	6.55	30	10.27
10		9.44	50	7.68

Firing Fuel Compartment Total Air Flow (%) = 30.82
Air Flow Above Burner Zone (%) = 23.73
Air Flow to Burner Zone (% of Theor. Air) = 94.72

COMPFLOW

Definition of Output

1. The "AREA WT. FLOW" is the ratio of the compartment free area to the total free area of the corner; as such it is a realistic approximation of the actual compartment (secondary) flow only when all compartment dampers are full open.

2. The comparment "ACTUAL FLOW" is the ratio of the compartment mass flow rate (including mill air if applicable) to the total mass flow to the corner (see ANALYSIS, equation (7)).

3. The "FIRING FUEL COMPARTMENT TOTAL AIR FLOW" is the ratio of the total mass flow rate to firing fuel compartments (including mill air if applicable) to the total mass flow to the corner.

4. The "AIR FLOW ABOVE BURNER ZONE" is defined as the percentage of the total mass flow rate supplied above the uppermost firing fuel compartment, less 50% of the flow to the compartment immediately above it.

5. % Theoretical Air to Burner Zone. $= \left(1 - \frac{\text{\% Air Above Burner Zone}}{100}\right)(100 + \text{\% Excess Air})$

COMPARTMENT LOSS COEFFICIENT VS. DAMPER POSITION

$$K = \frac{2(P_{T_x} - P_{s_y})/R}{(Q/A)^2}$$

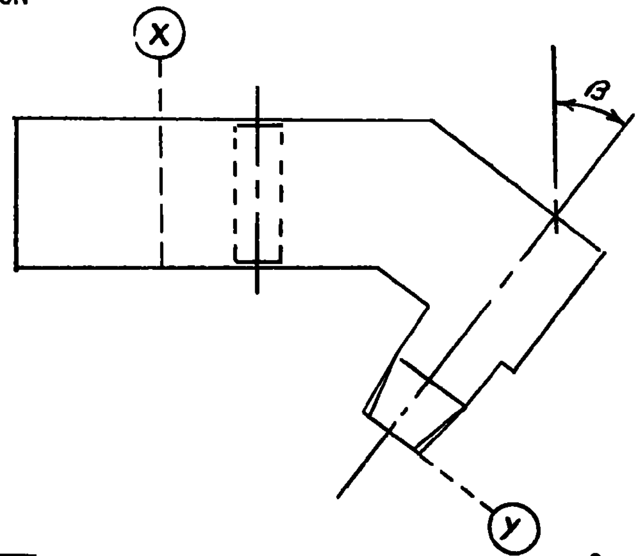
P_{T_x} = Total Pressure @ "x"

P_{s_y} = Static Pressure @ "y"

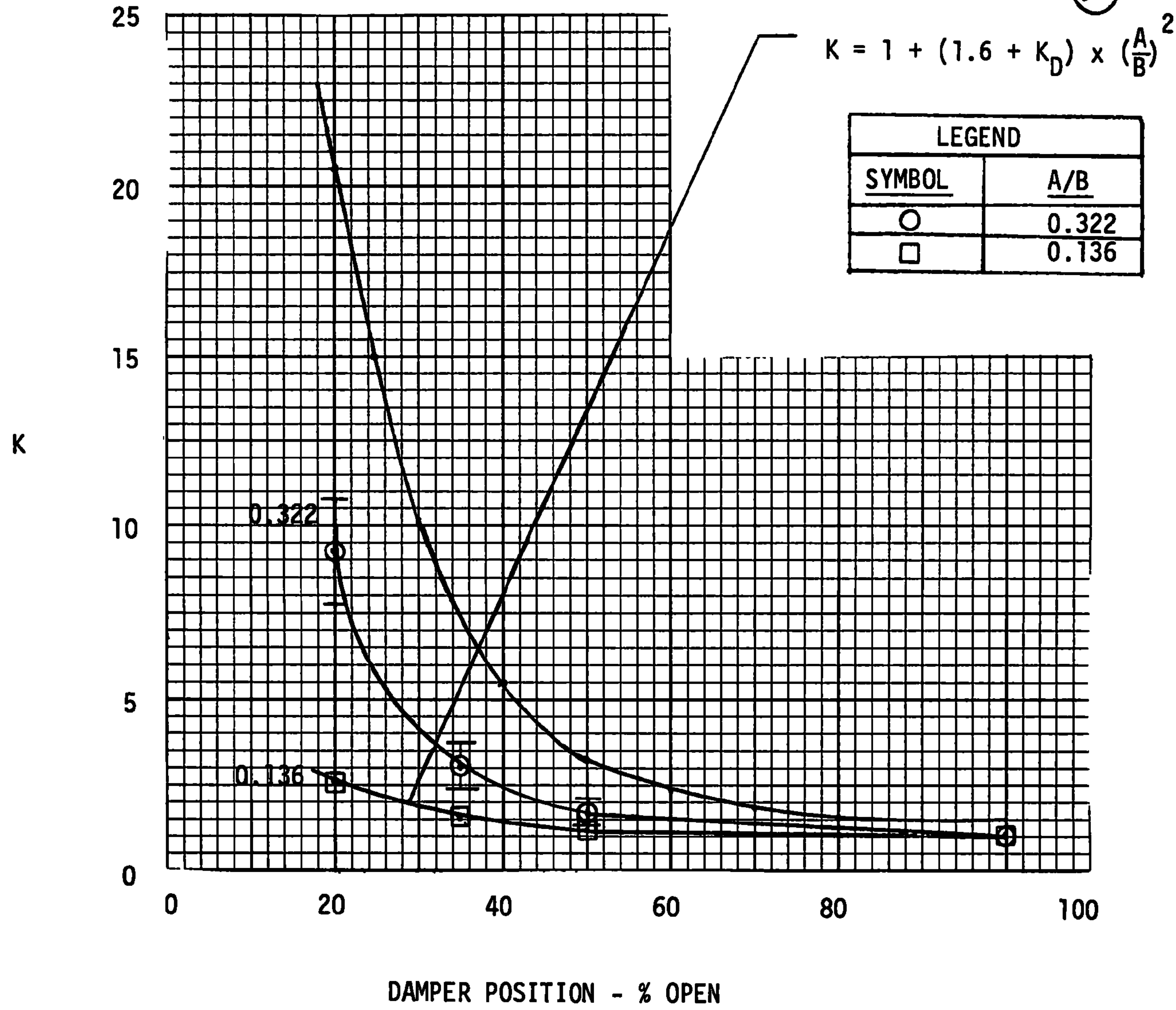
R = Fluid Density

Q = Volume Rate of Flow

A = Nozzle Exit Area



$$\frac{A}{B} = 0.534 = \frac{\text{Nozzle Exit Area}}{\text{Compart. Inlet Area}}$$



TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-650/2-73-005-a	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE Program for Reduction of NOx from Tangential Coal-Fired Boilers, Phase II		5. REPORT DATE June 1975
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Ambrose P. Selker		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Combustion Engineering, Inc. 1000 Prospect Hill Road Windsor, Connecticut 06095		10. PROGRAM ELEMENT NO. 1AB014; ROAP 21ADG-080
		11. CONTRACT/GRANT NO. 68-02-1367
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development NERC-RTP, Control Systems Laboratory Research Triangle Park, NC 27711		13. TYPE OF REPORT AND PERIOD COVERED Phase II Final; 7/73 - 3/75
		14. SPONSORING AGENCY CODE
15. SUPPLEMENTARY NOTES		

16. ABSTRACT The report gives results of Phase II of a program to reduce the emission of NOx from tangential coal-fired boilers. Results of Phase I, during which a suitable utility steam generator was selected to be modified for the Phase II studies, were presented in final report EPA-650/2-73-005, dated August 1973. The Phase II work included: the design, fabrication, and delivery of an overfire air system for the test unit; the installation of test equipment; planning; and baseline, biased firing and overfire air studies for NOx emission control while burning a Kentucky bituminous coal type. These test programs included an evaluation of the effect of variations in excess air, unit slagging, load, and overfire air on unit performance and emission levels. The effect of biasing combustion air through various out-of-service fuel nozzle elevations was also evaluated. The effect of biased firing and overfire air operation on waterwall corrosion potential was evaluated during three 30-day baseline biased firing, and overfire air corrosion coupon tests. Unit loading and waterwall slag conditions had minimal effects on NOx emission levels. Reductions in excess air levels and overfire air operation were found to be effective in reducing NOx emission levels.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution	Air Pollution Control	13B
Nitrogen Oxides	Stationary Sources	07B
Combustion Control	NOx Reduction	21B
Coal	Tangential Firing	21D
Boilers	Combustion Modification	13A

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