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SYSTEMATIC FIELD STUDY OF NO_x EMISSION CONTROL METHODS FOR UTILITY BOILERS

U.S. ENVIRONMENTAL PROTECTION AGENCY

BA-00128

SYSTEMATIC FIELD STUDY OF NO_x EMISSION CONTROL METHODS FOR UTILITY BOILERS

by
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ESSO RESEARCH AND ENGINEERING COMPANY
Government Research Laboratory
Linden, New Jersey

FOREWORD

This report presents the findings of the Boiler Test Program portion of a "Systems Study of Nitrogen Oxide Control Methods for Stationary Sources - Phase II," performed in the Government Research Laboratory of Esso Research and Engineering Company under the sponsorship of the Office of Air Programs of the Environmental Protection Agency (Contract No. CPA 70-90). Dr. William Bartok was the contractor's Project Director, and Mr. Allen R. Crawford acted as the senior member of the Boiler Test Program study team. The findings of other research conducted under this contract, "Laboratory Studies and Mathematical Modeling of NO_x Formation in Combustion Processes" are presented in a companion report (GRU.3GNOS.71).

To facilitate the presentation of this study the overall findings of the Boiler Test Program and the recommendations based thereon have been arranged to precede the detailed discussion of the results.

We wish to acknowledge the cooperation of electric utility concerns, American Electric Power, Consolidated Edison Company, the Los Angeles Department of Water and Power, Public Service Electric and Gas Company of New Jersey, and the Tennessee Vally Authority, which made this study possible. The participation of boiler manufacturer subcontractors, Babcock & Wilcox, Combustion Engineering, Inc., and Foster Wheeler Corp. in some of the boiler emission tests is also acknowledged. Finally, we wish to express our appreciation to the Esso Research and Engineering Company research technicians, Messrs. L. W. Blanken, T. C. Gaydos, and W. H. Reilly for their skilled performance of the boiler emission tests.

Mr. Stanley J. Bunas was the EPA Technical Project Officer during the initial part of this program and Mr. Robert E. Hall was the Technical Project Officer during the latter part.

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SUMMARY

As a major part of Esso's "Systems Study of Nitrogen Oxide Control Methods for Stationary Sources in Phase II," funded by the EPA under Contract No. CPA 70-90, a utility boiler field test program was conducted. The objectives of this study were to determine new or improved NO_x emission factors by fossil fuel type and boiler design, and to assess the scope of applicability of combustion modification techniques for controlling NO_x emissions from such installations. In addition, the concentrations of other combustion flue gas species were also determined, to evaluate the effect of combustion modification techniques on the emission of other potential pollutants, such as unburned combustibles.

A specially designed mobile sampling-analytical van was assembled for the purpose of this boiler test program. This system was equipped with continuous monitoring instrumentation for the measurement of NO, NO_2, CO_2, O_2, CO and hydrocarbons, with the later addition of an SO_2 monitor. Probing of the flue gases from boiler duct-work was accomplished by simultaneously withdrawing sample streams from 12 different locations, varied as dictated by the duct configuration. Usually, four sample streams compositing the contents of three probes each were monitored during test runs.

A statistically designed test program was conducted with the cooperation of utility owner-operators. Boilers to be tested in the program were selected based on fuel type fired, boiler size and design, and special features of interest to NO_x emission control. The objective was to make the boilers selected a reasonable "micro-sample" of the U.S. boiler population. Wall-fired, tangentially-fired, cyclone-fired, and vertically-fired boilers were tested in the program. Althogether, 17 boilers and 25 boiler-fuel combinations were tested.

The NO_2 portion of the total NO_x content in the flue gas was found to average five per cent or less, whenever NO_2 could be measured. For test data which did not include NO_2 measurements, the NO_x was calculated as 105% of the NO measured.

Major combustion operating parameters investigated included the variation of boiler load, level of excess air, firing pattern (staged, "off-stoichiometric", or "biased firing"), flue gas recirculation, burner tilt, and air preheat temperature. It was found that while NO_x emission levels reached very high levels (on the order of 1000 ppm) in large gas fired boilers, combustion modifications, particularly low excess air firing and staged air supply resulted in some cases in emission reductions at full load on the order of 80%. However, even for gas fired boilers, the degree of effectiveness of combustion modifications varied with individual boiler characteristics, such as burner design and spacing. Load reductions resulted in large reductions in NO_x emissions for gas fired boilers.

Similar trends on the effectiveness of combustion modifications were observed with fuel oil firing, albeit with a lesser degree of effectiveness. NO_x emission reduction from oil firing is less responsive to load changes and the application of combustion modification techniques is somewhat more difficult than in gas firing.

In coal firing, promising exploratory data were obtained on two of the seven coal fired boilers tested. For coal, the key to NO_x reductions (apart from operating under reduced load) appears to be the firing of burners with substoichiometric quantities of air, followed by second stage air injection for the burn-out of combustibles. This was accomplished in a 175 MW front wall fired boiler and in a 575 MW tangentially fired boiler with better than 50% reductions in NO_x, operating at 80-85% of full load. Boiler manufacturers participated in testing three coal fired boilers manufactured by them to assess the steam-side consequences (i.e., effects on thermal performance, slagging characteristics, coal in the fly-ash, and other boiler operability features) of applying combustion modifications. In the short-term tests conducted in this program, the boiler manufacturers (Babcock and Wilcox, Combustion Engineering and Foster-Wheeler) did not find undue problems caused by combustion modifications.

Unburned combustible emissions, i.e., CO and hydrocarbons were found to be very low under base-line boiler operating conditions for all boilers tested. However, using low excess air firing, the CO levels can increase sharply, and in fact, set the lower limit on excess air. In tests where unburned carbon in the fly ash was measured by boiler manufacturers, combustion modifications (staging with low excess air firing) did not result in increased carbon in the fly ash. More detailed testing will be needed under carefully controlled conditions.

The emission factors established in this study in conjunction with the overall correlations developed for NO_x emissions will allow making better estimates for individual boilers, according to fuel type fired, boiler size and design.

It is concluded that modification of combustion operating conditions offers good promise for the reduction of NO_x emissions from utility boilers. Further cooperative testing with boiler owner-operators and manufacturers are required to optimize and demonstrate the general applicability of these techniques to the control of NO_x emissions from gas and oil fired installations and to establish their complete potential for coal fired boilers.

1. INTRODUCTION

In Phase I of a "Systems Study of Nitrogen Oxide Control Methods"[1] sponsored by NAPCA (Contract No. PH 22-68-55), Esso Research and Engineering Company characterized the stationary NO_x emission problem in the U.S., assessed existing and potential control technology on the basis of cost-effectiveness, and developed a comprehensive set of 5-year R&D plans for stationary NO_x emission control. In addition, a first-generation mathematical model of NO_x formation in gas-fired combustion processes was formulated, and knowledge gaps pertinent to the NO_x control problem were defined.

The Phase I study established that stationary NO_x emissions predominantly result from fossil fuel combustion processes. Electric utility boilers were found to represent the largest stationary NO_x emission source category. Combustion modification techniques have been identified as potentially the most attractive for stationary NO_x control because of their relative simplicity and potentially low cost. However, the scope of applicability and degree of effectiveness of combustion modification techniques had to be defined on a systematic basis for the variety of combustion installations which emit NO_x.

As part of EPA's program on stationary NO_x emission control, based on the recommendations of the Phase I NO_x systems study, Esso Research and Engineering Company initiated further studies on this air pollution control problem under Contract CPA 70-90.

The present Phase II portion of the NO_x systems study had the following major objectives:

(a) A statistically designed systematic study was designed and conducted on utility boilers. One objective of this field study was to obtain new or improved emission factors based on parametric variations of fuel type, boiler size and design, and operating features. Another major objective of this systematic study (hereafter referred to as the "Boiler Test Program"), was to evaluate the effects of limited changes in design and operating parameters on NO_x emissions from existing power plant boilers. A representative sample of the U. S. boiler population was selected for these tests, in some of which boiler manufacturers also participated to assess the effects of operating changes on boiler performance.

(b) The first-generation mathematical model of NO_x formation and decomposition in combustion processes was extended. Additional kinetic information was used, and the model was programmed to incorporate the combustion of fuel oil droplets and coal particles. Mixing effects were simulated by programming a "macromixing" model to improve the model's approximation of actual combustion conditions. The predictions of this model were compared with actual experimental and test data. Further development of the model was found necessary for its use to guide research on combustion modification techniques for reducing NO_x emissions from existing equipment and to predict good combustor design.

(c) Laboratory studies were conducted to define basic factors affecting nitrogen oxide formation in the combustion of fossil fuels. Flame kinetics, the concentration of potential intermediate species and the relative role of bound nitrogen in the fuel were investigated. These laboratory studies were designed to provide a better understanding of the complex mechanism of NO_x formation in combustion processes and to provide information for the development of the NO_x mathematical model.

(d) Major modifications deemed necessary for the control of NO_x and other pollutant emissions were outlined in cooperation with boiler operators and boiler manufacturers. The recommended modifications are discussed in this report.

This report presents the detailed findings of the Boiler Test Program. Work performed on laboratory-scale combustion phenomena and mathematical modeling is discussed in a separate companion report (GRU.3GNOS.71).

2. OVERALL FINDINGS OF BOILER TEST PROGRAM

The NO_x emission data obtained in our Boiler Test Program were analyzed with the objective of developing overall correlations on all of the boilers tested with gas, oil, and coal firing. As discussed in this section, it was possible to arrive at statistically significant overall correlations applicable to all (or most) boilers tested within a given fuel category, regardless of the type of firing. Furthermore, the relationship between NO_x emissions and boiler load was established according to fuel type, covering again all types of firing methods.

These overall correlations are useful from several standpoints. First, they provide a common basis for rationalizing the NO_x emission data measured in testing boilers of different size and type, fired with different fuels, and subjected to combustion operating changes for NO_x emission control. Second, they can be used in conjunction with the NO_x emission factors developed based on the results of this study for making definitely improved emission estimates for boilers for which the emission levels have not been determined. Third, and perhaps most important, these overall correlations can be used for planning on a rational basis future field emission tests aimed at optimizing combustion control methods for different types of utility boilers and operations.

The overall correlations and conclusions resulting from this study, concerning the control of NO_x emissions from utility boilers, are discussed in this section including emission factors for NO_x and CO. Further sections of this report will discuss our recommendations for boiler operators and manufacturers on emission control, the details of this study and our recommendations on future boiler emission field testing studies.

2.1 Overall Correlations and Conclusions

In section 6 the individual boiler test results are presented for gas, oil and coal fuels. In this section we will analyze the results for all boilers tested according to fuel type, and then these results will be compared for all three fuels.

Summary tables of NO_x emissions have been prepared for boilers firing gas, oil, and coal, respectively. Each boiler is identified in these tables by its code letter, size (MW generating capacity), and type of firing. Uncontrolled NO_x emissions and per cent reductions for each of the combustion control methods applied are shown corresponding to the boiler load levels tested in the experimental program.

2.1.1 Gas Fired Boilers

As shown in Table 2-1, NO_x emissions from uncontrolled gas fired boilers operated at full load varied between 155 ppm and 992 ppm (corrected to 3% O_2, dry basis), or an average of 589 ppm. Although at full load there is some relationship between rated boiler size and NO_x emission level (ppm NO_x = 381 + 0.718 MW; r = 0.47), a better and more logical relationship exists between NO_x emissions and rated furnace size (ppm NO_x = 297 + 1.715 (MW per furnace); r = 0.61). Thus, about 37% of the variation in NO_x emissions about the average value of 589 ppm is "explained" by the variation in furnace load. Figure 2-1 is a plot of uncontrolled NO_x emissions vs. gross load per furnace for the gas fired boilers tested. Data points representing the individual furnaces are connected by lines so that the reduction in NO_x emissions with reduction in load for each boiler can be seen.

Figure 2-1 indicates a second relationship--the NO_x emissions from the front wall fired boilers tested change more with load changes than those from the horizontally opposed boilers, and average about twice the NO_x emissions for equivalent furnace load. This relationship suggests that an improved correlation may exist between NO_x emissions and load per furnace firing wall. The number of furnace firing walls for front wall, opposed wall, and tangentially fired boilers having single furnaces are 1, 2, and 4, respectively. Figure 2-2 is a plot of NO_x emissions vs. load in MW per furnace firing wall. The regression equation for full load, uncontrolled firing is ppm NO_x = 187 + 4.0 (MW per furnace firing wall) (r = 0.72). If Boiler G ("all-wall" firing) is omitted, the regression equation becomes ppm NO_x = 28 + 5.57 (MW per furnace firing wall) (r = 0.89). The unusual configuration of Boiler G ("all-wall", with division wall) results in six furnace firing walls.

Figure 2-2 also indicates the change in uncontrolled NO_x emissions with change in load for each gas fired boiler tested. With the exception of the "all-wall" fired Boiler G, all of the NO_x data fall within a relatively narrow band when plotted on this basis. Regression analysis indicates that about 80% of the variation in NO_x emissions is related to,or explained by the variation in the gross load per gas firing furnace wall. Table 2-2 summarizes the regression equations developed for uncontrolled, gas fired boilers according to type of firing. (Vertical firing from a single row of burners was assumed to be equivalent to a single furnace firing wall.)

TABLE 2-1

SUMMARY OF NO_x EMISSIONS FROM GAS FIRED BOILERS

Boiler			Full Load Conditions								Intermediate Load Conditions								Low Load Conditions							
Code Letter	Size (MW)	Type of Firing	Gross Load (MW)	Uncontrolled NO_x Emissions, ppm at 3% O_2, Dry Basis	% Reduction in NO_x: LEA	Staging	LEA and Staging	"NO Ports"	FGR	"Full Control"	Gross Load (MW)	Uncontrolled NO_x Emissions, ppm at 3% O_2, Dry Basis	% Reduction in NO_x: LEA	Staging	LEA and Staging	"NO Ports"	FGR	"Full Control"	Gross Load (MW)	Uncontrolled NO_x Emissions, ppm at 3% O_2, Dry Basis	% Reduction in NO_x: LEA	Staging	LEA and Staging	"NO Ports"	FGR	"Full Control"
		(4)																								
A (5)	180	FW	180	390	15	49	60	--	--	60	120	230	18	42	52	--	--	52	70	116	7	30	43	--	--	43
B	80	FW	82	497	15	24	37	--	--	37	50	240	29	17	--	--	--	--	20	90	--	--	28	--	--	28
C (5)	315	FW	315	992	6	--	--	--	--	--	223	768	--	--	33	--	--	33	186	515	--	--	--	--	--	--
Average	192	FW	192	626	13	37	48	--	--	48	131	413	24	30	42	--	--	42	92	240	7	30	36	--	--	36
D	350	HO	350	946	21	50	62	47	--	77	--	--	--	--	--	--	--	--	150	341	--	66	--	39	20	81
E (1)(5)	480	HO	480	736	9	--	--	38	--	81	360	610	6	--	--	53	--	57	250	363	9	--	--	32	--	70
F (5)	600	HO	559	570	16	--	--	--	--	--	410	335	19	--	--	--	--	--	325	253	61	53	70	--	--	70
G (5)	220	AW	220	675	23	58	60	--	--	60	190	550	21	35	48	--	--	48	125	313	25	58	66	--	--	66
Average	412	HO	402	732	17	54	61	42	--	73	320	498	15	35	48	53	--	52	212	318	32	59	68	36	20	72
H (2)(5)	320	T	320	340	--	--	--	--	--	66	240	230	--	--	--	--	60	65	--	--	--	--	--	--	--	--
I (3)	66	V	66	155	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Grand Ave	290	ALL	286	589	16	45	54	42	--	64	228	423	19	31	44	53	60	51	161	284	26	52	52	36	20	60

(1) Data supplied by boiler operator.
(2) Data supplied by boiler operator. Separate effects of individual controls not measured.
(3) Insufficient data for estimating effects of combustion controls.
(4) Type of firing codes: FW = front wall, HO = horizontally opposed, AW = all wall, T = tangential, V = vertical.
(5) Twin furnace or division wall in single furnace.

Figure 2-1

GAS FIRED BOILERS
UNCONTROLLED NO_x EMISSIONS PER FURNACE

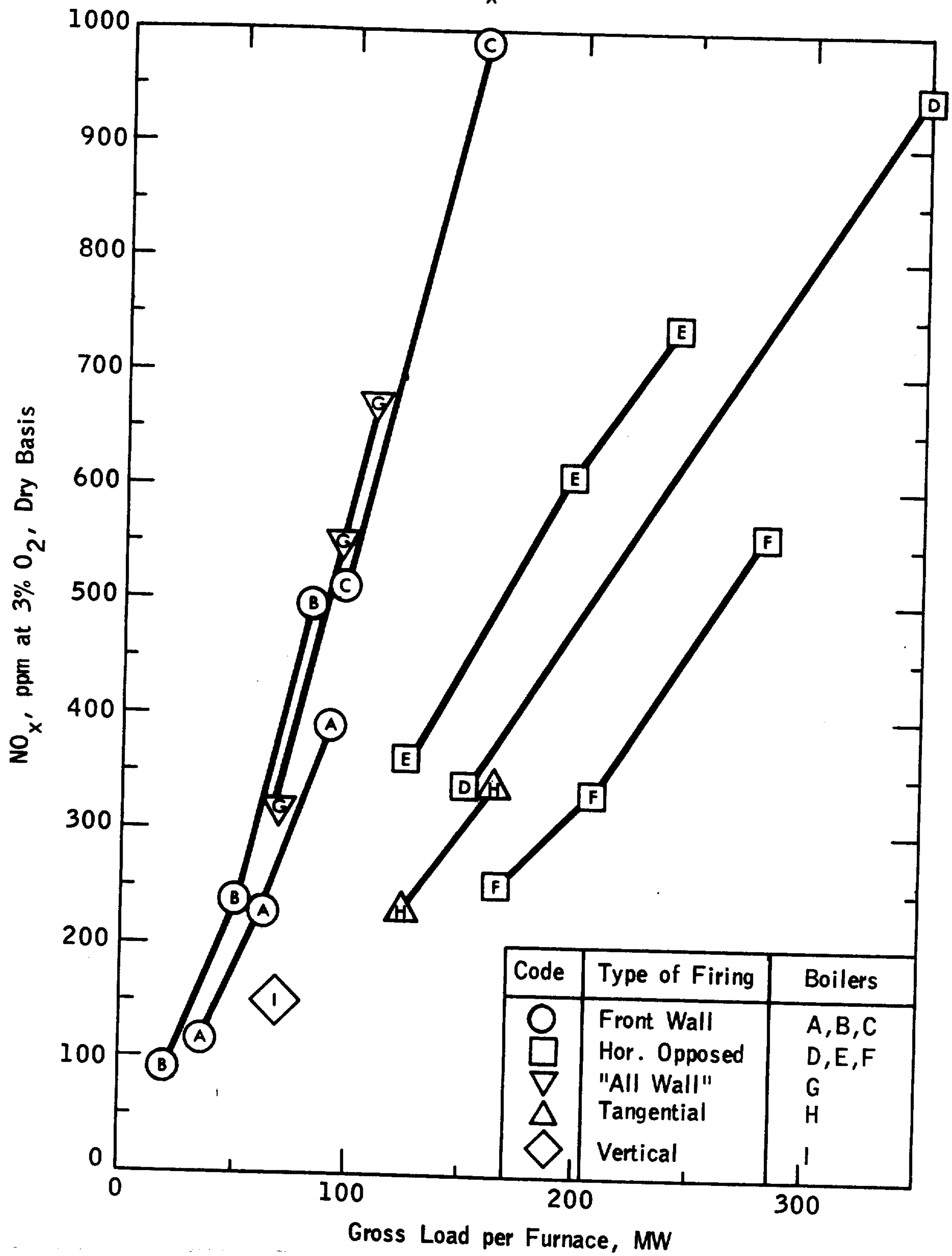


Figure 2-2

GAS FIRED BOILERS
UNCONTROLLED NO_x EMISSIONS PER
FURNACE FIRING WALL

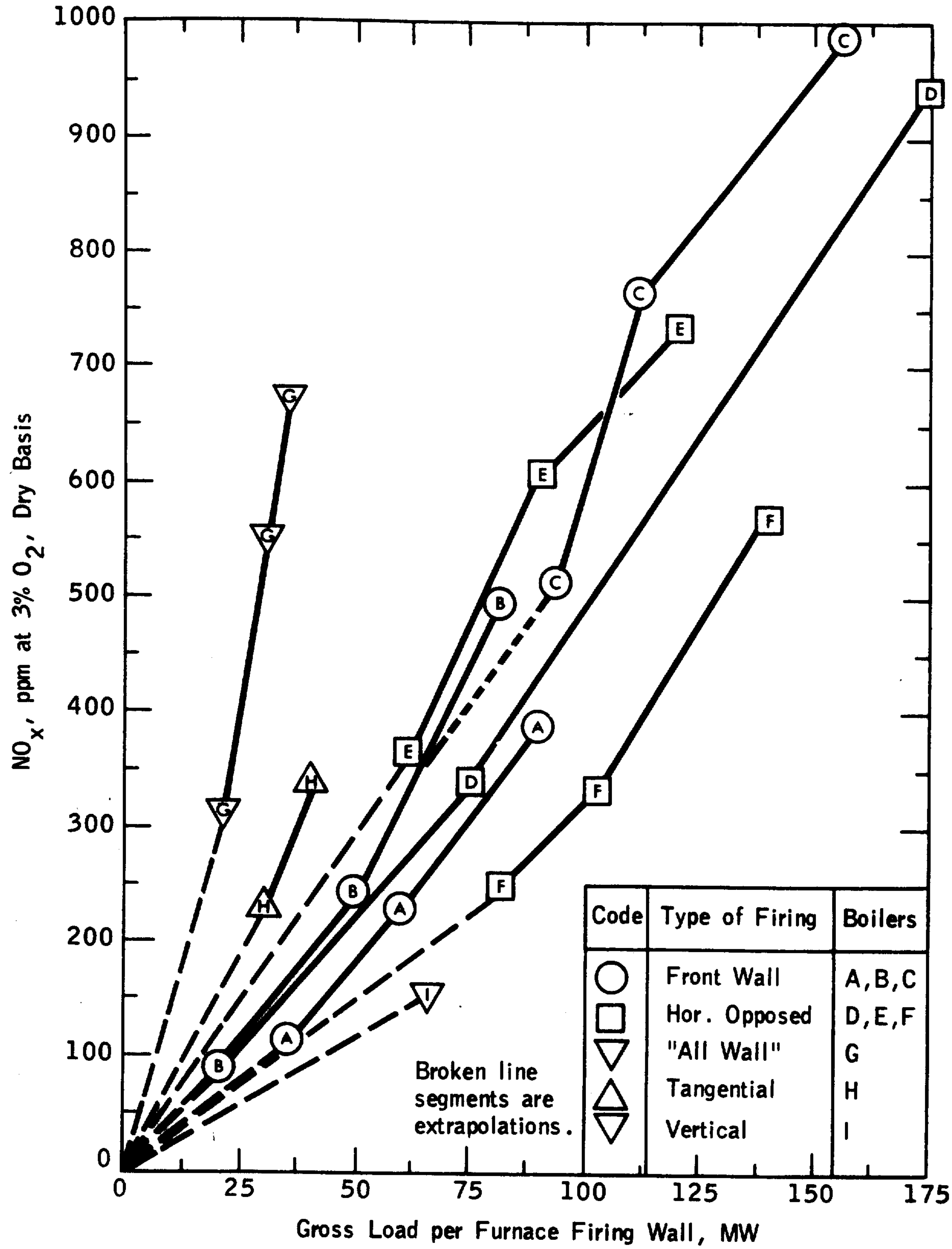


TABLE 2-2

LINEAR REGRESSION ANALYSES OF NO_x EMISSIONS FROM UNCONTROLLED GAS FIRED BOILERS

Boiler Data	Type Of Firing	No. of Data Points	Regression Equations[a]	Correlation Coeff. r	Std. Deviation ppm
A,B,C	FW	9	ppm NO_x = -118 + 7.01 MW/FFW	0.97[c]	74
D,E,F	HO	8	ppm NO_x = -43 + 5.31 MW/FFW	0.83[b]	143
A,B,C,D,E,F	FW and HO	17	ppm NO_x = -70 + 5.95 MW/FFW	0.91[c]	117
A,B,C,D,E,F,H	FW, HO, T	19	ppm NO_x = -17 + 5.51 MW/FFW	0.90[c]	118
A,B,C,D,E,F,H,I	FW, HO, T, V	20	ppm NO_x = -36 + 5.61 MW/FFW	0.89[c]	123
A,B,D,E,F,G,H,I	All Types Tested	23	ppm NO_x = 111 + 4.35 MW/FFW	0.75[c]	173

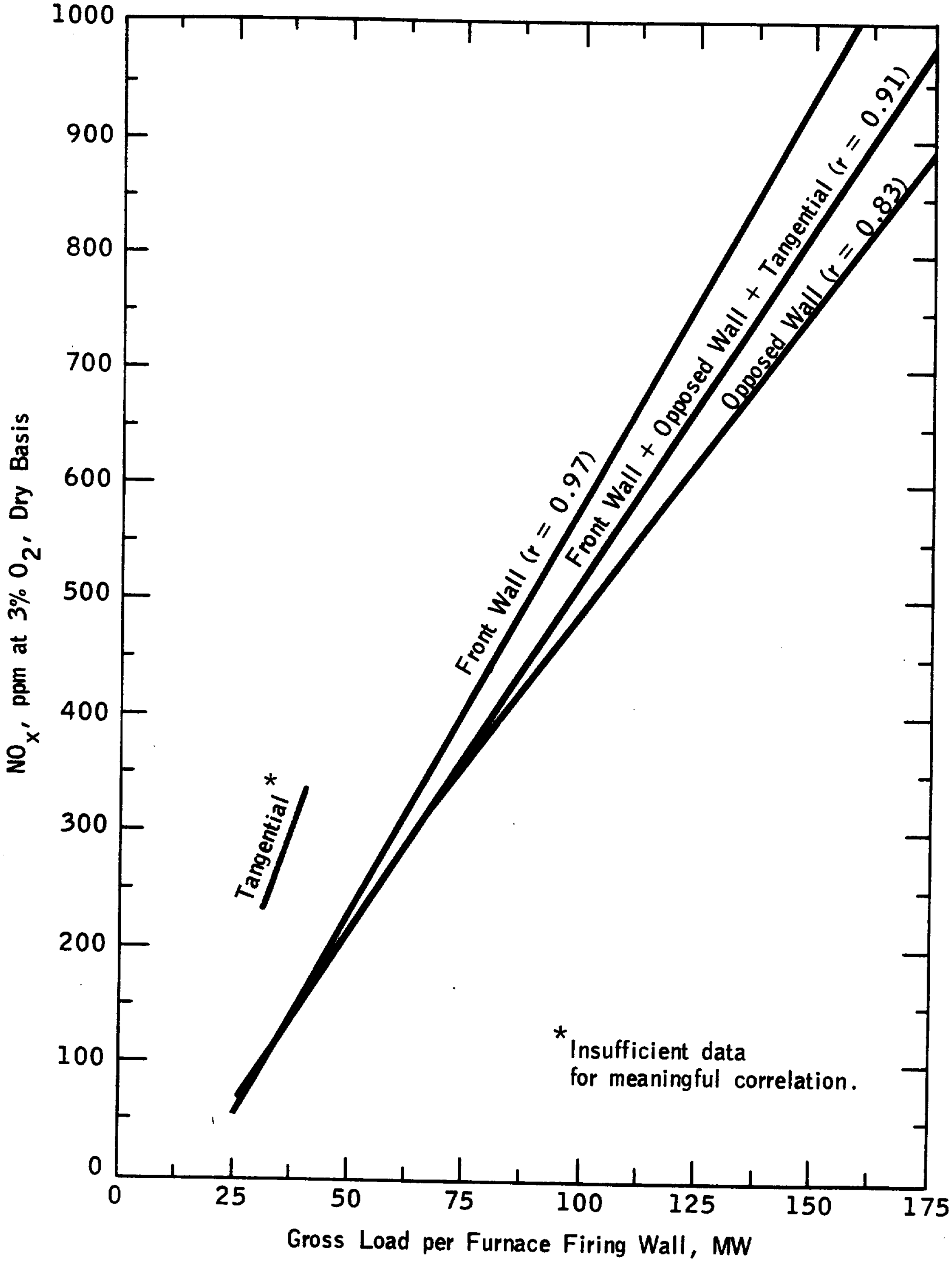
(a) ppm NO_x corrected to 3% O_2, dry basis; MW/FFW = load per furnace firing wall, MW.
(b) Significant at the 0.1% confidence level.
(c) Significant at the 1% level.

Figure 2-3 presents the plot of the regression equations listed in Table 2-2 for front wall and opposed wall, and for the combination of front wall, opposed wall, and tangentially fired boilers. As expected, the standard deviations of NO_x emissions are sizable, but these correlations are highly significant and should be valuable for the purpose of making emission estimates.

In summary, for gas fired boilers operated at full load, in six out of the nine boilers tested it was possible to reduce NO_x emissions by an average of 64%. The use of low excess air with staged firing accounted for the bulk of this reduction. At intermediate (2/3) to low (1/2) loads, the application of all control methods tested reduced NO_x emissions by 50 to 60% compared with uncontrolled NO_x emissions at these load levels. The use of existing "NO-ports" and flue gas recirculation equipment was also found to be effective for the few boilers where this type of equipment was available.

Figure 2-3

REGRESSIONS FOR GAS FIRED BOILERS
(UNCONTROLLED NO_x EMISSIONS VS. GROSS LOAD PER FURNACE FIRING WALL)



2.1.2 Oil Fired Boilers

Table 2-3 presents a summary of NO_x emissions measured from the nine oil fired boilers tested. Uncontrolled NO_x emissions at full load varied between 200 ppm and 580 ppm, with an average of 360 ppm NO_x, compared to a range between 155 ppm and 990 ppm, and an average of about 590 ppm NO_x for gas fired boilers. The relationship between uncontrolled NO_x emissions and gross load in MW per furnace firing wall at full load is ppm NO_x = 228 + 1.59 MW/FFW (r=0.59) for all nine oil fired boilers tested, and ppm NO_x = 237 + 1.324 MW/FFW (r=0.50) when the front wall, horizontally opposed, and tangential oil fired boilers only are included in the correlation. These correlations are not as good as the corresponding correlation coefficients of r = 0.72 and r = 0.89 for gas firing. Variation in fuel oil nitrogen content, viscosity, preheat temperature, spray pattern as well as the method of spray atomization, burner design characteristics, and air-fuel mixing patterns probably account for a large portion of these variations in NO_x emissions from oil fired boilers. Our limited testing indicated a average increase of 44 ppm NO_x per 0.1% combined nitrogen in the fuel for fuel oils containing combined nitrogen in the range of 0.3 to 0.6 wt.%. This corresponds to an average conversion of about 30% of the fuel nitrogen into NO_x. However, adjusting the NO_x emission data for fuel nitrogen content had only a marginal effect on the regression analyses, except for tangentially fired boilers.

In Figure 2-4 a plot of NO_x emissions from uncontrolled oil fired boilers operating over a range of load levels is presented. Comparison of the data in Figure 2-2 with those in Figure 2-4 for gas and oil firing respectively, shows the NO_x emissions from oil fired boilers exhibit considerably more variation than those from gas fired boilers. In addition, NO_x emissions from oil fired boilers decrease at a rate less than proportional to the corresponding fractional load reductions, while NO_x emissions from gas fired boilers decrease at a higher fractional rate than the corresponding load reductions. In Figure 2-5, the regression lines of uncontrolled NO_x emissions vs. load per furnace firing wall are plotted for oil fired boilers.

The NO_x emission reduction achieved through the application of combustion controls for each of the oil fired boilers tested are also given in Table 2-3. Use of all available control methods resulted in 45% to 60% reduction in NO_x for front wall fired boilers at full load, and from 30% to 50% reduction at about 2/3 load. Low excess air firing, staging, and flue air recirculation were all successful in reducing NO_x emission either separately or in combination to varying degrees of effectiveness. Only one of the front-wall fired boilers tested (J) was equipped with flue gas recirculation into the windbox.

One of the two oil fired, horizontally opposed wall boilers tested developed process control equipment problems during testing, and therefore, could not be tested with all possible combustion control methods. With other front wall oil fired boilers a 38% reduction in NO_x was obtained at full load, and 55% at about 1/2 load through a combination of low excess air firing with staging, and the use of the available "NO-ports". The "all-wall" fired unit tested was not equipped

TABLE 2-3

SUMMARY OF NO_x EMISSIONS FROM OIL FIRED BOILERS

Boiler			Full Load Conditions								Intermediate Load Conditions								Low Load Conditions							
					% Reduction in NO_x								% Reduction in NO_x								% Reduction in NO_x					
Code Letter	Size (MW)	Type of Firing	Gross Load (MW)	Uncontrolled NO_x Emissions, ppm at 3% O_2, Dry Basis	LEA	Staging	LEA and Staging	"NO Ports"	FGR	"Full Control"	Gross Load (MW)	UnControlled NO_x Emissions, ppm at 3% O_2, Dry Basis	LEA	Staging	LEA and Staging	"NO Ports"	FGR	"Full Control"	Gross Load (MW)	Uncontrolled NO_x Emissions, ppm at 3% O_2, Dry Basis	LEA	Staging	LEA and Staging	"NO Ports"	FGR	"Full Control"
A (3)	180	FW (2)	180	367	35	31	45	--	--	45	120	322	25	25	43	--	--	43	80	266	28	--	--	--	--	--
B	80	FW	80	580	19	30	46	--	--	46	50	361	12	20	30	--	--	30	21	258	28	20	21	--	--	21
J	250	FW	250	360	--	25	26	--	46	60	172	306	22	14	24	--	31	50	--	--	--	--	--	--	--	--
Average	170	FW	170	436	27	29	39	--	46	50	114	330	20	20	32	--	31	41	50	262	28	20	21			21
D	350	HO	350	457	3	34	35	33	--	38	--	--		--	--	--	--	--	150	264	14	47	42	34	--	55
E (3)	450	HO	455	246	9	--	--	19	--	--	365	219	16	--	--	25	--	26	228	186	12	--	--	17	--	--
G (3)	220	AW	220	291	19	--	--	--	--	--	170	267	--	34	44	--	--	44	120	324	10	--	--	--	--	--
Average	340	HO	342	331	10	34	35	26	--	38	268	243	16	34	44	25	--	35	166	258	12	47	42	26	--	55
H (3)	320	T	320 (1)	215	--	--	--	--	10	--	220	220	22	19	45	--	13	59	--	--	--	--	--	--	--	--
K	66	T	66	203	28	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
L	400	Cy	415	530	--	--	--	--	--	--	258	205	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Grand Ave	257	ALL	260	361	19	30	38	26	28	47	194	271	19	22	37	25	23	42	120	260	18	34	32	26	--	38

(1) Data supplied by boiler operator.
(2) Type of firing codes: FW = front wall, HO = horizontally opposed, AW = all wall, T = tangential, V = vertical.
(3) Twin furnace or division wall in single furnace.

Figure 2-4

OIL FIRED BOILERS
UNCONTROLLED NO_x EMISSIONS
PER FURNACE FIRING WALL

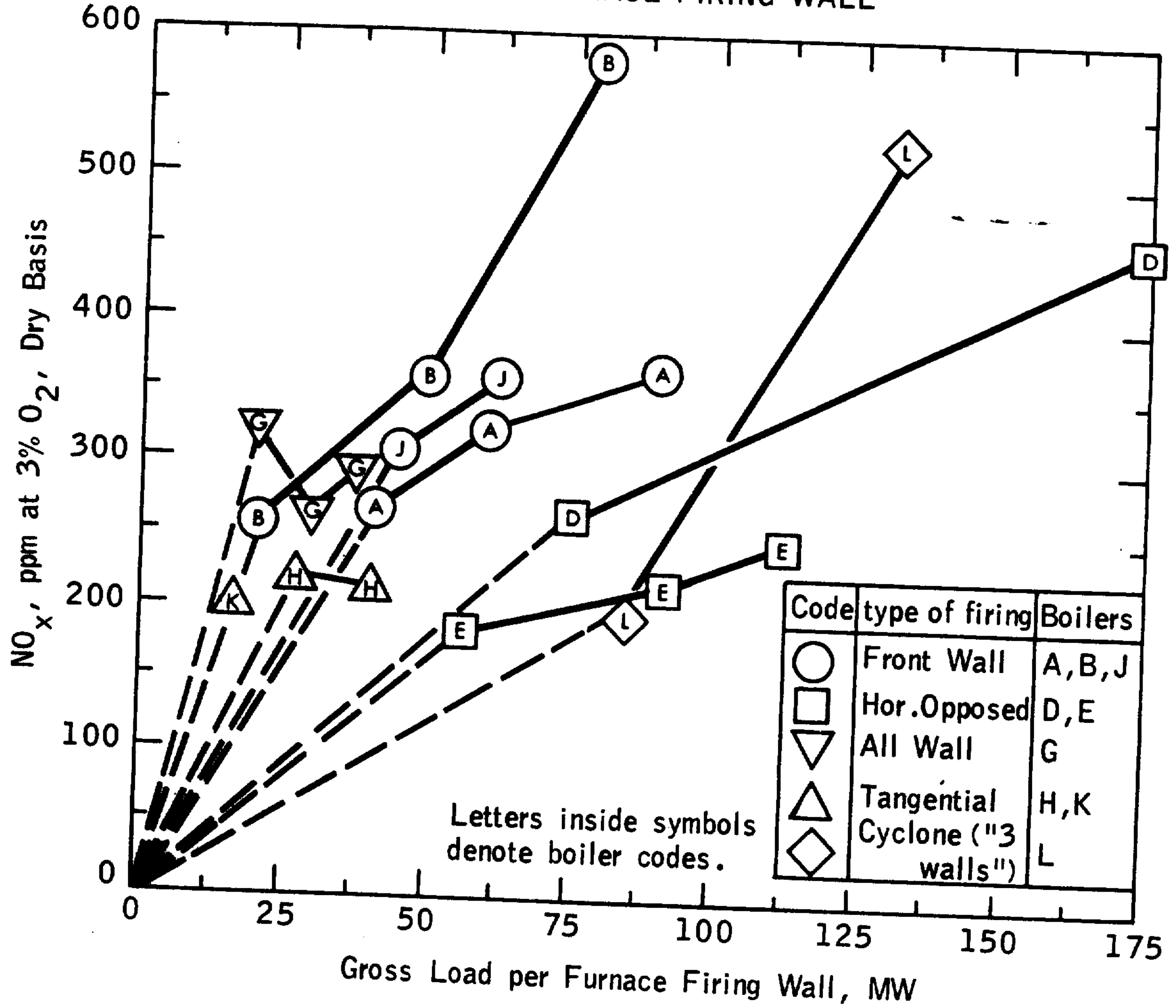
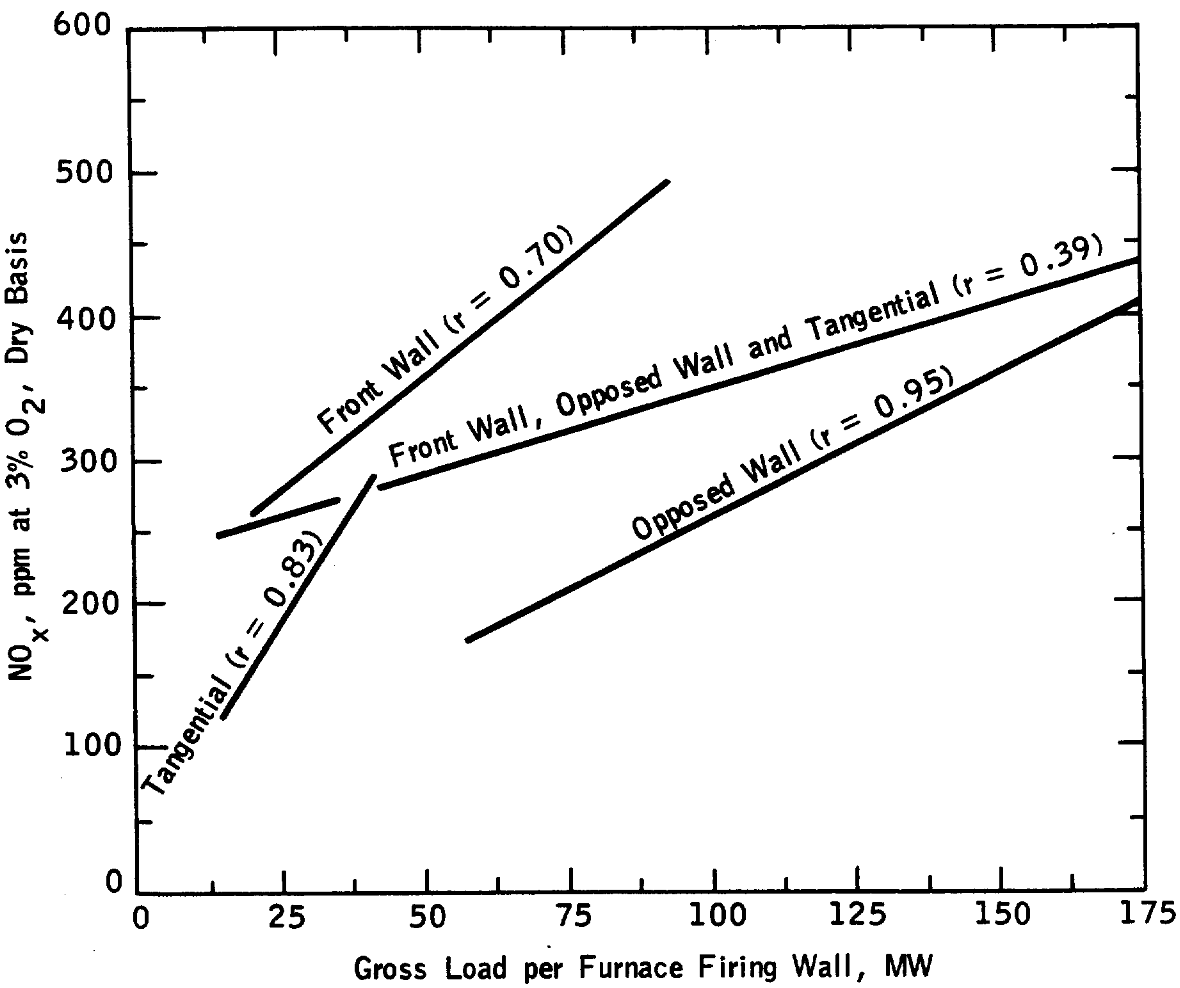


Figure 2-5

REGRESSIONS FOR OIL FIRED BOILERS
UNCONTROLLED NO_x EMISSIONS VS. LOAD
PER FURNACE FIRING WALL



with "big" oil guns which would have allowed staging at full load; however, at about 80% of full load, staged firing with low overall excess air resulted in a 44% reduction in NO_x, compared to uncontrolled NO_x emissions at this load level.

The 320 MW tangential boiler was tested at only 2/3 load so that staging could be accomplished, since "big" oil guns were not available for supplying additional fuel to the operating burners. Even though NO_x emissions were relatively low on an uncontrolled basis (215 ppm), the use of low excess air with staged firing and with flue gas recirculation resulted approximately in a 60% reduction to an NO_x level of 90 ppm. The small, 66 MW tangential boiler tested was not adequately equipped with boiler control devices to allow the application of low excess air firing with staging. The large, 400 MW, cyclone boiler tested could not be operated with low excess air or with staged firing. Consequently, no NO_x reduction could be obtained except by reducing boiler load.

In all oil fired boilers tested with low excess air and staged firing it was possible to reduce NO_x emissions significantly. However, with some of the old boilers tested, which were without adequate control equipment, control methods for NO_x emission reduction could not be applied.

2.1.3 Coal Fired Boilers

Table 2-4 presents a summary of NO_x emissions measured from the seven coal fired boilers tested. Uncontrolled NO_x emissions at full load varied between 568 ppm and 1490 ppm, with an average of 994 ppm. For oil and gas fired boilers the average NO_x emissions were 360 ppm and 590 ppm, respectively. The relationship between uncontrolled NO_x emissions at full load and gross load per furnace firing wall in MW is ppm NO_x = 569 + 2.76 MW/FFW ($r = 0.45$). Omitting the data on Boiler C which had unusual design features results in the regression equation ppm NO_x = 291 + 3.67 MW/FFW ($r = 0.95$). Thus, the correlation between uncontrolled NO_x emissions and load per furnace firing wall is good.

In Figure 5-6 the uncontrolled NO_x emissions are plotted vs. gross load per furnace firing wall for coal fired boilers. Again, with the exception of emissions from Boiler C all of the data fall within a narrow band. The number of "equivalent" furnace firing walls for the large, 704 MW cyclone fired Boiler Q was arbitrarily set at 3. In this boiler, the 14 cyclones are located in opposed walls of the single furnace in two rows, with four burners in the bottom row and three burners in the top row on each side. However, a large proportion of the total combustion takes place within each cyclone burner compared to normal opposed wall furnaces where all of the combustion takes place within the furnace. Thus, it is reasonable to propose that the number of "equivalent" firing walls for the cyclone burner is greater than two, but certainly less than 14. Using three "equivalent" firing walls the NO_x data from the cyclone boiler fall in line with all other coal fired boilers tested, except for Boiler C. As discussed earlier, Boiler C is rather unusual because it was designed to be operated as a wet bottom furnace at low load levels, fired with high slagging temperature coals. Thus, the lowest row of burners was located close to the flat, wet

TABLE 2-4

SUMMARY OF NO_x EMISSIONS FROM COAL FIRED BOILERS

Boiler			Full Load Conditions						Intermediate Load Conditions						Low Load Conditions					
					% Reduction in NO_x						% Reduction in NO_x						% Reduction in NO_x			
Code Letter	Rating (MW)	Type of Firing (1)	Gross Load (MW)	Uncontrolled NO_x Emissions, ppm at 3% O_2, Dry Basis	LEA	Staging	LEA + Staging	"Full Control"	Gross Load (MW)	Uncontrolled NO_x Emissions, ppm at 3% O_2, Dry Basis	LEA	Staging	LEA + Staging	"Full Control"	Gross Load (MW)	Uncontrolled NO_x Emissions, ppm at 3% O_2, Dry Basis	LEA	Staging	LEA + Staging	"Full Control"
M	175	FW							140	660	14	40	55	60						
C(2)	315	FW	275	1490	--	--	--	--	190	1280	--	--	--	--	160	1200	--	--	--	--
F(2)	600	HO	563	838	--	--	--	--	462	781	--	--	--	--	363	643	--	--	--	--
N(2)	800	HO	778	905	--	--	--	--	580	741	--	--	--	--						
O(2)	575	T							470	405	9	39	50	50	310	264	--	--	42	42
P(2)	300	T	300	568	27	--	--	--	240	418	28	--	--	--						
Q	700	CY	665	1170	--	--	--	--	545	882	--	--	--	--						
GRAND AVE.	495	ALL	516	994	27	--	--	--	375	738	17	39	52	55	278	702	--	--	42	42

(1) Type of firing codes: FW = Front Wall, HO = Horizontally Opposed, T = Tangential, CY = Cyclone.
(2) Twin furnace or division wall in single furnace.

bottom of the furnace, and a layer of insulating tile was placed along the furnace walls from the floor to an elevation above the top row of burners. This design results in high furnace flame temperatures, and relatively slow heat absorption in the lower furnace (maintaining the slag molten), and therefore, promotes high NO_x emission levels.

The linear regression analyses of the uncontrolled NO_x emissions from coal fired boilers are summarized in Table 2-5 at all load levels tested, corresponding to the data of Figure 2-6. Again, eliminating the data on Boiler C, the correlations improve significantly for both full load and variable load test conditions. Since the assignment of three as the number of furnace firing walls for the cyclone boiler Q was established somewhat arbitrarily, a regression analysis (number 5) was also made without including the data on Boilers Q and C for comparison with the regression analysis (number 4 in Table 2-5) on all coal fired boilers, except C. Both regressions are highly significant with over 80% of the variations in uncontrolled NO_x emissions explained by, or related to the single parameter, load per furnace firing wall in megawatts, over the entire load range tested. While as expected, the standard deviations in ppm NO_x are quite large, correlations (2, 4, and 5) in Table 2-5 should be useful for emission estimate purposes.

TABLE 2-5

LINEAR REGRESSION ANALYSES OF NO_x EMISSIONS FROM UNCONTROLLED COAL FIRED BOILERS

Boiler Data	No. of Data Points	Regression Equations(a)	Correlation Coeff. r	Std. Deviation ppm
1. All boilers at full load only	5	ppm NO_x = 569 + 2.76 MW/FFW	.45	361
2. All boilers at full load (Boiler C omitted)	4	ppm NO_x = 293 + 3.65 MW/FFW	.96(b)	88
3. All boilers at all loads	15	ppm NO_x = 423 + 3.49 MW/FFW	0.57(b)	299
4. All boilers at all loads (Boiler C omitted)	12	ppm NO_x = 252 + 3.82 MW/FFW	0.94(c)	89
5. All boiler at all loads, (Boilers C and Q omitted)	10	ppm NO_x = 256 + 3.68 MW/FFW	0.91(c)	93

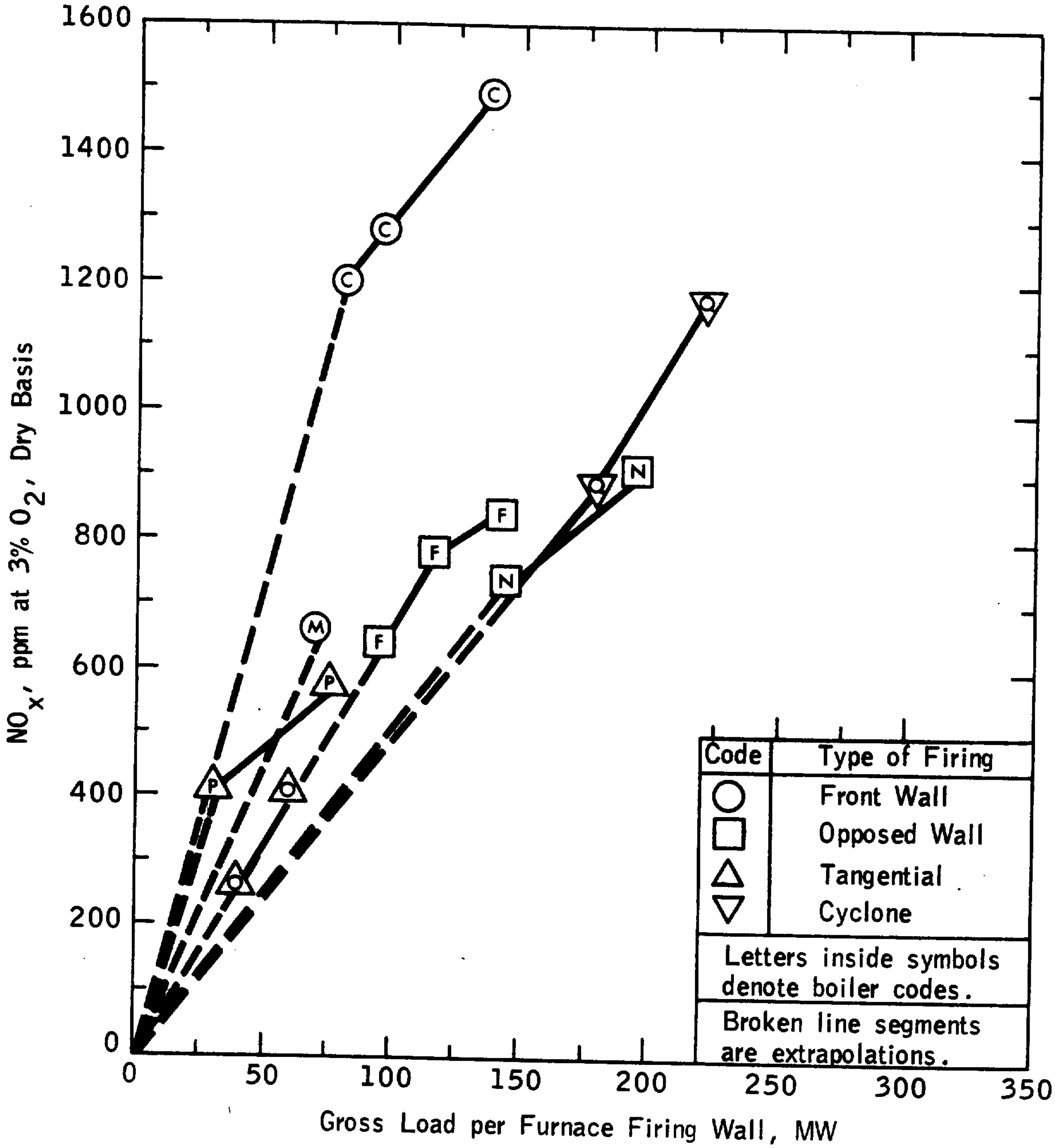
(a) ppm NO_x corrected to 3% O_2, dry basis, MW/FFW = load per furnace fixing wall, MW.

(b) significant at the 5% confidence level.

(c) significant at the 0.1% confidence level.

Figure 2-6

COAL FIRED BOILERS
UNCONTROLLED NO_x EMISSIONS VS. GROSS LOAD
PER FURNACE FIRING WALL



As shown in Table 2-4, Boiler M, a front-wall fired boiler and Boiler O, a tangentially fired boiler, were tested with a wide range of combustion controls at about 80% of full load. In both of these boilers it was found possible to significantly reduce NO_x emissions through the application of staged firing with low overall excess air. None of the other five boilers could be tested under what amounts to proper staging operations. Potential slagging problems were the chief reason why the boiler operators refrained from the use of low excess air, or from combining low excess air with staged firing on these coal fired boilers. A minor exception was Boiler P, a tangentially fired boiler which was operated for short periods of time with low excess air firing, resulting in reduced NO_x emissions.

An analysis was made to determine whether the limited data on the bound nitrogen content of the coal fuels fired could be correlated with the measured emissions. Unlike the data obtained on two oil fired boilers, for which different fuel oils could be incorporated into the experimental program designs, so that the effect of varying nitrogen content on NO_x emissions could be measured independently of load, excess air and other parameters, in coal firing the coal fuels varied according to what was available during the test programs. A regression equation (ppm NO_x = 291 + 3.67 MW/FFW, r = 0.95) of uncontrolled NO_x emissions measured at maximum load vs. load per furnace firing wall (including all boilers except C) was used to predict NO_x emissions without taking into account the effect of fuel nitrogen content. The differences between the actual measured uncontrolled NO_x emissions and these "predicted" values were correlated with the average nitrogen content of the coal fuel fired in each of the boilers tested, as shown in Table 5-6. The regression coefficient of 884 suggests an 88 ppm increase in NO_x emissions per 0.1% increase in fuel nitrogen content for 1.15 to 1.40 wt. % nitrogen content coals. Considerably more data are needed to define this relationship as the above correlation is not precise, and assumes that all of the increase in NO_x can be attributed to the increase in coal nitrogen content (equivalent to an average coal nitrogen conversion of about 50% into NO_x), without taking into account other combustion variables.

TABLE 2-6

CORRELATION OF COAL NITROGEN CONTENT WITH NO_x EMISSIONS

Boiler	Highest Load Fired	Actual ppm NOx Emissions	$\frac{MW}{FFW}$	"Predicted" NO_x Emissions, ppm	(Actual-"Predicted") NO_x (Δ)	Coal Nitrogen Content	"Predicted" Δ
M	140	660	70	547	113	1.33	34
F	563	838	141	808	30	1.38	78
N	778	905	195	1006	-101	1.17	-108
O	470	405	59	508	-103	1.25	-37
P	300	568	75	566	2	1.33	34
Q	665	1170	222	1106	64	1.30	7

* "Predicted" ppm NO_x = 291 + 3.67 MW/FFW, r = 0.95.

** "Predicted" Δ = -1142 + 884 (N content, wt.%), r = 0.74.

Figure 2-7

CORRELATION OF AVERAGE REDUCTIONS IN UNCONTROLLED NO_x EMISSIONS WITH REDUCTIONS IN BOILER LOAD

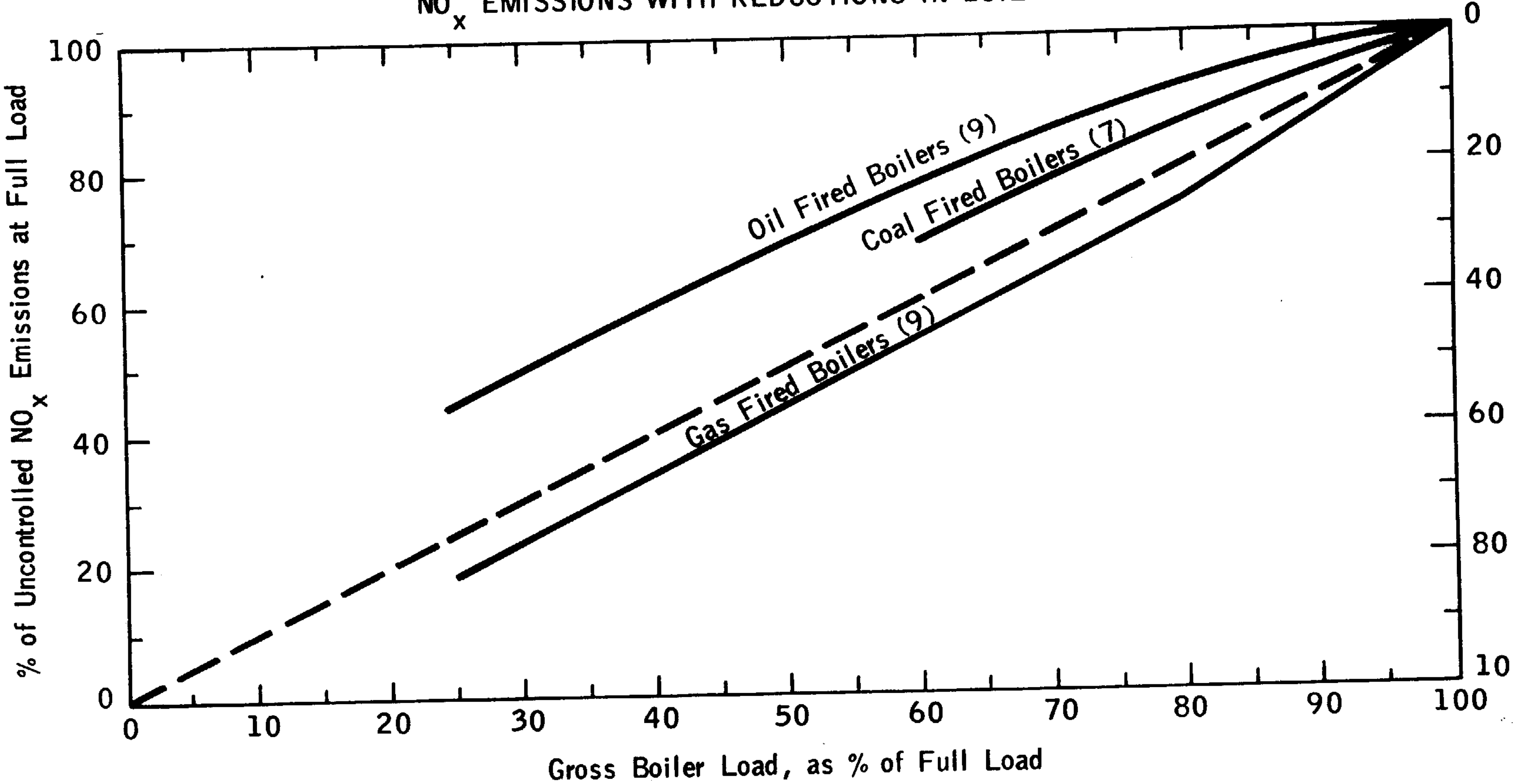


TABLE 2-7

SUMMARY OF NO_x EMISSIONS

Combustion Operating Modification and Furnace Load(1)

Fuel Fired	Type(2) of Firing	% Reduction in NO_x Emission														
		Low Exc. Air			Staging			LEA + Staging			Flue Gas Rec.			"Full"(3)		
		Full	Int.	Low	Full	Int.	Low	Full	Int.	Low	Full	Int.	Low	Full	Int.	Low
GAS	FW	13	24	7	37	30	30	48	42	36	--	--		48	42	36
	HO	17	15	32	54	35	59	61	48	68	--	--	20	73	52	72
	T	--	--	--	--	--	--	--	--	--	--	60	--	66	65	--
	ALL (Average)	16	19	26	45	31	52	54	44	52	--	60	20	64	51	60
OIL	FW	27	20	28	29	20	20	39	32	21	46	31	--	50	41	21
	HO	10	16	12	34	34	47	35	44	42	--	--	--	38	35	55
	T	28	22	--	--	17	--	--	45	--	10	13	--	--	59	--
	ALL (Average)	19	19	18	30	22	34	38	37	32	28	23	--	47	42	38
COAL	FW	--	14	--	--	40	--	--	55	--	--	--	--	--	60	--
	HO	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
	T	27	18	--	--	39	--	--	50	42	--	--	--	--	50	42
	ALL (Average)	27	17	--	--	39	--	52	52	42	--	--	--	--	55	42

(1) Furnace load: "Full" = 85%-105%, "Intermediate" = 60%-85%, Low = 50%-60% of rating.
(2) Type of firing: FW = Front Wall, HO = Horizontally Opposed, T = Tangential.
(3) "Full control": combination of techniques achievable on boilers tested.

2.1.4 Overall Conclusions

As discussed in detail in sections 6 and 2.1, extensive experience has been obtained and significant accomplishments have been made during this study in testing utility boilers for NO_x emission control by combustion modifications. A total of 277 test runs were made on 17 boilers (25 boiler-fuel combinations) as shown below in Table 2-8.

TABLE 2-8

BOILER TEST PROGRAM SUMMARY

(Number of Boilers and Test Runs by Fuel and Type of Firing)

	Type of Firing						
Fuel Fired	Front Wall	Horizontally Opposed	"All-Wall"	Tangential	Cyclone	Vertical	Total
Coal	2-24	2-10	--	2-35	1-6	--	7-75
Gas	3-30	2-23	1-14	1-8	--	1-4	8-79
Oil	3-52	2-36	1-13	2-13	1-5	--	9-117
Coal & Gas	1-6	--	--		--	--	1-6
Total	9-112	6-69	2-26	5-55	2-11	1-4	25-277

Significant reductions of NO_x emissions were obtained on many of the boilers tested. The remaining major problems and limitations have been defined for each of the three types of fossil fuel.

Under base line operating conditions, i.e., without control, NO_x emissions from medium and large gas fired boilers at full load ranged from about 400 ppm to a high of almost 1000 ppm for front wall and horizontally opposed fired boilers (all concentrations corrected to 3% O_2, dry basis). A medium sized tangential fired boiler had an NO_x emission level of only 330 ppm on an uncontrolled basis. The application of combustion modifications to gas fired boilers was successful in reducing NO_x emissions by 40% to 80% at full load and by over 90% at reduced loads. Combustion modifications on wall fired boilers included the application of low excess air, staged combustion, and use of NO ports, where available. These results indicate that effective NO_x emission control can be applied to gas fired boilers through operationally feasible combustion modification techniques.

NO_x emissions from uncontrolled oil fired boilers were generally lower (300-560 ppm) than NO_x emissions from uncontrolled gas fired boilers of the same design and size. However, in most cases, the application of combustion modifications to oil fired boilers could not reduce NO_x emissions to as low levels as achieved on the same boilers when firing gas. Part of this difference is probably due to the bound nitrogen content of oil fuels, although other factors, particularly droplet atomization, vaporization and combustion characteristics may be equally important. Therefore, additional research is needed to sort out these effects. On a front wall fired boiler equipped with flue gas recirculation into the windbox, the combination of low excess air, staged firing and flue gas recirculation resulted in about 60% reduction of NO_x. The maximum NO_x reduction with the combination of low excess air and staged combustion was about 45%. Additional research is needed on selected boilers to determine the optimum combination of controls where a variety of control options are possible.

Coal fired boilers presented the greatest difficulty in applying combustion control. Full load, uncontrolled NO_x emissions from large size, coal fired boilers ranged from 800 to about 1500 ppm in wall and cyclone fired boilers, while large tangentially fired boilers emitted about one-half of these levels. Of the seven coal fired boilers tested, combustion modifications resulting in substantially reduced NO_x emissions could be applied in only two of these units. In both cases (a front wall and a corner fired boiler) low excess air combined with staged firing (resulting in a loss in boiler rating of about 15% to 20%) resulted in NO_x emission reduction of over 50%, compared with full load conditions without control. The other five boilers could not be tested at sufficiently low excess air levels to expect much improvement in NO_x emissions. In some cases, this was due to observed, real slagging problems, and in others, a reluctance of boiler operators to risk potential problems even for a limited period of test time. Additional field testing of a carefully selected sample of coal fired utility boilers is required to define the scope of applicability of combustion modification techniques on a realistic basis.

The Boiler Test Program resulted in the definition of a number of problem areas which currently limit the control of NO_x emissions from coal fired boilers, and to a much lesser extent, from oil and gas fired boilers. Tables 2-9, 2-10 and 2-11 summarize our experience on the operating, design, and fuel quality problems, and on the limitations associated with each combustion control technique. The code letters indicate our assessment of the relative severity of the problem from "no effect" (D) to "major problem or limitation" (A). If insufficient experience had been obtained to properly rank the problem area, a question mark was used in these tables. Some of the major problems will be discussed below in further detail. Since coal firing entails the largest problem area, the features of Table 2-9 will be discussed before those of Tables 2-10 and 2-11.

In coal firing, improper slagging conditions can be a major operating problem severely limiting the use of low excess air and staged firing for the reduction of NO_x emissions. For example, dry bottom furnaces require a buildup of dry slag that tends to form balls that roll off the furnace surfaces for normal gravity collection and removal. If, however, local temperatures become so high that the normally dry slag becomes molten, it may

TABLE 2-9

COAL FIRED UTILITY BOILERS
OPERATING AND DESIGN PROBLEMS OR LIMITATIONS

	Combustion Control Technique					
	Low Excess Air	Staged Firing	Flue Gas Recirculation	Load Reduction	Burner Tilt	Air Damper Setting
A. Operating Problems & Limits						
1. Slagging	A-C	B	?	B	?	?
2. Steam Temperature Control	A-C	B	A-C	A	A	B
3. Furnace Wall Temp. Limits	B	C	B	C	B	B
4. Flame Impingement on Furnace Walls	A	A	?	+	C	B
5. Flame Impingement - Burner	A	B	?	D	C	B
6. Corrosion - Furnace Walls & Tubes	?	?	?-C	D	D	?
7. Corrosion - Ducts, Air Heater	+	?-D	?-C	B	D	D
8. High CO and Combustible Emissions	A	A	?	D	D	B
9. High Particulate Emissions	?	?	?	?	?	?
10. Reduced Operating Flexibility	B	B	?	A	B	B
11. Reduced Safety Margin	B	C	C	D	D	C
12. High Operating Cost	+	A-C	?	A	D	D
13. Flame Stability	B	B	?-A	D	D	C
B. Design, Instrument or Control Limitations						
1. Lack of Flue Gas Recirc. Facility	D	D	A	D	D	D
2. Lack of "NO-Ports"	D	B	D	D	D	D
3. Lack of Auto. Damper Controls	A	A	C	C	D	A
4. Lack of O_2 Instrument	A	A	A	D	D	B
5. Lack of CO, H.C. and Combustible Instruments	A	A	A	D	D	B
6. Lack of Automatic Control System	A	C	C	C	C	C
7. Burner Design	?	?	?	D	A	D
C. Fuel Quality Limitations						
1. High N - Content	B	D	B	D	D	D
2. Poor Slagging Characteristics	A	A	?	A	A	?
3. High Iron Pyrites Content	A	A	?	B	B	B
4. High Sulfur Content	C	C	?	D	D	?
5. Low Heating Value Fuel	B	B	?	D	D	D

A - Major Problem or Limitation
B - Moderate Problem or Limitation
C - Minor Problem or Limitation
D - No Problem or Limitation
? - Extent of Problem or Limitation Unknown
+ - Control Technique Aids Problem

run down furnace walls in rivulets and then freeze on furnace bottom surfaces necessitating a shutdown for expensive slag removal. Wet bottom furnaces, on the other hand, require uniformly high temperatures so that the slag remains sufficiently fluid to flow easily to the slag taps. These conditions are aggravated by the use of coals with slagging characteristics different than called for by the furnace design.

Steam temperature control may limit the full use of combustion control techniques to reduce NO_x emissions if insufficient temperature control flexibility is available. Flue gas recirculation, steam or water attemperation, flue gas dampers, and burner tilt are common methods of superheat and reheat temperature control. However, most current boilers are limited by design to the use of one or two of these methods of temperature control. Thus, the use of low excess air, staged combustion, maximum flue gas recirculation, and combinations of these techniques may cause changes in boiler heat distribution that can only be partially compensated for by the other temperature controls. Further, detailed experimentation is needed to find the optimum combination of combustion modifications at full and reduced loads for significant NO_x reductions with adequate boiler steam temperature control.

Flame impingement on furnace walls must be avoided to limit corrosion and excessive local temperatures at the water tubes. Thus, the use of low excess air may necessitate the readjustment of primary and secondary air damper damper positions, burner tilt (if available) position, and impeller position, to avoid long flames that impinge on furnace walls. This emphasizes again the necessity of visual inspection of the furnace, along with adequate experimentation in order to fully exploit the operating flexibility inherent to each boiler design.

The definition of corrosion problems within the furnace area, such as tube wall wastage, requires long-term testing with combustion control techniques for full understanding and quantification. Our Boiler Test Program emphasized short, intensive, multifactor experimental designs in order to maximize the information obtained within the relatively brief periods of time that could be allocated to each boiler. Based on this experience, it will be possible to plan longer tests at the most effective set of combustion control combinations. The proper adjustment of burners firing near the walls so that combustion modifications can be applied to the bulk of the burners should be helpful in avoiding furnace corrosion problems. Thus, the "tailoring" of combustion modifications to meet the requirements of individual boiler designs and fuel qualities are required for optimizing NO_x emission control.

Problems caused by condensation of corrosive materials due to formation of sulfur trioxide can be reduced by low excess air and staged firing. However, a practical operating limitation of the use of low excess air or the combination of low excess air with staged firing is the potentially excessive formation of CO, and other combustibles. Proper instrumentation, coupled with good maintenance of equipment, and adjustment of individual burners are necessary in order to obtain the full benefit of these control techniques. Improper operations of one or two burners can completely offset the effectiveness of low excess air and staged firing for NO_x control.

The quantitative effect of combustion control techniques on particulate formation has not been adequately characterized in coal fired boilers. Consequently, additional research is needed in order to assess the possible advantages and disadvantages of combustion modifications for NO_x emission reduction on the emission of particulates.

It is readily apparent that some reduction in operating flexibility results from the full use of combustion modifications for NO_x control. For example, the use of low excess air calls for close attention to individual burner operation; this means good maintenance practices and frequent measurement and observation of furnace conditions. Where burner tilt affects NO_x emissions, its use for steam temperature control is restricted. The use of flue gas recirculation and air damper settings for NO_x reduction also limit their use for steam temperature control. However, the reduction of NO_x emissions and improved fuel economy due to low excess air firing offer sufficient incentives that some loss of operating flexibility may become acceptable. Properly instrumented boilers, operated under sound maintenance and operating practices, should reduce this potential problem area to a minimum, without significantly limiting the application of combustion modification techniques.

Obviously, safe operating practices must be maintained while employing combustion modification techniques for NO_x emission control. Flame stability can be impaired with low excess air, staged firing and excessive flue gas recirculation. However, unsafe conditions are well known and can be avoided while operating to reduce NO_x if good design, operating, and maintenance practices are employed.

The effect of combustion modification techniques on operating costs is generally well understood. The use of low excess air reduces operating costs, while reduction in load increases operating costs per unit output. Generally, the use of staged firing results in reduced load, and therefore, increased unit operating costs. However, where the fuel burning capacity of individual burners can be increased, staged firing may result in reduced NO_x emissions with little reduction in load. Burner tilt and air damper settings should have little effect on operating costs, while additional research is needed on the economic effect of flue gas recirculation.

Design, instrument and control limitations may reduce the application of combustion modification techniques, particularly on older boilers. Thus, most coal fired boilers lack facilities for flue gas recirculation into the windbox, and we know of no coal burning boilers with "NO-ports" for two-stage combustion. However, where flue gas recirculation into the furnace for temperature control is available, it may be possible to add additional duct-work for recirculation into the windbox at relatively low cost. Also, the secondary air ports in some coal fired boilers can be adjusted with staged coal firing to obtain most of the advantages of staged firing with little or no additional equipment costs. Our experience indicates the necessity for adequate instruments for continuous measurement of the level of excess air and incompletely burned CO or other combustibles in order to use low excess air and staged combustion techniques with full effectiveness. It should also be noted that non-base loaded boilers which are required to change load frequently would be able to employ combustion control a higher proportion of operating time if automatic equipment and controls become available for changing air damper settings, turning individual burners on and off, etc. Finally, the effect of burner design in conjunction with combustion modification techniques is not completely understood, and therefore, should be further investigated.

Coal quality can play an important role in the potential scope of applicability of combustion modification techniques. The importance of matching coal slagging characteristics with furnace design parameters have been discussed earlier. Use of fuels containing high levels of iron pyrites can severely restrict the application of low excess air and staged firing in cyclone and other wet bottom furnaces due to possible metal corrosion. Additional field testing is needed in order to determine how to avoid corrosion problems and slagging difficulties while employing effective NO_x reduction with combustion modification techniques such as flue gas recirculation, low excess air and staged firing. In the case of cyclone boilers, recirculation directly into the cyclones may be required. The role of nitrogen in the coal fuel must be studied in detail from the standpoint of its impact on combustion modifications for NO_x emission control.

The application of combustion modification techniques for NO_x emission reduction on oil fired boilers presents considerably fewer problems and unknown areas than for coal fired boilers. For example, problems associated with slagging, and iron pyrites in the fuel are virtually eliminated. In addition, the measurement and control of fuel to air ratios on individual burners is considerably easier in oil firing than in coal firing, thus simplifying the application of low excess air and staged firing.

Table 2-10 summarizes the problems and limitations associated with NO_x emission control for oil fired boilers in a similar manner as Table 2-10 does for coal fired boilers. The more important limitations and problems for this equipment category are discussed briefly below.

The formation of smoke or haze is often a major limitation in obtaining the full benefit of applying low excess air in oil fired boilers. However, the design and operating problems associated with low excess air are well known. To achieve low excess air without increasing haze or smoke generation, it is necessary to have adequate windbox pressures for good air supply control, well-designed burner throats and impellers for proper air turbulence, well-matched patterns of oil atomization with air flow, balanced burners for proper air/fuel ratio on each burner, and good instrumentation to keep the air/fuel ratio under control as the demand for steam changes. Important advantages of low excess air firing in addition to lower NO_x emissions are increased boiler efficiency and reduced low-temperature corrosion.

Staged firing accomplished by providing air ports above the top row of burners, and modified staged firing or introducing air only through some burners in conjunction with low excess air have consistently resulted in significantly reduced NO_x emissions from oil fired boilers. The use of extra fuel capacity oil guns have enabled some boilers to maintain full load operation with staged firing. Thus, proper design and operating practices necessary

TABLE 2-10

OIL FIRED UTILITY BOILERS
OPERATING AND DESIGN PROBLEMS OR LIMITATIONS

	Combustion Control Techniques					
	Low Excess Air	Staged Firing	Flue Gas Recirculation	Load Reduction	Burner Tilt	Air Damper Setting
A. Operating Problems and Limits						
1. Haze or Smoke Formation	A	B	C	D	D	B
2. Steam Temperature Control	A	C	A	D	A	C
3. Furnace Wall Temp. Limits	C	A	A	D	D	C
4. Flame Impingement - Furnace Walls	B	B	?	D	D	C
5. Flame Stability	C	B	A	D	D	C
6. Corrosion - Furnace Walls & Tubes	C	C	D	D	D	D
7. Corrosion - Ducts, Air Heater	C	C	D	D	D	D
8. High CO, H.C. and Combustible Emissions	A	B	B	D	D	A
9. High Particulate Emissions	A	?	?	D	D	?
10. Reduced Operating Flexibility	B	B	B	A	B	C
11. Reduced Safety Margin	A	B	C	D	D	C
12. High Operating Costs	+	B	C	A	D	D
B. Design, Instrument or Control Limitation						
1. Lack of Flue Gas Recirculation Facilities	D	D	A	D	D	D
2. Lack of "NO-Ports"	D	A	D	D	D	D
3. Lack of Auto. Damper Controls	A	A	C	D	D	D
4. Lack of CO, H.C. or Combustible Instruments	A	A	B	D	D	C
5. Lack of Automatic Control System	B	C	C	C	C	C
6. Burner Design	?	C	D	D	A	D
7. Fuel Control to Burners	A	A	C	D	D	D
C. Fuel Quality Limitations						
1. High N-Content	B	D	B	D	D	D
2. High S-Content	C	C	C	D	D	D
3. High Metals/Ash Content	D	D	D	D	D	D

A - Major Problem or Limitation
B - Moderate Problem or Limitation
C - Minor Problem or Limitation
D - No Problem or Limitation
? - Extent of Problem or Limitation Unknown
+ - Control Technique Aids Problem

for low excess air firing generally eliminate the potential problems associated with staged firing. The problem of determining the proper pattern of burner firing at various loads in order to obtain low NO_x emissions without excessive CO and hydrocarbon formation, or temperature control problems can be solved by detailed, well-planned statistical experimental programs on each class of boilers.

Limited field testing of flue gas recirculation into the combustion zone has proven effective for NO_x reduction on oil fired boilers. However, additional research is needed to determine the best combination of low NO_x emissions without causing problems of temperature control, or high CO and particulate emission levels.

Because of the alternative combustion modification techniques available for the effective reduction of NO_x emissions, the use of load reduction with its high operating cost penalty appears to be relatively unattractive for NO_x control for oil fired boilers. Assuming the availability of proper instrumentation and control equipment, the major problem of NO_x reduction from oil fired boilers is to determine the optimum combination of available combustion control techniques that effectively reduce NO_x at each load without aggravating potential operating problems. Again, the problem of NO_x emissions due to fuel nitrogen oxidation must be assessed.

The application of combustion modification techniques for NO_x emission reduction from gas fired boilers presents fewer problem areas or limitations than either oil or coal firing. Our evaluations are summarized in Table 2-11 for this equipment category. Experience on many boilers has shown that low NO_x emissions can be obtained on well-maintained and operated boilers through the application of the proper combination of combustion modification techniques. However, the demonstration of efficient, planned multifactor experimental programs to rapidly achieve optimum NO_x reduction within the inherent boiler flexibility is needed to take full advantage of potential improvements. In addition, research is needed in order to determine the most effective burner design for wall and tangentially fired boilers.

TABLE 2-11

GAS FIRED UTILITY BOILERS
OPERATING AND DESIGN PROBLEMS AND LIMITATIONS

	Combustion Control Techniques					
	Low Excess Air	Staged Firing	Flue Gas Recir-culation	Load Reduc-tion	Burner Tilt	Air Damper Setting
A. Operating Problems or Limits						
1. Haze Formation	B	C	C	D	D	C
2. Steam Temperature Control	B	C	B	D	A	C
3. Furnace Wall Temp. Limits	C	C	C	D	D	C
4. Flame Impingement on Furnace Walls	C	C	C	D	D	C
5. Flame Stability	C	C	C	D	D	C
6. Corrosion - Furnace Walls & Tubes	D	D	D	D	D	D
7. Corrosion - Ducts, Air Heater	D	D	D	D	D	D
8. High CO, H.C. and Combustible Emissions	B	C	C	D	D	C
9. High Particulate Emissions	C	C	D	D	D	C
10. Reduced Operating Flexibility	C	C	C	A	D	C
11. Reduced Safety Margin	A	B	C	D	D	C
12. High Operating Costs	+	C	C	A	D	D
B. Design, Instrument or Control Limitation						
1. Lack of Flue Gas Recirculation Facilities	D	D	A	D	D	D
2. Lack of "NO-Ports"	D	B	D	D	D	D
3. Lack of Auto. Damper Controls	A	A	C	D	D	D
4. Lack of CO, H.C. or Combustible Instruments	A	B	C	D	D	C
5. Lack of Automatic Control System	B	C	C	C	C	C
6. Burner Design	?	?	C	B	A	D
7. Fuel Control to Burners	A	A	C	D	D	D
C. Fuel Quality Limitations	D	D	D	D	D	D

A - Major Problem or Limitation
B - Moderate Problem or Limitation
C - Minor Problem or Limitation
D - No Problem or Limitation
? - Extent of Problem or Limitation Unknown
+ - Control Technique Aids Problem

2.2 Emission Factors by Fuel Type and Boiler Firing Method

Nitrogen oxide and carbon monoxide emission factors corresponding to uncontrolled, base-line operating conditions, were calculated for each boiler tested. These emission factors are summarized in Tables 2-12, 2-13, and 2-14, respectively, for gas, oil, and coal fired utility boilers tested in our program. No attempt was made to calculate corresponding hydrocarbon emission factors, since as discussed earlier, the measurable levels of hydrocarbon emissions were negligibly small.

Inspection of the emission factor data, expressed both as parts per million (corrected to 3% oxygen in the dry flue gas), and quantity of NO_x expressed as equivalent NO_2 per unit energy input (calculated both as lb. NO_2 per 10^6 Btu and gm. NO_2 per 10^6 calories), indicates a wide variation of NO_x emission factors depending on fuel type and method of firing. In general, coal firing results in the highest NO_x emission factors, but the distinction between gas and oil firing is blurred, because of the strong influence of boiler design, size, firing intensity, bound nitrogen content of the fuel oils, and other factors.

Within a given category of boiler firing design, tangential firing appears to yield the lowest emission factors, as expected, based on prior information (1). The high intensity cyclone firing design is at the other extreme, resulting in high values of the NO_x emission factors. Carbon monoxide emissions, under normal operating conditions, were found to be low, without exception. This is reflected by the very low values of the CO emission factors tabulated. However, using modified combustion operating conditions for NO_x control, particularly with low excess air firing or with the combination of staged firing with overall low excess air, the CO emissions may increase sharply when the excess air is reduced below a critical level. As discussed in Sections 6 and 2.1 of this report, the critical level of excess air depends on the fuel type and boiler design and operating characteristics. The emission factors determined in this study in conjunction with the overall correlations of NO_x emissions discussed in Section 2.1, will be useful for obtaining better emission estimates for individual boilers than those which could be calculated based on "average" values available prior to this study (1, 8).

TABLE 2-12

EMISSION FACTORS FOR GAS FIRED BOILERS

Boiler			Emission Factor					
			NO_x			CO		
Code	Size and Load(1) MW	Type of Firing(2)	ppm, at 3% O_2, Dry Basis	lb/10^6 BTU (3)	gm/10^6 cal. (3)	ppm, at 3% O_2, Dry Basis	lb/10^6 BTU	gm/10^6 cal.
	Small							
B	80F	FW	497	0.65	1.16	52	0.043	0.074
I	66F	V	155	0.20	0.36	12	0.010	0.017
	Medium							
A	180F	FW	390	0.51	0.92	14	0.011	0.020
C	315F	FW	992	1.29	2.32	(6)	(6)	(6)
G	220F	AW	675	0.88	1.58	14	0.012	0.020
H	320F	T	340	0.44	0.79	175	0.145	0.249
D	355F	HO	946 (515) (4)	1.23	2.21	86 (67) (4)	0.068	0.122
	Large							
E	480F	HO	736 (140) (5)	0.96	1.73	20-400	0.016-0.33	0.028-0.57
F	600F	HO	570	0.74	1.33	8	0.006	0.011

(1) Load: F = Full Load, R = Reduced Load
(2) Type of Firing: FW = Front Wall
V = Vertical
AW = All Wall
T = Tangential
HO = Horizontally Opposed
(3) Expressed as equivalent NO_2
(4) Using "NO-ports"
(5) Using staged combustion
(6) Not available

TABLE 2-13

EMISSION FACTORS FOR OIL FIRED BOILERS

Boiler			Emission Factor					
			NO_x			CO		
Code	Size and Load(1) MW	Type of Firing(2)	ppm, at 3% O_2, Dry Basis	$lb/10^6$ BTU (3)	$gm/10^6$ cal. (3)	ppm, at 3% O_2, Dry Basis	$lb/10^6$ BTU	$gm/10^6$ cal.
	Small							
B	82F	FW	580	0.78	1.41	64	0.052	0.094
K	66F	T	203	0.27	0.49	28	0.023	0.041
	Medium							
A	180F	FW	367	0.50	0.89	19	0.016	0.028
J	250F	FW	360	0.49	0.87	30	0.025	0.044
D	349F	HO	457 (300) (4)	0.62	1.11	66	0.055	0.097
G	220F	AW	235	0.32	0.57	19	0.015	0.028
H	216R	T	161	0.22	0.39	13	0.011	0.019
	Large							
E	359F	HO	246 (200) (4)	0.33	0.60	14	0.017	0.021
L	415F	CY	530	0.72	1.29	6	0.005	0.009

(1) Load: F= Full Load, R = Reduced Load
(2) Type of Firing: FW = Front Wall
HO = Horizontally Opposed
AW = All Wall
T = Tangential
CY = Cyclone
(3) Expressed as equivalent NO_2
(4) Using "NO-ports"

TABLE 2-14

EMISSION FACTORS FOR COAL FIRED BOILERS

Boiler			Emission Factor					
			NO_x			CO		
Code	Size (1) MW	Type of Firing(2)	ppm, at 3% O_2 Dry Basis	$lb/10^6$ BTU (3)	$gm/10^6$ cal. (3)	ppm, at 3% O_2 Dry Basis	$lb/10^6$ BTU	$gm/10^6$ cal.
	Small							
M	140R	FW	660	0.90	1.63	97	0.081	0.146
	Medium							
C	275F	FW	1490	2.04	3.68	(4)	(4)	(4)
P	300F	T	568	0.78	1.40	25	0.022	0.038
	Large							
F	563F	HO	838	1.15	2.07	20	0.017	0.030
N	780F	HO	905	1.24	2.24	(4)	(4)	(4)
O	400R	T	405	0.55	1.00	20	0.017	0.030
Q	670F	CY	1170	1.60	2.89	(4)	(4)	(4)

(1) Load: F= Full Load, R = Reduced Load
(2) Type of Firing: FW = Front Wall
T = Tangential
HO = Horizontally Opposed
CY = Cyclone
(3) Expressed as equivalent NO_2
(4) Not available

- Can flue gases be recirculated into the primary combustion zone? If the boiler is equipped with appropriate gas handling equipment to the air supply to recirculate flue gases used for steam temperature control, this feature should be exploited. If flue gas recirculation is available but only into the bottom of the furnace, the option of installing additional ducting, fans, filters, etc., should be considered.

In addition to the above, all "minor" operating changes discussed in this report should be carefully considered. Once the most appropriate combination of combustion operating conditions and equipment modifications are selected for the particular boiler(s) to be controlled, standard modes of operation should be established by stepwise implementation of the changes. Naturally, the procedures adopted for one boiler should be applicable with minimal changes to similar units.

3.2 Recommendations for New Boilers

Obviously, both the boiler operator and the manufacturer will have more latitude to bring into line newly designed boilers than existing ones from the emission standpoint. To meet existing or anticipated performance standards, which in fact may become more stringent as new technology becomes available, we feel that it would be wise to provide for sufficient boiler flexibility in the design phase to satisfy such future needs. This may be accomplished without incurring prohibitive costs by considering the following factors in the specification of a new boiler.

- Provide for staged combustion and low excess air firing by individual control of fuel and air flow to burners. Install oversized burners to allow for changing burner patterns in staging.

- Design the unit with "NO-ports" or other overfire air capabilities and a sufficiently high secondary air supply capacity to penetrate into the flame zone.

- Install flue gas recirculation facilities into the primary combustion zone.

- Consider designing oversized furnaces, particularly for gas fired units which respond well to this type of change, and for cyclone boilers which await the development of novel designs (e.g., recirculation into or staging in the cyclone) to control NO_x emissions by other means.

- Install monitoring instrumentation for NO_x, unburned combustibles and other pollutants to see whether the control steps are indeed effective and the boiler complies with regulations.

4. BOILER TEST PROGRAM DESIGN AND PROCEDURES

A top priority recommendation of our Phase I NO_x Stationary NO_x Systems study(1) was to conduct a systematic investigation of the feasibility of applying combustion modification techniques to the control of NO_x emissions from utility boilers, and to obtain reliable emission factor data on this class of equipment.

Limited experience exclusively with gas and oil fired boilers, has shown the attractive potential of NO_x emission control using combustion modification techniques such as low excess air firing, two-stage combustion, flue gas recirculation, changing burner spacing and location and combination of such techniques(1). It was also known that certain firing types, such as tangential and vertical firing, result in inherently lower NO_x emissions than other types, e.g., wall firing.

The purpose of our Boiler Test Program was to systematically measure NO_x and other combustion gas emissions from utility boilers, based on a statistically designed program incorporating the variation of fuel type, boiler design and size, and combustion operating variables. Using this approach, we designed the test program to provide information on the scope of applicability of combustion modification techniques for NO_x control, as limited by the operability of the boilers tested, and to define problem areas and equipment design changes required for optimizing the use of the control techniques investigated.

Particular attention was paid to considerations of other undesirable emissions or boiler operability problems resulting from the practice of NO_x control techniques. Sampling and analysis on a real-time basis to yield statistically meaningful information was another consideration. Also, the cooperation of electric utility companies had to be obtained for emission tests on their equipment, based on the variation of combustion operating conditions within the limits of flexibility of the equipment. Finally, for a few carefully selected coal fired utility boilers, the participation of the boiler manufacturers was obtained to provide guidance on the limits of operability of the boilers, and to assess the steam-side boiler performance consequences of operating changes made for NO_x emission control.

This section of the report presents our approach to the statistically designed Boiler Test Program in which 17 boilers were tested, including the description of the mobile sampling-analytical system equipped with multiple probes and continuous gas analyzers.

4.1 Statistical Field Program Design

There are three major sampling problem areas in designing field test programs that require the use of sound statistical principles for their efficient solution. First is the problem of selecting a properly sized, representative sample of boilers for testing from all United States utility boilers. A second problem occurs in selecting the number, location and period of time to obtain flue gas samples from each boiler. Finally, the operating conditions for each test run, as well as the order and number of test runs conducted on each boiler presents a problem of statistical experimental design. This section describes each of these problems with the corresponding statistical principles involved in its solution.

4.1.1 Boiler Selection

Selecting a proper representative sample of United States boilers for a limited NO_x emission field test program is a particularly difficult problem because of the wide diversity of boilers in use, and the high dependence of NO_x emission rates on boiler design, operating and fuel factors.

There are about 3,000 utility boilers currently in use in the United States. These boilers vary considerably in age, design, size and fuel usage since boilers are custom-designed to economically meet the specific requirements of individual customers. Fuel availability, quality and cost, as well as changing boiler design and construction technology, in addition to other economic factors,have all contributed to the diversity of utility boilers in use.

The conceptual steps involved in statistically designing the selection of boilers were:

(1) Determine the total number of boilers to be tested considering limitations of cost, time, and other factors.
(2) Determine the major boiler design, fuel and operating factors for classification of boilers into strata or sub-populations.
(3) Allocate the total sample of boilers to the sub-populations in an optimum manner.
(4) Select individual boilers within each sub-population to minimize travel, administrative and other costs.

To plan the Boiler Test Program, the detailed information on boiler operating and design features and emissions obtained through the Steam-Electric Plant Survey of our Phase I Stationary NO_x Study(1) was analyzed. The total number of boiler-fuel combination to be tested was limited by the seven-month period available for the test program. Allowing one day each for system set up and breakdown, plus an average of three days required for testing (12 to 24 test runs), resulted in about one week of time available for testing a boiler-fuel combination. However, wherever practical, boilers capable of burning more than one fuel were selected, resulting in saving two days for each additional fuel as well as giving better precision in comparing fuels within boiler types. An average of three days testing per boiler-fuel combination was the minimum time required to explore adequately NO_x emission reduction through combustion control on most boilers. Allowing for travel time, boiler operating problems, and the required analytical train maintenance, resulted in a maximum of about 20 to 30 boiler-fuel combinations which could be tested in an optimum situation during the contractual period.

Classification of boilers into subpopulations or strata has many advantages. Emission data is assured for each prime subdivision of the entire population of boilers. Improved precision of the total estimated boiler emissions is obtained through stratified sampling. The complex sampling problem is reduced to manageable size and maximum use is made of prior information.

The three major variables used in classifying boilers for sampling were fuel burned (coal, gas and oil), type of firing (front wall, opposed wall, tangential, vertical and cyclone) and boiler size (steam rates of less than 1, 1 to 3 and over 3 million pounds of steam per hour). This classification system defines 45 subpopulations without considering other important variables such as burner configuration, number of furnaces, furnace loading, burner types, air system, boiler operating flexibility and fuel grade. Breakdown of boilers into the above three size categories represents the gross distribution of electric utility boilers in the U.S., weighted by actual electrical generation.

Table 4-1 presents the planned proportional, stratified sample of test boilers. The allocation of test boilers to the subpopulations was determined using the statistical guidelines of optimum allocation considering the number of boilers in use within each subpopulation, the relative variation of boilers in each subpopulation, and the cost of testing within each subpopulation. This ideal plan called for twenty boilers (34 boiler-fuel combinations) to be tested with replication in the most important groups. Thus, 6 our of 7 of the "A" groups, 3 out of the "B" groups, 5 out 8 "C" and 9 out of 10 "D" groups were to be sampled.

The selection of individual boilers to represent each subgroup was based on a number of technical as well as economic factors. Boiler operating flexibility, availability of special combustion control equipment such as flue gas recirculation and two-stage combustion "NO-ports," and the ability to burn more than one type of fuel were key factors. To reduce administrative costs, the number of cooperating companies was minimized consistent with wide geographic dispersion of boilers to assure a variety of fuel compositions. Stations with several boilers, particularly those that burned more than one fuel type were given special consideration in order to minimize travel time and administrative costs. In addition, station management experience in operating boilers under a variety of operating conditions and their willingness to run their boilers according to a planned statistical program were considered in selecting boilers.

Thus, to briefly summarize this section, there were many statistical principles which guided the selection of boilers, even though a strict probability sampling plan was not used. A proportional, stratified sample of boilers was selected for testing. Replication within several important strata was planned so that objective measures of boiler-to-boiler variation could be obtained. Paired sampling was employed to reduce costs and to enhance the comparison of emissions from different fuels within the same boilers. A minimum number of companies and stations were selected in order to minimize necessary meetings for agreement and approval of test

TABLE 4-1

BOILER SUBPOPULATIONS TO BE STUDIED

Boiler Size as Steam Rate (10^6 Lbs./Hr.)	Fuel and Type of Firing														
	Oil					Coal					Gas				
	FW	HO	V	T	CY	FW	HO	V	T	CY	FW	HO	V	T	CY
< 1	A 5 13		C	C 9		B		A	A 9	C	A 13		D 10	D 9	C
1-3	A 1 2 8 11	B 12 14*		C 15	D 4	B 2 8 17			A 7	C 18	A 2 8 11	B 12 14*		C 15	D 18
≥ 3		D 16		D			D 3		D 6 20	D 19		C 3		D 16	

* All-Wall Fired Boiler

Code Letters	Estimated % of United States Boilers Within Each Fuel Type
A	> 12
B	8 to 12
C	4 to 8
D	< 4

Code Numbers   1 to 20 identify boilers in original program plan.

Type of Firing Codes:

FW - Front Wall
HO - Horizontally Opposed
V - Vertical
T - Tangential
CY - Cyclone

programs, and to minimize travel time so that a maximum number of boilers could be tested in the allotted time period. In addition, representative boilers of all four major U. S. boiler manufacturers (Babcock and Wilcox, Combustion Engineering, Foster-Wheeler and Riley Stoker) were tested.

4.1.2 Representative Sample Selection

The characterization of flue gases from existing stacks or ducts requires a sampling program that is statistically significant. Since the volume of gas passing any given cross-section of the duct per unit time is the product of the average gas velocity and the cross-sectional area, and the composition of the stream may vary within the given cross-section, one must be sure that the sampling procedure provides a true characterization of the flue gas stream.

In choosing the location for the measurement of the gas stream, two things must be kept in mind. First, the determination should be made where the gas flow is as uniform as possible and second, the area should be convenient for setting up equipment.

Having selected the location at which to make the test, the number and location of sampling points must be determined. The number of areas samples should be large enough to insure a reasonably accurate measurement of the average velocity over the entire cross-section. However, where there is a fluctuation in the velocity with time at any one point it is preferable to make many observations at a few points to a few observations at many points.

For this test program the number of equal duct areas that could be monitored reliably was 12. Three points were composited and measured for two minutes once every eight minutes. This procedure was repeated four times for each test. During the two minute test period the flue gas composition cycled one to two times and an average value was recorded. In some tests where large variations occurred, each point was recorded to determine the differences betwen extremes for a particular boiler test configuration. Thus, a total of 16 measurements (of 3 point composites) were obtained from each test run. The average of these 16 measurements is equivalent to a proportional, stratified sample of 48 grab samples. This measurement system also provided the opportunity for internal check of time-to-time variation as well as variation within the cross section of the duct for each test run. Thus, gross errors and responses to unplanned boiler changes could be detected and evaluated before final run average emissions were calculated.

4.1.3 Boiler Test Program Design

Modern statistical experimental design offered effective guidance in planning the test program for each boiler so that required data could be obtained with minimum cost, time, and effort. A systematic procedure was used to assure that all pertinent information was gathered and evaluated in planning each test program. Table 4-2 provides an outline of this procedure which was used in planning test programs on all boilers.

TABLE 4-2

Planning the Test Program

1. Design the Test Program

   a. Hold a Conference of all Parties Concerned

      1. State the objectives of the test program.
      2. Agree on magnitude of emission differences considered worthwhile.
      3. Choose the operating factors to be studied.
      4. Determine the practical range of each factor and specific levels.
      5. Choose end measurements to be made.
      6. Consider sampling variability and precision of test methods.
      7. Determine limitations of time, cost, operating flexibility, manpower, testing equipment, weather, etc.

   b. Design Program in Preliminary Form

      1. Prepare a systematic and inclusive schedule.
      2. Provide for sequential staging of schedule.
      3. Eliminate effects of variables not under study by controlling, balancing, or randomizing them.
      4. Minimize number of experimental runs.

   c. Review the Design with All Concerned

      1. Adjust program if desirable.
      2. Spell out steps in unmistakable terms.

2. Plan and Carry Out Experimental Work

      1. Develop methods, test equipment, and sampling equipment.
      2. Determine sampling and testing errors and standardize procedures.
      3. Repeat base runs to determine true repeatability error.
      4. Run experimental trials sequentially.

The major objectives of the boiler test programs were to (1) obtain base-line uncontrolled emission rates on boilers representative of the most important types in the United States, and (2) to determine the applicability of the potential combustion controls to NO_x emission control.

Due to limited time, it was not possible to determine optimum boiler operating conditions for NO_x control, although in a number of cases the general optimal region could be outlined from analysis of the test results obtained.

The most important guiding principles used in planning each test program were: (1) minimize the number of test runs required to meet test program objectives by using the most efficient experimental design available considering each boiler's operating flexibility and the estimated experimental error, (2) make use of all accumulated knowledge and experience available in crystallizing test objectives and planning the experimental design for each boiler test program, (3) utilize the sequential approach to experimental design by planning readily augmentable blocks of experimental runs, (4) take advantage of fractional factorial designs where the possible number of experimental runs obtained through varying pertinent operating factors was too large, (5) replicate a sufficient number of test runs to obtain a reliable measure of experimental error or repeatability, (6) determine the order of runs by a pure random selection process unless this procedure would lead to excessive operating costs or a greatly reduced number of test runs per day, and (7) reduce the effects of variables not under study by controlling, balancing, or randomizing them.

These guiding principles, based on both theory and practice, led us to take advantage of factorial type experimental designs in most boiler test programs. Full factorial designs make it possible (1) to estimate the main effects of each factor independent of each other, (2) to determine the dependence of the effect of every factor upon the level of the others (interactions), (3) to determine the effects with maximum precision, and (4) to obtain an estimate of the experimental error for the purpose of assessing the significance of the effects. Where the number of operating variables was too large to perform a complete factorial design, fractional designs were used.

The combustion control variables included in most of the experimental programs were load, excess air level and some form of staged combustion. With two levels of each of the three variables tested, a complete factorial would require 8 runs while a total of 27 runs would be required for a full factorial design of 3 variables each at 3 levels. The need to test a relatively large number of boiler-fuel combinations restricted the number of test runs feasible on each boiler, and thus most operating variables were tested at only two levels. An exception to this general rule was boiler load. The first few oil and gas fired boilers in the study were tested at three load levels in order to determine if emission rates changed linearly with load and also if there were significant excess air and staging interactions with load. Later, boilers were generally tested at only two load levels since interactions were found to be fairly small. Roughly linear relationships were found between NO_x emissions and load, and rather complete combustion control evaluation was desired at full load and at reduced load conditions. Where 5 or 6 operating variables were available for testing, a complete factorial experiment at two levels would require 32 and 64 runs, respectively. Consequently, partially replicated factorials were designed with emphasis placed on areas felt to be of the greatest interest, such as full load, low excess air, and/or staged combustion.

A practical balance was sought between the statistical desirability of pure randomization of the order of test runs (which would often greatly reduce the number of test runs accomplished per day) compared to ordering test runs in light of operating costs and convenience. In most cases, it was felt that the increased number of runs available per day through evaluation of operating considerations more than offset the possible loss in quantification of statistical probabilities. In addition, the effect of variable fuel quality and unmeasured boiler operating factors with time were minimized by limiting the test program to fewer test days. Another violation of pure randomization of run order was often made to assure better "paired comparisons" within one day's runs. For example, the lowest level of excess air that could be used at a given load without exceeding acceptable hydrocarbon or carbon monoxide emission limits* was heavily dependent upon a number of boiler design and operating conditions, and therefore, was difficult to predict in advance. Thus, it was often desirable to first reduce the excess air to the minimum possible under the prevailing boiler conditions, and then make a run at a higher excess air level, with a known minimum difference, rather than make these runs in the reverse order.

* Measureable hydrocarbon emissions in this study were found to be negligible. The "acceptable" level of CO was set at 200 ppm, which corresponded to the practice of some of the boiler operators, and was found to correspond to the level of excess air below which a sharp rise in CO emissions would occur.

4.2 Design of Mobile Sampling and Analytical System

Meeting the objectives of our field program of measuring NO_x and related products of combustion emitted from a variety of power boilers required a versatile, transportable sampling and analytical train. Such a system had to be self-contained, mobile, and include provisions for wet chemical analysis of grab samples. Minimum set-up time was another requirement for the sampling and analytical system, which had to be installed at the actual sampling site to reduce the possibility of changes in the flue gas composition. Ideally, the instruments should have been located at the sampling point, but since this location was frequently inaccessible and was usually unsheltered, some compromise had to be made. Other requirements for the instruments for the measurement of the concentration of the flue gas components were easy calibration, maintenance-free and repeatable operation, and the ability to monitor gas compositions continuously. The last requirement is of extreme importance in a field program, where directional effects of operating changes must be assessed immediately.

Finally, the instrumental methods had to be compared against wet chemical methods of analysis, as needed, to validate the accuracy of the sampling system and continuous monitoring instrumentation.

4.2.1 Sampling System

The objective of obtaining data from coal, as well as oil and gas fired boilers required the development of an elaborate sampling system. Consideration of the solubility of NO_2 in water, the presence of oxides of sulfur, and the high concentration of particulates in the combustion gases were taken into account in the design of the sampling system. The sampling system was designed with adequate flexibility to allow gas sampling from different size boilers or other stationary combustion equipment. It could handle flue gases with heavy particulate loading from coal fired units, as well as light particulate loading from oil fired units. The sampling assembly was a dry-type system with appropriate particulate filters, pumps, and a refrigeration unit to cool the samples to a 35°F dew point before analysis.

The sampling points for flue gas components were usually located in the duct-work between the economizer and the air heater. This was done to provide reasonably homogeneous gas samples at the temperatures to which the probes could be subjected, and to avoid dilution of the samples by leakage in the air heaters of the boilers tested. In this part of the duct-work, temperatures usually ranged between 550°F and 800°F, and gas velocities were between 30 and 80 feet per second.

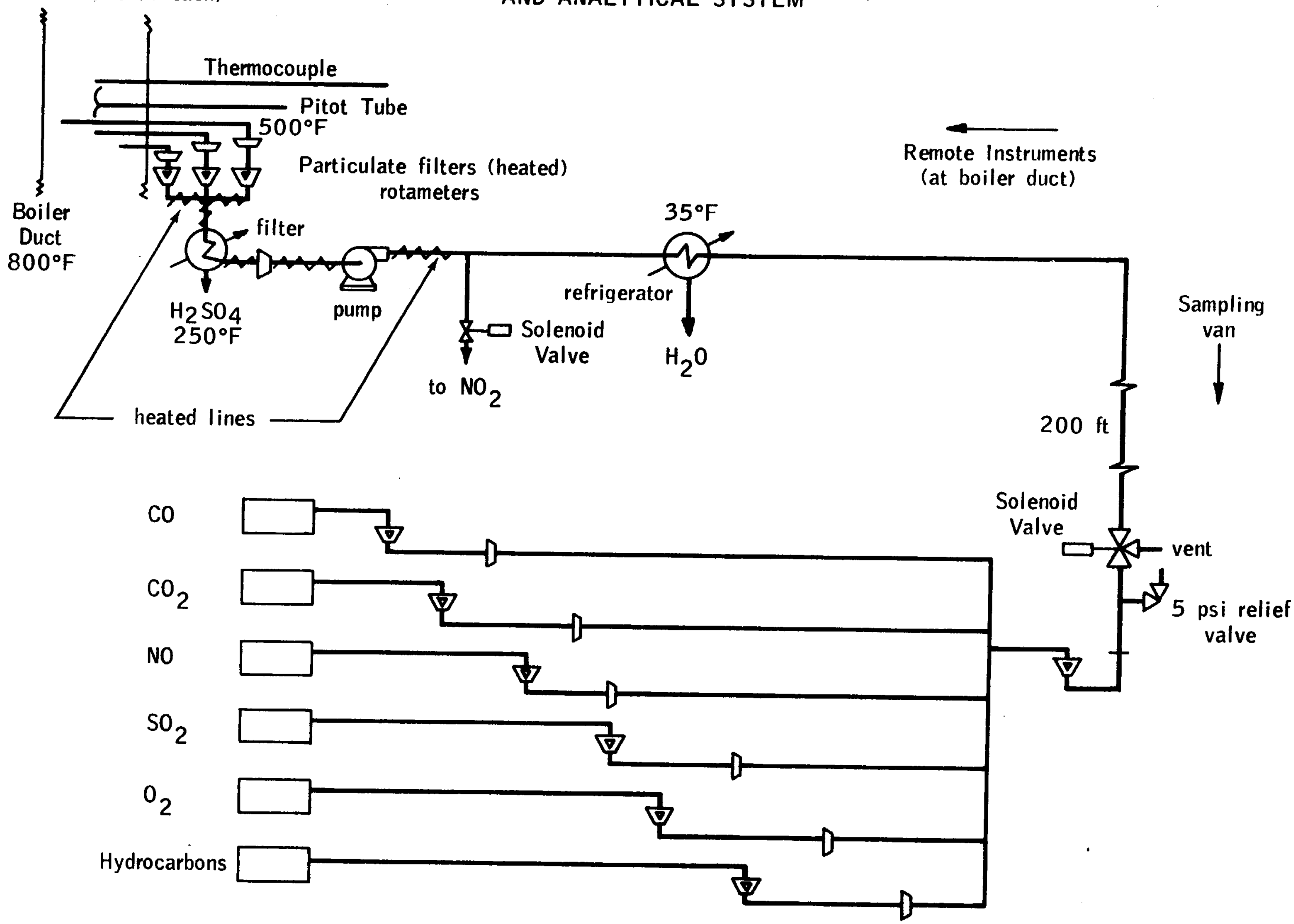
The variability of ducting between different boilers required the design of adjustable sampling probes. These probes were designed with interchangeable gas sampling tubes. Since we sampled from "equal areas" in ducts of different sizes, the probes were assembled on location for the particular duct. A special pitot tube and a thermocouple were located at the midpoint of each probe with a sampling tube. The remaining two gas sampling tubes were then assembled and the entire probe was ready to be inserted into the duct. Each probe was fitted with a quick disconnect as a mounting assembly for easy insertion into the boiler. All pieces of the sampling equipment between the van and the probes were of the quick-disconnect type for ease of assembly and assurance of a leak-proof connection at all intermediate points. Figure 4-1 shows a schematic diagram of the sampling and analytical system. Detailed illustrations of this system are given in the Appendix.

In running field tests, the gas samples were withdrawn from the boiler under vacuum through stainless steel probes to heated paper filters where the particulate matter was removed. These paper filters were maintained at 300-500°F. The gases were then passed through rotameters, which were followed by a packed glass wool column for SO_3 removal. Initially, the gas temperatures were kept as high as possible to minimize condensation in the particulate filters. After leaving the packed column at 250-300°F, the gas samples passed at temperatures above the dew-point through heated Teflon lines to the vacuum/pressure pumps. The sample was then split with a portion at 120°F sent to the NO_2 instrument and the balance of the stream refrigerated to a 35°F dew-point before being sent to the van for analysis. Usually, the van was located 100 to 200 feet from this point and the gas stream flowed through Teflon lines throughout this distance.

The sampling system performed well during the test program, however, some difficulties were encountered with the vacuum pressure pumps. The pumps originally acquired for our sampling system were stainless steel bellows pumps. These pumps were manufactured with a clearance volume for slugging liquid entrainment. After about 40 hours of use the pumps began to leak and inspection revealed that the bellows became deformed and perforated with pinholes. The probable cause of failure was condensate remaining in the pump during the compression stroke deforming the bellows. The manufacturer (Metal Bellows Corp.) supplied replacement sets of pumps and we revised the sampling system in an attempt to overcome the problem. Water knockouts were incorporated before the pumps and the pumps were mounted upside down to facilitate draining of liquids that condensed during shutdown. This procedure did not eliminate the problem and new Teflon faced neoprene diaphragm pumps (Diapumps) had to be installed. These proved to be satisfactory in use for the remainder of the field test program.

Figure 4-1

ESSO RESEARCH TRANSPORTABLE SAMPLING AND ANALYTICAL SYSTEM



Another problem of air leaking into the lines was found to be due to the flexible lines. While these lines were designed for high pressures and temperatures, their flexibility was not sufficient for our purpose. After severe bends, necessitated by probe locations, leaks would develop when the lines were heated to high temperatures. We are currently experimenting with a new design which eliminates the protective wire braid from the line on a replacement basis. Preliminary evaluation shows that this type of line is superior to the old one. Also, pressure-testing all lines at each boiler in future work will be required to correct this problem.

4.2.2 Analytical Instrument Train

The selection of instruments for the measurement of flue gas composition was complicated by the relatively short delivery time necessitated by the requirement to begin the field test program in the early part of the contractual period. The instruments had to be installed and wired in a console and checked out before the test program could begin. Beckman Instruments Inc. was chosen as the supplier for these instruments because of their ability to deliver monitoring instrumentation in a short time and Esso Research and Engineering Company's prior familiarity with their analyzers in other air pollutant measurement trains. Another reason was the availability of the field service organization of Beckman which was felt to be an important asset for field studies.

The instruments selected for monitoring flue gases were those that had been demonstrated to be accurate and relatively trouble-free in previously used exhaust gas analytical trains at Esso. Our van was equipped with Beckman non-dispersive infrared analyzers to measure NO, CO, CO_2 and SO_2, a non-dispersive ultraviolet analyzer for NO_2 measurement, a polarographic O_2 analyzer and a flame ionization detector for hydrocarbon analysis. The measuring ranges of these continuous monitors are listed in Table 4-3.

TABLE 4-3

Continuous Analytical Instruments in Esso Van

Beckman Instruments	Technique	Measuring Range
NO	Non-dispersive infrared	0-400 ppm 0-2000 ppm
NO_2	Non-dispersive ultraviolet	0-100 ppm 0-400 ppm
O_2	Polarographic	0-5% 0-25%
CO_2	Non-dispersive infrared	0-20%
CO	Non-dispersive infrared	0-200 ppm 0-1000 ppm
SO_2	Non-dispersive infrared	0-600 ppm 0-3000 ppm
Hydrocarbons	Flame ionization detection	0-10 ppm 0-100 ppm 0-1000 ppm

The instruments were housed in a console which was shock-mounted inside the van. All connections to the console were made beneath the floor to prevent a tripping hazard. Separate raceways for piping and electric wires terminated in the base of the cabinet. Each analyzer was connected in parallel to the sample and calibration gas lines to insure that each analyzer would be operated independently of the others.

In the original design of the sampling-analytical train and during its construction, sufficient flexibility was engineered into our system to allow additional analyzers to be installed, and for modifications and special sample handling techniques to be incorporated. In addition to analytical instrumentation for continuously measuring all of the major flue gas components including NO, NO_2, CO, CO_2, O_2 and hydrocarbons (with an instrument added later to measure SO_2), the temperature and velocity of the gases in the duct could also be measured. A novel programmable sample timer was installed to allow any sample cycle to be simply dialed into the equipment.

Normally, measurements from four different locations within the ducts could be made in eight minutes. After steady state conditions in the boiler had been established, the sampling time of 32 minutes per test allowed 4 repeats of each location assuring that reproducible data were obtained. The programmable sample timer proved to be very useful when monitoring operations at very low excess air levels, because the most sensitive areas had to be monitored more frequently.

Separate calibration gas cylinders in appropriate concentrations with N_2 carrier gas for each analyzer were installed in the van. Each cylinder was equipped with a regulator, safety relief valve, excess flow check valve and other necessary valves and piping. The cylinders were securely fastened to the body and frame of the vehicle to insure safe transportation. Each cylinder was piped directly to the analyzer for ease of operation.

The sample gases were pumped to the van from four separate probes. While one sample was being monitored, the other three were vented from the van to insure that a fresh sample would be available when required. This operation was performed automatically by the sample timer.

The gases were analyzed as received at the 35°F dew point except for the NO instrument which had twin chemical driers for the removal of water. The driers were filled with fresh indicating drierite before each run and were only used until the color change had reached the mid-point of the tubes.

The hydrocarbon instrument, a Beckman Model 400 flame ionization detector, measured only the hydrocarbons that reach the instrument. Only hydrocarbons volatile under the sampling conditions could be measured by this instrument because of the sample preparation system. The initial filtration at 300-500°F removed solid as well as liquid particulates. The glass wool packed column, maintained at 250°-300°F, might have removed lower boiling liquids. The gases were then refrigerated to a 35°F dew point before being analyzed for hydrocarbons. The condensate from the refirgeration unit was analyzed for organic carbon in selected test runs, and was found to contain on the average 20-30 ppm hydrocarbon equivalent in the flue gas.

In addition to the recorders in the van, separate trend recorders for NO, O_2 and CO were provided for remote observation of flue gas concentrations in the control room of the utility. The effects of changes in operating variables, therefore, were continuously displaced to provide information to the operating personnel in the control room.

While in most cases the instruments performed satisfactorily, some special problems did arise. The CO instrument, which has a long path infrared cell. was found to be sensitive to 200 ppm CO full scale. Moisture interference was a major problem for this long path instrument. Changes were made in the filter cells, heater circuits, and in the gold coating of the sample cell. These changes reduced the problem but could not completely eliminate it. Although this problem may be circumvented by using chemical driers upstream of the sample cell, a more satisfactory solution is desirable for future measurements of this type. Narrow band-path optical filters will be installed to reduce moisture interference with the response of the sample cell.

The NO_2 instrument, a non-dispersive ultraviolet analyzer, was designed for 100 ppm NO_2 full scale. However, the accuracy of measuring extremely small amounts of NO_2 in the flue gases was affected by the noise level of the instrument. This noise level was substantially increased by the remote location of the NO_2 instrument, and the varying temperature environment.

Our experience demonstrated that with the NO_2 analyzer (an instrument designed for a laboratory environment) even though it was shock mounted for vibration, the sensitivity of the mirror adjustment was such that we lost calibration during runs due to boiler-induced and other vibrations of very low frequency. Also, because this instrument was used for measuring hot samples of the corrosive flue gas which had not been subjected to condensation, the analyzer was fouled easily. Small temperature variations due to the wind-chill factor at unprotected outside boiler locations could cause condensation in the analyzer. Then, an elaborate cleaning procedure was required, which could not be performed during actual testing. Based on these findings, our future plans are to redesign this portion of the analytical system.

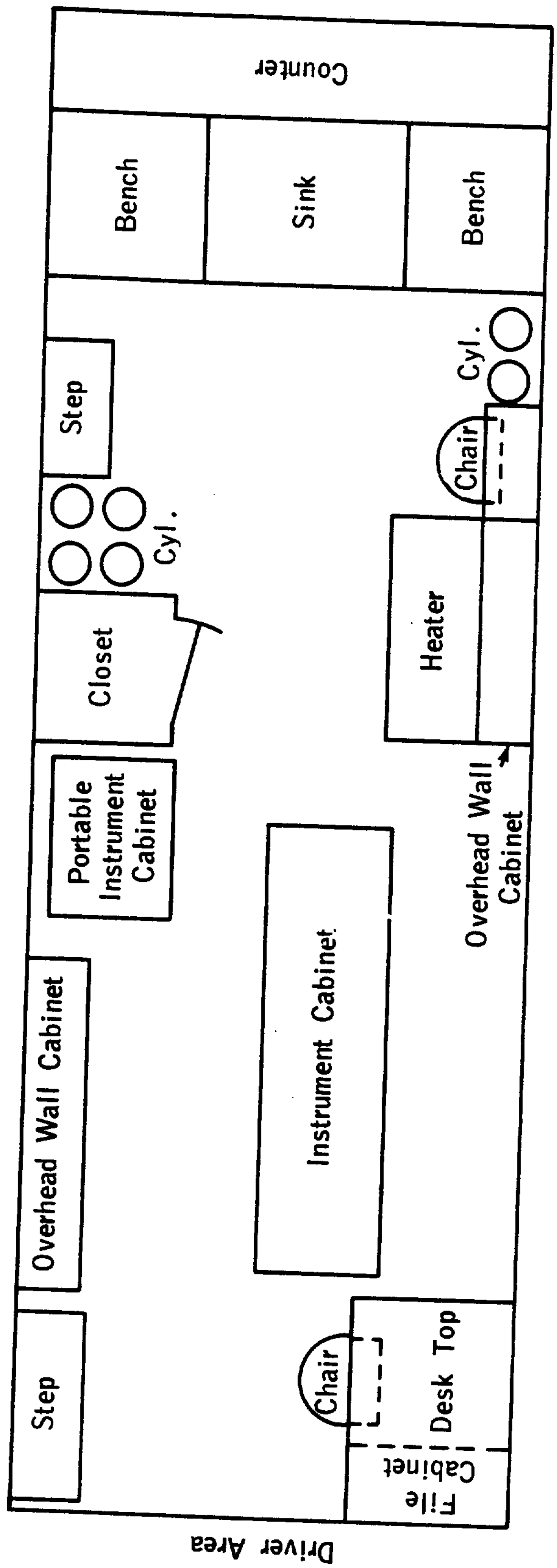
4.2.3 Integration of Sampling-Analytical System into Mobile Van

The van used to house the instruments, sampling train, and wet chemical laboratory is a Winnebago mobile home shell. The basis for the selection was availability, allowable payload weight and a self-contained propulsion system to provide maximum mobility. The shell is 27 feet long by 7 feet 6 inches wide and is mounted on a Dodge truck chassis. The driver compartment is located in the first 5 feet of the shell. The van is air conditioned and heated for all-weather operation. A gasoline-powered electric generator housed in a compartment of the chassis provides power for lighting and air conditioning during the initial equipment deployment. However, during sampling and data collection the van operated with electricity provided at the generating station. A floor plan of the van is presented in Figure 4-2.

The instruments are housed in a permanent shock mounted instrument console. The calibration gases are permanently installed in the rear of the van. These cyclinders are securely mounted for traveling and each bottle has its own low pressure safety valve and velocity check in addition to standard regulators and valves. The rear of the van is designed as a laboratory bench including a sink. It is used for experimentation and as a foul weather workbench. A swingaway desk top and a file cabinet provide an area for data analysis inside the van. A Sony programmable desk calculator for preliminary data reduction is part of the equipment carried in the van.

Figure 4-2

FLOOR PLAN OF SAMPLING-ANALYTICAL VAN



An electrical distribution center for the van includes voltage regulators ahead of the instrumentation to anticipate any large variations in line voltage between generating stations. Normal power requirements are 14 KVA for the van and the remote sampling train.

The van holds its own water supply and has a portable winch for equipment deployment. The external connections to the van are all quick disconnects in an umbilical area.

4.2.4 Comparisons of Van Data with Other Methods

A number of times during the test program comparisons were made with other methods for determining the gaseous composition of the test stream. Generally excellent agreement has been obtained and summaries of these data are presented in the following tables. The NDIR NO_x values reported in these comparison tables are the quantities of NO measured adjusted by a factor of 1.05 to take into account the NO_2 portion of the total NO_x. The same correction factor was found to be acceptable in actual test runs when the NO_2 analyzer was malfunctioning or its reading was within the noise range of the instrument.

The Envirometrics NS-200 instrument was compared with the Beckman NDIR NO analyzer. The NS-200 was operated in two modes: (1) with a scrubber to remove SO_2 as is done with the Dynasciences analyzer based on a similar electrochemical principle and (2) without the scrubber to allow compensation for SO_2 in dual mode operation. The SO_2 compensation was calculated manually for the purposes of this test. While the scrubber did remove some of the NO and NO_2 in the sample gas, operation with the scrubber appeared to give closer agreement with NDIR than operation without the scrubber; there seemed to be an approximately 20 ppm uncertainty in the SO_2 reading. These comparisons are shown in Tables 4-4 and 4-5.

TABLE 4-4

COMPARISON OF ENVIRONMETRICS ANALYZER* WITH NDIR (SO_2 SCRUBBING)

	NO_x Environmetrics ppm (Dry Basis)	NO_x NDIR ppm (Dry Basis)	Difference ppm
	170	173	-3
	155	153	+2
	200	207	-7
	200	196	+4
	205	207	-2
	190	201	-11
	175	177	-2
	185	191	-6
Average =	185	188	-5

* Readings to nearest 5 ppm (1000 ppm full scale).

TABLE 4-5

COMPARISON OF ENVIROMETRICS ANALYZER* WITH NDIR (NO SO_2 SCRUBBING)

NO_x Reading** ppm (Dry Basis)	SO_2 Reading ppm (Dry Basis)	Compensated*** NO_x Reading ppm (Dry Basis)	NO_x NDIR ppm (Dry Basis	Difference ppm
530	325	170	177	7
465	245	195	187	8
505	280	195	173	22
475	310	135	170	35
545	355	155	190	35
	Average =	166	179	21

* Readings to nearest 5 ppm (1000 ppm full scale).
** NO_x reading is 100% of NO, 80% of NO_x, 110% of SO_2.
*** Manually calculated compensation (Envirometrics analyzer has automatic compensation mode).

A comparison between the Beckman NDIR and a Whittaker (Dynasciences) polarographic NO_x instrument was also performed on flue gas from a 200 MW boiler using 0.5% sulfur fuel oil. Numerous changes were made during the course of the tests, including the variations of excess air, flue gas recirculation, and staged firing of the burners. No details of the exact conditions are presented in Table 2-6, since the purpose of these measurements was to compare the relative readings of the two analyzers.

TABLE 4-6

COMPARISON OF WHITTAKER POLAROGRAPHIC NO_x AND NDIR NO INSTRUMENTS

Polarographic,* ppm NO_x (dry)	NDIR* ppm NO, (dry)	Difference ppm
376	352	24
340	315	25
293	286	7
251	249	2
281	271	10
220	227	7
320	330	10
385	414	29
	Average =	14

* Each point is the average of four readings over an eight minute period. Flue gas oxygen levels varied between 1.8 and 2.7 percent.

The polarographic instrument responds to both NO and NO_2: this particular sensor was found to respond 100% to NO_2 in dry N_2. The NDIR responds only to NO. A liquid scrubber for SO_2 was used on the polarographic instrument. Tests indicated that it absorbed 1.5 percent of the inlet NO in a dry N_2 stream. No tests were conducted to determine the amount of NO_2 removed in the scrubber but the manufacturer states that less than 5% is removed. During the four hour test period, it was not necessary to zero or span the polarographic instrument and the NDIR instrument required only infrequent calibration.

No independent NO_2 measurements were made during this comparison test. NO_2 measurements using a Beckman NDUV NO_2 analyzer in previous tests under similar conditions were in the 10 to 20 ppm range. Hence, although the polarographic instrument responds to both NO and NO_2, the absorption of part of the NO_2 by the scrubber and the low anticipated level of NO_2 should cause the readings of the two instruments to be in fairly close agreement.

Comparisons made against a DuPont 461 NO_x analyzer and another NDIR CO instrument are presented below. These data were obtained by sampling the flue gas generated in a coal fired fluid bed laboratory combustor. For five gas measurements, the NO_x readings by all methods were corrected to 3% O_2 on a dry basis.

	Others*	Van*	Difference, ppm
CO, ppm (3% O_2)	631	648	17
NO_x, ppm (3% O_2)	687	680	7

* O_2 level 5%.

Both NO and CO checks gave good agreement. Comparison data obtained in testing boiler A on NO_x, O_2, and CO_2 are presented in Table 2-7.

TABLE 4-7

COMPARISON OF VAN INSTRUMENTS IN BOILER TESTS

	Van			Others*			NO_x
Probe	NO_x ppm (3% O_2)	O_2 %	CO_2 %[2]	NO_x ppm (3% O_2)	O_2 %	CO_2 %[2]	Difference ppm
1	129	2.7	10.7	125	2.9	10.1	4
2	151	1.0	11.6	136	1.2	11.1	15
3	201	2.6	10.8	192	2.8	10.5	9
4	379	2.3	10.9	357	2.2	10.8	22

* Average of 3 samples by PDS for NO_x and Orsat analysis for O_2.

For all three species compared in Table 4-7, the differences obtained with different analytical methods were within the accuracy of the measurements.

The following tables provide comparison data on NO_x and O_2 obtained at Boiler H and Boiler C with wet chemical methods performed by an outside laboratory.

TABLE 4-8

BOILER H ANALYTICAL COMPARISONS

	Van		Others*		NO_x
	NO_x, ppm (3% O_2)	O_2 %	NO_x, ppm (3% O_2)	O_2 %	Difference ppm
Test IV Avg. of 5 Samples	217	6.2	217	6.4	0
Test IX Avg. of 3 Samples	148	3.9	180	3.9	32

* Average of PDS for NO_x and Orsat analyses for O_2.

TABLE 4-9

BOILER C ANALYTICAL COMPARISONS

	Van		Others*		
	NO_x, ppm ($3\%\ O_2$)	O_2 %	NO_x, ppm ($3\%\ O_2$)	O_2 %	NO_x Difference ppm
Test V Avg. of 4 Samples	400	2.6	400	2.6	0
Test II Avg. of 12 Samples	270	2.2	300	2.6	30
Test III Avg. of 4 Samples	675	3.3	678	3.0	3

* Average of PDS for NO_x and Orsat analyses for O_2

In general, the agreement was excellent between NDIR and PDS methods, similar to the conclusions of a recent study by Fisher and Huls(2) which showed that an NDIR NO analyzer gave comparable readings over a wide range to those obtained by the PDS method. However, in their comparisons the Saltzman technique gave consistently lower values (by about 100 ppm) than either the NDIR or PDS methods.

4.3 Test Procedures

The planning and implementation of measuring emissions from utility boilers consisted of the following major phases in this study:

- First, on a preliminary basis, candidate boilers were selected for testing, corresponding to the considerations discussed in Section 4.1, i.e., based on the distribution of utility boilers by fuel type, size, and type of firing.

- Second, the voluntary cooperation of utility owner-operators was solicited. In these initial meetings with them, our program plans, major objectives, and the desirable boiler features for emission testing were discussed with the owner-operators. For testing emissions from three specially selected coal fired boilers, personnel of the boiler manufacturer subcontractors who suggested representative boilers of their manufacture also participated in the meetings with the utility owner-operators.

- Third, the final boiler selection, the detailed schedule for the test program, and the changes in boiler operating variables were agreed upon with the utility owner-operators prior to testing. Sequentially blocked test programs were designed for each boiler in such a way that important findings of the initial emission tests could be used to modify the plans for subsequent testing of the boiler during the course of the program.

- Fourth, according to the overall Boiler Test Program schedule, the Esso sampling-analytical van was deployed to each generating station where emission testing would take place. Our equipment was set up for measuring emissions under diverse operating conditions effected by the operating utility personnel cooperating with us, and the program plans were implemented to obtain data under base-line and modified operating conditions, within the limits of flexibility of the equipment tested. Steam-side data were gathered on the three selected coal fired boilers by their respective manufacturers, to assess the thermal consequences of operating changes made for reducing NO_x emissions.

Detailed aspects of planning and conducting the Boiler Test Program with owner-operators and manufacturers are discussed in this section.

4.3.1 Planning the Program with Boiler Owner-Operators and Manufacturers

Our preliminary boiler selection for testing was based on the information available to us through the detailed steam-electric plant survey conducted as part of the Phase I stationary NO_x study (1) which provided data on 670 boiler-fuel combinations, and other information sources. In addition to trying for a proper balance of boilers to be tested according to type of fuel, type of firing, and size, we strongly focused on the potential operating flexibility of the boilers for implementing changes beneficial to NO_x emission control, as identified in our Phase I study.

Thus, we were able to generate a preliminary list of boilers to be tested, representing on a weighted basis the most important utility boiler-fuel combinations. Of the 20 boilers initially selected, 15 were actually tested and two additional boilers were included in the program.

Major variables of interest to NO_x emission control were the boiler load, level of excess air, potential for staged combustion, flue gas recirculation, air preheat temperature, and other characteristics which could affect the level of NO_x emissions, e.g., fuel composition, furnace and burner configuration and operation.

Representatives of electric utility companies who cooperated with us in the Phase I stationary NO_x study (1) by supplying data on the design and operation of their boilers and emission levels measured by them were visited to solicit their cooperation in the Boiler Test Program. Our strategy was to visit the minimum number of utility headquarters for in-priniciple agreement to participate in the program, and then to take advantage of the availability of several utility boilers at a given generating station chosen for testing, to maximize the amount of information obtained on representative major boiler types. Also, in scheduling the tests, we felt it was desirable to carry out the early part of the program near the Linden Esso Research Center to enable us to make necessary corrections and changes in the sampling-analytical system. Furthermore, we attempted to include utilities in the program with background and experience in emission testing and control. In general, these first meetings with the utilities consisted of brief presentations of the Phase I stationary NO_x study findings, and of the plans and objectives of the Boiler Test Program. As a result of these discussions, we obtained the agreement of the utility owner-operators to cooperate in the program and their permission to visit candidate boilers to obtain a better understanding of their design and operation, and to discuss plans and potential problems with operating personnel. Thus, we were able to validate our thinking about the conceptual test program design, and modify it by additions or substitutions of boilers to be tested based on the information gathered during these visits and discussions.

The detailed review of the test plans with boiler operating and boiler manufacturing personnel also included the discussion of provisions for sampling locations, additional operating data logging, fuel sampling, and other pertinent variables to be monitored during the emission measurements.

4.3.2 Conducting the Test Program

Conducting the test program efficiently was greatly simplified due to the detailed planning and preparation for testing carried out jointly with boiler owner-operators, and manufacturers. Thus, the agreed upon operating program, detailed data recording forms, communication links with all parties, alternative experimental plans (in case of unplanned changes in loads, fuels or equipment), arrangement for manpower to obtain fuel samples, overtime provisions, etc., provided a basis for rapid accomplishments and decisions on necessary changes to plans.

Flue gas samples were taken to represent planned steady state furnace and steam conditions. Thus, it was necessary to determine by careful observations of furnace flames, control room instruments, and flue gas measurements that the operating variables such as load, excess air, flue gas recirculation rates, damper settings, etc., were at their proper levels for each experimental run.

The length of each steady state run had to be sufficiently long that accurate and representative emissions could be determined. Our experience had demonstrated that 30 to 45 minutes of continuous measurements covering 12 sampling points were adequate for gaseous components.

The actual results of each block of experimental runs were compared to the results expected on the basis of both theory and practical experience. Such preliminary analyses then provided a flexible basis for curtailing or expanding experimentation, where desirable, since the original blocks were designed to be augmentable. In addition, it was desirable to take advantage of unplanned changes in operating conditions and equipment where possible.

5. COMBUSTION MODIFICATION TECHNIQUES FOR NO_x EMISSION CONTROL

Our Phase I stationary NO_x study (1) assessed combustion modification techniques for NO_x emission control in two broad categories:

(a) Modification of combustion operating conditions.
(b) Modification of combustion equipment design features.

To investigate the scope of applicability of combustion modifications for NO_x emission control from utility boilers, limited by available equipment, only changes in combustion operating conditions could be considered for the present study.

The Boiler Test Program was designed to explore the broad limits of applicability of combustion modifications, within the flexibility of the equipment. Known combustion operation modifications (1, 3, 4) previously applied in full scale tests exclusively on gas and oil fired installations provided the starting point for our tests. The prime objective of the Esso field tests was to conduct a statistically designed program with all three fossil fuel types on a representative sample of boilers, taking into account the known major variables. The major combustion operation changes explored in our study are discussed in this section.

5.1 Load Reduction

Operating boilers under reduced load conditions decreases the combustion intensity or volumetric heat release rate. The net effect is to produce lower effective peak temperatures for NO formation in the furnace section of the furnace. Our experimental design called for measuring emissions at normal ("full") load conditions, and at various fractional load levels, as feasible with each boiler-fuel combination tested. The lower limit of reduced load operation was usually set by considerations of steam temperature control, and the demand on generating capacity.

5.2 Low Excess Air Firing

Low excess air firing of gas and oil in boilers reduces NO_x emissions, primarily because of the lack of availability of oxygen. Firing with "low excess air" is of course a relative term, because of the boiler-to-boiler variations in the "normal" level of excess air, as established by the boiler operators, depending on fuel type and boiler design and operating conditions. In our Boiler Test Program, the objective was to measure emissions under baseline, "normal" excess air conditions, and then to determine the extent of reduction in NO_x by asking the operator to run the furnace with the lowest permissible excess air supply. The lowest practical excess air levels were dictated by the need to limit the emissions of unburned combustibles (CO, hydrocarbons and smoke) to control operating problems, excessive vibrations, and for coal fired installations, to avoid potential slagging problems and corrosion problems due to the reducing environment resulting from changes in combustion operation.

5.3 "Staged Combustion"

The so-called "two-stage combustion" technique for control of NO_x emissions from gas and oil fired utility boilers was originally developed as a cooperative effort between the Southern California Edison Company and the Babcock and Wilcox Company in the late 1950's (1). A standardized design and operating procedure was established, consisting of firing the fuel with only 90-95% stoichiometric air, and supplying the additional air required for burn-out of the combustibles through second-stage "NO-ports" (air registers located ten feed above the top row of burners). NO_x emissions are reduced, because the bulk of the combustion occurs under fuel rich conditions, and interstage cooling minimizes further NO_x formation during the second stage burnout.

Use of the standardized two-stage combustion technique results in average reductions on the order of 40-50% in NO_x compared with single stage operation. However, test results obtained in two 750 MW gas fired, horizontally opposed boilers indicated even more dramatic reductions by admitting air only through the top row of burners, and maintaining a low overall low excess air level of about 5% (1, 3). Recent work on gas fired utility boilers of the Southern California Edison Company (5, 6) showed that the staged combustion principle could be further modified to reduce NO_x by "off-stoichiometric firing" of some burners fuel-rich, others fuel-lean, or in staggered configurations of some burners supplying air only. This type of firing has also been called "biased firing" (7).

In our Boiler Test Program, we were guided by both theoretical and practical considerations in applying "staged combustion" for NO_x control. (All modifications of the standardized two-stage combustion technique are called "staged combustion" in this report.) To assure that combustion should occur under fuel rich, reducing conditions, the burners supplied with both fuel and air were operated, where feasible, under sub-stoichiometric air conditions. Also, to delay the mixing of secondary air with fuel rich combustion zones, our objective was to operate burners on air only as close to the top row or level of burners as possible. This was not always feasible, for the following reasons:

- In some boilers, the operator determined the burner pattern for best steam temperature control, which did not necessarily correspond to optimum NO_x control (when mass flow is reduced superheat capacity is affected).

- The flame monitoring system for burner cells of three vertical burners each allowed the use of "air only" operation of the middle burners only in another, gas fired boiler tested.

- The maximum possible increase in fuel supply to burners operating on both fuel and air determined the number of burners which could be operated on "air only" under normal full load conditions. Otherwise, modified staged combustion was also accompanied by a reduction in boiler load.

Where the optimum configuration of operating the top row of burners was not possible, we attempted to introduce maximum separation between the burners firing fuel. This approach allowed testing of the "staged combustion" approach successfully in several installations where optimum staging for NO_x control could not be achieved because of constraints imposed by steam temperature control requirements.

A specific consideration in applying staged combustion operation to pulverized coal fired utility boilers was that the staging had to be implemented by mills, to prevent plugging of idle coal pipes. This was no handicap in the two successful sets of tests for staging pulverized coal boilers, because the mills supplying the top row (or level) of burners could be shut down.

5.4 Flue Gas Recirculation

Recirculation of flue gases into the combustion zone has been shown to be an effective method of reducing NO_x emissions from gas fired laboratory and domestic size oil fired combustion equipment (1). The reason for lower NO_x emissions is two-fold: (i) the temperature of the flame zone is reduced by recirculating cool flue gases, and (ii) the concentration of oxygen available for NO production is reduced. Of these two, the thermal effect is generally accepted to be more important (1,3). The effect of flue gas recirculation in stationary equipment is thus similar to that of exhaust gas recirculation in internal combustion engines: lowering the combustion temperature results in lower NO_x emissions. In effect, even steam or water injection have been shown to have similar effects on NO_x production by thermal dilution (1). The injection of such inert diluents could not be tested in our field program limited by the available boiler equipment, as the boilers were not equipped for steam or water injection.

The applicability of flue gas recirculation to NO_x control for utility boilers has been regarded as questionable by some investigators (1). Flue gas recirculation is a standard design feature in some utility boilers for steam temperature control. Commonly, the flue gases are recirculated into the bottom of the furnace, rather than into the primary combustion zone. Thus, the earlier tests which measured only small, if any, effect on NO_x emissions with flue gas recirculation into the bottom of the furnace were not considered by us to be convincing evidence for the lack of effectiveness of this technique.

Since in utility boilers flue gas recirculation into the primary combustion zone is usually not available, a special point was made in planning the boiler test program to include measurements on such facilities. As discussed in this report, a front wall, oil fired boiler with flue gas recirculation into the windbox, and also a tangential, gas or oil fired unit with recirculation into the combustion zone were identified, and agreement of the owner-operators was obtained to measure emissions from these boilers.

5.5 Air Preheat Temperature

Since NO_x emissions are very strongly influenced by the effective peak temperatures of the combustion process, any modification that lowers these temperatures is expected to lower NO_x emissions. Thus, lowering the air preheat temperature has been predicted to result in lower NO_x emissions (1,3).

In general, this approach is not very practical, because the boiler operators can vary air preheat temperature only within rather narrow limits in existing units, without upsetting the thermal balance of the system. Major steam side redesign would be required for effecting large changes in air preheat temperature. However, we found it possible in our test program to make minor excursions in air preheat temperature, by by-passing a portion of the flow around the air heater.

5.6 Burner Tilt

Tilting burners is a design feature used in tangentially fired boilers for superheat temperature control. This additional flexibility in combustion operations was exploited, where possible, in planning and conducting our Boiler Test Program.

Varying burner tilt away from the horizontal position can to some extent "enlarge" or "constrict" the effective furnace combustion zone. Thus, depending on flame patterns and transport effects, a longer effective residence time may be available for NO_x formation, or conversely, a lower combustion intensity may prevail in the enlarged combustion zone, leading to lower NO_x emissions. The first one of these two alternatives was expected to be more likely because of the diffuse, swirling fireball pattern prevailing in tangentially fired boilers.

5.7 Other Modifications

In addition to the combustion operating variables discussed above, the effects of some other variables were also explored inasmuch as possible with the boilers tested. One example of this type of "opportunistic" approach was to vary the primary to secondary air ratio in the burner air supply. Restricting the flow of air through the secondary air registers increases turbulence in the flame, resulting in more intense combustion conditions, which can lead to somewhat higher levels of NO_x emissions. Although it was recognized at an early stage of the program that burner configuration could have a major effect on NO_x emission, a systematic exploration of this factor was beyond the scope of our study.

In summary, it must be emphasized that while the selection of combustion operating modifications for NO_x control was made based on considerations of known theoretical and practical factors, the actual detailed implementation of the program plans had to be adapted to particular set design and operating features of each boiler tested. Details of the results obtained in this study on exploring combustion modification techniques, individually, or in combination with one another, are presented in the following section of this report.

6. RESULTS OF THE BOILER TEST PROGRAM

As discussed in Section 4.1 of this report, a statistically designed field test program was conducted to measure NO_x and other emissions from utility boilers. Details of the experimental approach taken included the study of a representative sample of U. S. fossil fuel power boilers according to fuel type, boiler size, method of firing, flexibility for combustion operating changes, geographical location, and being representative of current design practices of manufacturers.

Features of the Esso Research sampling-analytical van including the description of the equipment and a discussion of the sampling and analytical procedures used in the Boiler Test Program have been discussed in Section 4.2.

Our prime objective in the Boiler Test Program was to assess the scope of applicability of combustion modification techniques limited by the design and operability of representative boilers for the control of NO_x emissions. Since such combustion modifications may lead to adverse effects on the emissions of other pollutant species, such as CO, hydrocarbons and other unburned combustibles, our approach was to continuously monitor the concentrations of CO and hydrocarbons during the test runs, as well as visually observe the condition of the stack plume for haze or particulate emissions.

Another important corollary of effecting combustion operating changes for NO_x emission control is the potential impact on boiler performance. It was not possible within the scope of this study to optimize the performance of the boilers tested in a detailed manner, but rather, we have worked very closely with the operating personnel of the cooperating utility companies to gain information on gross changes that might have occurred. For three of the coal fired boilers, however, the respective boiler manufacturers participated in the test programs (Babcock and Wilcox at Boiler Q, Combustion Engineering at Boiler O, and Foster-Wheeler at Boiler N). The role of the boiler manufacturers was to give us and the operators guidance on the limits of flexibility in operating the boilers, to ascertain whether the boilers were in normal operating condition, and to obtain detailed steam side data for the characterization of boiler performance corresponding to the emission test conditions.

A natural consequence of the systematically designed boiler test program was to obtain base-line emission data on NO, NO_2, CO and hydrocarbons in addition to the usual constituents of the combustion flue gases. Test runs under base-line boiler operating conditions were necessary for comparison of the emission levels obtained _via_ combustion modifications with standard practices. As a result of these tests, we were able to accumulate reliable emission data on boilers of different design types (wall fired, tangentially fired, cyclone fired, and vertically fired) using gas, oil, and coal fuels. Thus, by measuring base line emissions on the 17 boilers tested (25 boiler-fuel combinations), adequate information was generated to establish improved emission factors for NO_x, CO and hydrocarbons in power generation. This is useful information, as the "average" emission factors used in the past are clearly not applicable to individual units (1), (8), and a definite improvement has been made on this problem in this study.

The best way to characterize the nature of our boiler test program is to call it "exploratory" in nature. Because of the scarcity of information available on NO_x emission control for utility boilers, it was deemed necessary to obtain such information on as many units as possible within the contractual period. As a consequence, we did not attempt to optimize, or "demonstrate" the feasibility of NO_x emissions by combustion modification techniques, but rather, to explore the broad limits of emission control attainable with different firing patterns, in a variety of boilers for all three fossil fuel types. Furthermore, in exploring the effectiveness of combustion operating changes, we paid particular attention to the definition of potential problem areas, such as slagging, corrosion, flame lift-off and impingement, and safety considerations. The sum total of the information gathered proved to be necessary for establishing what the future direction should be for the application of combustion modifications for pollutant emission control, and in addition, what design changes may be required for reducing NO_x emissions to minimum levels.

Significant progress was achieved on a systematic basis in the course of the Boiler Test Program on the control of NO_x emissions from boilers. As will be discussed, the results indicate an excellent potential for emission control for gas fired boilers, promising, but somewhat less effective control for oil fired boilers, and a major remaining problem area for the control of NO_x and other pollutant emissions from coal fired boilers.

The results of our Boiler Test Program are discussed in this section of this report, organized according to fuel type and corresponding to the types of boiler firing methods studied.

6.1 Boiler Designation and Description

Design characteristics of the 17 boilers tested for NO_x emission control in the Boiler Test Program are summarized in Table 6-1. This table lists for each boiler coded in alphabetical order the general design information (e.g., full load rating, type of firing, fuels burned, manufacturer, etc.), specifics of the furnace design (e.g., furnace volume and heating surface, number and configuration of burners, etc.), and availability of NO_x emission control equipment (e.g., NO-ports, flue gas recirculation, etc.).

TABLE 6-1

SUMMARY OF BOILER DESIGN INFORMATION

Design Characteristics	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
General																	
1. Maximum Cont. Rating (10^3 lb. steam/hr.)	1,200	810	1,900	2,060	3,316	4,000	1,638	2,305	680	1,900	620	2,450	1,000	5,280	3,850	2,750	4,900
2. Full load rating - MW	180	80	315	350	480	600	220	320	66	250	66	450	175	820	575	300	704
3. Type of firing	F.W.	F.W.	F.W.	H.O.	H.O.	H.O.	A.W.	T	V	F.W.	T	CY	F.W.	H.O.	T	T	CY
4. Manufacturer	C.E.	R	F-W	B&W	B&W	F-W	B&W	C.E.	B&W	B&W	C.E.	B&W	B&W	F-W	C.E.	C.E.	B&W
5. Initial Year of operation	1959	1948	1959	1966	1964	1968	1961	1962	pre-1950	1957		1964	1956	1970	1960	pre-1950	1963
6. Nominal heat rate, B.t.u./KWH	1,080	10,850 (G) 11,500 (O)	9,600 (C)	8,700 (G) 9,000 (O)	9,236	8,690	9,850	10,010					9,630			9,500	8,777
7. Fuels burned-Coal, Gas, Oil	G,O	G,O	G,C	G,O	G,O	G,C	G,O	G,O	G	O	O	O	C	C	C	C	X
8. Suction or Pressurized	S	P	P	P	P	P	P	P	S	P	S	P	S	P	S	S	P
Furnace																	
1. Number of furnaces	1	1	2	1	1	1	1	2	1	2	1	1	1	2	2	2	1
2. Division wall	Yes	No	No	No	Yes	Yes	Yes	No	No	No	No	No	Yes	No	No	No	No
3. Furnace Volume ($10^3 ft^3$)	65	31.8	173	109.9	161.9	354.6	2	112.5	24.4	92.0	29.0	152.3	72.0	477.0	429.2	250.0	340.6
4. Furnace Heating Surface ($10^3 ft^2$)	20.4	8.45	37.8	15.9	24.7	72.1	13.1	18.6	12.9	10.3	7.8	20.8	14.8	83.7	55.1	50.1	41.'
5. Number of burners	16	12	24	24	16	24	24	24	6	24	16	8	16	36	40	64	14
6. Wet or Dry Bottom	D	D	W	D	D	D	D	D	W	D	D	W	D	D	D	D	W
7. Steam or Mechanical Atomization	S	M	N.A.	M	M	N.A.	M	M	N.A.	M	S	M	N.A.	N.A.	N.A.	N.A.	N.A.
8. Ring, Spud, Radial Spud Burners	R																
9. Number of rows or levels	4	2	3	6	4	3	2	3	1	3	4	2	4	3	5	8	2
Controls																	
1. 2-Stage Combustion - "NO-Ports"	No	No	No	Yes	Yes	No	Yes	No	No	No	No	No	No	No	No	No	No
2. Flue Gas Rec. Before, After Burn.	A	No	No	B/A	B	No	No	B*	No	B*	No	No	No	No	No	No	A
3. Tilting Burners	No	No	No	No	No	No	No	Yes	No	No	No	No	No	No	Yes	Yes	No
4. Attemperation	Yes	Yes	No	Yes	Yes	Yes	Yes	No	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes
5. Other	CO Meter	Air Pre-heater Bypass	Extra Tile Insulation	No	No	No	No	No	No	No	No	No	Dry Limestone Injection for SO_2 Removal	No	No	Air Pre-heater Bypass	No

CODES:* Flue Gas Recirculation Into Flame Zone; N.A. = Not Applicable

Type of Firing
- F.W. - Front Wall
- H.O. - Horizontally Opposed
- CY - Cyclone
- T - Tangential
- V - Vertical
- A.W. - All wall

Manufacturer
- B&W - Babcock & Wilcox
- CE - Combustion Engineering
- F-W - Foster-Wheeler
- R - Riley Stoker

6.2 Individual Emission Results on Gas Fired Boilers

Test programs were run on eight boilers firing gas: three front wall fired, three horizontally opposed fired, one "all-wall", and one vertically fired boiler. A tangentially fired boiler which was tested on oil firing was also scheduled for gas firing. However, abnormal weather conditions and local gas shortage at that time forced us to cancel the scheduled gas fired program. Fortunately, the boiler operator-owner has kindly supplied their own representative emission data over a variety of operating conditions on this boiler. Thus, our total sample covers nine gas fired boilers and 79 test runs.

6.2.1 Front Wall Gas Fired Boilers

Boilers A, B, and C are front wall fired boilers built by Combustion Engineering, Riley Stoker, and Foster-Wheeler, rated at 180, 80 and 315 MW generating capacity, respectively. The experimental procedures and results for Boiler A are presented in some detail. Only the highlights will be discussed for the other two boilers since the same principles and approaches were used.

For Boiler A, the test program design shown in Table 6-2 was developed according to sound statistical principles. All of the major operating variables (load, excess air level,and staging) were varied in accordance with a partially replicated factorial design so that the response to each major factor and the interactions between factors as well as experimental error could be measured independently with maximum efficiency. Other major design features such as "NO-ports", flue gas recirculation into the wind box, tilting burners, etc. were not available with boiler A. The levels of each factor were set at the extreme limits of their practical operating range. Replicate runs (on different days) were made at full load at all four combinations of excess air and staging so that a pure measure of repeatability or experimental error could be obtained independent of higher order interactions. In addition, independent analysis of NO_x, O_2 and CO_2 were made by the boiler operator for comparison to our measurements. Loads were set at the highest (full load) and lowest (120 MW) operating levels, with all 16 burners in use. An additional low load level (70 MW) was provided (at the lowest efficient load using 12 burners) so that any non-linearity of emissions with load could be determined. At full load, the lowest permissible level of excess air was determined by limiting CO emissions to increase to a maximum of about 200 ppm. At the lowest load, flame stability determined the lower limit of excess air. The staging patterns set for each load were based upon extensive plant experience to reach a balance between reduction of NO_x and CO emission with adequate steam temperature control. Table 6-2 summarizes the NO_x emissions measured on the basis of the test program design.

TABLE 6-2

BOILER A EXPERIMENTAL DESIGN - GAS FIRED
(Average NO_x Emissions, ppm @ 3% O_2, Dry Basis)

	(L1) 180 MW		(L2) 120 MW		(L3) 70 MW	
	Hi Air	Lo Air	Hi Air	Lo Air	Hi Air	Lo Air
S_1 Normal Firing	7* 387 11 393	8 331 13 334	12 230	3 188	9 116	2 108
S_2 Staged Firing	6 195 15 201	5 156 16 155	4 133	11 88	1 81	10 66

*Circled numbers indicate run numbers.

TABLE 6-3

SUMMARY OF EMISSION DATA FROM BOILER A (180 MW, FRONT WALL, GAS FIRED)

Run No.	Operating Data							Ave. Flue Gas Components (3)					Flue Gas Temp. °F	Independent Analysis (4)		
	Boiler Gross Load (MW)	Steam Flow 10^3 lbs/hr	Fuel Gas Flow 10^3 Ft^3/Hr	Excess Air (1)	Staged Firing (2)	No. of Burners		%, Dry Basis		3% O_2 Dry Basis - ppm				%		ppm
						Firing	Air Only	O_2	CO_2	NO_x	CO	HC		O2	CO_2	NO_x
1	70	420	650	Hi	yes	10	2	2.88	10.3	81	16	--	630			
2	71	420	650	Lo	no	12	0	1.23	11.3	108	13	--	626			
3	119	740	1060	Lo	no	16	0	1.05	11.5	188	17	--	663			
4	120	744	1020	Hi	yes	12	4	3.08	10.6	133	15	< 3	658	2.9	10.1	125
5	182	1225	1520	Lo	yes	12	4	1.68	11.5	156	20-100	< 1	711	1.2	11.1	136
6	182	1225	1530	Hi	yes	12	4	3.23	10.8	195	16	< 1	712	2.8	10.5	192
7	180	1220	1540	Hi	no	16	0	2.78	11.0	387	14	< 1	718	2.2	10.8	357
8	181	1235	1540	Lo	no	16	0	1.15	12.0	331	18-150	< 1	714			
9	70	420	620	Hi	no	12	0	3.05	10.4	116	13	< 1	612			
10	70	420	620	Lo	yes	10	2	1.70	11.1	66	21-140	< 1	612			
11	121	760	1030	Lo	yes	12	4	1.13	11.4	88	20-200	< 1	650			
12	122	760	1030	Hi	no	16	0	2.35	10.8	230	15	< 1	670			
13	179	1220	1570	Lo	no	16	0	1.05	7.9	334	17-90	< 1	712			
14	181	1220	1530	Hi	no	16	0	2.75	10.6	393	14	< 1	720			
15	180	1220	1530	Hi	yes	12	4	3.08	10.5	201	15	< 1	716			
16	180	1220	1530	Lo	yes	12	4	1.68	11.3	155	15-85	< 1	708			

(1) Test program design.

(2) Burner Patterns:

	0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0
	A 0 0 A	0 0 0 0	A 0 0 A	0 0 0 0
	X X X X	X X X X	0 A A 0	0 0 0 0
	0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0
Staged:	Yes	No	Yes	No
Load:	70 MW	70 MW	120 MW and 180 MW	

Key: 0 - Firing Fuel
A - Air Only
X - No Air or Fuel

(3) *Average of 16 Data points per run. Each data point from a composite of 3 gas sample streams.

(4) Average of 3 samples by PDS or Orsat Analysis.

Table 6-3 presents a summary of emission and operating data for each of 16 runs made on Boiler A. Table 6-4 and Figure 6-1 present the detailed NO_x emission test results. Uncontrolled, full load NO_x emissions averaged 390 ppm (3%, O_2, dry basis). Reducing load by one-third (120 MW) resulted in a 41% reduction in NO_x, while a 60% reduction in load (70 MW) resulted in a 70% reduction in NO_x emissions. The application of low excess air at full, 67%, and 40% load reduced NO_x emissions by 49, 42, and 30%, respectively, while the combination of low excess air and staging reduced NO_x emissions by 60% at full load, 52% at 67% load, and by 43% at 40% load, compared with uncontrolled emissions at each of these loads.

TABLE 6-4

BOILER A - GAS FIRED
NO_x REDUCTION THROUGH COMBUSTION CONTROL

Load		Combustion Control			
MW	% Reduction	None	Low Excess Air	Staging	LEA + Staging
180	0%	390 ppm 0% 0%	332 ppm 15% 0%	198 ppm 49% 0%	156 ppm 60% 0%
120	33%	230 ppm 0% 41%	188 ppm 18% 43%	133 ppm 42% 33%	88 ppm 52% 44%
70	61%	116 ppm 0% 70%	108 ppm 7% 67%	81 ppm 30% 59%	66 ppm 43% 58%

Analysis of variance summarized in Table 6-5 indicates quantitatively the significance of each of the main factors and their interactions.

TABLE 6-5

BOILER A - GAS FIRED
ANALYSIS OF VARIANCE

Source of Variation	Degrees of Freedom	Mean Square	F Ratio	$F_{0.001}$
1. Load	2	31,564	1,973	22
2. Excess Air	1	3,710	232	29
3. Staging	1	34,454	2,153	29
4. Load x Air Interaction	2	432	27	22
5. Load x Staging	2	5,385	337	22
6. Excess Air x Staging				
7. Load x Air x Staging	$7\left\{\begin{array}{l}1\\2\\4\end{array}\right.$	$16\left\{\begin{array}{l}2\\34\\10\end{array}\right.$		
8. Repeats				
9. Total	15	--	--	

Figure 6-1

NO_x EMISSIONS FROM BOILER A

(180 MW, Front Wall, Gas Fired)

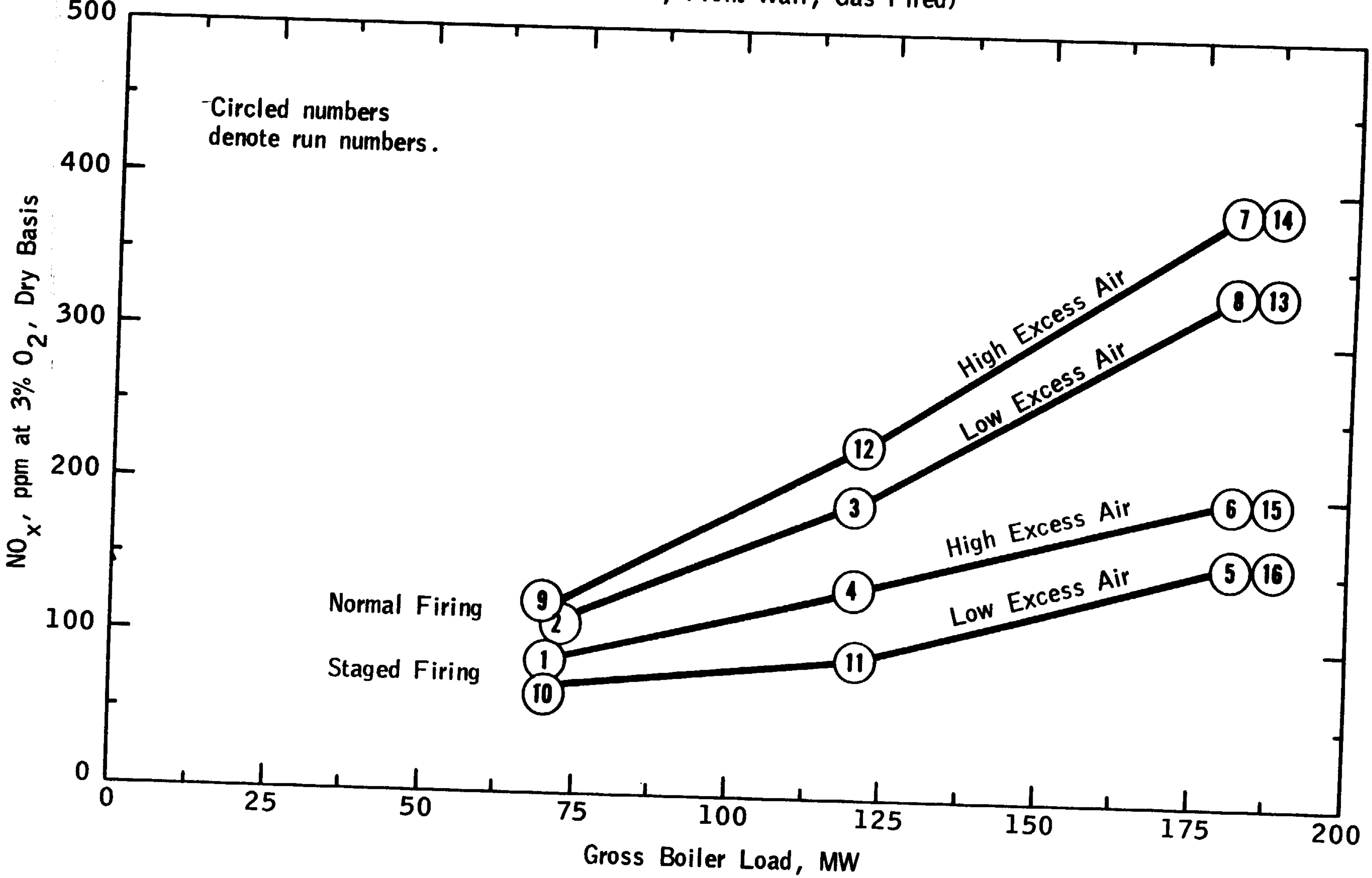


TABLE 6-6

SUMMARY OF EMISSION DATA FROM BOILER B (80 MW, FRONT WALL, GAS FIRED)

Run No.	Operating Data							Ave. Flue Gas Components (2)					Flue Gas Temp. °F.
	Boiler Gross Load MW	Steam Flow 10^3 Lb/Hr	Fuel Gas Flow 10^3 Ft^3/Hr	Excess Air(1)	Staged Firing (5)	No. of Burners		% Dry Basis		ppm 3 % O_2, Dry Basis			
						Firing	Air Only	O_2	CO_2	NO_x	CO	HC(4)	
9	20.5	175	240	Low	Yes	10	2	3.50	10.0	65	60-360	<1	565
10	20.5	175	240	Normal	No	10	0	4.65	9.1	90	52	<1	519
11	49.5	425	540	Low	No	12	0	2.03	10.4	170	(3)	<1	626
12	50.0	425	538	Normal	Yes	10	2	5.08	8.7	200	63	<1	640
13	81.5	740	900	Normal	Yes	10	2	5.03	8.6	376	56	<1	789
14	81.9	740	890	Low	No	12	0	2.59	10.3	421	68-185	<1	763
15	81.5	740	900	Low	Yes	10	2	2.80	9.9	311	108-370	<1	784
16	82.0	740	900	Normal	No	12	0	4.18	9.5	497	52	<1	778

(1) Test program design.

(2) Average of 16 data points per run. Each data point from a composite of 3 gas sample streams.

(3) Not measured.

(4) Excluding hydrocarbons collected in condensate.

(5) Burner patterns:

	0A00A0	0Ø00Ø0	0A00A0	000000
	000000	000000	000000	000000
Staged	Yes	No	Yes	No
Load	20 MW	20 MW	50 MW	& 80 MW

0 = Fuel and air

A = Air only

Ø = Burner out of service

The estimated experimental error from the repeated full load test is equal to 3.2 ppm NO_x ($\sqrt{10} = 3.2$). Combining the sum of squares for the nonsignificant (excess air x staging) and (load x excess air x staging) interactions with repeats results in a revised estimated experimental error of 4 ppm NO_x ($\sqrt{16} = 4$), with 7 degrees of freedom. This revised estimate of error was used in testing the significance of the three main effects and the remaining two-factor interactions. All are highly significant ($p < 0.001$), with staging and load accounting for most of the variation in NO_x emissions.

Ninety-five percent confidence limits can be estimated for each of the test runs by adding and subtracting 8 ppm ($\pm$ t.055 = $\pm$ 1.90 x 4.0 = $\pm$ 8). As discussed before, detailed analysis of the results obtained in testing Boiler A is shown in order to demonstrate that the point estimates presented in Table 6-2 and plotted in Figure 6-1 are highly significant and that summary tables such as 6-3 do show real differences.

CO emissions averaged between 13 to 17 ppm except when low excess air was applied at higher loads. The inherent cycling of fuel and air with automatic controls resulted in a range of CO values at low excess air. Thus, a slight reduction in excess air below a critical level could result in greatly increased CO emissions. Individual probes gave widely different results as the average level of excess air was reduced, indicating that some individual burners produced high CO values. Hydrocarbons consistently measured less than one ppm.

Table 6-6 presents a summary of operating and emission data obtained from Boiler B, firing gas. The statistical design including the corresponding NO_x emission results is shown in Table 6-7. A full factorial design was run at full load while a fractional factorial (two level, latin square) was run at intermediate and low loads. Thus, all 8 runs were made in one day of testing with emphasis on full load runs. Figure 4-2 presents the NO_x data obtained from this boiler in graphical form.

TABLE 6-7

BOILER B EXPERIMENTAL DESIGN - FIRING GAS

(Average NO_x Emissions, ppm at 3% O_2, Dry Basis)

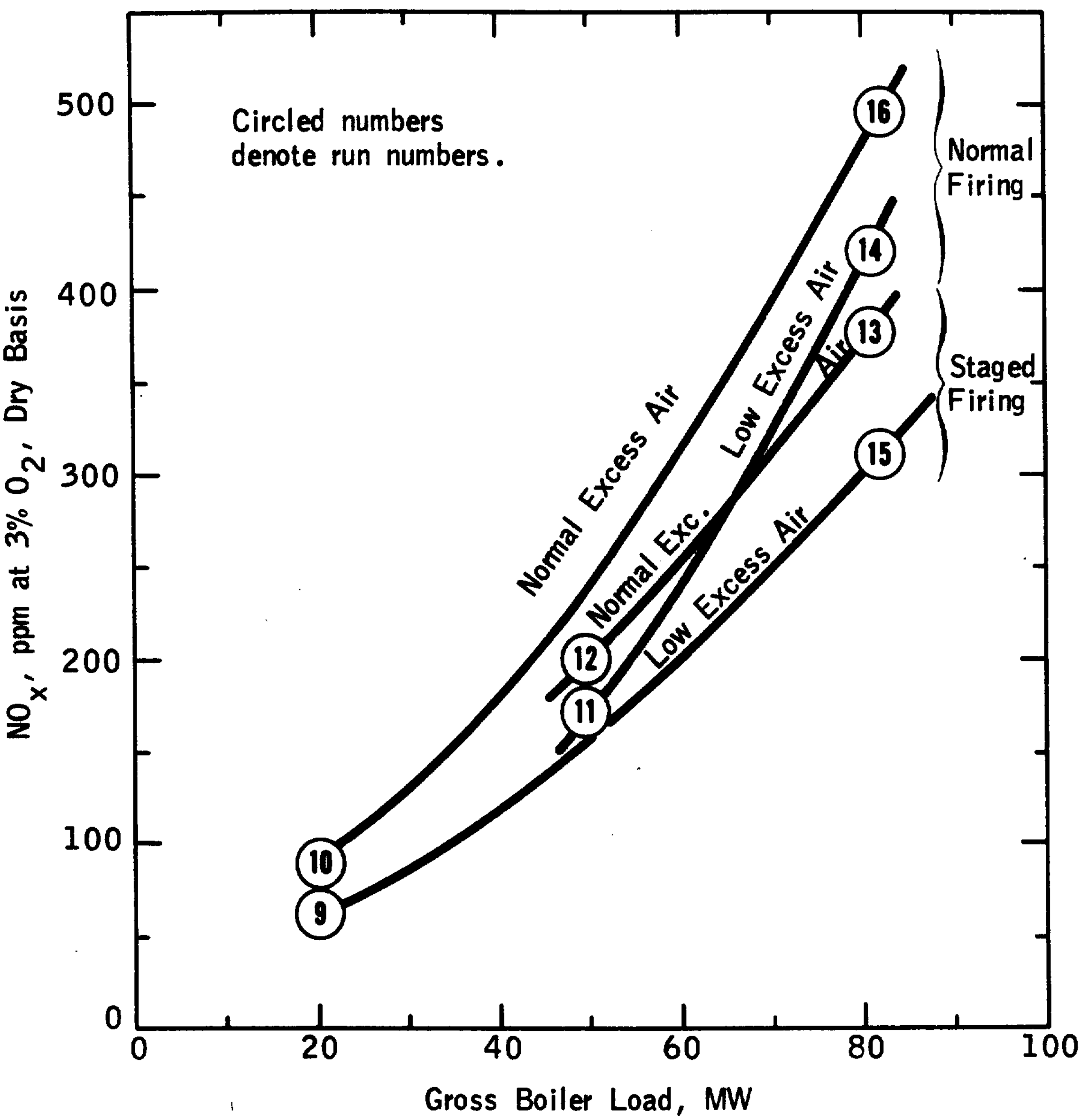
	L_1 (82 MW)		L_2 (50 MW)		L_3 (20 MW)	
	A_1(Normal)	A_2(Lo Air)	A_1(Normal)	A_2(Lo Air)	A_1(Normal)	A_2(Lo Air)
S_1(Normal Firing)	16* 497	14 421		11 170	10 90	
S_2(Staged Firing)	13 376	15 311	12 200			9 65

* Circled numbers denote run numbers.

Figure 6-2

NO_x EMISSIONS FROM BOILER B

(80 MW, Front Wall, Gas Fired)



Uncontrolled, full load NO_x emissions averaged about 500 ppm. This relatively high level for a small boiler (80 MW) is probably due to the relatively close spacing of the 12 front wall burners as discussed more fully in section 2.3. However, significant NO_x emission reductions were obtained through combustion control. Reducing load by 76% to 20 MW reduced uncontrolled emissions by 82% and "fully controlled" emissions (low excess air plus staging) by 80%. An estimated standard deviation for experimental error of 5.5 ppm NO_x was calculated from the full factorial results. This compares with 3.2 ppm for boiler A. At full load, the application of low excess air, staged firing, and the combination of low excess air with staged firing reduced NO_x emissions by 15%, 24%, and 37%, respectively. Table 4-8 summarizes these and other comparisons on NO_x emissions for this boiler.

TABLE 6-8

BOILER B - GAS FIRED

NO_x REDUCTION THROUGH COMBUSTION CONTROL

Load		Combustion Control			
MW	% Reduction	None	Low Excess Air	Staged Firing	LEA Staging
82	0%	497 ppm 0%	421 ppm 15% 0%	376 ppm 24% 0%	311 ppm 37% 0%
50	39%	240 ppm * 52%	170 ppm 29%* 60%	200 ppm 17% 47%	
20	76%	90 ppm 82%			65 ppm 28% 80%

* Estimated value to provide basis for comparison.

Due to the limited time available for testing this boiler, only the staged firing pattern**, shown below, was applied:

OAOOAO Where: A - Air only
OOOOOO 0 - Air and Fuel

However, the following staged firing patterns would be likely to result in improved NO_x emission performance if the boiler could be modified to achieve full load with four to six burners on air only. Other firing patters of interest may include the following which would tend to delay mixing of the air with fuel, and prevent excessively high NO_x and CO emissions:

OAOOAO or OAOAOA
OOAAOO AOAOAO

Additional experimentation is needed to optimize this boiler from the standpoint of NO_x emission control. In principle, mixing of air and fuel is delayed best by imposing a maximum possible separation between the "on air only" burners, but this objective may entail other emission or operating problems.

** Based on prior experience of the utility owner-operator.

Table 6-9 presents a summary of operating and emission data obtained from Boiler C. This twin furnace boiler has a capacity of about 315 MW. The superheater furnace (from which emissions were sampled) provides about 55% of the boiler heat release at full load and 50% at one-half load. Uncontrolled, full load NO_x emissions were 990 ppm. These high emission levels (confirmed on coal and combined coal-gas firing) are likely to result from the particular design features of this boiler. Originally, this boiler was designed to burn coal and to maintain a wet bottom (molten slag) under low load firing. Thus, the twin furnaces were designed with the bottom row of burners close to the flat floor of the furnace. In addition, the bottom and sides of each furnace up to the top row of burners are insulated so that slag is maintained in the molten state. These design features result in relatively low heat absorption rates, and therefore high flame temperatures and high NO_x emission levels.

A 41% reduction of load resulted in a reduction of 47% in NO_x emissions. Partial staging (firing fuel lean on the top row of burners and more fuel rich on the bottom two rows), combined with low excess air at 29% reduced load resulted in a 48% reduction in NO_x emissions. Only very limited data could be obtained on emissions from this boiler because of boiler operating difficulties.

TABLE 6-9

SUMMARY OF EMISSION DATA FROM BOILER C

(315 MW, Front Wall, Gas Fired)(1)

Operating Data					Average Flue Gas Components			
Run No.	Furnace Load (MW) (2)	Fuel Gas Flow $10^6 ft^3/hr.$	Staged Firing (3)	Excess Air	Dry Basis O_2 (%)	Dry Basis CO_2 (%)	3% O_2 Dry Basis NO_x (PPM)	Flue Gas Temp. °F
13	157	1.46	No	Low	2.4	16.6	931	649
14	155	1.46	No	High	4.5	9.2	992	648
15	93	0.83	No	Low	4.4	9.1	529	532
16	93	0.83	No	High	6.4	7.4	515	588
17	111	1.04	Yes	Low	2.9	9.8	515	620
18	112	1.05	Yes	High	4.6	8.9	768	---

(1) Measurements on one of twin furnaces.

(2) Total turbine MW generated is about double this number.

(3) Staged firing: No - equal fuel rate on all 3 rows; Yes - fuel lean on top row (20% of total fuel) and rich on middle and bottom rows (40% of total fuel).

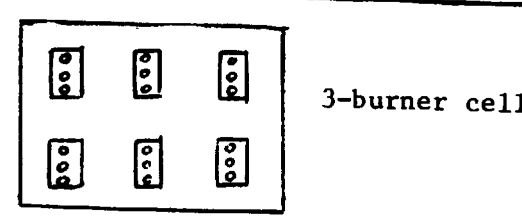
TABLE 6-10

SUMMARY OF EMISSION DATA FROM BOILER D

(350 MW, Horizontally Opposed, Gas Fired)

Operating Data							Ave. Flue Gas Components				
Run No.	Gross Load MW	Total Steam Flow 10^6 lb/hr	Fuel Gas $10^6 ft^3/hr$	Excess Air(1)	"NO-Ports"	Staging (2)	O_2 %	CO_2 %	3% O_2, Dry Basis NOx, ppm	3% O_2, Dry Basis CO, ppm	Flue Gas Temperature °F
1	355	2.13	2.93	Low	Shut	Yes	1.5	11.1	355	105-195	693
2	357	2.15	2.93	Low	Open	Yes	2.0	10.6	213	100-185	693
3	355	2.15	2.93	Low	Open	No	1.9	10.7	381	84	692
4	355	2.15	2.93	Low	Shut	No	1.6	10.8	783	74	692
5	356	2.15	2.95	Hi	Shut	No	2.6	10.2	946	86	693
6	355	2.15	2.94	Hi	Open	No	2.8	10.0	515	67	695
11	356	2.15	2.95	Hi	Open	Yes	3.4	9.6	275	75	701
17	153	0.95	1.39	Low	Shut	No	1.3	11.2	249	57	631
18	153	1.00	1.39	Low	Open	Yes	2.1	10.8	56	76	621
14	152	0.95	1.37	Low	Open	Yes	2.1	10.6	72	68	566
16	152	0.97	1.38	Low	Shut	No	1.7	10.7	299	64	576
15	152	0.95	1.37	Low	Open	No	1.7	10.5	165	74	598
13	152	0.95	1.36	Low	Shut	Yes	1.7	10.7	87	54	593
19	151	1.00	1.35	Low	Open	Yes	1.7	10.5	75	59	594
20	153	1.00	1.36	Low	Shut	Yes	1.6	10.6	121	192	601

(1) Test program design.
(2) Staging: No - All 24 burners firing gas equally.
Yes - Top burner in each 3 upper burner cell on air only, except for Runs 19 and 20 in which middle burner in each upper cell on air only.



Burner Configuration

6.2.2 Horizontally Opposed Gas Fired Boilers

Boilers D, E and F are horizontally-opposed fired boilers. Boiler G is an unusual "all-wall" fired boiler which was fired during our test program in several modes including, horizontally opposed firing and, therefore, will be discussed with this group of boilers tested.

Table 6-10 presents a summary of emissions from boiler D with gas firing. The primary operating variables included in the statistically planned experimental program were load, staging, excess air and "NO-port" setting (open or closed). The staging pattern which had demonstrated the lowest NO_x emissions with safe operating conditions from prior test runs conducted by the boiler operator was used, i.e., the top burner of each upper 3 burner cell on air only, as shown in Table 6-10. To obtain an independent check on this staging pattern, two runs (19 and 20) were made with the middle burner of each upper cell on air only. "Normal" flue gas recirculations (for steam temperature control) was used in all runs, except in runs 17 and 19 were there was maximum flue gas recirculation into the bottom of the furnace. Because of the shortage of gas fuel, six originally planned test runs had to be omitted. The statistical design and the corresponding NO_x measurements are shown in Table 6-11.

TABLE 6-11

BOILER D EXPERIMENTAL DESIGN - FIRING GAS

(Average NO_x Emissions, ppm at 3% O_2, Dry Basis)

		L_1 (350 MW)		L_2 (150 MW)			
		"NO-Ports" Open	"NO-Ports" Closed	"NO-Ports" Open		"NO-Ports" Closed	
		Min. FGR	Min. FGR	Max. FGR	Min. FGR	Max. FGR	Min. FGR
A_1 Low Excess Air	Staged Firing	2 213	1 355	18 56	14 72 19 75		13 87 20 121
	Normal Firing	3 381	4 783		15 165	17 249	16 299
A_2 High Excess Air	Staged Firing	11 275					
	Normal Firing	6 515	5 946				

Note: Circled numbers denote run numbers. Staged firing: top burner on air only except for Runs 19 and 20 with middle burner on air only. FGR = Flue gas recirculation for steam temperature control (i.e., into the bottom of the furnace).

Table 6-10 and Figure 6-3 summarize the effects of changing operating variables on NO_x emission rates for this boiler. Full load (350 MW) operation with no combustion controls applied resulted in 946 ppm NO_x (corrected to 3% O_2, dry basis). Low excess air at full load reduced NO_x emissions by 21% (Runs 1, 2 and 3 vs. 5, 6 and 11). Opening the "NO-ports" which were designed specifically to reduce NO_x emissions resulted in about 50% reduction in NO_x at full load, (Runs 2, 3 and 6 vs. 1, 4 and 5) and about 40% NO_x reduction at reduced load (Runs 14, 15 and 19 vs. 13, 16 and 20). It should be noted that under normal operating conditions, the "NO-ports" of this boiler are kept closed at reduced load. Staging reduced NO_x emissions by 50% at full load (Runs 1, 2 and 11 vs. 3, 4 and 6) and by 65% at reduced load (Runs 13 and 14 vs. Runs 15 and 16). Maximum flue gas recirculation (Runs 18 and 17) resulted in a NO_x reduction of about 20% compared to no flue gas recirculation (Runs 14 and 16). The effect of changing the staging pattern from "top burner-air only" to "middle burner air-only" increased NO_x emissions by about 20% (Runs 19 and 20 vs. Runs 14 and 13). The combinations of low excess air, staging, and keeping "NO-ports" open reduced NO_x emissions by almost 80% at full load (213 ppm vs. 946 ppm). The combination of staging, "NO-ports" open, maximum flue gas recirculation, and low excess air resulted in over 80% lower NO_x emissions than using only low excess air at reduced load. The recirculation of flue gases into the bottom of the furnace produced an 18% reduction in NO_x emission (Runs 17 and 18 vs. 16 and 14). Reducing load by 57%, reduced NO_x emissions by an average of 64% (Runs 1, 2, 3 and 4 vs. Runs 13, 14, 15 and 16). Table 6-12 presents a summary of the measured reductions in NO_x emissions.

CO emissions averaged 70 ppm, except for a few low excess air runs where CO emissions as high as 195 were recorded from Boiler D.

Table 6-13 presents a summary of emissions data from Boiler E, firing gas. Boiler E is equipped with 8 "NO-ports" for reducing NO_x emissions. In addition, the top burner of each two upper burner cells has its gas line sealed closed, with its air ducts open as shown in Table 6-13. Thus, this boiler always uses staged firing when burning gas, and it could not be tested under a firing configuration without staging. (Emission data were obtained from the operator on the conditions which prevailed before this change).

The operating variables included in the single replicated, factorial design were load (450 and 220 MW), excess air (normal and high) and "NO-ports" (open or closed). Table 6-14 and Figure 6-4 summarize the effects of changing operating variables on NO_x emission rates for boiler E. Full load NO_x emissions without combustion controls were only 236 ppm due to the beneficial effect of staged firing.

Analysis of variance for boiler E indicates quantitatively the significance of the NO_x reductions found, as shown in Table 4-14A.

The three-factor interaction mean square provides an estimated standard deviation for experimental error equal to 4.2 ppm NO_x ($\sqrt{18} = 4.2$), with one degree of freedom. This estimate agrees well with the standard deviation for experimental error calculated from boiler A replicated runs of 3.2 ppm NO_x, and 5.5 ppm NO_x for boiler B.

Figure 6-3

NO_x EMISSIONS FROM BOILER D

(350 MW, Horizontally Opposed, Gas Fired)

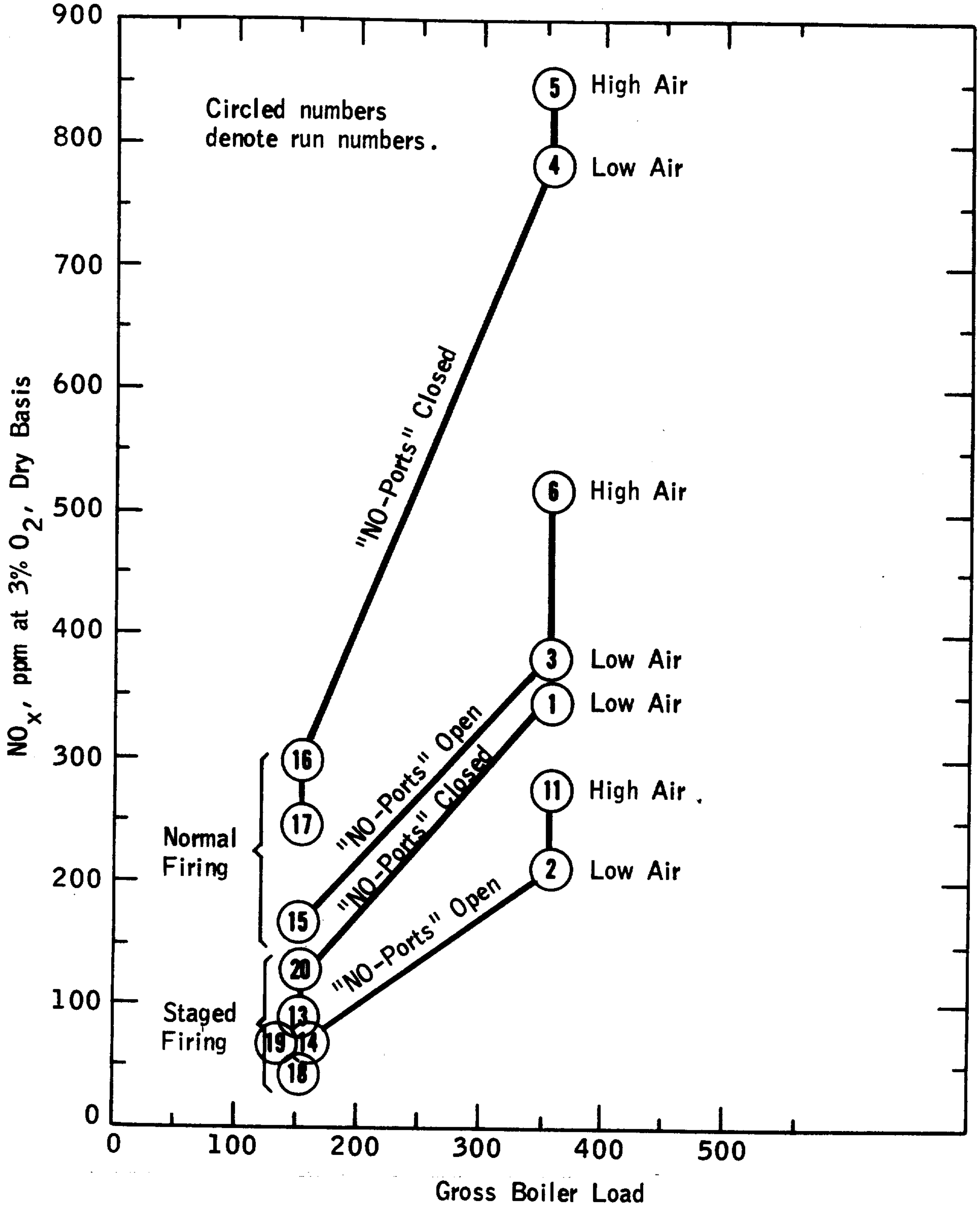


TABLE 6-12

BOILER D - GAS FIRED
NO_x REDUCTION THROUGH COMBUSTION CONTROL

Load		Combustion Control					
MW	% Reduction	None	Low Excess Air	Open "NO-Ports"	Staging	FGR	Full Control"
350	0%	946 ppm-0% 0%	21%	47%	50%		77%
150	57%	341 ppm*-0% 64%		39%	66%	20%	81%

* Estimated to provide basis for comparison.

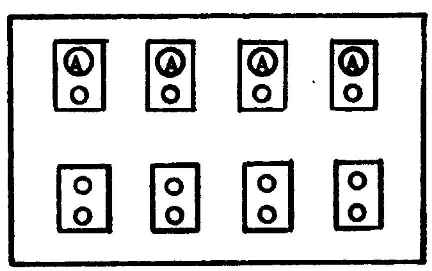
TABLE 6-13

SUMMARY OF EMISSION DATA FROM BOILER E

(450 MW, Horizontally Opposed, Gas Fired)

Operating Data						Ave. Flue Gas Components				
						Dry Basis		3% O_2, Dry Basis		
Run No.	Gross Load (MW)	Fuel Gas Flow 10^6 Ft^3/Hr.	NO-Ports	Excess Air Level (1)	No. of Burners Firing	O_2 %	CO_2 %	NO_x, ppm	CO, ppm	Flue Gas Temperature °F
8	227	2.20	Closed	Normal	24	3.0	10.1	120	15-70	509
5	227	2.15	Open	Normal	24	2.9	10.0	70	20-1000	510
6	225	2.11	Open	High	24	4.5	8.9	95	15	511
7	227	2.15	Closed	High	24	4.5	8.9	166	15	508
3	448	3.65	Closed	High	24	4.0	9.6	236	12	624
2	443	3.65	Open	High	24	4.0	9.6	145	13	628
1	443	3.65	Open	Normal	24	3.0	9.8	140	20-400	624
4	443	3.65	Closed	Normal	24	3.0	9.8	198	61	621

(1) Test program design
(2) Average of 16 data points per run. Each data point has a composite of 3 gas sampling points.



Burner Configuration

(Front and Rear Furnace Faces)

TABLE 6-14

BOILER E - GAS FIRED
NO_x REDUCTION THROUGH COMBUSTION CONTROL

Load		Combustion Control (In Addition to Staged Firing)			
MW	% Reduction	None	Low Excess Air	Open NO-Ports	• LEA + NO-Ports
450	0%	236 ppm-0% 0%	198 ppm-16% 0%	145 ppm-39% 0%	140 ppm-41% 0%
220	51%	166 ppm 30%	120 ppm-28% 39%	95 ppm-43% 35%	70 ppm-58% 50%

Figure 6-4

NO_x EMISSIONS FROM BOILER E

(480 MW, Horizontally Opposed, Gas Fired)

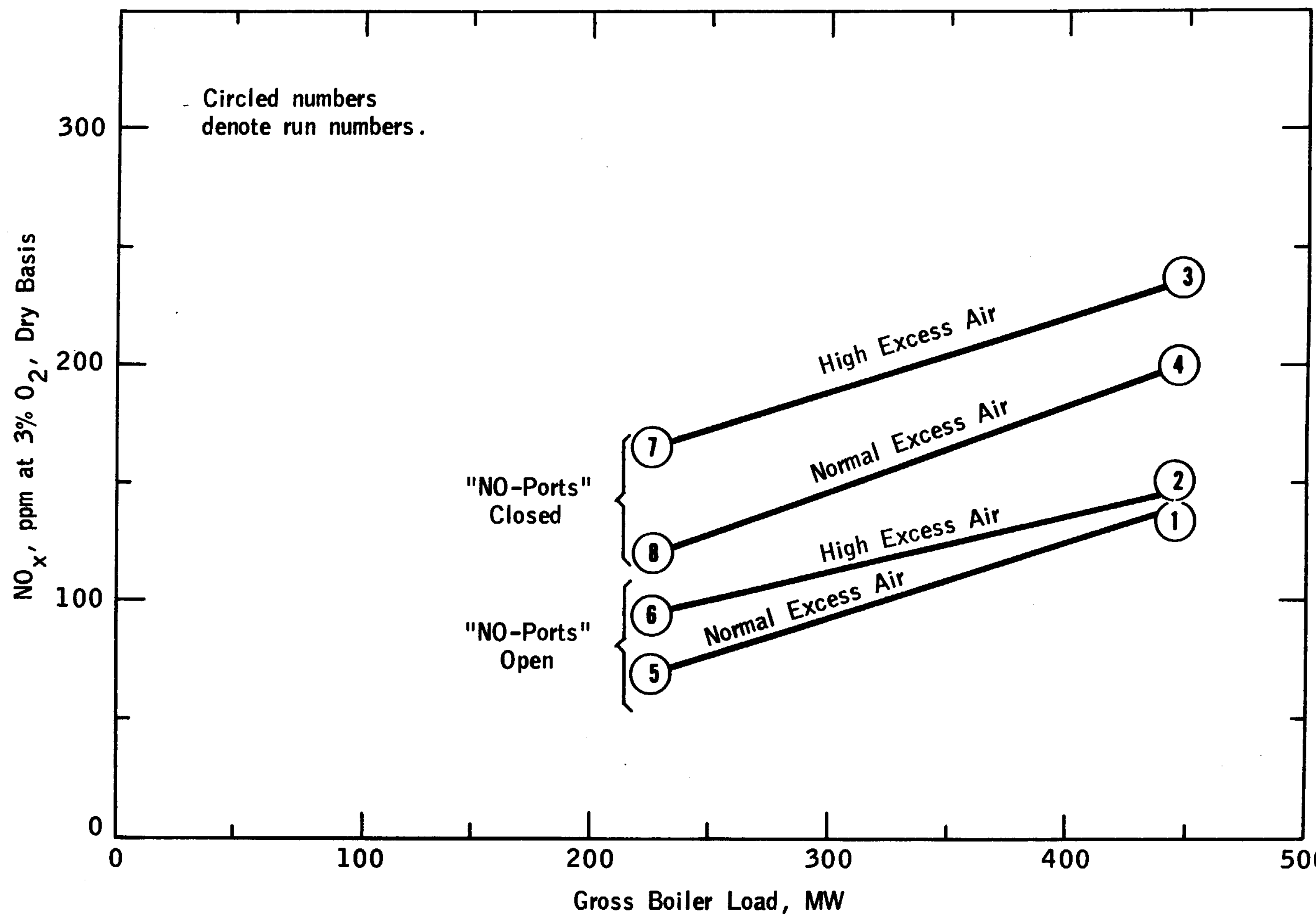


TABLE 6-14A

BOILER E - GAS FIRED - ANALYSIS OF VARIANCE OF NO_x EMISSIONS

Source of Variation	Degrees of Freedom	Mean Square	F Ratio
1. Load	1	8978	126(b)
2. Excess Air	1	1624	23(a)
3. "NO-Ports"	1	9112	128(b)
4. (Load X Air) Interaction	1	98	1.4(e)
5. (Load X Ports) Interaction	1	98	1.4(e)
6. (Air X Ports) Interaction	1	364	5.1(d)
7. (Load X Air X Ports) Interaction	1	18	(71.3, d.f. = 3)
8. Total	7	20292	

(a) significant at the 5% level (F.05 (1,3) = 10.1)
(b) significant at the 1% level (F.01 (1,3) = 34.1)
(c) revised estimate of experimental error (98 + 98 + 18) ÷ 3 = 71.3
(d) possible significance, F.10 = 5.5
(e) not significant

TABLE 6-15

SUMMARY OF EMISSION DATA FROM BOILER F. (600 MW, HORIZONTALLY OPPOSED, GAS FIRED)

Operating Conditions				Average Flue Gas Components and Temperatures (2)									
				Duct Number 21					Duct Number 22				
Run No.	Gross Load MW	No. of Burners Firing	Staging (1)	O_2 %	NO_x (ppm) 3% O_2, Dry Basis	CO_2 %	CO ppm	Temp. °F	O_2 %	NO_x (ppm) 3% O_2 Dry Basis	CO_2 %	CO ppm	Temp. °F
1	554	24	No	3.1	571	7.9	7	633	1.2	478	8.8	8	600
2	563	24	No	3.5	570	7.8	8	643	2.3	542	8.4	8	610
3	415	24	No	4.1	345	7.6	13	566	3.0	339	8.2	14	545
4	406	24	No	2.5	314	8.3	5	530	1.2	271	9.1	5	--
5	325	24	No	2.3	225	8.6	9	513	1.2	185	9.2	10	--
6	326	24	No	4.0	253	9.1	20	525	2.7	239	9.9	20	--
7	327	16	Yes	4.4	120	9.3	3	535	3.1	88	10.0	4	--
8	324	16	Yes	3.2	109	9.9	4	520	1.6	79	11.0	10	--
9	322	16	Yes	2.6	105	10.3	--	520	1.1	77	11.2	--	--

(1) Staging: no, all burners firing equal amounts of fuel.
yes, top row of burners on air only.

(2) Average of eight composite samples of 3 gas streams at actual stack conditions.

Note: Computer results on periodic tests:
Fuel rate (10^6 ft.^{3}/hr), run 1:5.12; run 2:5.22; run 3:3.81; run 7:3.07 and run 8:3.04.
Heat rate (BTU/KWH), run 1:9,834; run 2:9,875; run 3:9,824; run 7:10,077 and run 8:10,088.
(heat rate 11-13% above design heat rate due to high pressure heaters out of service, and other factors)

CO emission levels were low except for Runs 1 and 5 where 400 to 1000 ppm levels were reached. A slight increase in excess air is expected to reduce these high CO emissions levels with very little increase in NO_x emission rates.

Table 6-15 presents a summary of emission data from Boiler F. This boiler has two separate ducts leading from the economizers to the air heaters. Our flue gas samples were taken from two probes (3 sampling points per probe) inserted into each duct. The NO_x and O_2 concentration measurements for duct number 1 were consistently higher than the corresponding measurements for duct number 2. These differences were real and not masked by overall averages, as verified by oxygen measurements taken indpendently by the boiler operator. Due to a shortage of gas fuel at the time of testing Boiler F, it was not possible to make additional runs.

Figure 6-5 presents Boiler F NO_x emission data in graphical form, while Table 6-16 summarizes the NO_x reductions obtained in the same format as used for the boilers discussed before. Staged combustion at 42% reduced load resulted in about 80% reduction in NO_x compared to full load, uncontrolled NO_x, while low excess air with staged firing resulted in about 86% NO_x reduction. Low excess air firing alone reduced NO_x emissions by 15 to 25%

Figure 6-5

NO_x EMISSIONS FROM BOILER F

(600 MW Horizontally Opposed, Gas Fired)

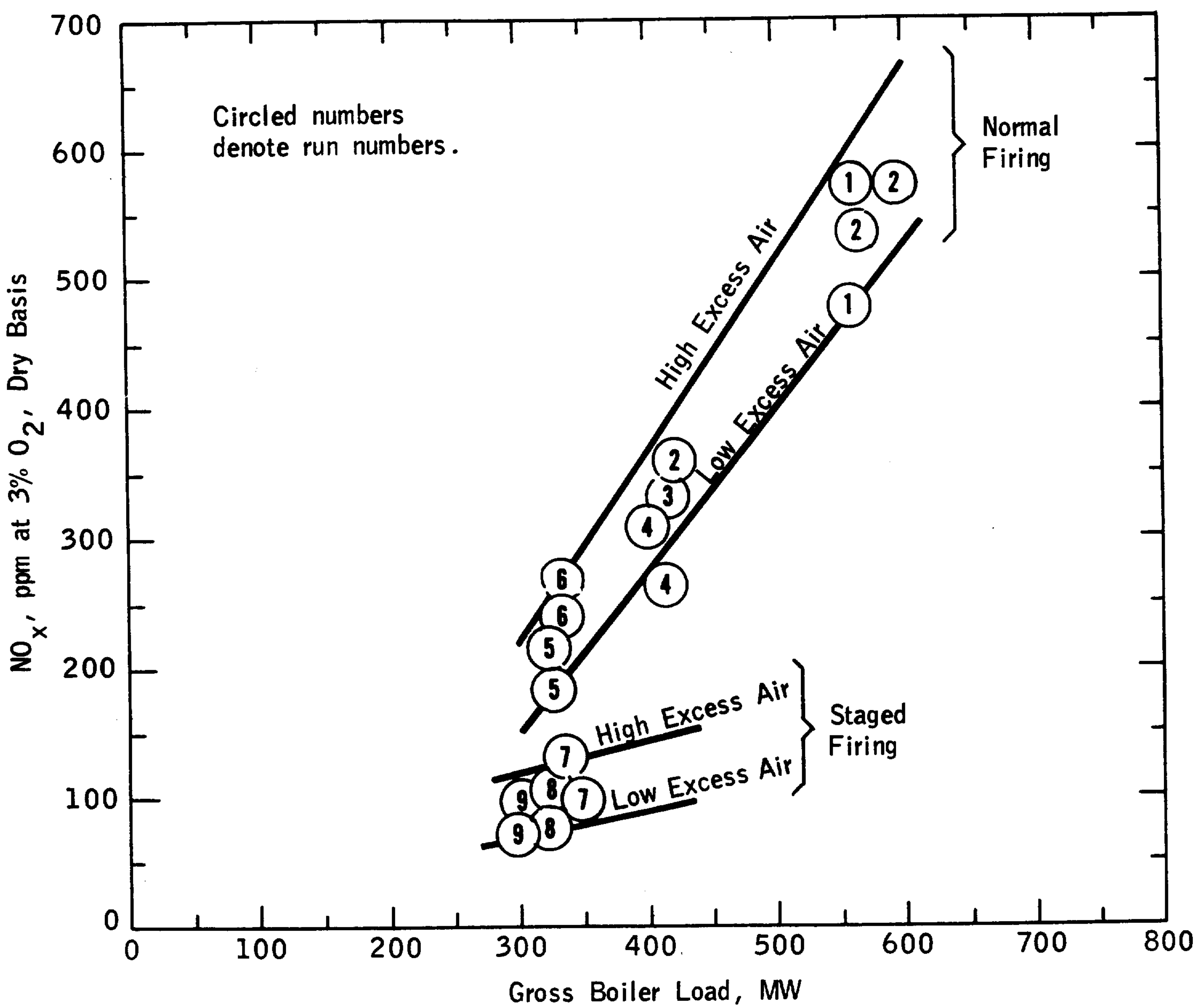


TABLE 6-16

BOILER F - GAS FIRED
NO_x REDUCTION THROUGH COMBUSTION CONTROL

Load		Combustion Control			
MW	% Reduction	None	Low Excess Air	Staged Firing	LEA + Staged Firing
560	0	560 ppm-0%	478 ppm-15%	---	---
410	27%	335 ppm-40%	271 ppm-19% 43%	---	---
325	42%	253 ppm-55%	185ppm-27% 61%	120ppm-53%	77ppm-70%

The experimental design and the measured average NO_x emissions for Boiler G, firing gas, are shown in Table 6-17. This boiler was selected for testing because of its unusual flexibility. The "all-wall" firing furnace provided an opportunity to simulate different burner patterns and their effects on NO_x emissions under both staged and unstaged firing conditions. There were several practical limitations that resulted in the actual experimental design of 14 runs shown in Table 6-17. Only two days were available for testing this boiler on gas firing, thus limiting the test program to a total of 14 runs. Full load (220 MW) could be achieved with normal firing (24 burners) and "minimum NO_x, staged firing" (18 burners). A maximum load of 190 MW could be achieved with opposed wall firing (16 burners firing) and a maximum load of 125 MW could be reached with simulated corner firing (12 burners firing). Eight small "NO-ports", located above the top row of front and rear burners, could not be closed. Thus, a limited degree of two-stage combustion was inherent to the design of this boiler. Within these constraints, the program was designed to provide the maximum amount of information. NO_x emission reduction due to reduced load and low excess air were in line with the reductions experienced in Boilers A through F. The emission data obtained in testing Boiler G are summarized in Table 6-18.

TABLE 6-17

BOILER G EXPERIMENTAL DESIGN - FIRING GAS*

(Average NO_x Emmissions, ppm at 3% O_2, Dry Basis)

Burner Firing Pattern - Burner No.	(L_1) 220 MW		(L_2) 190 MW		(L_3) 125 MW	
	Hi Air	Lo Air	Hi Air	Lo Air	Hi Air	Lo Air
(S_1) Normal - All Burners Firing - All Wall	675 3	519 1			313 12	236 7
(S_2) "Minimum NO_x" Pattern - 9, 10, 12 on Air Only	286 4	270 2			150 13	107 8
(S_3) Horizontally Opposed - 3, 4, 9, 10 Air Only			359 6	284 5	225 14	
(S_4) Horizontally Opposed - 3, 4, 9, 10 No Air or Fuel				400 5a		
(S_5) Simulated Corner - 1, 3, 5, 7, 9, 11 Air Only					130 11	
(S_6) Simulated Corner - 1, 3, 5, 7, 9, 11 No Fuel or Air					350 11a	

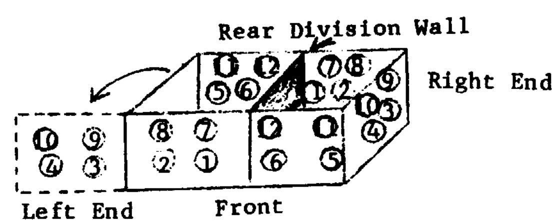
* Circled numbers denote run numbers.

TABLE 6-18

SUMMARY OF EMISSION DATA FROM BOILER G (220 MW, "ALL-WALL", GAS FIRED)

Operating Data										Avg. Flue Gas Components (2)			
						No. of Burners				ppm, 3% O_2 Dry Basis			
Run No.	Gross Load (MW)	Steam Flow 10^3 lbs/hr	Fuel Gas Flow 10^6 Ft^3/hr	Excess Air Level (1)	Staging	Firing Gas	Air Only	Burners on Air Only (3)	Burners: No Fuel or Air (3)	NO_x	CO	O_2 %	CO_2 %
12	124	890	1.05	High	No	24	0	None	None	313	21	4.9	8.3
13	123	860	1.05	High	Yes	18	6	9,10,12	None	150	19	4.6	8.4
14	123	840	1.05	High	Yes	16	8	3,4,9,10	None	225	19	4.6	8.2
11	125	870	1.05	High	Yes	12	12	1,3,5,7,9,11,13	None	350	19	5.6	7.4
11a	123	860	1.05	High	No	12	0	None	2,4,6,8,10,12	350	19	5.6	7.4
7	121	840	1.00	Low	No	24	0	None	None	236	24	2.4	9.3
8	124	850	1.04	Low	Yes	18	6	9,10,12	None	107	86	2.8	8.8
5	188	1330	1.53	Low	Yes	16	8	3,4,9,10	None	284	35	2.7	10.2
5a	190	1350	1.53	Low	No	16	0	None	3,4,9,10	400	28	2.6	10.1
6	191	1360	1.55	High	Yes	16	8	3,4,9,10	None	359	--	4.0	9.3
2	220	1630	1.83	Low	Yes	18	6	9,10,12	None	270	25	2.2	10.1
1	220	1640	1.84	Low	No	24	0	None	None	519	34	1.7	10.2
3	223	1640	1.86	High	No	24	0	None	None	675	14	3.3	9.2
4	218	1640	1.80	High	Yes	18	6	9,10,12	None	286	14	3.9	9.7

(1) Test program design.
(2) Average of 16 measurement per run.
(3) Refer to burner pair numbers shown in burner configuration diagram.



All forms of staged combustion produced significant NO_x emission reductions, with the combination of low excess air and staged firing consistently giving further improvements. At a load of 125 MW, without low excess air, the highest NO_x emissions resulted from simulated corner firing (S_6, only 12 burners firing and no staging), followed by S_1, normal firing of 24 burners, S3 horizontally opposed staged firing, S_2 "minimum NO_x" firing pattern (18 burners firing and burners 6 on air only), and S_5, simulated corner staged firing (12 burners firing and 12 burners on air only). These results are in the expected order. With no staging, 12 burners produced more NO_x than 24 burners fired at only one-half the fuel rate. With staged firing, the simulated corner firing produced lower NO_x than horizontally opposed firing. For full load staged firing, 3 pairs of burners could be operated on air only. Experience gained in testing this boiler indicates that pairs 9, 10 and 12 on air only would give minimum NO_x emissions.

Carbon monoxide emissions measured from Boiler G were less than 100 ppm and hydrocarbon measured less than 1 ppm. No visible haze was allowed to occur during our tests. Consequently, combustion was essentially complete in all runs.

The results obtained in testing Boiler G are presented again in Table 6-19 and Figure 6-6 to aid in the analysis and interpretation of the data. Full load, uncontrolled (except for the "built-in" two-stage combustion) NO_x emissions of 675 ppm measured in this boiler were rather high. The boiler operator indicated that changing the gas spuds to a newer design had resulted in roughly doubling the NO_x emission levels. Although we had no opportunity to verify this increase by running tests with the two different gas burner designs, this factor points out a potentially fruitful area for emission control research.

TABLE 6-19

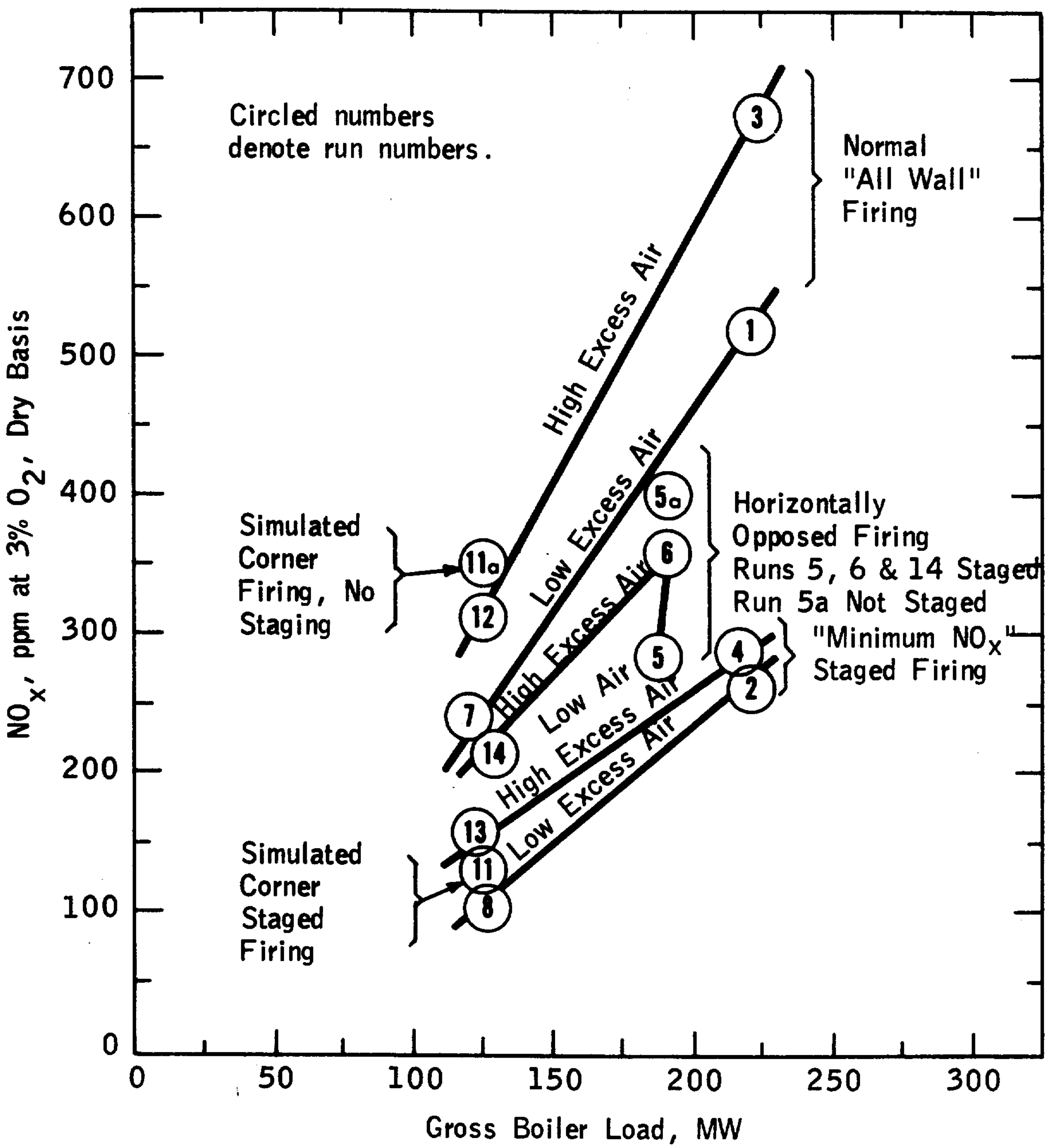
BOILER G - GAS FIRED NO_x REDUCTIONS THROUGH COMBUSTION CONTROL

Load		Combustion Control							
				Staged Firing			Staged Firing + LEA		
MW	% Reduction	None	LEA	"Min.NOx"	H.O.	Corner	"Min.NOx"	H.O.	Corner
220	0	675 ppm 0%	23%	58%			60%		
190	14%	550 ppm(1)	21%(2)		35%			48%	
125	43%	313 ppm 54%	25%	52%		58%	66%	53%	

(1) Estimated from trend line calculated from runs 3 and 12.
(2) Reduction due to low excess air in horizontally opposed firing runs at 190 MW.

Figure 6-6

NO_x EMISSIONS FROM BOILER G
(220 MW "ALL-WALL", GAS FIRED)



6.2.3 Tangential and Vertical Gas-Fired Boilers

Boiler H in our test program was a medium sized (320 MW), tangentially fired boiler. Although this boiler is operated with either gas or oil, only the latter fuel was fired during our tests. Therefore, a summary of gas fired emission data and operating variables were requested from the boiler owner operator which were kindly supplied to us. These experimental runs, made over a period of time, led to their "finall acceptable operating modes" for loads varying between 320 MW and 60 MW as indicated in runs 31 through 36. Operating variables tested by the boiler operator in addition to load were staging (air only to a row of burners), flue gas recirculation (through secondary air dampers), burner tilt, air damper settings, and excess air level.

Analysis of the NO_x emission data presented in Table 6-20 indicates that flue gas recirculation at low excess air levels provides a practical and effective means of reducing NO_x emissions from this boiler operated on gas fuel. Figure 6-7 presents the relationship between percent flue gas recirculation and NO_x emissions. The use of 18% (at 320 MW load) to 43% (at 60 MW load) flue gas recirculation with low excess air (while maintaining low CO emissions) appears to provide good NO_x emission control for this tangentially fired boiler. The use of staged firing was reported by the boiler operator to introduce operating difficulties, and therefore, has not been used by them for reducing NO_x emissions. Burner tilt and air damper setting are adjusted at each load to avoid higher water tube metal temperatures with minimum use of attemperation sprays. Thus, the use of their "finalacceptable operating mode" accomplished a reduction in NO_x emissions from 340 ppm to 110 ppm at full load (320 MW) with further reduction between 65 ppm and 85 ppm NO_x at lower loads.

The emission data obtained in testing Boiler I are summarized in Table 6-21. This boiler was originally designed as a wet bottom vertical coal fired boiler. It has been converted to gas firing. Boiler I has six burners in a single row firing downwards from the roof of the furnace. Our planned series of experiments on this boiler could not be performed completely. High load demands at the time of the test program did not allow emission tests at reduced loads. Also, after running four tests, the boiler was suddenly taken "off line" due to fuel gas shortage caused by cold weather conditions. Thus, some planned experiments with low excess air firing, staging and adjusting air damper positions to vary air-fuel mixing could not be performed. Plant experience using Orsat measurements indicated that air leaks upstream of our probes amounted to between 5% and 8% of the total flue gas. Thus, our O_2 measurements were probably 1.0% to 1.6% higher than the residual O_2 concentrations at actual furnace conditions.

Analysis of the data obtained at full load conditions suggests that air damper positions at the burner as well as staged firing have an important influence on NO_x and CO emissions from this boiler. A high excess air level (5.3% O_2 in the flue gas) with air dampers 80% to 100% open resulted in relatively low NO_x emissions of 155 ppm and low CO emissions of about 12 ppm. Lowering excess air to the point where CO emissions

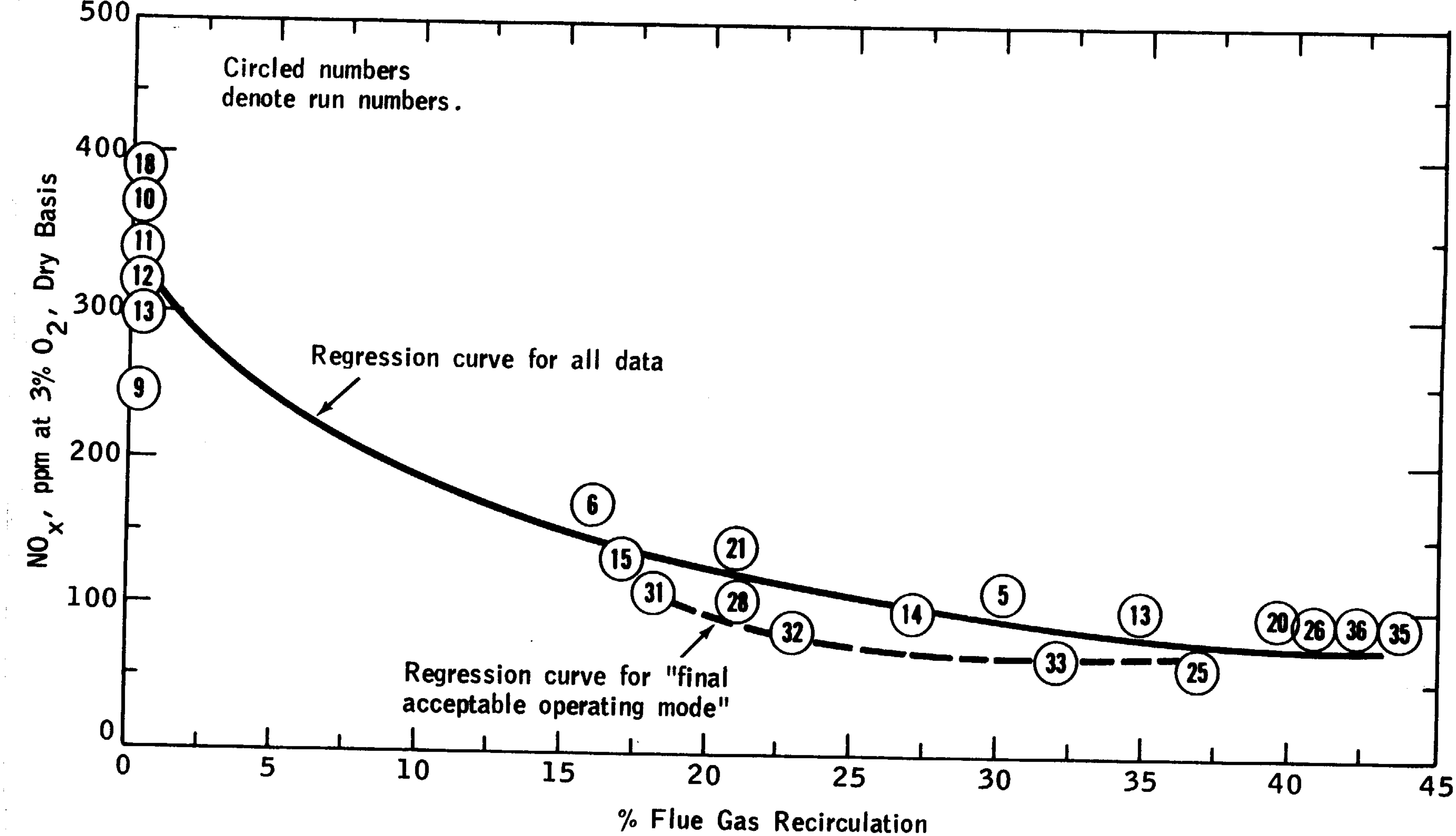
TABLE 6-20

SUMMARY OF EMISSION DATA FROM BOILER H
(320 MW, TANGENTIAL, GAS FIRED[1])

Run No.	Boiler Load MW	Staging	% Flue Gas Recirculation	Burner Tilt	Primary/Secondary Air Dampers	% O_2 Dry Basis	ppm 3% O_2, Dry Basis NO_x	ppm 3% O_2, Dry Basis CO	Run Conditions
1	320	No	0	Normal	Normal	3.3	340	175	(2)
3	320	No	0	+Max. (up)	Normal	2.7	335	50	(2)
5	320	No	30	Normal	Normal	2.2	105	50	(2)
6	320	No	16	Normal	Normal	2.7	165	80	(2)
9	320	No	0	Normal	32%100%	2.7	245	100	(2)
10	315	Yes	0	Normal	Closed	5.5	375	200	(2)
11	280	Yes	0	Normal	Closed	5.6	320	80	(2)
13	280	No	35	Normal	Open	2.5	95	50	(2)
14	320	No	27	Normal	Open	2.9	90	50	(2)
15	320	No	17	Normal	Open	2.4	130	60	(2)
16	240	No	0	Normal	Normal	5.0	230	2100	(2)
17	240	No	0	Normal	Normal	7.5	435	50	(2)
18	240	No	0	+Max. (up)	Normal	6.0	390	50	(2)
20	240	No	39	Normal	Normal	2.9	95	50	(2)
21	240	No	21	Normal	Normal	4.1	135	100	(2)
24	240	Yes	0	Normal	Open	6.2	345	50	(2)
25	240	Yes	0	Normal	Open	5.7	315	160	(2)
26	240	No	41	Normal	Normal	2.7	90	100	(2)
28	320	Yes	21	Normal	Open	2.2	105	150	(2)
31	320	No	18	Normal	Normal	2.0	110	50	(3)
32	240	No	23	Normal	Normal	2.2	80	600	(3)
33	160	No	32	Normal	Normal	2.9	65	50	(3)
34	120	No	37	Normal	Normal	5.5	65	50	(3)
35	80	No	43	Normal	Normal	8.9	85	50	(3)
36	60	No	43	Normal	Normal	11.0	85	50	(3)

(1) Data supplied by boiler owner-operator.
(2) Initial experimental runs.
(3) "Final acceptable operating mode."

Figure 6-7
NO_x EMISSIONS FROM BOILER H*
(320 MW, Tangential, Gas Fired)



*Emission date supplied by boiler operator.

TABLE 6-21

SUMMARY OF EMISSION DATA FROM BOILER I (66MW, VERTICAL, GAS FIRED)

Run No.	Gross Boiler Load Equivalent (MW)	Steam Generation 10^3 lb/hr	Number of Burners Firing	Staged Firing	Burner Air Dampers % Open	Average Flue Gas Components (1) Dry Basis		3% O_2, Dry Basis		Flue Gas Temp. °F
						O_2 %	CO_2 %	NO_x	CO	
1	66	683	6	No	80-100	5.3	9.4	155	12	553
2	66	682	6	No	40-45	3.2	9.7	252	405	551
3	66	682	6	No	20	3.4	9.6	235	143	548
4	66	683	6	Yes (2)	50	2.5	10.9	127	528	555

(1) Average of 12 data points. Each data point measured on a composite of 3 gas streams.

(2) 2 end burners fired fuel lean, 4 inner burners fired fuel rich.

became high (405 ppm), but closing the air dampers to only 40-45% open, increased the NO_x emission level to 252 ppm. This increase might be explained by higher flame temperatures caused by better air-fuel mixing. In Run 3 the excess air level was increased slightly to reduce CO emissions to about 140 ppm, and the dampers were closed to a 20% open position. NO_x emissions were reduced by less than 10%. In Run 4, the end burners were run fuel lean, while the middle 4 burners were run at a fuel rich condition. The excess air was reduced to the point that the CO emissions increased to over 500 ppm. This method of operation resulted in NO_x emissions of about 127 ppm.

Our overall conclusions on combustion modifications for NO_x emission control for gas fired boilers are discussed in section 2 of this report.

6.3 Individual Emission Results on Oil Fired Boilers

Field test programs were run on nine oil fired boilers. Three front wall fired (A, B, J), two horizontally opposed (D, E), one "all-wall" (G), two tangential (H, K), and a cyclone fired boiler (L) were tested. Six of these boilers (A, B, D, E, G and H) were also tested while firing gas as discussed in section 4.2. Comparison of the emissions data obtained on these boilers fired with either gas or oil is discussed in section 2 of this report.

6.3.1 Front Wall Oil Fired Boilers

Boilers A, B and J are front wall fired boilers, manufactured by Combustion Engineering, Riley Stoker and Babcock and Wilcox, respectively. Boiler J was selected for testing because of its unusual feature of flue gas recirculation directly into the windbox. Unfortunately, this boiler was not equipped for gas firing and thus the comparison of emissions as affected by fuel type could not be made.

Table 6-22 presents the average NO_x emission results corresponding to the statistical experimental design with oil firing of Boiler A. A summary of the 16 test runs made on Boiler A, fired with "low sulfur" fuel oils, is given in Table 6-23. Runs 1-14 were made with one grade of oil, while Runs 15-18 were made with a second grade of oil containing lower sulfur and nitrogen levels. Figure 4-8 presents the NO_x emissions in graphical form. Loads and relative excess air levels were the same in gas and oil fired test program designs; however, a third level of staging was used in oil firing. To achieve full load operation with staged firing, special "big" oil guns had to be used so that 12 burners could fire the same amount of fuel oil as 16 normal guns. Thus, at full

TABLE 6-22

EXPERIMENTAL DESIGN FOR BOILER A - FIRING OIL

(Average NO_x Emissions, ppm at 3% O_2, Dry Basis)*

	L_1 (180 MW)		L_2 (120 MW)		L_3 (80 MW)	
	A_1 Lo Air	A_2 Hi Air	A_1 Lo Air	A_2 Hi Air	A_1 Lo Air	A_2 Hi Air
S_1 (All Burners Equal)	238 6	367 5 259 18	241 4 181 17	322 3	191 2	266 1
S_2 (Staged Firing)	201 12 160 15	253 11	185 9	241 10 232 10		
S_3 ("Big" Oil Guns)	315 14	418 13				

* Circled numbers denote run numbers.

TABLE 6-23

SUMMARY OF EMISSION DATA FROM BOILER A (180 MW, FRONT WALL, OIL FIRED)

Run No.	Gross Boiler Load MW	Steam Flow 10^3 lbs./hr.(4)	Fuel Oil Fired 10^3 lbs./hr.	Staged Firing (3)	No. of Burners Firing	Avg. Flue Gas Components(1) %,Dry Basis O_2	%,Dry Basis CO_2	ppm, 3% O_2, Dry basis NO_x	ppm, 3% O_2, Dry basis CO	ppm, 3% O_2, Dry basis HC	Independent Analyses (2) %,Dry Basis O_2	%,Dry Basis CO_2	ppm, 3% O_2, Dry Basis NO_x	Flue Gas Temp. °F
1	77	460	38	No	12	4.6	12.7	266	14	<1				603
2	77	470	39	No	12	2.0	14.8	191	20	<1				586
3	122	750	57	No	16	4.6	12.7	322	19	<1				632
4	120	758	56	No	16	1.7	14.9	241	25	<1				642
5	182	1220	83	No	16	3.9	13.1	367	19	<1	3.5	13.0	348	682
6	182	1240	82	No	16	1.7	14.7	238	42	<1	1.3	14.4	217	688
9	119	750	56	Yes	12	3.5	13.4	185	29	<1	3.1	13.3	169	687
10	119	740	57	Yes	12	4.8	12.5	241	18	<1	4.4	12.2	207	688
11	179	1210	82	Yes	12	4.9	12.4	253	21	<1	4.3	12.1	238	588
12	179	1220	82	Yes	12	3.7	13.5	201	32	<1	3.3	13.0	189	585
13	179	1210	82	No	12	4.4	12.9	408	18	<1				632
14	178	1219	82	No	12	2.5	14.6	315	32	<1				643
15	178	1215	83	Yes	12	3.9	12.8	160	43	<1				684
16	120	730	57	Yes	12	5.4	11.6	232	26	--				688
17	119	750	56	No	16	1.8	14.5	181	31	--				681
18	179	1210	83	No	16	3.1	13.4	252	24	--				673

(1) Average of 16 data points per run. Each data point from a composite of 3 gas streams.
(2) Analyses obtained by boiler operator. NO_x by PDS: O_2 and CO_2 by Orsat analyses.
(3) Burner patterns:

	0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0
	0 0 0 0	0 0 0 0	■ 0 0 ■	A 0 0 A
	0 0 0 0	0 0 0 0	0 ■ ■ 0	0 A A 0
	0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0
Staging:	No	No	No	Yes
Load:	70 MW	120 MW	120 MW and 180 MW	
Burner Gun Size:	Normal	Normal	Normal	"Big"

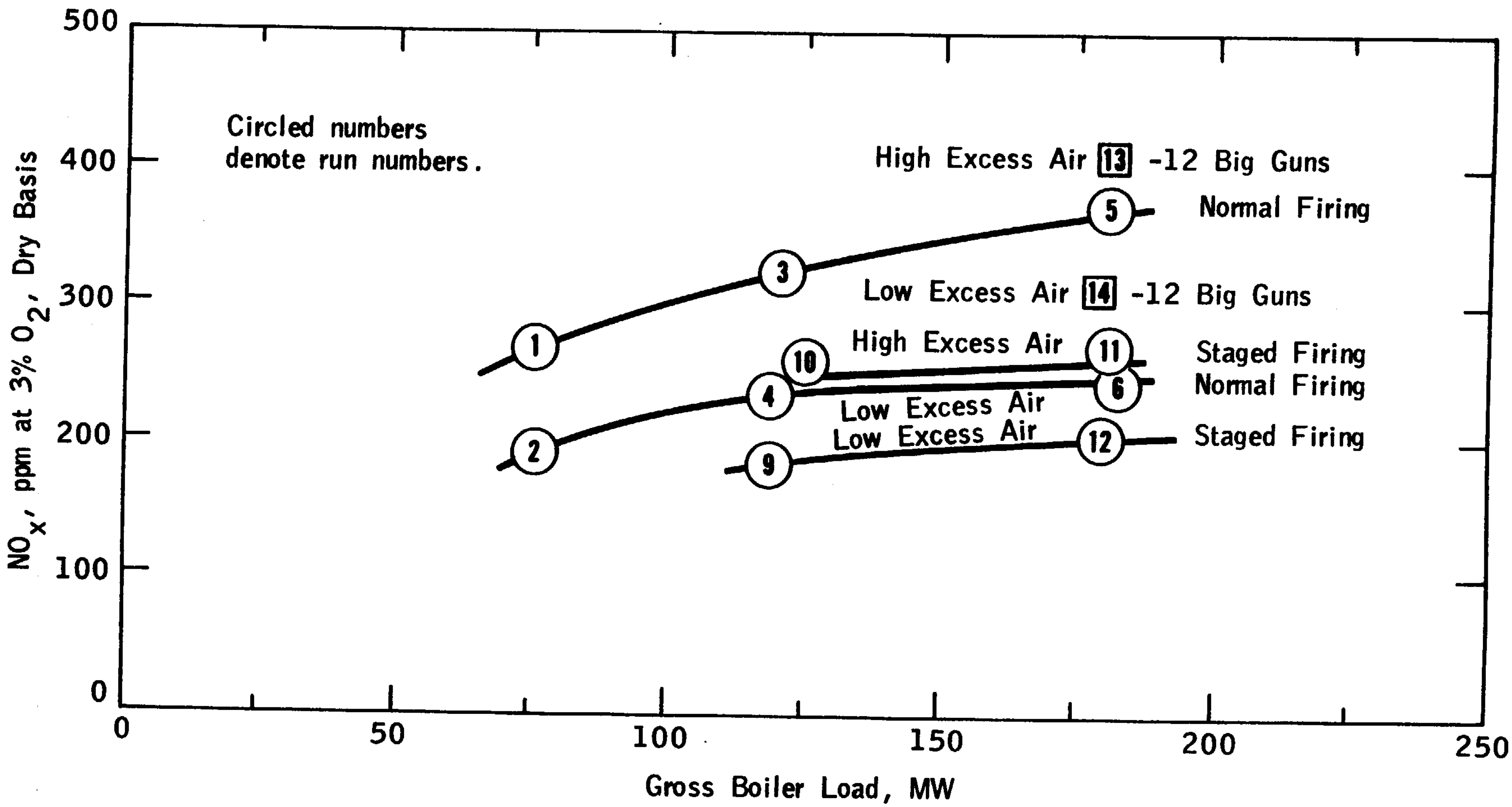
Key:
0 - Firing Fuel
A - Air Only
■ - No air or fuel

(4) All runs with "low sulfur" fuel oil. Runs 1-14 with one grade of fuel oil, Runs 15-18 with another lower S and N content fuel oil.

Figure 6-8

NO_x EMISSIONS FROM BOILER A

(180 MW, Front Wall, Oil Fired)



load, S_1 denotes firing with 16 oil gusn; S_2, firing 12 "big" guns with four burners on air only; and S_3, firing 12 "big" guns.

Analysis of the results obtained indicates that reducing the load in oil firing does not reduce NO_x emissions as much as reducing the load in gas firing. Low excess air firing, however, did reduce NO_x emissions between 18% and 35% for all loads and types of firing. Staged firing reduced NO_x emissions between 25% to 35%. The combination of low excess air with staged firing resulted in the largest reduction of about 45% in NO_x emissions. The effects of these combustion modifications on NO_x emissions are summarized in Table 6-24.

TABLE 6-24

BOILER A - OIL FIRED
NO_x REDUCTION THROUGH COMBUSTION CONTROL

Load		Combustion Control			
MW	% Reduction	None	Low Excess Air	Staging	LEA + Staging
180	0%	367 ppm 0% 0%	238ppm 35%	253ppm 31%	201ppm 45%
120	33 %	322ppm 0% 12%	241ppm 25% 1%	241ppm 25% 5%	185ppm 43% 8%
80	56 %	266ppm 0% 28%	190ppm 28% 20%		

The use of 12 "big" oil guns at full load and no staging resulted in an average 20% increase in NO_x emissions, compared with staged firing with 16 smaller burners. The use of low sulfur (0.18% vs. 0.45% by weight), low nitrogen (0.21% vs. 0.36% by weight) fuel oil reduced NO_x an average of 30% (to 183 ppm from 263 ppm) at comparable operating conditions (Runs 15 through 18 vs. Runs 12, 10, 4 and 5). This corresponds roughly to a 30% conversion to NO_x of the differential in fuel nitrogen between the two fuel oils. Because of other differences in fuel oil quality, these changes in emission may also have been due to factors other than fuel N content.

Table 6-25 presents a summary of emission data obtained from Boiler B firing oil. The primary operating variables included in the experimental design were load, excess air level, staged firing, and grade of fuel oil. The full load rating of this front wall Riley Stroker boiler is about 80 megawatts. The lowest load with which the boiler could be operated efficiently while firing all 12 burners was about 50 megawatts. With 10 burners firing, the lowest effective load was about 20 megawatts. Excess air was limited to the

TABLE 6-25

SUMMARY OF EMISSION DATA FROM BOILER B
(82 MW, FRONT WALL, OIL FIRED)

Run No.	Gross Load MW	Total Steam Flow 10^3 lb/hr.	Oil(3) Flow Bbl/hr.	Staging	Excess Air	No. of Burners		Burner Position (inches out)	Flue Gas Components (1) and Temperatures					
									Dry Basis		3% O_2 Dry Basis		Temp. (4) °F	Burner Pattern
						on Fuel	Air Only		O_2 %	CO_2 %	NO_x (PPM)	CO (PPM)		
1	21.0	190	160	No	Low	10	0	10	4.3	12.8	185	45	515	0X00X0 000000
2	20.5	190	160	Yes	High	10	2	10	6.1	11.2	207	38	524	0A00A0 000000
3	50.5	440	330	Yes	Low	10	2	14	3.9	13.0	252	94	623	0A00A0 000000
4	51.5	450	325	No	Normal	12	0	14	4.5	12.4	361	46	637	000000 000000
5	81.5	750	550	Yes	Low	10	2	22	3.3	13.3	293	59-130	758	0A00A0 000000
6	81.8	745	520	No	Normal	12	0	22	3.9	13.2	560	59	768	000000 000000
7	81.5	750	540	Yes	Normal	10	2	22	5.0	12.3	373	63	775	0A00A0 000000
8	81.5	745	530	No	Low	12	0	22	2.4	14.2	453	79-970	750	000000 000000
17	20.0	170	160	Yes	Low	10	2	10	5.3	12.2	203	87	477	0A00A0 000000
18	21.0	180	162	No	Normal	10	0	10	5.8	11.8	258	--	488	0X00X0 000000
19	50.0	425	320	No	Low	12	0	14	2.6	14.1	218	104	602	000000 000000
21	82.0	750	445	No	Normal	12	0	22	3.4	13.6	600	69	760	000000 000000
22	82.0	750	540	Yes	Low	10	2	22	3.5	13.7	99-580	209	748	0A00A0 000000
23	82.0	750	540	No	Low	12	0	22	2.0	14.6	70-379	265	737	000000 000000
24	82.0	750	540	Yes	Normal	10	2	22	5.1	12.3	434	64	769	0A00A0 000000

(1) Hydrocarbon emissions measured <1 ppm.
(2) Burner Code: X No Fuel or Air, A Air Only, 0 Fuel and Air
(3) Runs 1-8 on "low S" 0.31% N fuel oil, runs 1-17 on "normal S", 0.41% N fuel oil.
(4) Runs 17 and 18 air preheater by-pass used.

lowest air level at which the boiler could be operated with a clear stack (slight "efficiency haze" only)*, and at CO levels generally less than 200-300 ppm. Staging was accomplished by introducing air only through two burners of the top row, as shown in Table 6-25.

Tables 6-26 and 6-27 summarize the effects of changing the boiler operating variables on NO_x emission levels. This information is presented graphically in Figure 6-9. Reducing load from 82 MW to 21 MW (i.e., by 74%) reduced NO_x emissions by 35% to 60%. Staging (introducing air only through two top row burners) reduced NO_x emissions by 20% to 35%. Reducing excess air when operating at full load consistently reduced NO_x emissions by about 20% both under normal and staged firing conditions. Comparison of NO_x emissions from low N oil firing (Runs 21 through 24) with NO_x emissions for higher N oil firing (Runs 5 through 8) at full load showed a reduction in NO_x emissions of about 9%. The combination of staged combustion with low excess air firing reduced NO_x emissions by 46% at the full load of 82 MW, by 30% at 50 MW, and by 21% at 21 MW load.

TABLE 6-26

TEST PROGRAM DESIGN FOR BOILER B - FIRING OIL

(NO_x Emissions, ppm at 3% O_2, Dry Basis)*

	L_1 (82 MW)		L_2 (50 MW)		L_3 (20 MW)	
	A_1 (Normal)	A_2 (Lo Air)	A_1 (Normal)	A_2 (Lo Air)	A_1 (Normal)	A_2 (Lo Air)
S_1 (Normal Firing)	6 560 21 600	8 453 23 486	4 361	19 318	18 258	1 185
S_2 (Staged Firing)	7 373 24 434	5 293 22 335	20 290	3 252	2 207	17 203

* Circled numbers are test run numbers.
Runs 1 through 8 fuel oil composition: 0.31% N, 0.26% S, and 0.03 ash
Runs 17 through 24 fuel oil composition: 0.41% N, 0.32% S, and 0.10 ash

---

* "Efficiency haze" is a term used by the boiler operator to describe a slightly opaque stack condition resulting from lowering the excess air level for increasing boiler efficiency.

Figure 6-9
NO_x EMISSIONS FROM BOILER B
(82 MW, Front Wall, Oil Fired)

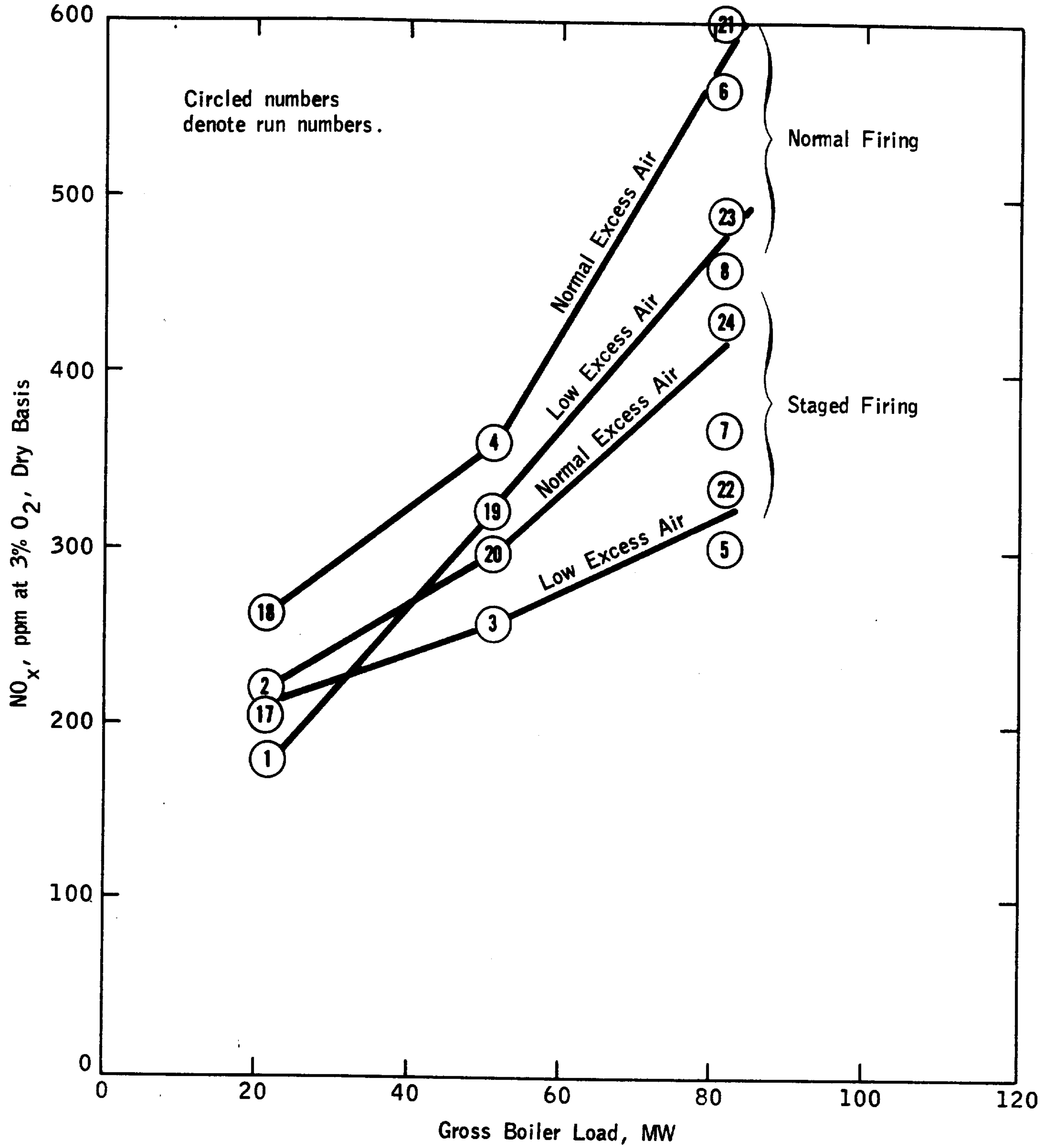


TABLE 6-27

BOILER B - OIL FIRED
NO_x REDUCTION THROUGH COMBUSTION CONTROL

Load		Combustion Control			
MW	% Reduction	None	Los Excess Air	Staged Firing	LEA + Staging
82	0%	580 ppm 0%	470ppm 19%	404ppm 30%	314ppm 46%
50	39%	361ppm 38%	318ppm 12% 32%	290ppm 20% 28%	252ppm 30% 20%
21	74%	258ppm 54%	185ppm 28% 61%	207ppm 20% 49%	203ppm 21% 35%

Table 6-28 presents the summary of the emission data obtained from Boiler J. This medium-sized (250 MW), twin-furnace, front wall boiler had duct work for flue gas recirculation into the windbox of each furnace. Boiler boiler. In addition, sampling pump failures and boiler control problems have more uncertainty than those obtained later on. Our sampling and analytical system had been substantially improved after the "break-in" experience on this boiler. In addition, sampling pump failures and boiler control problems resulted in an incomplete implementation of the statistical experimental design.

In spite of the above limitations, analysis of the data led to the following conclusions. The combination of full capacity flue gas recirculation with low excess air and staged firing reduced NO_x emissions by more than 50% at full load (from about 340 ppm to less than 150 ppm) and about 50% at two-thirds load (from about 300 ppm to 155 ppm). Staged firing (top row fired lean, and middle and bottom rows fired rich) without flue gas recirculation reduced NO_x emissions by about 20%.

Regression analysis indicated that about 75% of the variation in NO_x emissions could be explained by, or were related to combustion controls. With NO_x expressed in parts per million corrected to 3% O_2, dry basis, the regression equation was:

$$\text{ppm } NO_x = 238 - 25.4\ X_1^2 + 0.31\ X_2X_3 - 17.6\ X_2X_4$$

where: X_1 = extent of flue gas recirculation (0 for none, 1 for partial, 2 fur full capacity),
X_2 = excess air level (% O_2 in flue gas),
X_3 = load (MW),
X_4 = staging (0 for normal firing and 1 for staged firing).

A slightly better fit was obtained by correlating the logarithm of the NO_x emissions measured as ppm with the above variables.

$$\text{Log (ppm } NO_x) = 2.36 - 0.0559\ X_1^2 + 0.0049\ X_2X_3 - 0.0279\ X_2X_4$$

The correlation coefficients and standard errors of estimate for the linear and the logarithmic regressions were r = 0.86 and 0.90, and s_y = 32 ppm and 0.054 log units, respectively.

TABLE 6-28

SUMMARY OF EMISSION DATA FROM BOILER J
(250 MW, Front Wall, Twin Furnace, Oil Fired)

Run No.	Gross Boiler Load (MW) (1)	Staged Firing (2)	Excess Air Level (3)	Extent of Flue Gas Capacity Used	Flue Gas Components and Temperatures (4): Dry Basis %, O_2	Dry Basis %, CO_2	ppm, at 3% O_2, Dry Basis: CO	ppm, at 3% O_2, Dry Basis: NO_x	°F Temp.
1	79	Yes	Low	Partial	1.0	14.4	--	239	--
2	84	No	Low	Partial	1.0	15.1	--	218	--
3	86	No	Low	Partial	1.6	13.8	--	198	532
4	84	No	High	None	2.6	13.8	--	353	510
5	86	No	Low	None	1.0	15.0	--	298	550
6	86	Yes	Low	None	0.9	14.4	--	229	514
7	84	Yes	High	None	2.2	13.7	--	274	520
8	86	Yes	High	None	2.3	13.5	--	267	515
9	116	No	High	None	2.5	13.9	--	305	--
10	118	Yes	Low	Full	1.4	14.3	--	142	--
11	124	No	High	None	2.9	13.2	20	350	--
12	127	Yes	Low	Partial	1.9	13.7	(5)	265	695
13	122	Yes	High	None	2.0	13.8	270	270	590
14	127	No	High	None	2.0	13.7	41	370	582
15	84	No	High	None	3.1	12.7	10	260	545
16	83	Yes	High	None	2.9	12.8	8	246	545
17	84	Yes	Low	Full	1.0	14.9	(5)	153	545
18	83	No	Low	Full	1.2	14.7	53	174	550

(1) Per furnace, including 7 MW equivalent for each 100,000 lb. of steam supplied to customer.

(2) Staged firing: yes - top row of burners fired fuel lean (about 20% of total fuel), bottom 2 rows fuel rich (about 40% each).

(3) Test program design.

(4) Average flue gas composition from No. 2 furnace only (average of 6 to 8 flue gas samples).

(5) >1000 ppm on probe with lowest O_2 measurements.

6.3.2 Horizontally Opposed Oil Fired Boilers

Table 6-29 presents the summary of emission data obtained in testing with oil firing boiler D, a 350 MW, horizontally opposed single furnace Babcock and Wilcox boiler equipped with "NO-ports" for two-stage combustion.

TABLE 6-29

SUMMARY OF EMISSION DATA FROM BOILER D
(350 MW, Horizontally Opposed, Oil Fired)

Operating Data							Flue Gas Components (1) and Temperature				
							Dry Basis		3% O_2		
Run No.	Gross Boiler Load MW	Total Steam Flow 10^6 lb/hr	Fuel Oil Flow Bbls/hr	Excess Air Level	"NO-Ports"	Burner Staging (2)	O_2 %	CO_2 %	NO_x (ppm)	CO (ppm)	Temp. °F
6	349	215	485	Low	Open	No	1.8	14.8	308	66	711
5	348	215	487	Low	Shut	No	1.4	14.8	442	53	694
2	351	215	484	Low	Open	Yes	2.2	13.0	284	61	697
3	352	215	486	High	Open	Yes	3.4	12.4	297	65	703
1	350	216	484	Low	Shut	Yes	1.8	13.5	292	92	692
4	351	216	484	High	Shut	Yes	3.0	12.6	302	85	699
7	151	96	237	Low	Open	No	2.1	14.6	173	59	617
8	154	100	245	Low	Shut	No	1.7	14.9	228	60	609
9	154	99	240	Low	Shut	Yes	2.2	14.4	152	52	615
10	155	98	245	Low	Open	Yes	2.6	14.2	118	59	615
11	154	98	244	High	Open	Yes	3.6	13.5	139	55	619
12	154	98	242	High	Shut	Yes	3.2	13.8	177	45	620

(1) Average of 16 data points per run. Each data point based on composite of 3 gas sample streams.

(2) "Off-stoichiometric" combustion, middle burner of each 3 burner cell on air only (except cell No. 7, top burner on air only).

BURNER CONFIGURATION

Front Face				Rear Face			
0	0	0	0	0	0	@	0
@	@	@	@	@	@	0	@
0	0	0	0	0	0	0	0

Code: 0 Fuel and air.
@ Air only.

The experimental design and the average NO_x emissions measured in testing Boiler D firing fuel oil are summarized in Table 6-30. The operating variables included in the experimental program were load, excess air, staged firing and "NO-port" setting. The staged firing was performed with the middle burner of each 3 burner cell on air only, except for cell number 7 which had the top burner on air only (as shown in Table 6-29) due to a mechanical problem. With the limited time available for field testing, staged firing was emphasized over normal firing.

TABLE 6-30

TEST PROGRAM DESIGN FOR BOILER D - FIRING OIL

(NO_x Emissions, ppm at 3% O_2, Dry Basis)*

		(L_1) 350 MW		(L_2) 150 MW	
	"NO-Ports"	Closed	Open	Closed	Open
(S_1) Normal Firing	(A_1) Hi Air	(457)		(264)	
	(A_2) Lo Air	5 442	6 308	8 228	7 173
(S_2) Staged Firing	(A_1) Hi Air	4 302	3 297	12 177	11 139
	(A_2) Lo Air	1 292	2 284	9 153	10 118

* Circled numbers denote run numbers.

In order to provide an indirect comparison of NO_x emissions reduced by combustion control for boiler D firing gas or oil, estimates were made of uncontrolled emissions at full and partial loads as shown in the footnotes of Table 6-31. Thus, the high excess air, normal firing, closed "NO-port" results were estimated assuming that the reduction in NO_x emissions due to the application of low excess air supply was the same for normal as for staged firing. Although these estimates are subject to considerable error, they provide bases for comparisons without affecting all of the other direct relationships as shown in Figure 6-10 for oil firing. Low excess air firing with staged combustion reduced NO_x emissions by less than 5% at full load and about 15% at reduced load, compared with the same mode of operation but using high excess air. The use of open "NO-ports" combined with low excess air and normal firing reduced NO_x by 30% at full load, and 24% at reduced load. "Full combustion control" (low excess air, with staged combustion and open "NO-ports") reduced NO_x emissions an estimated 38% at full load, and 55% at reduced load. As in other boilers burning either gas or oil, the fractional reductions in NO_x emissions for "full control" are less for oil than for gas firing. However, since uncontrolled gas fired NO_x emissions are higher for gas then oil, "fully controlled" NO_x emissions for the two fuels are similar to each other.

TABLE 6-31

BOILER D - OIL FIRED

NO_x EMISSION REDUCTION THROUGH COMBUSTION CONTROL

Load		Combustion Control				
MW	% Reduction	None	Low Excess Air	"NO" Ports	Staging	"Full"
350	0%	457[(1)] ppm 0%	442ppm 3%	308ppm 33%	297ppm 35%	284ppm 38%
154	56%	264 ppm(2) 42%	228ppm 14% 48%	173ppm 34% 44%	139ppm 47% 53%	118ppm 55% 58%

(1) Estimated: $442 \times \frac{302}{292} = 457$ppm

(2) Estimated: $228 \times \frac{177}{153} = 264$ppm

A multiple regression analysis of the data indicated that 92% ($r = 0.96$) of the variation in NO_x emissions from Boiler D firing oil was related to, or explained by the combustion controls as shown in the following regression equation:

$$\text{ppm } NO_x = 111 + 1.24\ X_1 - 45.9\ X_2 - 0.258\ (X_1 X_3)$$

Where: X_1 = gross load (MW)
X_2 = "NO-Ports" (1 for closed, 2 for open position)
X_3 = Staged Firing (1 no staging, 2 staging)

The estimated standard error of estimate calculated from this regression model with 8 degrees of freedom was 29 ppm NO_x. Since this standard error is considerably higher than our estimated standard deviation for experimental error, it is apparent that such a regression model is over-simplified. Extensive field testing on an oil fired boiler is needed to provide the data for a more realistic, but more necessarily complex empirical model.

Table 6-32 presents the experimental design and a summary of the emission data from Boiler E, firing oil. This large (480 MW), opposed wall fired boiler is equipped with "NO-ports" above the top row of burners. The statistically designed field test program on this boiler could not be completed because boiler control equipment failed to operate properly. However, as shown in Table 6-32, nine runs were made and some important information on NO_x emission control could be obtained.

Figure 6-10

NO_x EMISSIONS FROM BOILER D

(350 MW, Horizontally Opposed, Oil Fired)

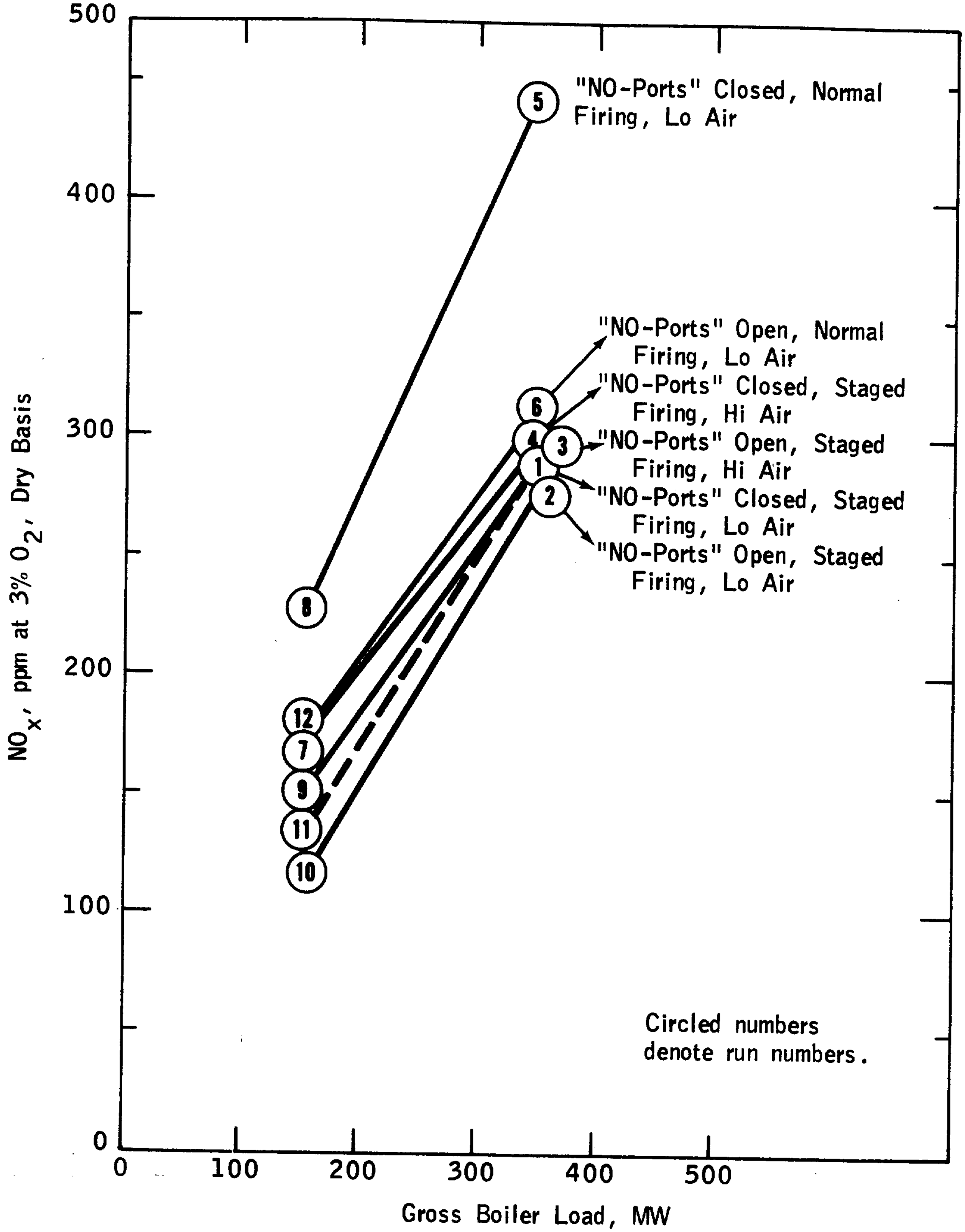


TABLE 6-32

TEST PROGRAM DESIGN FOR BOILER E - FIRING OIL*

(NO_x Emissions, ppm at 3% O_2, Dry Basis)

"NO-Ports"	Excess Air	(L_1) (455 MW)		(L_2) (364 MW)		(L_3) (228 MW)	
		(A_1) Hi	(A_2) Lo	(A_1) Hi	(A_2) Lo	(A_1) Hi	(A_2) Lo
(P_1) "NO-Ports" Closed	(S_1) Normal Firing	2 246	3 223	9 219	8 183		4 163
	(S_2) Staged Firing			15 --	14 --	7 --	
(P_2) "NO-Ports" Open	(S_1) Normal Firing	1 200	16 --	11 164	10 163	5 155	
	(S_2) Staged Firing			13 --	12 --		6 --

* Circled numbers denote run numbers.

Operating conditions and emission test data for Boiler E are given in Table 6-33. The degree of NO_x emission reduction obtained is summarized in Table 6-34, as a function of the combustion controls applied. These results are presented graphically in Figure 6-11. Uncontrolled, full load NO_x emissions of 246 ppm were relatively low from this boiler when fired with low sulfur fuel oil. However, NO_x emissions did not decrease in proportion to load reductions. Low excess air, and the use of "NO-ports", each reduced NO_x emissions but the combination of these controls showed no significant improvement over the use of "NO-ports" alone. Additional field tests are required to optimize combustion controls on this type of boiler.

TABLE 6-33

SUMMARY OF EMISSION DATA FROM BOILER E
(480 MW, HORIZONTALLY OPPOSED, OIL FIRED)

Operating Data							Flue Gas Components (1)(2)				Flue Gas Temp. °F
							Dry Basis		3% O_2, Dry Basis		
Run No.	Gross Boiler Load (MW)	Fuel Oil Flow 10^3 lbs./hr.	Main Steam Flow 10^3 lbs./hr.	"NO-Ports"	Excess air Level (3)	No. of Burners Firing	O_2 %	CO_2 %	NO_x ppm	CO, ppm	
4	227	115	145	Closed	Low	16	3.5	13.1	163	12	525
5	229	124	150	Open	High	16	5.0	11.3	155	14	523
9	364	175	228	Closed	High	16	5.3	12.4	219	19	594
2	454	216	285	Closed	High	16	4.7	13.1	246	15	636
3	454	215	290	Closed	Low	16	3.6	13.9	223	20	625
1	459	220	290	Open	High	16	4.6	13.1	200	21	634
11	358	175	236	Open	High	16	4.6	13.1	164	21	649
10	368	173	233	Open	Low	16	4.0	13.5	163	21	621
8	368	175	230	Closed	Low	16	3.6	13.9	183	19	622

(1) Average of 16 data points per run. Each data point from a composite of 3 gas streams.
(2) Hydrocarbons measured <1 ppm.
(3) Test program design.

Figure 6-11
NO_x EMISSIONS FROM BOILER E
(480 Megawatts, Horizontally Opposed, Oil Fired)

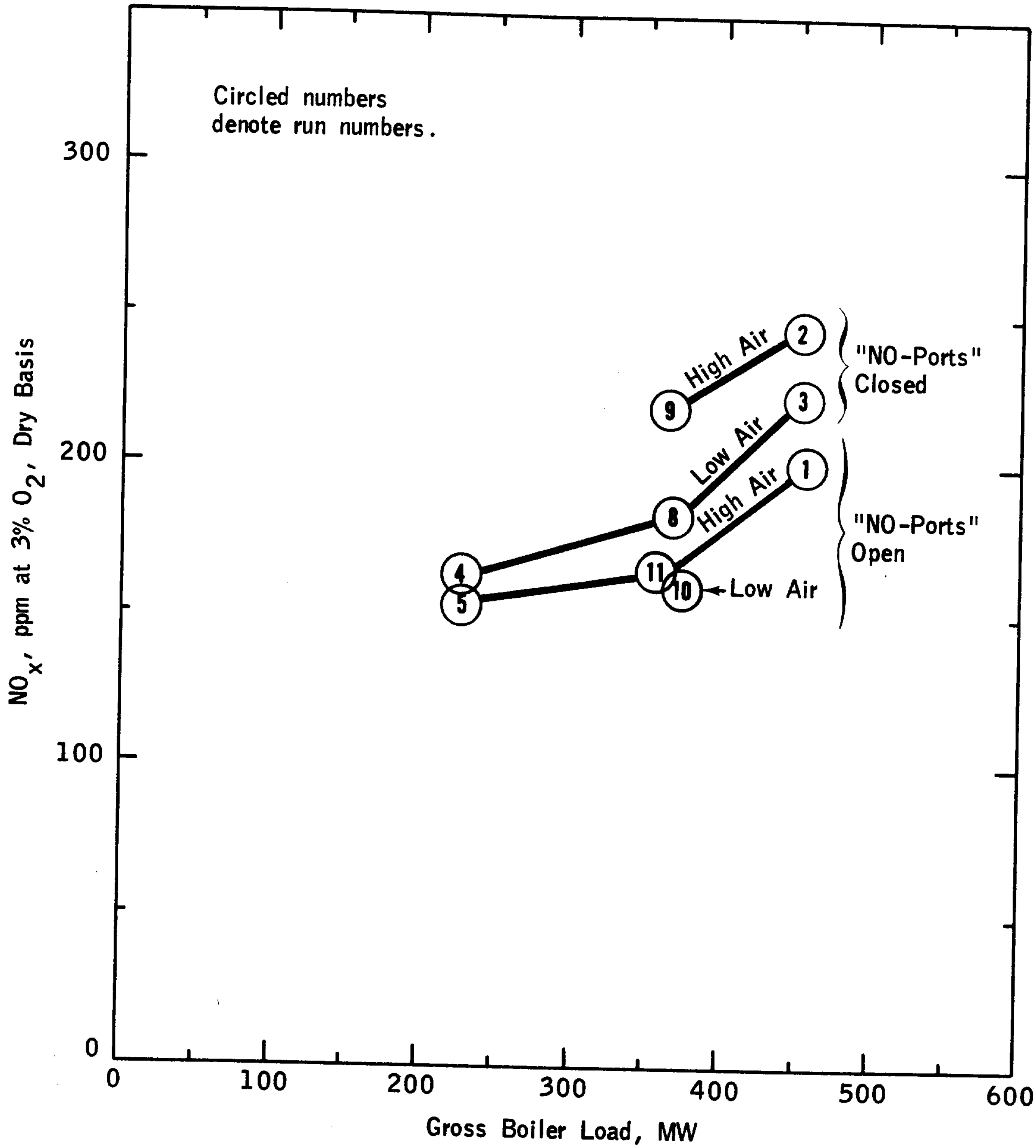


TABLE 6-34

BOILER E OIL FIRED
NO_x REDUCTION THROUGH COMBUSTION CONTROL

Load		Combustion Controls			
MW	% Reduction	None	LEA	"NO-Ports"	"Full"
455	0%	246 ppm	223 ppm-9%	200 ppm-19%	--
365	20%	219 ppm 11%	183 ppm-16% 18%	164 ppm-25% 18%	163 ppm 26%
228	50%		163 ppm 27%	155 ppm 22%	

Table 6-35 presents the emission data and corresponding operating conditions for the field tests run on boiler G when firing oil. This boiler (described earlier in Section 6.2 in connection with tests on gas firing) is an "all-wall" fired, 220 MW Babcock and Wilcox boiler. It has a single furnace with a division wall. The burner configuration is shown in Table 6-35. The major objective in testing this boiler with oil firing was to utilize the flexibility of its burner configuration in the same manner as in the gas fired test program. Because of the high tube failure experienced at the division walls, a severe limitation on conducting these tests was the upper limit of water tube metal temperatures. In addition, the unavailability of special high capacity oil guns meant that each gun taken out of service reduced load correspondingly. Thus, the experimental plan was designed to provide base level emissions at full load, and various firing patterns at the highest loads attainable. Since the boiler had not been run previously with most of planned burner patterns, alternate runs were planned in case operating limits forced cancellation of original plans. Normally this boiler fires all of its burners regardless of load. Table 6-36 shows the matrix of the planned runs (1 through 14) as well as the test actually made on NO_x emissions. The NO_x emission data are presented in graphical form in Figure 6-12.

In line with the behavior of some of the other boilers tested for NO_x control, this boiler proved to be less flexible with oil than with gas firing. The high water tube metal temperatures developed when Run 8 was attempted forced the cancellation of Runs 8, 9, 10, 11, 13 and 14. Runs 15 and 16 were made to verify an unexpected increase in NO_x emissions with decreasing load experienced in Runs 1, 2, 7 and 12. The conditions for Run 19 (6 burners on air) were approached gradually through Runs 17 (3 burners on air) and 18 (4 burners on air) to prevent conditions leading to high water tube metal temperatures. Run 20 was then made by gradually lowering the load and using the staged firing pattern of Run 19 until water tube metal temperatures began to increase at a load of 150 MW.

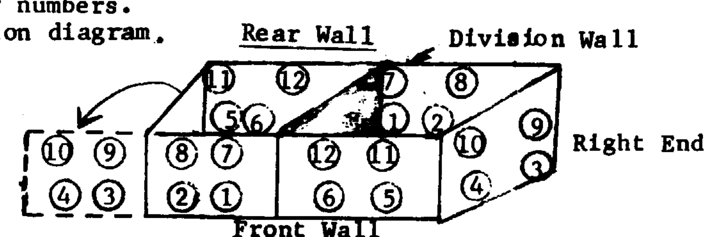
Analysis of the twelve runs provided the following conclusions. Low excess air reduced NO_x emissions by 10 to 20%. Staged firing reduced NO_x emissions by about 35% at normal excess air levels under both opposed wall (burner pairs 3, 4, 9, 10 on air only) and "minimum NO_x" (burner pair 12 on air only). Smaller reductions were obtained when only one or two pairs of burners were operated on air only.

TABLE 6-35

SUMMARY OF EMISSION DATA FROM BOILER G
(220 MW, "ALL-WALL", OIL FIRED)

Run No.	Gross Boiler Load (MW)	Steam Flow 10^3 lbs/hr	Fuel Oil Flow 10^3 lbs/hr	Excess Air Level (5)	Staging (3)	Number of Burners Firing Oil	Number of Burners Air Only	Burners on Air Only (2)	NO_x, ppm 3% O_2 Dry Basis	Dry Basis O_2 %	Dry Basis CO_2 %	CO ppm 3% O_2 Dry Basis	HC ppm 3% O_2 Dry Basis
1	219	1620	100	Normal	No	24	0	0	235	2.6	13.2	19	3
2	220	1620	101	High	No	24	0	0	291	3.9	11.9	19	<1
5	189	1360	90	Normal	Yes (4)	16	8	3,4,9,10 pairs	236	5.0	11.3	13	<1
3	189	1350	88	Normal	Yes	18	6	9,10,12 pairs	170	4.8	11.6	17	<1
7	122	840	58	Normal	No	24	0	0	293	5.3	11.4	20	<1
12	123	840	59	High	No	24	0	0	319	6.6	10.3	22	<1
15	154	1050	72	Normal	No	24	0	0	308	5.7	11.4	12	<1
16	195	1380	88	Normal	No	24	0	0	267	4.5	12.5	14	<1
17	195	1380	88	Normal	Yes	22	2	9 pair	234	4.5	12.5	14	<1
18	195	1380	89	Normal	Yes	20	4	9,10 pairs	199	4.5	12.4	16	<1
19	199	1400	91	Normal	Yes	18	6	9,10,12 pairs	183	4.4	12.5	15	<1
20	160	1000	72	Normal	Yes	18	6	9,10,12 pairs	172	5.7	11.3	16	<1

(1) Average of 8-16 measurements per run. Each data point from a composite of three gas streams.
(2) Diagram of burner pair numbers.
(3) See burner configuration diagram.



(4) Simulation of horizontally opposed firing mode.
(5) Test program design.

TABLE 6-36

TEST PROGRAM DESIGN FOR BOILER G - FIRING OIL*

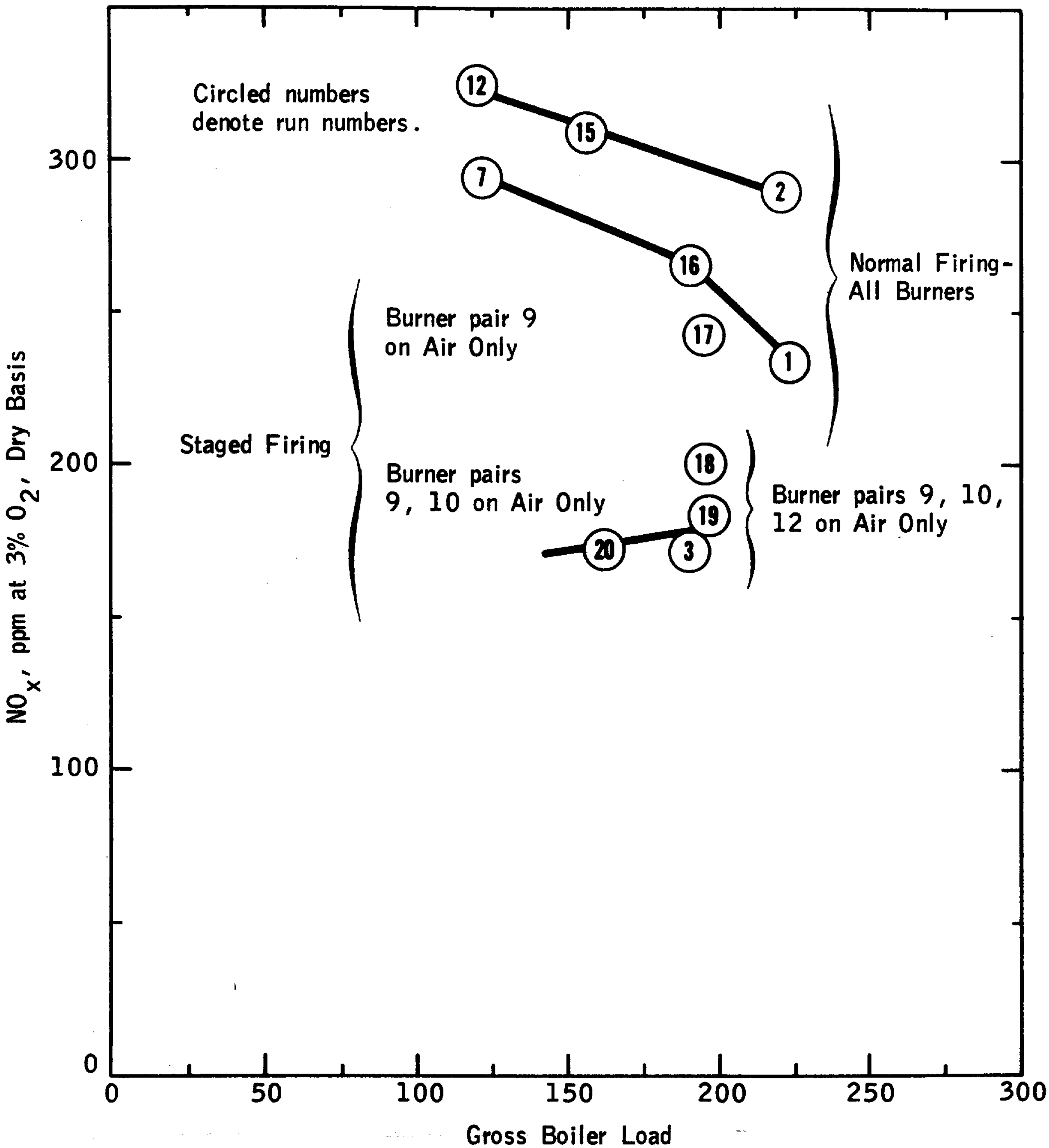
(NO_x Emissions, ppm at 3% O_2, Dry Basis)

Firing Patterns	(L_1)220 MW (A_1)Hi Air	(L_1)220 MW (A_2)Normal Air	(L_2)190 MW (A_1)Hi Air	(L_2)190 MW (A_2)Normal Air	(L_3)150 MW (A_1)Hi Air	(L_3)150 MW (A_2) Normal Air	(L_4)120 MW (A_1)Hi Air	(L_4)120 MW (A_2)Normal Air
(S_1)Normal All Burners	2 291	1 235		16 267	15 308		12 324	7 293
(S_2) "Minimum NO_x" 9,10,12 on Air			6	3 170 19 183		20 172	13	8
(S_3) H.O. 3,4,9,10, on Air			4	5 193			14	9
(S_4)Tang. Alg. on Air							11	10
(S_5)Special 9 on Air				17 243		22		
(S_6)Special 9,10 on Air				18 199		21		

Figure 6-12

NO_x EMISSIONS FROM BOILER G

(220 MW, "All Wall", Oil Fired)



6.3.3 Tangential Oil Fired Boilers

Table 6-37 presents the summary of emission data obtained from boiler H firing oil. The operating variables included in the experimental design on this tangential boiler were staged firing, excess air, burner tilt, flue gas recirculation, and air damper settings. All 25 test runs were made at a load of about 220 MW, the highest load attainable with staged firing. Based on information supplied by the boiler operator, uncontrolled NO_x emissions at full load (320 MW) from this boiler were about 215 ppm.

Staged firing was accomplished by introducing air only through the bottom row of burners on each furnace. (This furnace is designed "upside-down", i.e., the combustion gases travel down through the furnace and super-heat sections of the boiler.) Excess air levels were established at normal (3-4% O_2) and high (5-6% O_2 levels). The boiler operator would not allow firing with low excess air because of the possibility of emitting visible plumes. (Normally, the appearance of the stack is clear except for the appearance of water vapor during cold weather.) The burners were fired at the extreme ranges of tilt, i.e., 30° down from horizontal (normal) to 10° up from horizontal. Flue gas recirculation was established at the maximum and minimum settings attainable based on reaching the necessary steam temperature levels. Primary and secondary air damper settings were adjusted as shown in Table 6-37, i.e., maximum primary and minimum secondary, or minimum primary and maximum secondary.

Table 6-38 lists NO_x emissions according to the statistical experimental design. A single replicated factorial design was run at the normal excess air level, while a one-half replicated factorial design was run at the high excess air level. Several two and three-factor interactions were found to be statistically significant, tending to mask the main effects. Therefore, Table 6-39 was calculated to indicate more clearly the effects of varying flue gas recirculation, staging, and excess air levels by averaging the results over all burner tilt and air damper settings. Table 6-39 indicates the grand weighted average values of all main effects listed in order of importance.

TABLE 6-37

SUMMARY OF EMISSION DATA FROM BOILER H

(320 MW, Tangential, Oil Fired)

Run No.	Gross Boiler Load (MW)	Staged Firing(2)	Air Dampers, % Open		Excess Air Level (3)	Burner Tilt From Degrees Horzontally	Flue Gas Recirculation	Fuel Oil Flow (10^3 lbs/hr)	Main Steam Flow 10^6 lb/hr	% O_2 in Flue Gas		Flue Gas Components (1)				Flue Gas Temperature °F
												Dry Basis		3% O_2, Dry Basis		
			Primary	Secondary						E	W	O_2 %	CO_2 %	NO_x (ppm)	CO (ppm)	
1	221	No	100	39	Normal	-30	Max	1006	1.34	3.6	3.3	3.9	12.8	141	9	714
2	216	No	100	52	Normal	+10	Min	962	1.32	3.7	3.2	3.6	12.9	161	13	665
3	217	No	50	39	High	+10	Min	976	1.32	5.9	6.2	6.3	10.4	203	16	685
4	221	No	50	39	High	-30	Max	1029	1.32	5.7	6.2	6.2	10.3	217	18	706
5	217	Yes	50	95	High	-30	Min	1010	1.33	6.7	6.6	6.3	10.1	204	17	695
6	216	Yes	50	100	High	+10	Max	1016	1.33	6.6	7.0	6.4	10.1	177	18	706
7	215	Yes	100	20	Normal	+10	Max	994	1.33	3.2	3.4	3.3	12.7	131	13	694
8	219	Yes	100	30	Normal	-30	Min	1024	1.33	4.7	3.6	4.1	13.4	139	13	679
9	218	No	95	0	Normal	+10	Max	958	1.31	3.7	3.7	3.9	12.8	148	11	703
10	219	No	100	0	High	-30	Min	998	1.33	6.0	6.0	5.0	10.8	235	12	679
11	214	No	40	70	High	-30	Min	976	1.33	6.6	5.3	6.3	10.7	174	14	671
12	217	No	40	100	Normal	+10	Max	982	1.32	3.7	3.8	3.9	12.4	194	14	703
13	208	Yes	50	75	Normal	+10	Min	986	1.32	5.1	5.3	5.4	11.2	139	14	667
14	217	Yes	50	80	Normal	-30	Max	1024	1.31	4.0	4.5	4.5	11.7	144	14	703
15	214	Yes	100	30	High	-30	Max	1000	1.32	6.1	6.2	6.1	10.3	170	15	671
16	207	Yes	100	30	High	+10	Min	980	1.33	6.2	6.1	6.5	9.8	185	15	659
17	219	No	100	20	High	+10	Max	1014	1.33	5.7	5.7	5.5	10.9	184	15	530
18	209	No	50	60	Normal	+10	Min	972	1.34	4.8	4.2	4.9	11.7	143	14	639
19	213	No	50	60	Normal	-30	Min	992	1.33	5.3	4.8	5.3	11.3	171	22	653
20	223	No	50	90	Normal	-30	Max	1022	1.34	3.9	4.1	4.3	11.8	150	24	712
21	219	No	100	20	Normal	-30	Min	992	1.33	5.3	4.6	5.3	11.1	244	21	657
22	217	Yes	100	20	Normal	-30	Max	1018	1.32	4.0	3.9	4.0	12.6	110	23	675
23	211	Yes	50	100	Normal	-30	Min	1004	1.31	5.2	5.5	5.6	11.2	136	27	653
24	212	Yes	50	100	Normal	+10	Max	996	1.31	4.0	4.3	4.1	12.4	97	28	676
25	201	Yes	100	0	Normal	+10	Min	972	1.31	4.5	5.3	5.3	11.4	150	27	622

(1) Average of 16 data points per run. Each data point from a composite of 3 gas streams.

(2) Staging: no-all 24 burners firing equally; yes-16 burners firing, bottom level on air only.

(3) Test program design.

TABLE 6-38

TEST PROGRAM DESIGN FOR BOILER H-FIRING OIL
(NO_x Emissions, ppm at 3% O_2, Dry Basis)

Air Dampers		(R_1)Max. Flue Gas Recycle				(R_2)Min. Flue Gas Recycle			
		(S_1)Normal Firing		(S_2)Staged Firing		(S_1)Normal Firing		(S_2)Staged Firing	
		(D_1) (1)	(D_2)	(D_1)	(D_2)	(D_1)	(D_2)	(D_1)	(D_2)
(A_1)Normal Excess Air	(T_1) (2)	141	150	110	144	244	171	139	136
	(T_2)	148	194	131	97	161	143	156	139
(A_2)High Excess Air	(T_1)		217	141		235	174 (3)		204
	(T_2)	184			177		203	184	

(1) (D_1) - Primary air dampers at maximum open, secondary air dampers at minimum settings.
(D_2) - Primary air dampers at minimum open, secondary air dampers at maximum settings.

(2) (T_1) - Burners tilted down.
(T_2) - Burners tilted up.

(3) Extra run not used in calculating grand averages in Table 6-39.

TABLE 6-39

BOILER H-FIRING OIL GRAND AVERAGE NO_x EMISSIONS* PPM AT 3% O_2, DRY BASIS

	(R_1)Maximum Flue Gas Recirculation		(R_2)Minimum Flue Gas Recirculation		Grand Average
	(S_1)	(S_2)	(S_1)	(S_2)	
A_1 (Normal Air)	158	120	180	142	150
A_2 (Hi Exc. Air)	200	159	219	194	193
Grand Averages	179	140	200	168	172

* NO_x emissions averaged over all burner tilt and air damper settings tested.

As shown in Table 6-39, the overall grand average of NO_x emissions was 172 ppm. The base-line emission level (minimum flue gas recirculation, normal firing, and normal excess air) was 180 ppm NO_x. Increasing excess air with normal firing and minimum flue gas recirculation increased NO_x emissions by about 22% to 219 ppm. The lowest average NO_x emissions (120 ppm) resulted from combining maximum flue gas recirculation and staging with normal excess air firing. Additional improvements were made by tilting the burners up with minimum opening of the primary dampers (97 ppm NO_x), or by normal burner tilt and maximum primary air settings.

Figure 6-13 presents graphically the average NO_x emissions listed in Table 6-39. The separate effects of changing the three most important operating variables (excess air, firing mode and recirculation levels) are readily seen in this figure.

Table 6-40 presents a summary of emission and operating data obtained in testing boiler K, a small, oil fired tangential boiler. This boiler had been selected for our Boiler Test Program because gas as well as different grades of fuel oil were expected to be fired, supplied from barges adjacent to the plant. However, the oil lines and docking facilities were removed a few weeks prior to our actual test program. Consequently, only a limited number of test runs could be made on this boiler.

Boiler K and another boiler provide steam to a single turbine generator. The second boiler was down for repair work, consequently, boiler K could not be run at less than 600,000 lb. of steam per hour due to minimum turbine steam requirements. Although a more detailed test program was planned, gas was not available due to cold weather conditions, and only one grade of oil could be fired. No fuel adjustments could be made on the lower level of burners because of the absence of pressure gauges. Therefore, "simulated" staging using the lower level burners could not be performed.

Run 1 was made under normal "full load" (620,000 lbs. of steam per hour) conditions with all burners firing equally. Runs 2 and 3 were made to simulate staged combustion at the lowest excess air level available as dictated by plant smoke measurements. No reductions in NO_x emissions were found resulting from these highly limited attempts at staged firing.

Figure 6-13

NO_x EMISSIONS FROM BOILER H

(320 MW, Tangential, Oil Fired)

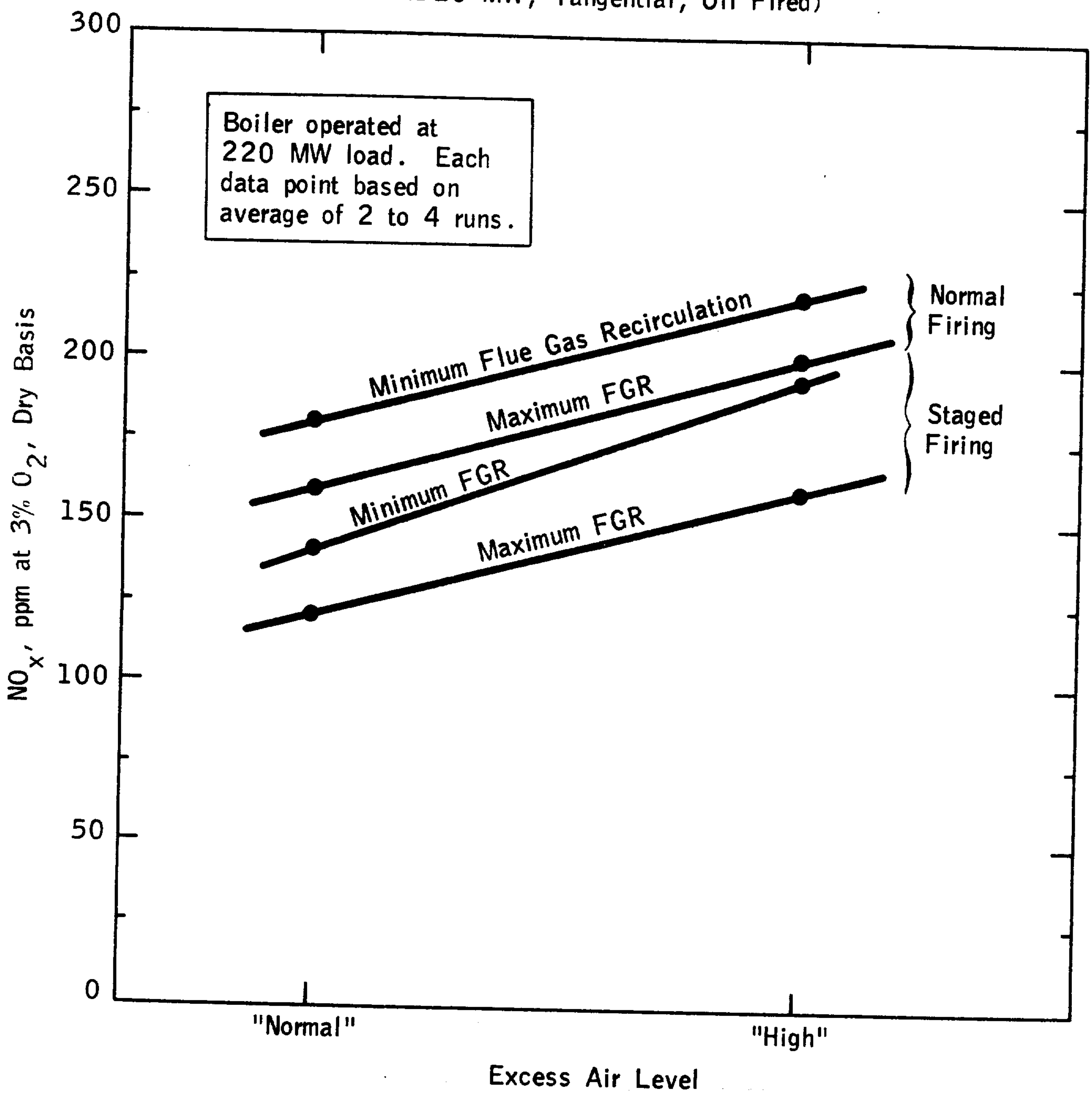


TABLE 6-40

SUMMARY OF EMISSION DATA FROM BOILER K (66 MW, TANGENTIAL, OIL FIRED)

Run No.	Gross Boiler Load(4) MW	Steam Flow 10^3 lb/hr	Number of Burners Firing	"Staged" Firing	Flue Gas Components(1)				Flue Gas Temp. °F
					Dry Basis		NO_x (ppm) 3% O_2 Dry Basis	CO (ppm) 3% O_2 Dry Basis	
					O_2 %	CO_2 %			
1	66	620	8	No	2.4	14.9	146	27	674
2	66	608	8	Yes(2)	4.0	13.4	203	28	673
3	66	600	8	Yes(3)	2.8	14.0	146	37	685

(1) Average of two data points. Each data point from composite of three gas sample streams. Hydrocarbons not measured.

(2) 2 opposite burners on top level fired fuel lean (1/2 normal fuel rate).

(3) 4 burners on top level fired fuel lean (about 1/2 normal fuel rate).

(4) Estimated. Electrical equivalent of boiler steam generation.

6.3.4 Oil Fired Cyclone Boiler

Table 6-41 presents a summary of emission and operating data obtained in testing Boiler L, a 400 MW cyclone fired boiler. This boiler was originally designed for coal firing, but subsequently it was fitted for oil firing and will also be equipped for gas firing in the near future. The emissions from the two ducts sampled are given separately in Table 6-41, due to the wide differences in the gas compositions of the two ducts.

Boiler L had limited operating flexibility. Consequently, the only operating variables studied in the field tests were load (full and partial), excess air level, and simulated staged combustion. Analysis of the NO_x emission data indicates that at full load emissions averaged about 530 ppm, while a reduction in load of 38% (from 415 MW to 260 MW) reduced NO_x emissions by over 60%. This is a significantly larger NO_x reduction than those measured in other oil fired boilers operated at reduced load, and may be inherent to the cyclone firing design. Run 5 was made to simulate staged combustion (within the flexibility of this boiler). Two upper level cyclones were fired on air only, while the other six cyclones were fired at increased rates to maintain load. This change resulted in an increase of NO_x emissions by about 50% (206 to 310 ppm), presumably because of the higher intensity firing of the operating six cyclones.

It appears that NO_x emissions from cyclone furnaces will be difficult to control because of their inflexibility. Most of the combustion takes place within the individual cyclone where low excess air, two-stage combustion, and flue gas recirculation controls could not be tested with existing designs. However, dropping the load on the boiler may be an interim solution for such boilers if regulations restrict the allowable level of NO_x emissions.

TABLE 6-41

SUMMARY OF EMISSION DATA FROM BOILER L (400 MW, CYCLONE, OIL FIRED)

Run No.	Gross Boiler Load (MW)	No. of Cyclones Firing	Flue Gas Compositions(1) and Temperatures: Duct No. 1, Dry Basis %, O_2	Duct No. 1, Dry Basis %, CO_2	Duct No. 1, ppm, 3% O_2 Dry Basis, NO_x	Duct No. 1, ppm, 3% O_2 Dry Basis, CO	Duct No. 1, Temp. °F	Duct No. 2, Dry Basis %, O_2	Duct No. 2, Dry Basis %, CO_2	Duct No. 2, ppm, 3% O_2 Dry Basis, NO_x	Duct No. 2, ppm, 3% O_2 Dry Basis, CO	Duct No. 2, Temp. °F	O_2, %(2)
1	421	8	4.1	12.2	548	8	610	2.7	12.8	572	6	666	2.1
2	410	8	4.9	11.4	505	6	615	4.3	11.8	497	6	670	2.7
3	255	8	4.6	12.0	214	--	592	6.5	7.4	200	--	652	2.2
4	262	8	2.5	13.3	211	3	580	4.9	11.3	200	3	580	4.2
5	275	6(3)	5.1	11.2	315	1	620	6.9	9.5	306	2	604	4.5

(1) Average of four data points. Each data point from composite of three gas sample streams.

(2) Boiler O_2 recorder data.

(3) 6 cyclones firing oil and 2 cyclones on air only to simulate staged combustion.

6.4 Individual Emission Results on Coal Fired Boilers

Seven coal fired boilers were included in the field tests consisting of two front wall, two horizontally opposed wall, two tangential, and one cyclone fired unit. Coal fired boilers presented the greatest difficulty in applying combustion operating modifications for NO_x control. Full load, uncontrolled NO_x emissions from large, coal fired boilers ranged between 800 and 1500 ppm for wall and cyclone fired boilers, while tangentially fired boilers emitted about one-half of these levels. Of the seven coal fired boilers tested, combustion modifications resulting in substantially reduced NO_x emissions could be applied in only two of the units. In both cases (one a front wall, the other one a tangentially fired boiler), the combination of overall low excess air with staged firing resulted in a reduction in NO_x emissions of over 50% and a loss in load rating of about 15-20%, compared with uncontrolled, full load operations. The other five coal fired boilers could not be tested at sufficiently low excess air levels to expect much improvement in NO_x emissions. In some cases this was due to directly observed, real slagging problems, and in others it was due to a reluctance of boiler operators to risk the occurrence of potential problems even for a limited period of test time. The results of the field program on all the coal fired boilers tested are discussed in this section.

6.4.1 Coal Fired Front Wall Boilers

Table 6-42 presents a summary of the emission and operating data obtained in testing Boiler M. This 175 MW, 16-burner, front wall fired, pulverized coal Babcock and Wilcox boiler had a single dry-bottom furnace with a division wall. In addition to being representative of medium sized, coal fired front wall boilers, this unit had two unique features for field testing that favored its inclusion into our sample of boilers to be tested. First, it was equipped with limestone injection into the furnace for sulfur oxide emission control and second, special water cooled probes were available for sampling flue gases at elevated temperatures. The first of these features provided an opportunity to check whether dry limestone injection could affect NO_x emissions (perhaps through catalytic decomposition activity at high temperatures), while the second one enabled us to check whether the NO_x concentration would remain "frozen" (as expected) between high temperature locations and our usual sampling locations at 600-700°F. Due to the significantly different concentration levels measured in this boiler, which were caused by imperfect combustion control of burners, the emission data are presented separately in Table 6-42 for each of the two ducts probed.

The average NO_x emissions in each of the two ducts sampled for each run are given in Table 6-43, arranged according to the statistical experimental plan. All runs were made at a load of about 140 MW, in order to obtain a direct comparison of staged combustion with normal firing. Staged combustion was accomplished by operating the top row of burners on air only, i.e., shutting down the pulverizer mill supplying coal to the top row. Other combustion operating variables included in the experimental plan were excess air level and position of the secondary air dampers (relatively open vs.closed down). In addition to a complete factorial design with no limestone injection, a two-level, two-factor latin square design was used with limestone injection. Although this complimentary latin square with limestone injection (to complete the factorial) was also planned, mechanical problems with the limestone injection system forced the cancellation of these planned runs. Runs 20 and 20a were made to compare the gas composition from duct sampling locations just upstream of the air heater at about 670°F with those sampled from the superheater section at 1480 to 1640°F.

TABLE 6-42

SUMMARY OF EMISSION DATA FROM BOILER M (175 MW, FRONT WALL, COAL FIRED)

Run No.	Gross Boiler Load MW	Steam Flow 10^3 lbs./hr.	Limestone Injection 10^3 lbs./hr.	Secondary Air Dampers	Excess Air Level(2)	Staging	Flue Gas Components and Temperatures									
							Left Duct					Right Duct				
							%, Dry Basis		ppm, 3% O_2, Dry Basis			%, Dry Basis		ppm, 3% O_2, Dry Basis		
							O_2	CO_2	NO_x	CO	Temp.	O_2	CO_2	NO_x		Temp. °F
1	139	975	24	Closed	Low	Yes	2.4	15.5	318	54	694	6.1	12.4	331	46	725
6	140	978	0	Closed	Low	Yes	3.7	14.0	383	61	721	3.1	14.7	275	94	728
6a	137	985	0	Closed	Low	Yes	4.1	15.0	296	115	695	2.4	16.7	233	86	711
7	140	975	0	Open	Normal	Yes	3.9	13.9	415	46	717	6.0	11.8	286	79	731
8	140	975	0	Open	Low	No	3.9	15.6	587	99	720	2.0	17.2	468	95	732
9	139	970	0	Closed	Normal	No	5.1	14.0	670	105	701	3.3	15.8	654	115	724
10	141	970	0	Open	Normal	No	5.2	14.1	651	103	722	3.0	16.1	552	96	747
11	138	965	0	Open	Low	Yes	4.0	14.5	356	120	652	2.6	15.9	244	396	691
11a		1,005	0	Open	Low	Yes	3.6	15.5	237	179	678	2.1	16.8	213	938	719
12	138	970	0	Closed	Normal	Yes	5.3	13.9	524	29	660	3.9	14.6	335	41	760
13	136	960	0	Closed	Low	No	3.3	15.1	676	44	675	1.3	17.1	512	37	740
14	139	980	0	Open	Normal	No	4.2	14.3	650	20	667	2.2	16.1	513	19	746
15	148	1,050	0	Open	Normal	No	2.6	16.0	641	19	661	1.1	17.1	482	36	674
16	140	980	20	Closed	Low	No	2.4	16.1	654	67	667	1.4	17.2	455	92	713
17	130	900	20	Closed	Normal	Yes	3.1	16.1	315	48	687	3.2	16.4	232	658(3)	706
18	130	890	20	Open	Low	Yes	2.3	16.5	264	50	671	2.4	16.8	197	96	673
19	140	940	20	Open	Normal	No	4.8	13.4	631	148	675	3.2	15.1	494	168	724
20	140	950	0	Open	Normal	No	5.0	13.0	697	798 (3)	670	4.9	12.8	696	728 (3)	1480
20a	140	950	0	Open	Normal	No	4.8	12.9	705	1111(3)	660	4.8	12.8	708	1106(3)	1640

(1) Average of two data points for each duct. Each data point from composite of three gas sample streams.

(2) Test program design.

(3) CO analyzer reading observed to drift during runs.

TABLE 6-43

TEST PROGRAM DESIGN FOR BOILER M-FIRING COAL*

(Average NO_x Emissions Per Duct, ppm at 3% O_2, Dry Basis)

	Position of Secondary Air Dampers	(S_1) Normal Firing		(S_2) Staged Firing	
		(A_1) Normal Exc. Air	(A_2) Low Exc. Air	(A_2) Normal Exc. Air	(A_2) Low Exc. Air
(L_1) No Limestone Injection	(D_1) Open	10 651,552 14 650,513 20 697,696 20a 705,708	8 587,468 15 641,483	7 415,286	11 356,244 11a 237,213
	(D_2) Closed Down	9 670,654	13 676,512	12 524,335	6 383,275 6a 296,233
(L_2) Limestone Injection	(D_1) Open	19 631,494	3	4	18 264,196
	(D_2) Closed Down	2	16 654,455	17 315,232	1 318,331

* Circled numbers denote run numbers.

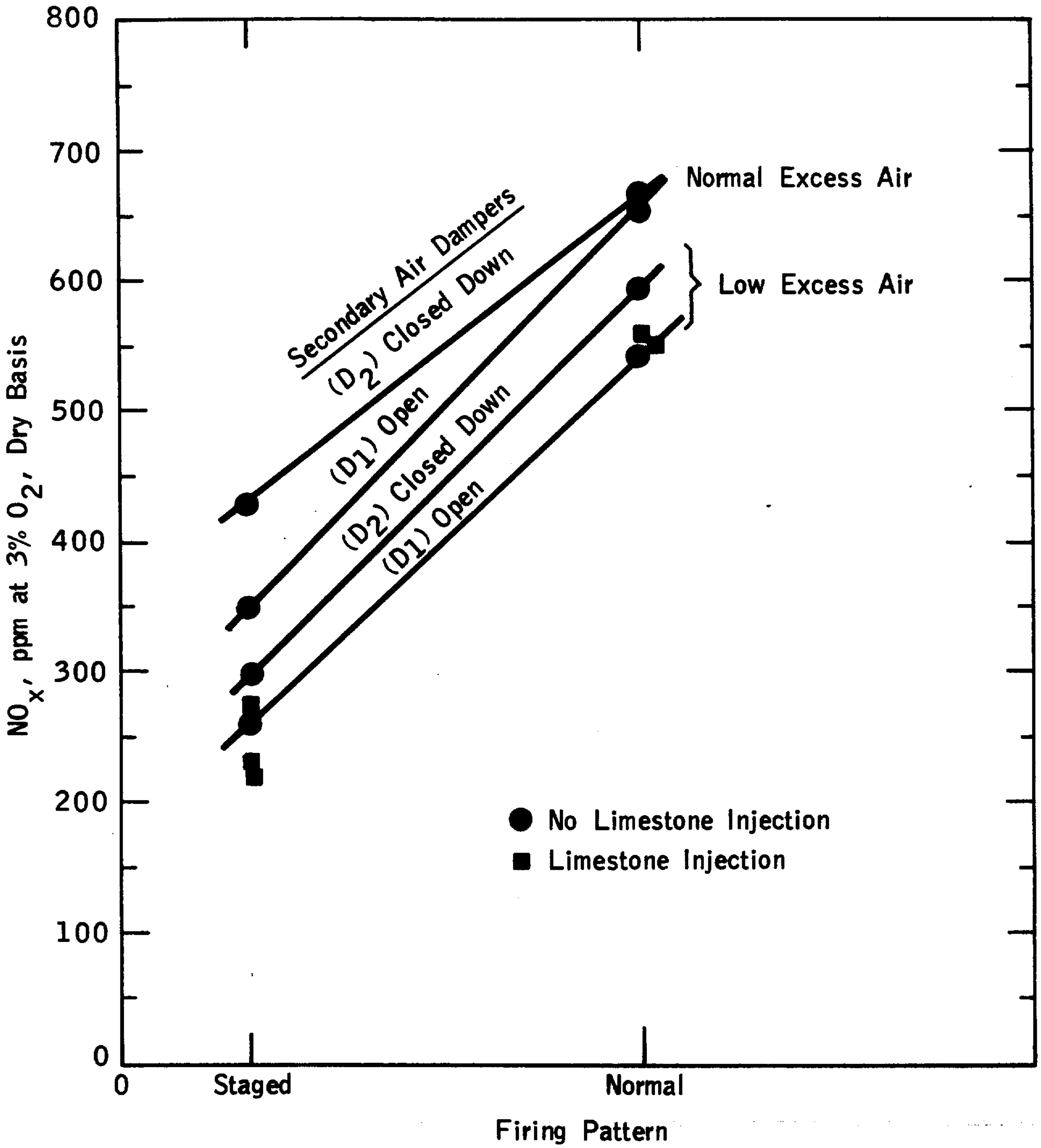
The average NO_x emissions measured are related to combustion control variables in Figure 6-14. Without limestone injection, uncontrolled NO_x emissions at 140 MW (80% of full load) averaged about 660 ppm. Using the combination of low excess air with staged firing (top row of four burners on air only), and with relatively open secondary air damper positions reduced NO_x emissions by about 60% or to about 260 ppm. Low excess air firing by itself reduced NO_x emissions by 14%, while low excess air combined with staged firing reduced NO_x emissions by 28% (from an average of 390 ppm to about 280 ppm). An additional incremental decrease in NO_x emissions was obtained by adjusting the secondary air dampers to a relatively open position, which resulted in less intense firing conditions. No significant differences were obtained in comparing simultaneous measurements of NO_x at high temperatures with those obtained at relatively low temperatures.

The five runs made with limestone injection (Runs 1, 16, 17, 18, and 19) showed lower average NO_x emissions than the corresponding paired runs made without limestone injection (average values of 369 ppm vs. 448 ppm). This average reduction of NO_x by about 18% is statistically significant (Students' t = 3.5 for 4 degrees of freedom vs $t_{.025} = 2.8$). However, these results must be considered tentative because the differences are confounded with different operating days and hence burning different coals, and by other operating changes. Breakdown of the limestone injection facility coupled with practical operating inflexibilities during our field tests prevented the implementation of an idealized random pattern of runs to avoid this confounding influence.

Figure 6-14

NO_x EMISSIONS FROM BOILER M

(175 MW, Front Wall, Coal Fired)



The summary of emission data obtained in testing Boiler C firing coal alone and mixed firing of coal and gas is presented in Table 6-44. Because of potential slagging and flame impingement problems, the full effect of staged firing with low excess air could not be tested on this boiler, for firing coal alone. A 40% reduction in load from 275 MW to 160 MW resulted in a 20% reduction in NO_x emissions.

Mixed fuel firing (2/3 coal and 1/3 gas) produced NO_x emissions which were intermediate between the very high levels measured with coal firing and the somewhat lower but still high NO_x emissions measured with gas firing. (The data obtained on this boiler with gas firing alone have been discussed in Section 6.2.)

The very high emission levels measured in this boiler are likely to be a consequence of the furnace design. In this unit, the bottom row of burners are located relatively closely to the flat bottom of the furnace and insulating tile had been installed on the inside furnace walls up to an elevation above the top row of burners. This boiler design was aimed at maintaining wet bottom conditions under low load firing conditions for easy removal of the slag.

6.4.2 Coal Fired Horizontally Opposed and Cyclone Boilers

Coal fired Boilers F, N, P and Q could be tested only with very limited combustion operating modifications. Consequently, none of the test programs conducted on these boilers resulted in significant NO_x reductions through combustion control. However, full load, uncontrolled emissions were measured for the purpose of developing representative emission factors. In addition, the effect of operating these boilers under reduced load conditions on NO_x emissions was determined. Tables 6-45 (Boiler F), 6-46 (Boiler N), 6-47 (Boiler P), and 6-48 (Boiler Q) present summaries of NO_x emission data and boiler operating variables for these units. In all cases, load reduction resulted in decreased NO_x emissions. However, the fractional decreases in NO_x were less steep in general than those measured for gas firing at corresponding fractional load levels. The cyclone fired Boiler Q showed the relatively highest sensitivity of NO_x emission reduction to load reduction. In testing Boiler P, a 300 MW tangentially fired unit, the air preheater was bypassed in Run No. 2 with a limited portion of the flow, resulting in somewhat lower NO_x emissions than those prevailing under normal operating conditions.

The emission data obtained on these and all other coal fired boilers tested in this study are discussed further in Section 2 of this report in the context of general conclusions.

TABLE 6-44

SUMMARY OF EMISSION DATA FROM BOILER C
(315 MW, FRONT WALL, COAL AND MIXED COAL/GAS FIRED)

Run[4] No.	Operating Data: Gross Boiler Load MW	Operating Data: Fuel[2] Coal or Coal/Gas	Operating Data: Staging[3]	Operating Data: Excess Air[5]	Average Flue Gas Components[1]: %, Dry Basis O_2	Average Flue Gas Components[1]: %, Dry Basis CO_2	Average Flue Gas Components[1]: 3% O_2, Dry Basis ppm NO_x
1	275	C	No	Low	3.5	15.4	1490
2	263	C	No	High	5.4	13.4	1480
3	160	C	No	Low	5.7	12.7	1160
4	160	C	No	High	7.5	10.7	1200
5	193	C	Yes	Low	4.6	13.7	1190
6	186	C	Yes	High	6.5	11.7	1280
1A	280	C/G	No	Low	3.9	13.2	1240
2A	280	C/G	No	High	5.3	12.0	1080
3A	148	C/G	No	High	6.1	11.7	970
4A	145	C/G	No	High	7.1	10.6	860
5A	194	C/G	Yes	Low	3.2	15.0	630
6A	193	C/G	Yes	High	5.4	12.3	830

(1) Average of 15 to 16 data points per run. Each data point from a composite of 3 gas sample streams. (CO and hydrocarbons were not measured in these runs.)
(2) Mixed fuel firing: top row on gas, middle and bottom rows on coal.
(3) Staged firing: No - equal amount of fuel fired in all three rows; Yes - fuel firing in lean top row, fuel rich in middle and bottom burner rows.
(4) One of two twin furnaces tested.
(5) Test program design.

TABLE 6-45

SUMMARY OF EMISSION DATA FROM BOILER F
(600 MW, HORIZONTALLY OPPOSED, COAL FIRED)

	Operating Data				Ave. Flue Gas Components (1)				
					%, Dry Basis		ppm, 3% O_2, Dry Basis		
Run No.	Gross Boiler Load MW	No. of Burners	Fuel Rate Tons Coal/Hr	Heat Rate(2) BTU/KWH	O_2	CO_2	NO_x	CO	Flue Gas Temp. °F
1	563	24	200	9182	6.2	11.5	838	(3)	684
2	462	20	167	9319	4.9	11.8	781	18	619
3	366	20	138	9755	4.7	11.4	621	21	563
4	359	29	137	9922	5.8	9.7	665	23	603

(1) Average of 12 to 16 data points per run. Each data point from a composite of three sample gas streams. (Hydrocarbon not measured)

(2) Data obtained from on-line computer of boiler.

(3) Not measured.

TABLE 6-46

SUMMARY OF EMISSION DATA FROM BOILER N
(820 MW, HORIZONTALLY OPPOSED, COAL FIRED)

Run No.	Operating Date: Gross Boiler Load MW	Fuel Data 10^3 lbs./hr.	Steam Flow 10^3 lbs./hr.	Excess Air Level	Pulverizers Operating (2)	No. of Burners Firing Coal	No. of Burners on Air Only (3)	Ave. Flue Gas Components (Dry Basis)(1): O_2 %	CO_2 %	NO_x, ppm, 3% O_2	Flue Gas Temp. °F
1	771	580	4590	Normal	1 through 5	30	0	5.9	12.5	902	731
2	785	583	4590	Normal	1 through 5	30	0	6.1	12.2	908	725
12	577	448	3600	Normal	2 through 4	24	0	7.1	11.2	767	658
13A	580	440	3600	Normal	2 through 4	24	6	7.0	11.0	733	650
13B	580	432	3600	Normal	2 through 4	18	12	6.9	10.8	723	650

(1) Average of 16 data points per run. Each data point from a composite of three gas sample streams.
(2) Numbered consecutively from front top to bottom and rear top to bottom. No. 6 pulverized feeding the six bottom rear-wall burners was inoperative during the tests due to mechanical problems.
(3) In Run 13A air only was introduced through the top row of the front-wall burners.
In Run 13B air only was introduced through the top row of the front-wall burners and through the bottom row of the rear-wall burners.

TABLE 6-47

SUMMARY OF EMISSION DATA FROM BOILER P
(300 MW, TANGENTIAL, COAL FIRED)

	Operating Date					Average Flue Gas Components (1)				
		Steam Flow				% Dry Basis		$3\%\ O_2$, ppm, Dry Basis		
Run No.	Gross Boiler Load MW	Main 10^6 lb./hr.	Reheat 10^6 lb./hr.	Excess Air Level (3)	Air Preheater Bypass	O_2	CO_2	NO_X	CO	Flue Gas Temp. °F
1	240	2.00	1.45	Normal	Closed	3.9	14.3	418	12	(2)
2	237	1.87	1.37	Normal	Open	4.3	13.8	395	23	557
3	300	(2)	(2)	Low	Closed	3.0	13.8	414	25	595
4	300	2.30	1.85	High	Closed	5.6	12.0	568	24	720
5	250	2.30	1.85	Low	Closed	2.2	15.5	301	67	(2)

(1) Average of 12 to 16 data points per run. Each data point from a composite of three gas sample streams.

(2) Not measured.

(3) Test program design.

TABLE 6-48

SUMMARY OF EMISSION DATA FROM BOILER Q
(704 MW, CYCLONE, COAL FIRED)

Run No.	Operating Date					Flue Gas Components[1]			
	Gross Boiler Load MW	Feed Water Flow 10^3 lb./hr.	Excess Air Level	Staging[2]	No. of Burners Firing Coal	Dry Basis O_2 %	Dry Basis CO_2 %	3% O_2, Dry Basis NO_x, ppm	Flue Gas Temp. °F
1	665	4,650	Normal	No	14	5.3	13.1	1197	628
2	668	4,700	Normal	No	14	5.3	13.2	1112	616
3	660	4,700	Normal	Yes	14	5.4	13.0	1203	624
4	545	3,700	Normal	No	14	5.3	13.3	886	594
5	545	3,700	Normal	Yes	14	5.1	13.6	915	610
6	548	3,100	Normal	Yes	14	5.6	13.0	846	612

(1) Average of 16 data points per run. Each data point from a composite of three gas sample streams. CO emissions were not measured. Hydrocarbons emissions measured <1 ppm.
(2) "Staged firing" simulated by operating top cyclone burners under highly fuel-lean conditions.

TABLE 6-49

SUMMARY OF EMISSION DATA FROM BOILER O
(575 MW, TANGENTIAL, COAL FIRED)(1)

Run No.	Boiler Gross Load MW	Operating Conditions: Steam Flow 10^3 lbs/hr	Air Flow 10^3 lbs/hr	Superheat Temp. °F	Reheat Temp. °F	Coal Classifier Setting	Burner Tilt Degrees from Horizontal	Staging(2)	Air Damper Setting: "Coal Air"	Auxiliary Air	Excess Air Level(6)	Burner Levels(2): Firing Coals	On Air Only	Average Flue Gas Components(3),(5): Dry Basis O_2 %	CO_2 %	NO_x, ppm 3% O_2, Dry Basis	CO, ppm 3% O_2, Dry Basis	Flue Gas Temp. °F
1	468	165	158	1030	1015	Min.	-30	Yes	Max.	Min.	Low	2,3,4,5	1	2.4	16.4	235	26	582
2	470	164	155	1055	1005	Min.	+30	Yes	Max.	Min.	Low	2,3,4,5	1	2.2	16.1	319	130	607
3	462	161	155	1032	1005	Min.	0	Yes	Min.	Max.	Low	2,3,4,5	1	2.3	15.4	254	29	597
4	478	169	170	1025	1010	Max.	-30	No	Min.	Max.	Normal	ALL	0	3.2	14.4	405	26	606
5	480	167	168	1045	1010	Max.	0	No	Max.	Min.	Normal	ALL	0	2.8	14.7	369	31	615
8	458	166	162	1020	995	Min.	-30	Yes	Min.	Max.	Normal	2,3,4,5	1	3.3	15.0	255	42	599
9	455	158	160	1042	995	Min.	0	Yes	Max.	Min.	Normal	2,3,4,5	1	3.6	14.8	251	45	601
6	464	163	150	1010	980	Max.	-30	No	Max.	Min.	Low	ALL	0	2.1	16.3	377	71	600
7	465	163	151	1050	1005	Max.	0	No	Min.	Max.	Low	ALL	0	2.2	16.3	385	93	595
10	479	170	171	1022	1000	Min.	-30	No	Max.	Min.	Normal	ALL	0	3.0	15.8	453	(4)	612
11	480	170	171	1050	1005	Min.	0	No	Min.	Max.	Normal	ALL	0	3.1	15.6	387	(4)	616
10A	478	168	170	1070	1015	Min.	-30	No	Max.	Min.	Normal	ALL	0	2.8	16.2	467	(4)	624
30	300	148	091	890	830	Min.	0	No	Max.	Min.	Low	2,3,4	0	1.3	17.2	253	(4)	497
31	300	137	092	894	833	Min.	+10	Yes	Max.	Min.	Low	2,3,4	1	1.7	16.5	195	(4)	527
32	320	140	101	905	840	Min.	+10	No	Max.	Min.	Low	3,4,5	0	1.5	16.5	274	(4)	528
33	310	139	100	920	855	Min.	+10	Yes	Max.	Min.	Low	3,4,5	1	2.5	15.5	152	(4)	525
34	306	137	091	935	877	Min.	+10	No	Max.	Min.	Low	1,3,5	0	1.5	16.1	266	(4)	527
35	320	138	092	938	893	Min.	+10	Yes	Max.	Min.	Low	1,3,5	2,4	1.3	16.1	237	(4)	544
14	445	177	151	1005	968	Min.	-30	No	Min.	Max.	Low	ALL	0	1.9	16.7	364	15	581
15	450	176	155	1018	995	Min.	0	No	Max.	Min.	Low	ALL	0	2.1	16.5	392	22	582
18	440	175	149	987	970	Min.	-30	No	Max.	Min.	Low	ALL	0	1.9	16.5	401	16	574
19	440	174	147	1020	995	Min.	0	No	Min.	Max.	Low	ALL	0	1.9	16.5	345	44	568
13	428	173	139	1010	972	Max.	0	Yes	Max.	Min.	Low	2,3,4,5	1	2.5	16.5	192	46	589
12	430	173	138	1014	976	Max.	-30	Yes	Min.	Max.	Low	2,3,4,5	1	2.2	16.4	198	111	577
16	445	168	150	1005	965	Max.	-30	Yes	Max.	Min.	Normal	2,3,4,5	1	3.4	15.3	240	45	600
17	455	169	163	1025	996	Max.	0	Yes	Min.	Max.	Normal	2,3,4,5	1	3.2	15.3	239	49	601
20	420	155	138	915	965	Min.	0	Yes	Max.	Min.	Low	2,3,4,5	1	2.1	16.6	187	67	584
21	420	154	144	952	910	Max.	0	Yes	Min.	Max.	Low	2,3,4,5	1	2.4	16.4	177	133	583
22	435	158	147	955	907	Max.	-30	Yes	Max.	Min.	Low	2,3,4,5	1	2.2	16.5	197	89	584
23	452	168	153	962	915	Min.	-30	Yes	Min.	Max.	Low	2,3,4,5	1	2.1	16.6	195	53	587

(1) Only Furnace B of twin-furnace boiler tested.
(2) Staged firing according to burner patterns indicated in table. Burner levels numbered from top to bottom (see burner configuration shown in Table 4-51).
(3) Average of four data points. Each data point from composite of three gas sample streams.
(4) CO not measured.
(5) Hydrocarbons measured <1 ppm.
(6) Test program design.

6.4.3 Coal Fired Tangential Boilers

A summary of the emission data obtained and the operating conditions for Boiler O are presented in Table 6-49. This large (575 MW), corner fired, twin furnace Combustion Engineering boiler had considerable flexibility for combustion control. The statistically planned test program and average NO_x emissions for each of the 24 runs made under essentially constant load conditions are shown in Table 6-50. The combustion control variables were (1) firing pattern (normal and staged); (2) burner tilt (horizontal, up and down); (3) air damper settings (maximum "coal air"* with minimum auxiliary air and minimum "coal air" with maximum auxiliary air); (4) excess air level (normal and low); and (5) coal classifier setting (maximum and minimum).

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* Secondary air in this installation is referred to as "coal air".

TABLE 6-50

TEST PROGRAM DESIGN FOR BOILER O - FIRING COAL**
(NO_x EMISSIONS, PPM AT 3% O_2, DRY BASIS

		(S_1) Normal Firing				(S_2) Staged Firing				
		(T_1) Horizontal Tilt		(T_2) Down Tilt		(T_1) Horizontal Tilt		(T_2) Down Tilt		(T_3) Up Tilt
Air Damper		(D_1)	(D_2)	(D_1)	(D_2)	(D_1)	(D_2)	(D_1)	(D_2)	(D_1)
(A_1) Normal Excess Air	(C_1)	369 (5)			405 (4)		239 (17)	240 (16)		
	(C_2)		387 (11)	(10) 453 (10A) 467		251 (9)			255 (8)	
(A_2) Low Excess Air	(C_1)		385 (7)	377 (6)		192 (13)	177 (21)	197 (22)	198 (12)	
	(C_2)	392 (15)	345 (19)	401 (18)	364 (14)	187 (20)	254 (3)	235 (1)	195 (23)	319 (2)

** Circled numbers denote run numbers.

C_1 - Maximum, C_2 - minimum classifier setting.
D_1 - "Coal air" dampers open, auxiliary air dampers closed.
D_2 - "Coal air" dampers closed, auxiliary dampers open.
S_1 - Normal firing.
S_2 - Staged firing, top row of burners on air only.

Uncontrolled NO_x emissions operating at 80-85% of full load (normal firing and excess air) averaged about 405 ppm. Low excess air firing alone reduced NO_x emissions by less than 10%. However, staged firing with normal excess air reduced NO_x emissions by an average of about 40% (246 from 405 ppm), and with low excess air firing by about 50% (204 ppm from 405 ppm). The overall average effects of burner tilt, air damper settings, and classifier settings on NO_x emissions were small; however, interaction effects were found to be significant, indicating that for each combination of firing and excess air there is probably one optimum combination of classifier setting with burner tilt and air damper position.

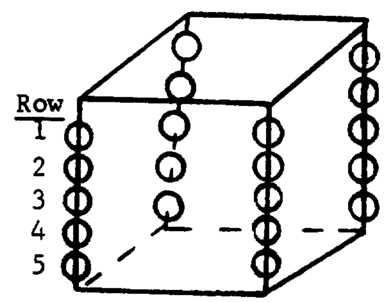
The NO_x emissions measured in Boiler O under reduced load conditions (300-320 MW) with various patterns of staged firing are presented in Table 6-51. These runs were made to obtain information on the effect of burner spacing and staged firing on NO_x emissions.

TABLE 6-51

TEST PROGRAM DESIGN FOR BOILER O - FIRING COAL
(REDUCED LOAD CONDITIONS - STAGED FIRING PATTERNS)

Run No.	Burner Rows: Firing Coal	Burner Rows: On Air Only	ppm NO_x 3% O_2, Dry Basis
30	2, 3, 4	None	253
31	2, 3, 4	1	195
32	3, 4, 5	None	274
33	3, 4, 5	1	152
34	1, 3, 5	None	266
35	1, 3, 5	2	273

Burner Configuration



In the reduced load, staged firing tests, all other variables were standardized, i.e., emission measurements were made at a minimum coal classifier setting of +10°, and air dampers at maximum "coal air" and minimum auxiliary air settings. Staged firing with the firing coal reduced NO_x emissions from 253 to 195 ppm, or about 23%, compared with firing these rows without overfire air. However, increasing the separation between the operating burners in the bottom three rows (3, 4, and 5) and overfiring with air in the top row resulted in lowering NO_x emissions from 274 ppm to 152 ppm or about 45%. Introducing air in Row No. 2 between operating Rows No. 1 and 3 actually increased the NO_x emissions from 253 to 273 ppm.

A multiple regression analysis of all 30 runs made on Boiler O resulted in the following regression equation:

$$\text{ppm } NO_x = 352 - 114\, X_1 + 0.00394\, X_2^2 - 30.7\, X_3 - 14.1\, (X_1 X_4)$$

where: X_1 = Staging (single stage-1, staged firing-2)
X_2 = Load (MW)
X_3 = Classifier setting (mimimum-1, maximum-2)
X_4 = Air damper setting (maximum "coal air"/minimum auxiliary - 1, minimum "coal air"/ maximum auxiliary air-2

The multiple correlation coefficient was found to be 0.94, indicating that 88% of the variation in NO_x emissions were related to, or explained by the independent variables. The standard error of estimate was 31 ppm NO_x for these tests.

6.5 Steam-Side Analyses by Boiler Manufacturers on Coal Boilers

For the coal fired Boilers O, N, and Q, the respective manufacturers of these boilers (Combustion Engineering, Foster Wheeler, and Babcock and Wilcox) participated in the emission test programs. Their role was to provide advice on the limits of operability of the boilers when combustion modifications were to be tested for NO_x emission control, to pre-check the boilers prior to testing, and to assess the consequences of combustion modifications on thermal performance, boiler operability, amount of unburned carbon, and other boiler operating variables.

The findings of the boiler manufacturers in connection with our Boiler Test Program are presented in their reports given in Appendix B of this report. During the short duration tests carried out in these studies, no noticeable effect could be detected on boiler operability resulting from combustion modifications, such as the successful application of low excess air firing and two-stage combustion to Boiler O, where NO_x emissions were reduced by over 50%. Carbon in the fly-ash showed no increase, and no slagging problems were encountered. Because of the inability of the boiler operators to apply combustion operating modifications for NO_x emission control to the horizontally opposed Boiler N, and the cyclone Boiler Q, respectively, the manufacturers' reports on these units essentially reflect normal operating conditions.

Clearly, these evaluations are of a preliminary nature, and the findings on Boiler O, while promising, should not be construed as demonstrated technology. Long-term evaluations in cooperation with boiler operators and manufacturers will be needed to define and demonstrate the applicability of combustion modifications to the operation of utility boilers for pollutant emission control.

7. RECOMMENDATIONS FOR FUTURE UTILITY BOILER TESTING

As discussed in previous sections, the major problem area in reducing NO_x emissions by combustion modifications is to apply these techniques to coal fired boilers. In spite of the excellent progress made in controlling emissions from gas and oil fired boilers, detailed demonstration of the technology still also remains to be performed for boilers fired with these fuels.

The data obtained in Phases I and II of our Systems Study of Nitrogen Oxides Control Methods for Stationary Sources provides a sound basis for the selection of boiler types to be tested in the future Table 7-1 shows the number of boilers of each type which appear to be the logical choice for future field testing.

TABLE 7-1

NUMBER AND TYPES OF UTILITY
BOILERS TO BE TESTED IN A RECOMMENDED BOILER TEST PROGRAM

	Fuel Fired							
Type of Firing	Coal		Oil		Gas		Expected Total	
Wall	2 to 3	(4)	1 to 2	(6)	1	(6)	3 to 6	(16)
					or			
Tangential	3 to 4	(2)	1 to 2	(2)	1	(1)	4 to 7	(5)
Cyclone	1 to 2	(1)	None	(1)		(0)	1 to 2	(2)
Vertical		(0)		(0)		(1)	0	(1)
Expected Total	6 to 8	(7)	2 to 3	(9)	1 to 2	(8)	9 to 12	(24)

Note: Numbers in parenthesis indicate the number of boilers tested in Phase II Boiler Test Program on each fuel.

Major emphasis should be placed on coal fired boilers (6 to 8) with oil next (2 to 3) and gas fired boilers least (1 to 2). Wall fired and tangential boilers should be given equal emphasis. One or two coal fired cyclone furnace boilers may be tested if sufficiently flexible boilers can be located and arrangements with the owner-operators can be made.

The prime factors evaluated by fuel and type of firing in developing Table 7-1, were (1) amount of United States NO_x emissions, (2) difficulty of NO_x emission reduction by combustion modification, (3) extent of field research and demonstrated success in NO_x emission reduction, (4) operating flexibility, and (5) relative number of large size boilers in each group.

Coal fired utility boilers are the largest single source of stationary NO_x emissions in the U.S., i.e., 3 million tons emitted in 1970, compared to 0.5 million tons for gas and 0.3 million tons for oil firing. Coal fired boilers have experienced very limited field testing, with less success in NO_x reduction compared to gas fired boilers, while oil fired boilers are in an intermediate position. The operating flexibility of coal fired boilers is generally less than that of oil fired boilers, with gas fired boilers generally having the greatest flexibility. Tangentially fired boilers have more flexibility, (for example, tilting burners and primary to secondary air damper settings) than wall fired boilers. Cyclone furnaces have the least flexibility, especially when firing coal. The number of boilers reported in Esso's steam electric plant survey (1) generating over 2 million pounds of steam per hour by fuel and type of firing are: Coal, 40 tangential, 24 cyclone, and 16 wall fired; Gas, 9 tangential, 18 wall, 1 cyclone fired; and Oil, 4 tangential and 6 wall fired.

The coal types to be considered for future testing should include Eastern bituminous and sub-bituminous, Midwest bituminous and Western low-sulfur bituminous and lignite coals. Oil types to be considered include typical oils having low and very low sulfur content, low and high nitrogen content, and low and high ash and metals content.

The basis for selecting specific boilers for testing within each of the fuel type groups should include the evaluation of many operating factors, in addition to being representative of current design practices for large utility boilers.

Operating flexibility is a prime selection factor. Thus, designed flexibility (equipment for flue gas recirculation, air ducts for over-firing with air, control of air and fuel to individual burners, tilting burners, etc.), operating flexibility (ability and willingness to fire with low excess air, to reduce loads, and to employ staged firing), and fuel flexibility (range of fuel types and grades) should be evaluated. In addition, the boiler operators' willingness to cooperate by providing proper sampling access, assistance in obtaining fuel samples, good supervision for faster change in operations, research-mindedness and experience in NO_x control would be evaluated. Obviously, the boilers selected must be in good repair and have the proper instrumentation and controls so that proper data for fuel usage, combustion and steam side analysis can be obtained. The continued cooperation of boiler manufacturers and boiler operators should be obtained to help in the boiler selection process.

The basis for selection of individual boilers in cooperation with boiler manufacturers and boiler operators has been discussed above. However, the order in which the selected boilers are tested is also an important consideration. The best approach should aim at the objective of obtaining the required test results with maximum efficiency. The normal cycle of planning, testing, and analysis of results should be used for each major <u>group</u> of boilers. Thus, testing of a coal fired tangential boiler would be followed by testing of a wall fired boiler and of a cyclone fired boiler, before testing the second coal fired tangential boiler. This would allow the necessary time for planning the second series of tangential boiler tests based on a more thorough analysis of the initially tested tangential boiler. In addition, the relative desirability of testing a third tangentially fired boiler compared to testing a third wall fired boiler can be properly evaluated. Thus, full benefit of cumulative experience and information can be taken at each planning cycle.

Since it is desirable to test representative types of coal and oil fuels that are fired in different geographic regions of the United States, it is also desirable to use the concept of cluster sampling in order to minimize travel time. Consideration should be given to testing in fringe areas where different fuel types can be supplied to the same boilers.

Thus, the proper selection and efficient scheduling of boiler tests depends upon having a large backlog of suitable boilers of each fuel-design group available for testing. The cooperation of boiler manufacturers and boiler operators which contributed to the accomplishments of the present Boiler Test Program would be needed for initial planning and periodic updating of future field testing efforts.

The experimental program to investigate NO_x emission control by changing operating variables should utilize the knowledge and experience gained in our Boiler Test Program. With the cooperation of boiler manufacturers and boiler operators, a systematic planning process should be used to assure full exploitation of the operating flexibility of each boiler in an efficient manner.

It appears to be generally desirable to hold an initial planning meeting at the station with all parties concerned in order to obtain accurate, up-to-date information on operating flexibility, boiler condition, scheduled overhaul periods, data acquisition and logging facilities, availability of sampling ports, etc. A formal list of the operating factors, their practical range, how they are interrelated, the time it takes to change from one operating level to the next one and the potential operating problems or limits related to each variable should be agreed upon. Potential experimental programs should be considered from a practical operating standpoint. The expected number of test runs achievable per day will be then established. Problems of accurate measurement of key variables such as fuel burned and air flow should be considered, as well as determining how to obtain representative samples of the fuel burned.

The information obtained at the initial planning meeting would then be used to develop a proposed test schedule, listing the test runs to be made each day, with the specific levels of all operating variables. This plan must be based upon sound statistical experimental design principles and incorporate all practical operating limitations. Thus, provisions should be made for blocking the tests to minimize the effect of unavoidable changes from day-to-day, and from fuel batch-to-batch on the variables of interest. Sequential blocking should be planned so that advantage can be taken of current information on variables showing no effect or unexpected effects in scheduling the next series of tests. The Box-Wilson strategy of designing initial tests in the form of efficient fractional factorial designs, using the method of "steepest ascent" to procede rapidly to the operating region of maximum initial improvement and then planning the necessary runs for full exploration of the optimum region should be considered.

The proposed test schecule at each boiler should be reviewed with all concerned prior to actual testing. At this time, possible improvements in the proposed program can be evaluated, adjustments can be made in line with current operating or fuel restrictions, and the responsibilities of each party during the experimental program can be clearly established. In addition, the necessary boiler pre-testing inspections, checking of instrument calibration, measuring air leakage into flue ducts, calibration of coal scales, development of data recording forms, etc., can be performed. A comprehensive check list developed from our Boiler Test Program should be helpful in assuring that all necessary planning details have been accomplished.

Carrying out the test program efficiently can be greatly simplified due to the detailed planning and preparation for testing carried out jointly with boiler manufacturers and boiler operators. Thus, the agreed upon operating program, detailed data recording forms, communication links with all parties, alternative experimental plans (in case of unplanned changes in loads, fuels or equipment), arrangement for manpower for taking fuel samples, overtime, provisional, etc. would provide a basis for rapid accomplishment if all proceeds according to plans, and for rapid decisions on necessary changes to plans.

Flue gas samples are to be taken to represent planned steady state furnace and steam conditions. Thus, it is necessary to determine by careful observations of furnace flames, control room instruments and flue gas measurements that the operating variables such as load, excess air, exhaust recirculation rates, air damper settings, etc. are at their proper levels for each experimental run. The exercise of experienced judgment is extremely useful at this point, as a few illustrations will demonstrate. Low excess air has been demonstrated to be an effective NO_x control variable as well as providing improved boiler efficiency and reduced maintenance due to low temperature corrosion in oil and coal fuel boilers. Thus, in testing low excess air firing (in combination with other control variables), it is desirable to lower the excess air as much as practical. The practical limit should be determined by furnace observation to check burner flames (pattern, impingement on walls, color, stability, etc.) slagging conditions, damper adjustments; control room checking of fuel and air flows, oxygen in flue gas measurements, steam temperatures, wind box pressures, and instrumented van checking of flue gas components across the sampling points. Detailed recording of operating and emission data should be started only when all checks indicate proper levels, steady conditions and adherence to proper safety and other operating practices. Other operating variable settings requiring the same detailed checking and experienced judgment during testing are burner tilt, primary and secondary air damper settings, degree of staged firing, and extent of flue gas recirculation.

In a few carefully selected cases, it would be desirable to determine the effect of electrostatic precipitators on NO_x emissions, by sampling before and after the precipitator. Similarly, the effect of combustion modifications on particulates before and after the precipitator should be considered.

The length of each steady state run must be sufficiently long so that accurate and representative, gaseous and particulate emission can be determined. Experience has demonstrated that 30 to 45 minutes of continuous measurements covering 12 sampling points are adequate for gaseous components. Particulate measurements are not continuous but are cumulative, and generally require longer sampling periods for adequate representation of an operating condition. Thus, a two-stage program may be the best approach. First, run a series of designed experimental runs for gaseous components to determine the operating region of best NO_x control. Second, make relatively long baseline and NO_x control runs to repeat the measurement of gaseous components but primarily to make particulate measurements as well as slagging and corrosion observations.

The actual results of each block of experimental runs should be compared to the results expected on the basis of both theoretical knowledge and practical experience. This preliminary analysis should then provide a flexible basis for curtailing or expanding experimentation where desirable, since the original blocks should have been designed to be augmentable. In addition, it is desirable to take advantage of unplanned changes in operating conditions and equipment availabilities where possible.

8. REFERENCES

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3. Bartok, W., Crawford, A.R., and Skopp, A., "Control of NO_x Emissions from Stationary Sources", Chem. Eng. Progr. 67, 64 (1971).

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6. Bagwell, F.A., Rosenthal, K.E., Teixeira, D.P., Breen, B.P., Bayard de Volo, N., and Kerho, S., "Utility Boiler Operating Modes for Reduced Nitric Oxide Emissions", J. Air Poll. Contr. Assoc., 21, 702 (1971).

7. Sommerlad, R.E., Welden, R.P., and Pai, R.H., "Nitrogen Oxide Emission — an Analytical Evaluation of Test Data", presented at American Power Conference, 33rd Annual Mtg. Chicago (April, 1971).

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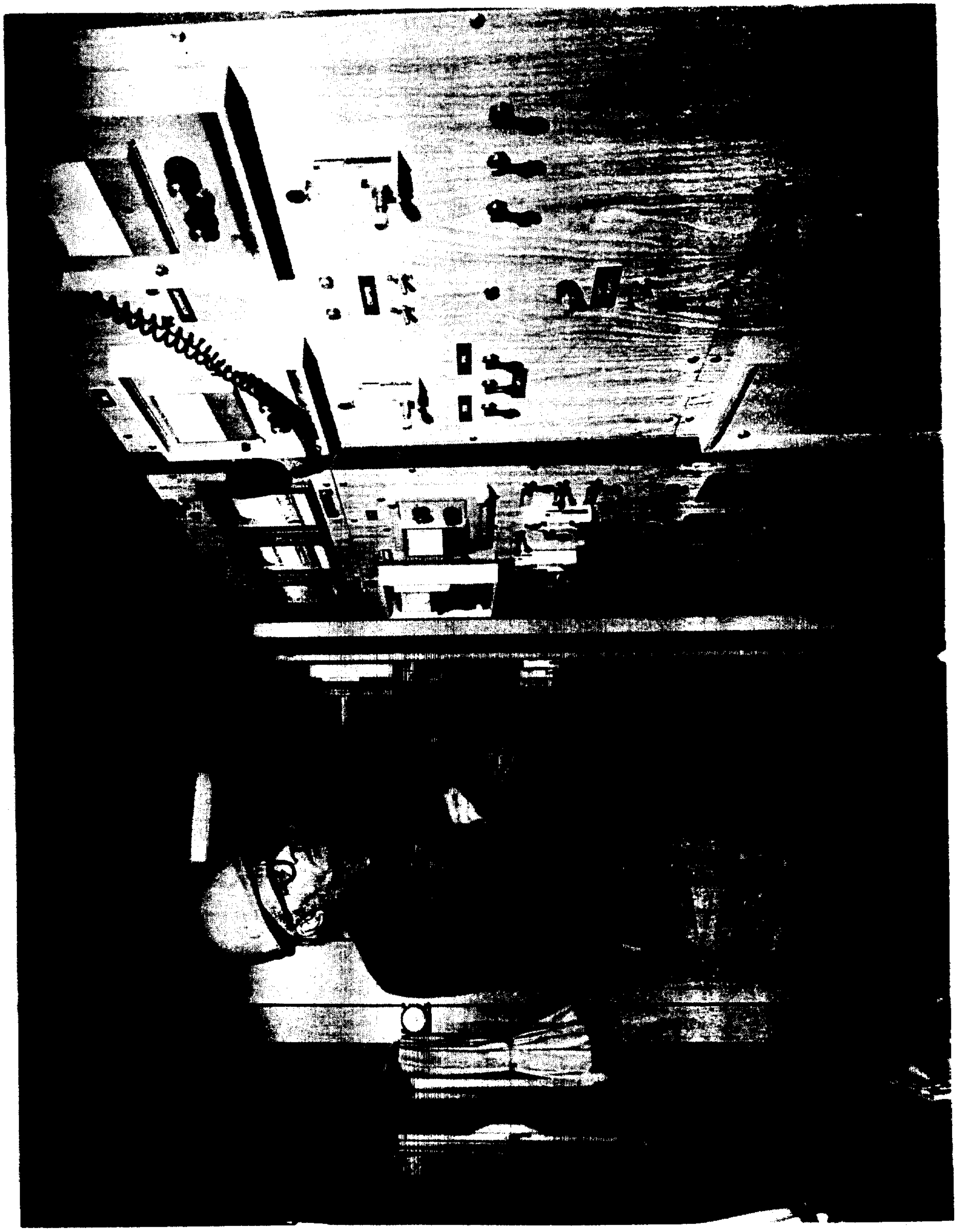
APPENDIX A

SAMPLING-ANALYTICAL VAN DETAILS

This section of the report contains illustrative photographs of the exterior and interior of Esso Research and Engineering Company's sampling-analytical van used for emission measurements in the Boiler Test Program.

EXTERIOR VIEW OF SAMPLING-ANALYTICAL VAN ON LOCATION



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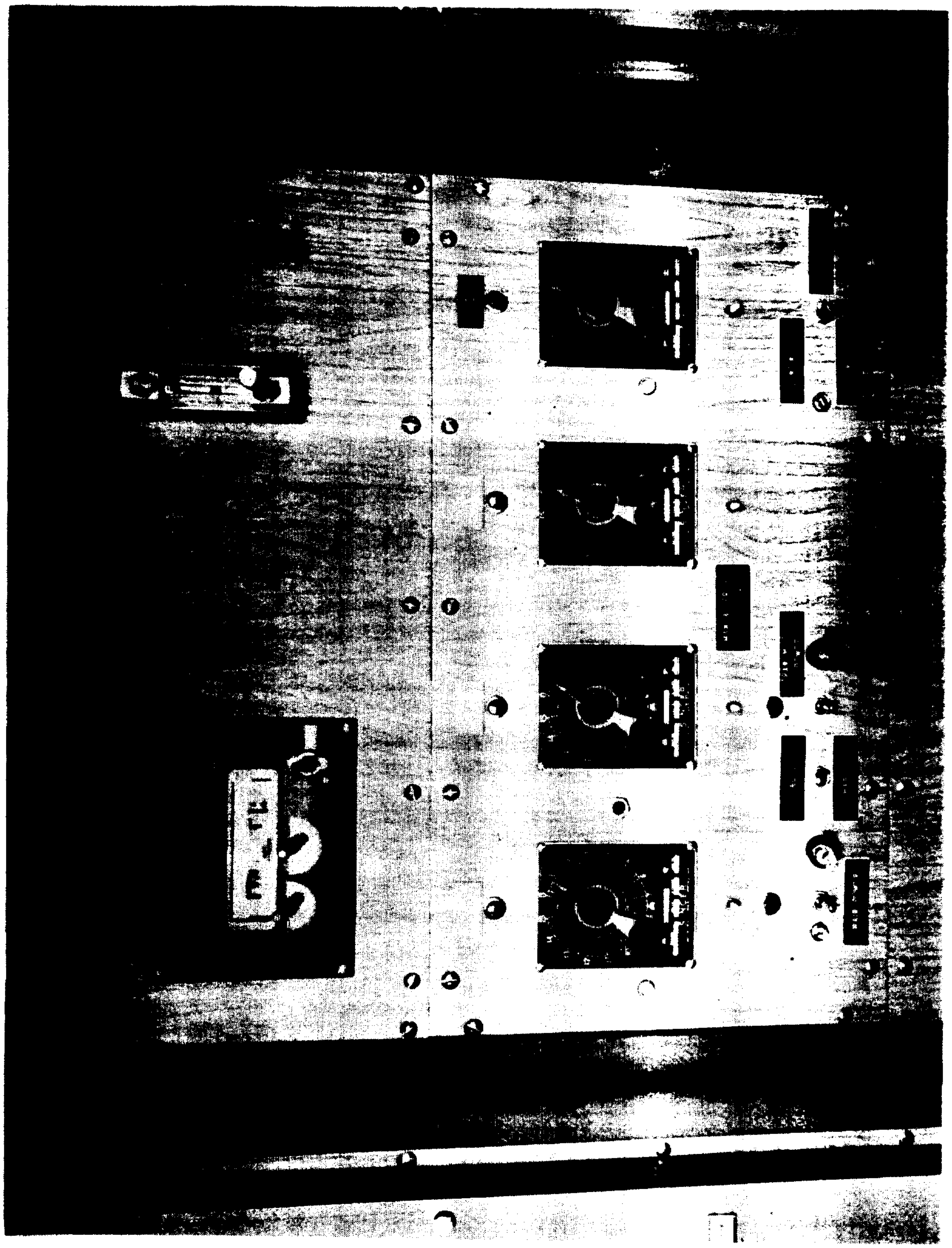
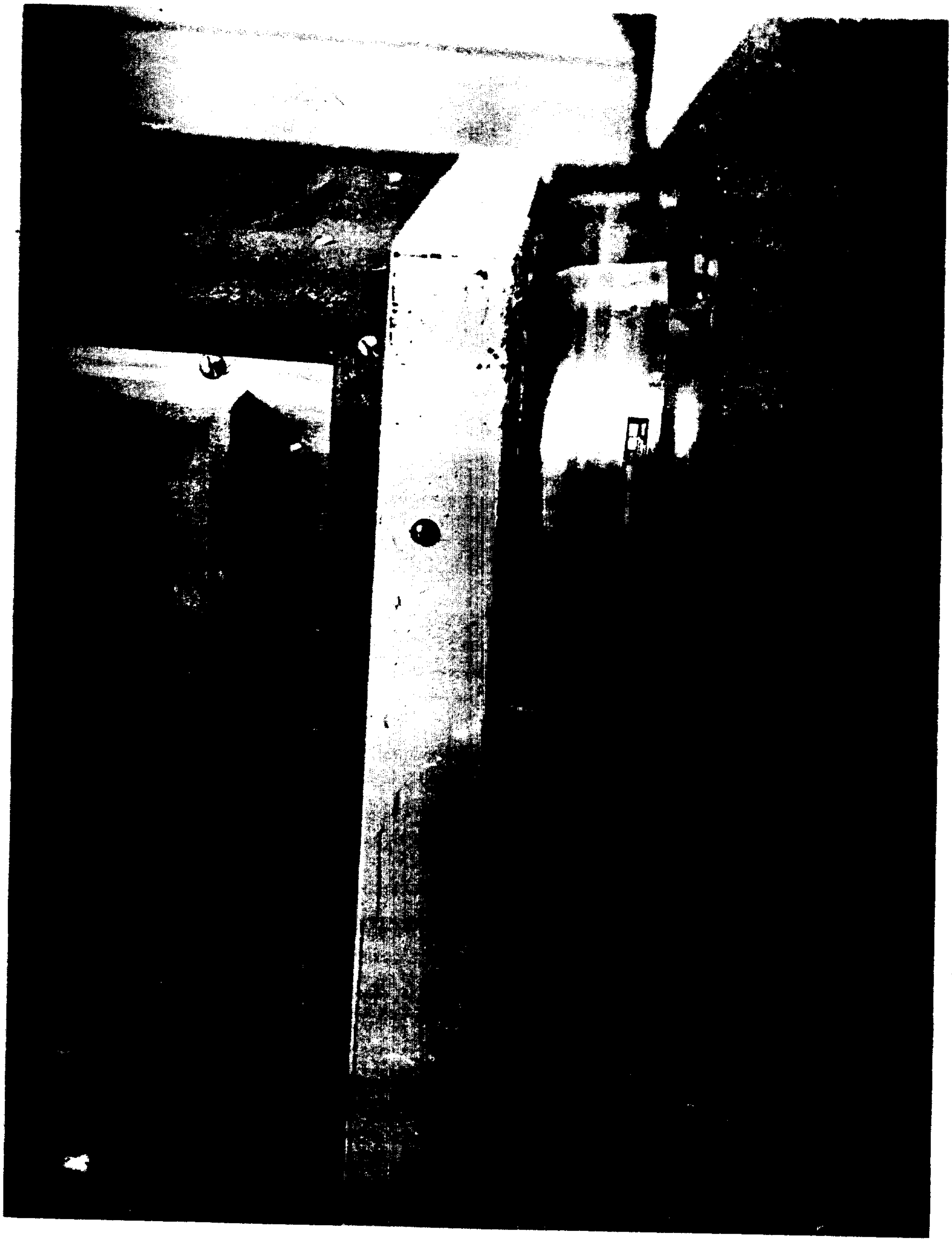
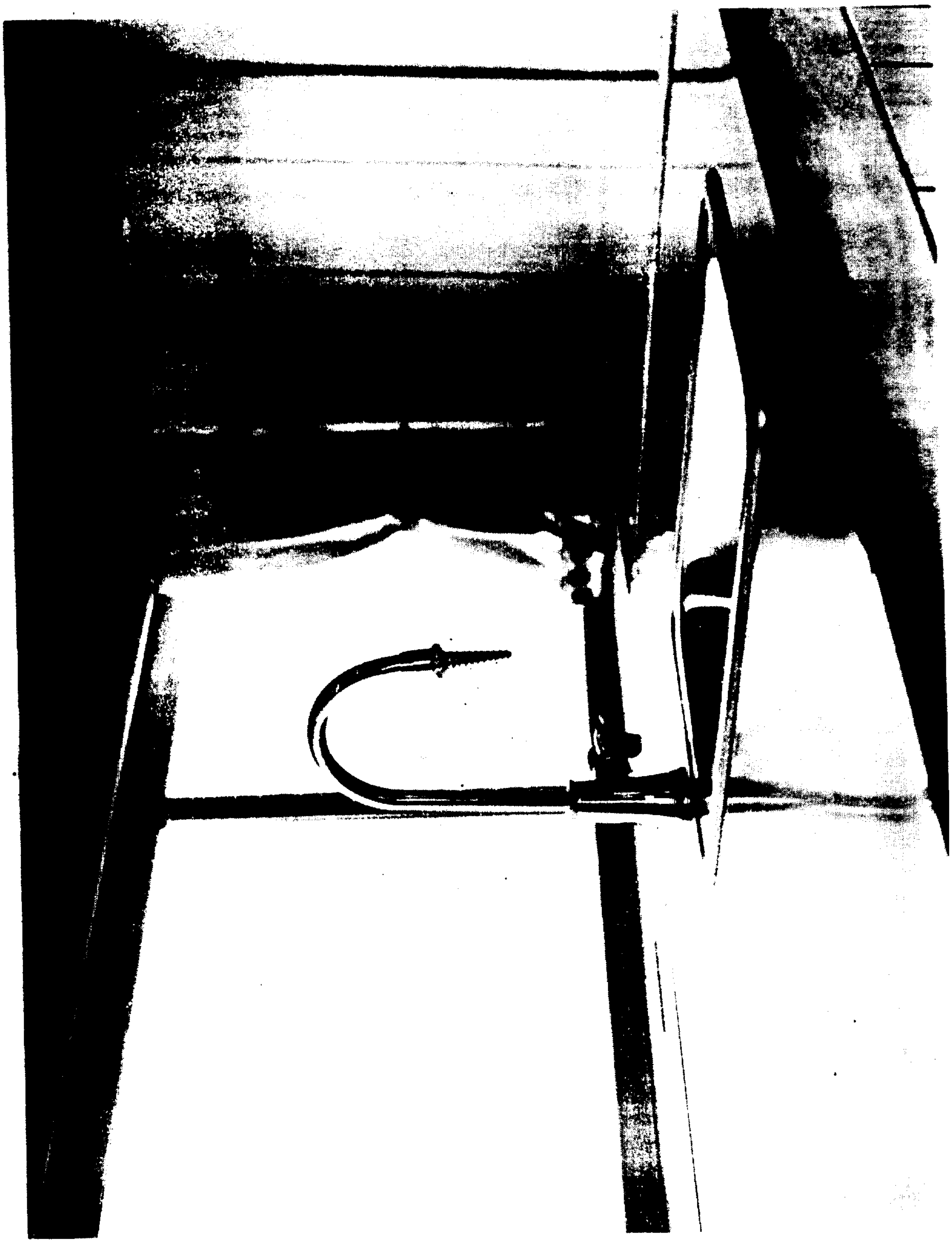
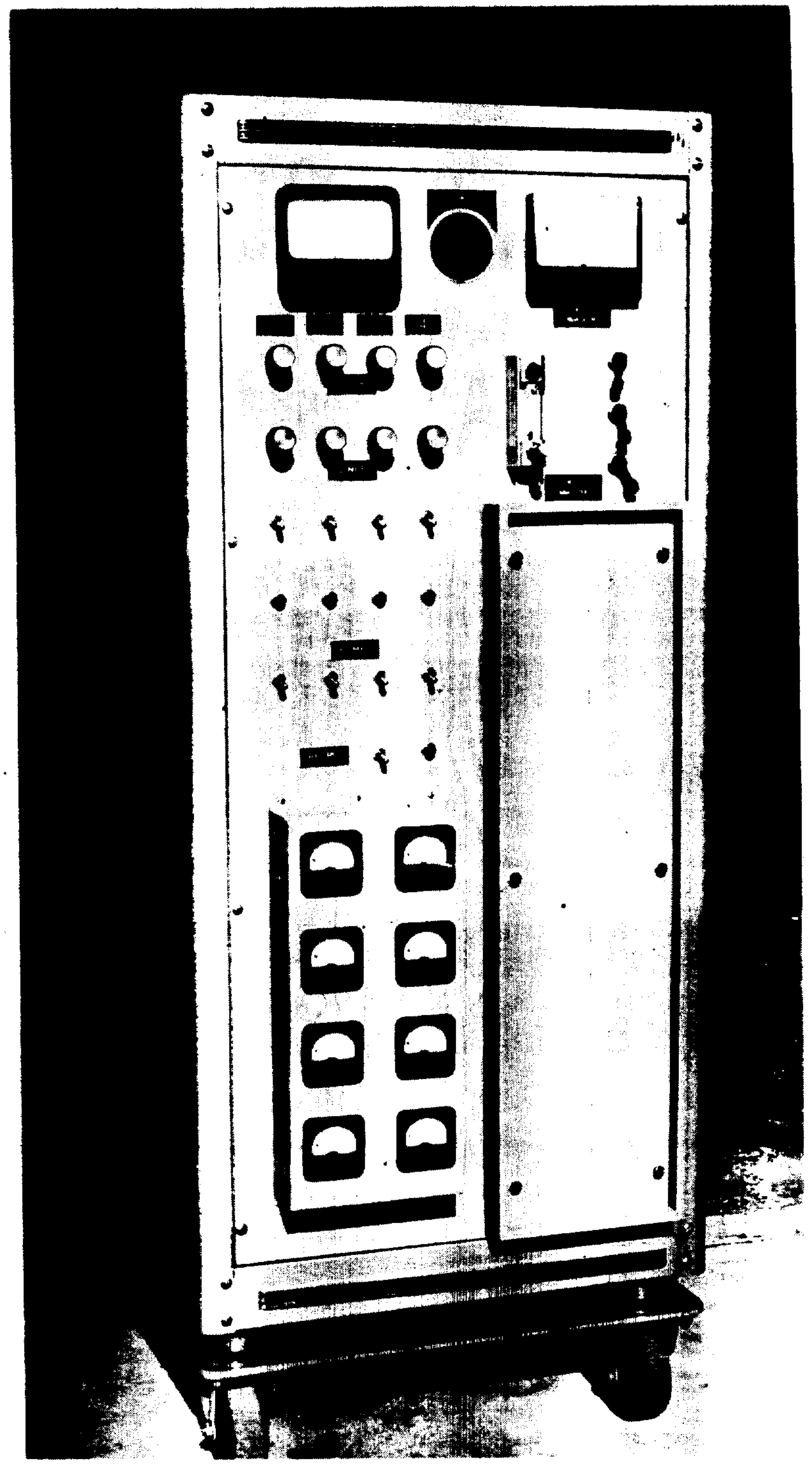




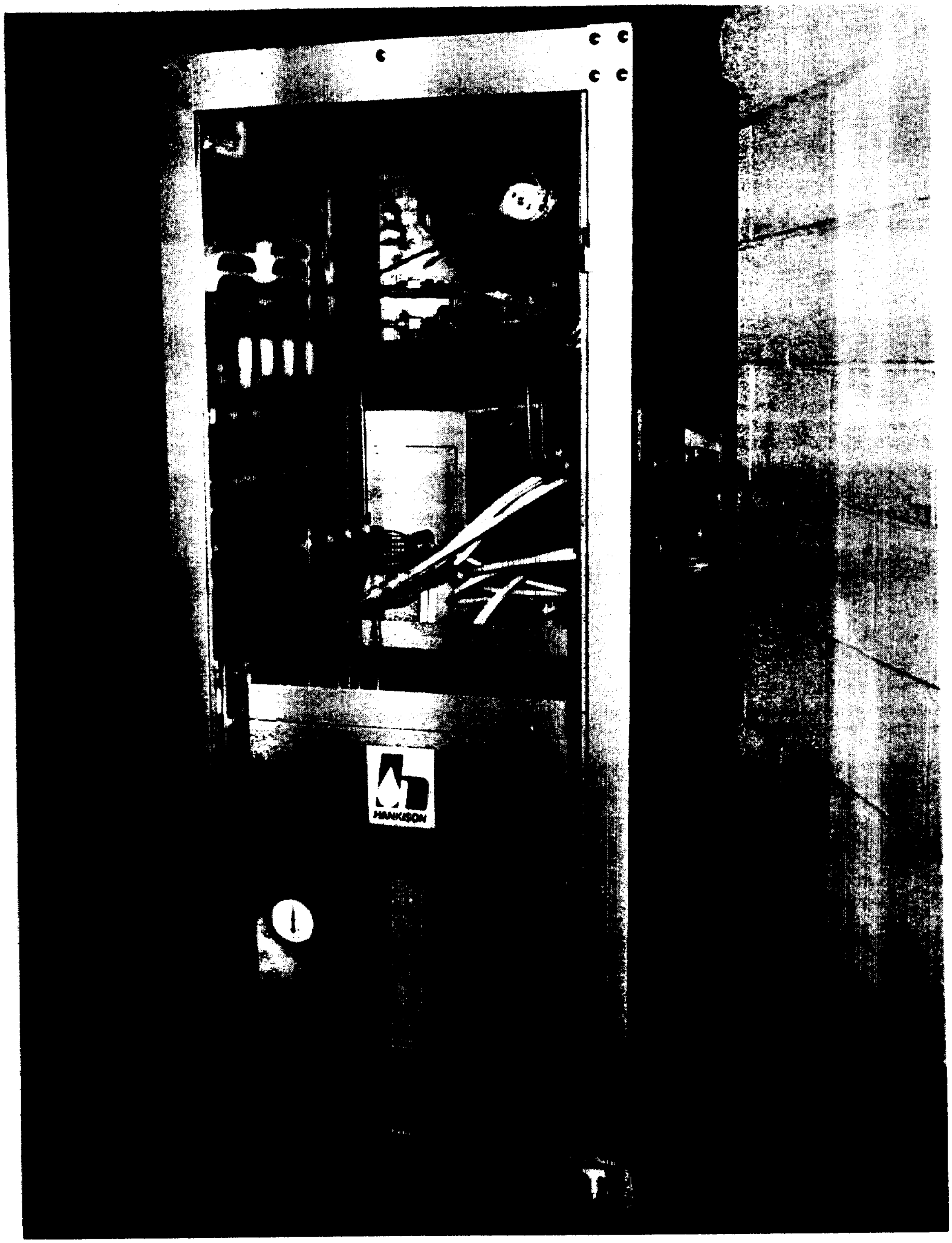


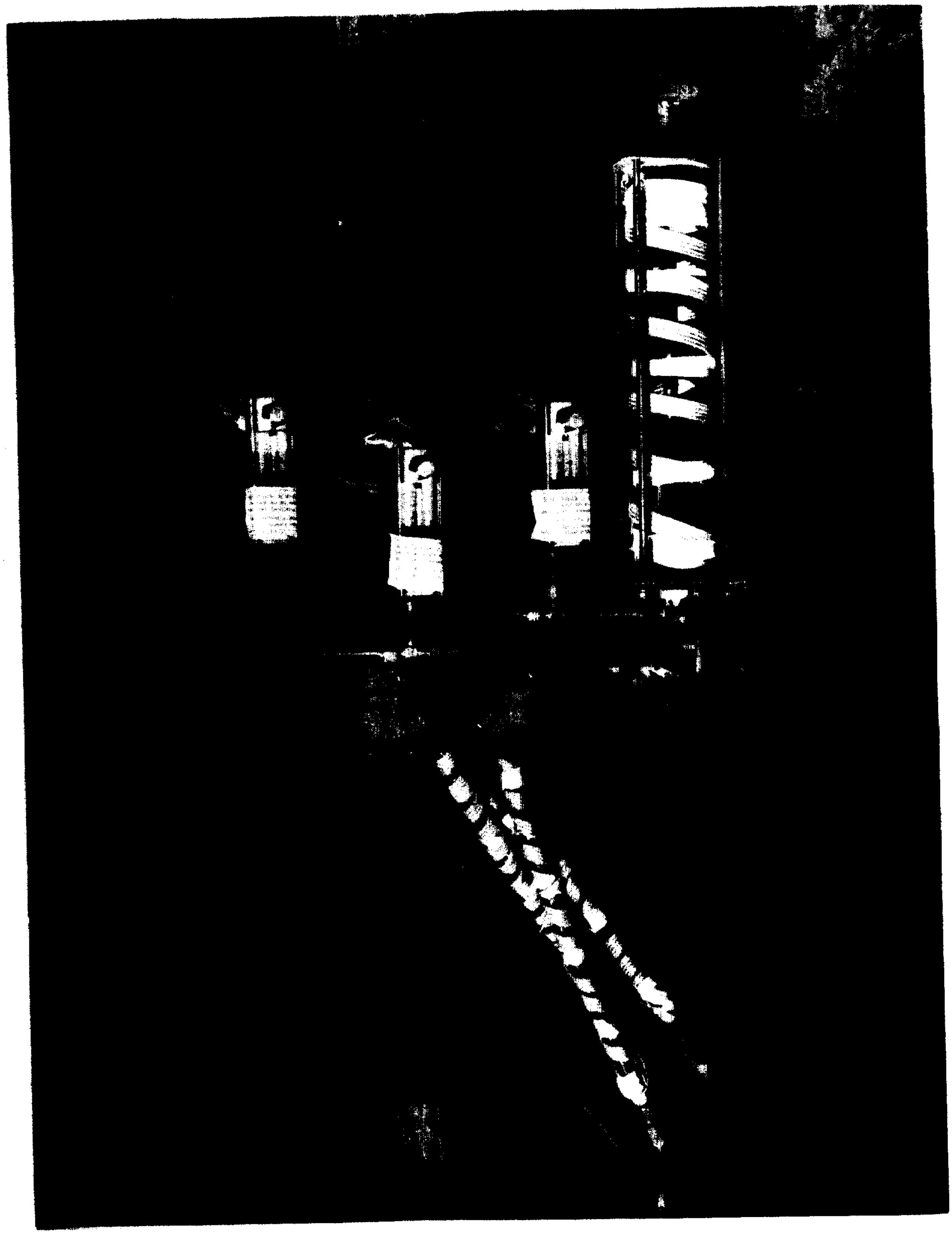
[illegible] WAN

PORTABLE INSTRUMENT CABINET INSIDE VAN
PUMPS, REFIGERATIONS AND NO2 SENSOR

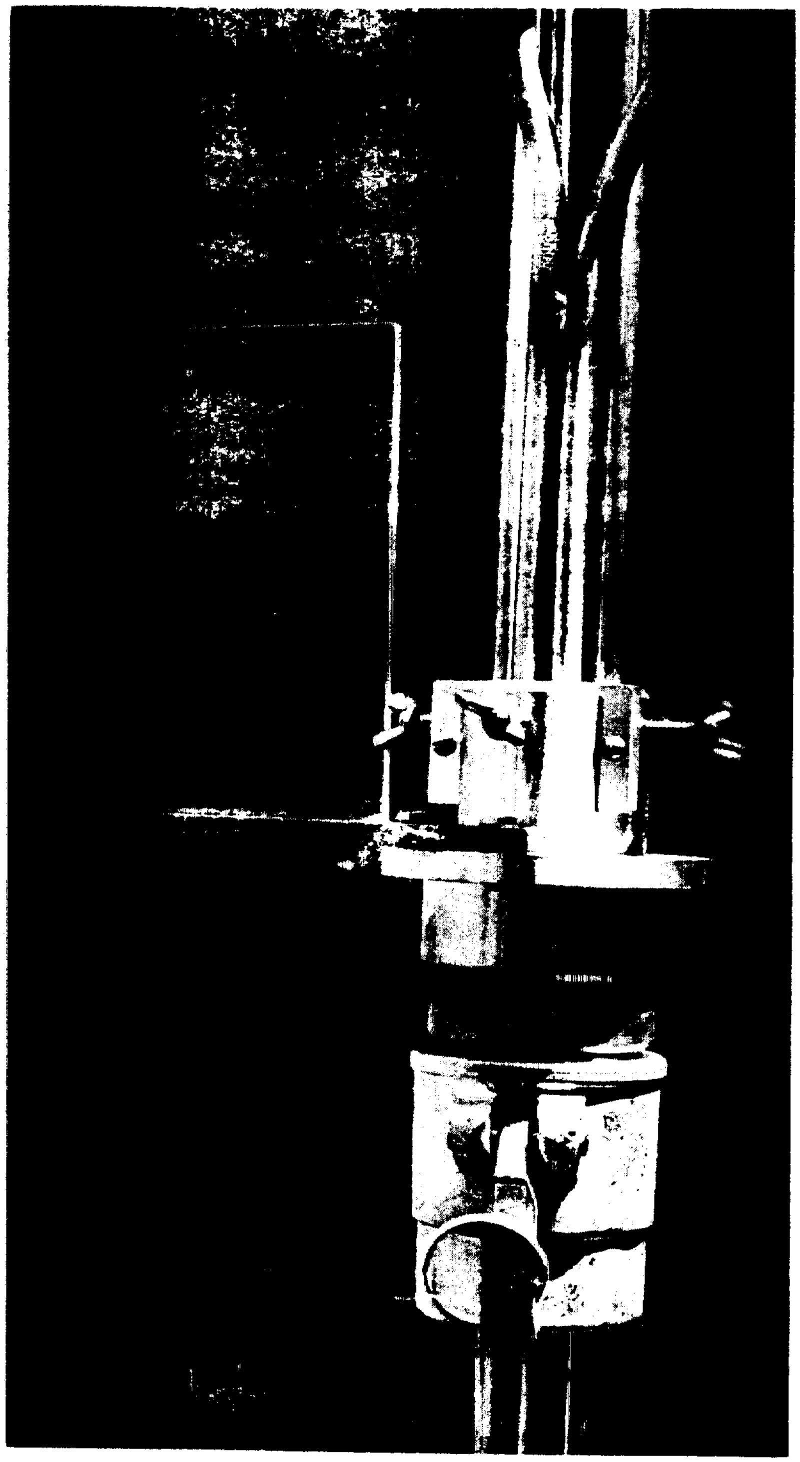


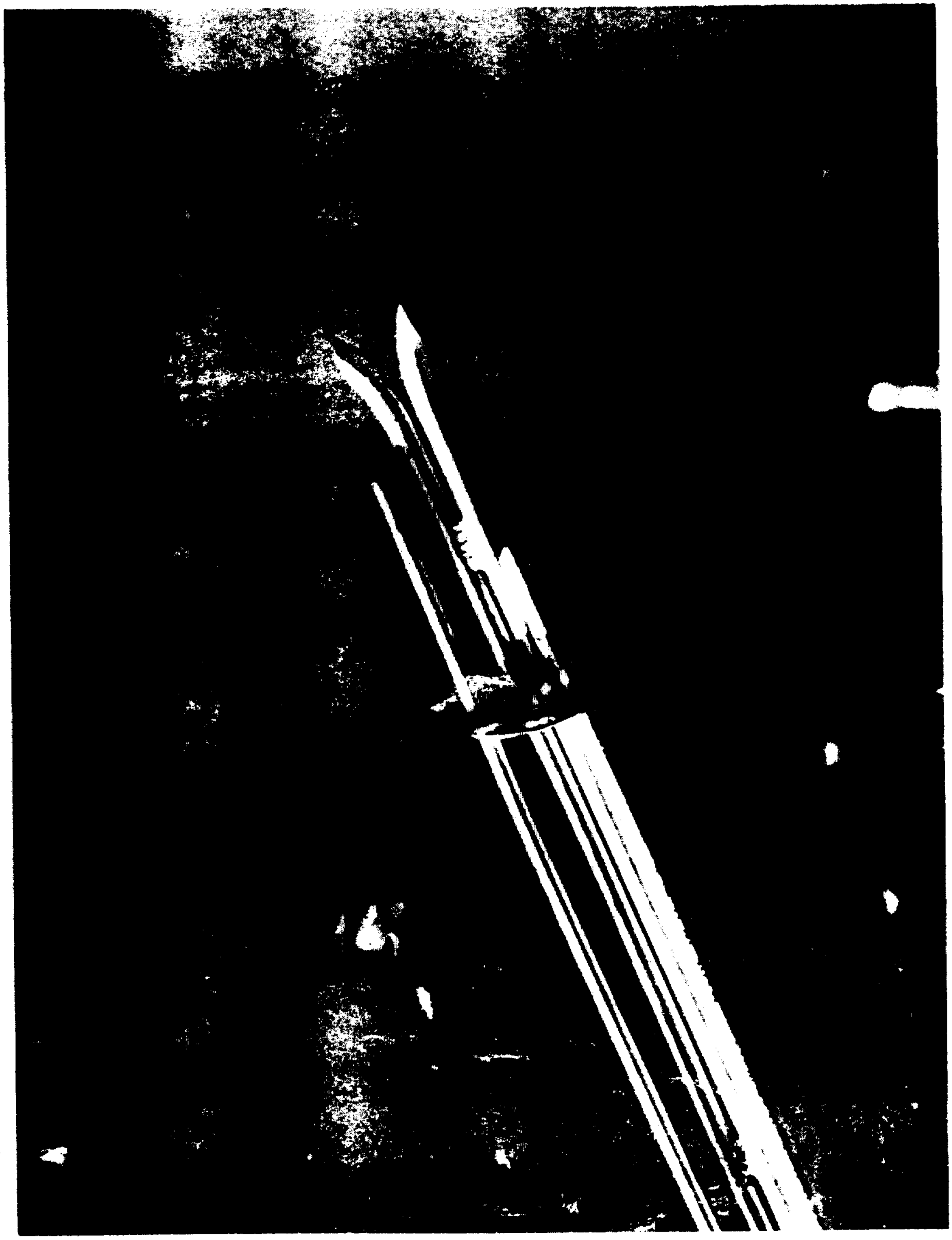
REAR VIEW OF PORTABLE INSTRUMENT CABINET





QUICK [illegible] ASSEMBLY FOR SAMPLING PROBE





APPENDIX B

This section of the report presents the data supplied by two of the boiler manufacturers, Combustion Engineering and Babcock and Wilcox, who participated in the test programs at Boilers O and Q, respectively. Their reports have been incorporated directly, with the exception that the boilers have been coded instead of designated by name. Because it was not possible to explore combustion modifications for NO_x emission control at Boiler N, Foster-Wheeler did not perform a steamside analysis on that unit.

APPENDIX B-1

BOILER O

MONTHLY PROGRESS REPORT NO. 3
JUNE 1, 1971 TO JUNE 30, 1971
ON
SUBCONTRACT NO. ESC-12
BOILER FIELD TEST SUPPORT
TO
ESSO RESEARCH AND ENGINEERING COMPANY
PRIME CONTRACT CPA 70-90

PREPARED FOR THE
OFFICE OF AIR PROGRAMS
CINCINNATI, OHIO 45227

JULY 10, 1971

COMBUSTION ENGINEERING, INC.
FIELD TESTING AND PERFORMANCE RESULTS
1000 PROSPECT HILL ROAD
WINDSOR, CONNECTICUT 06095
(203) 688-1911

J. D. CAVERS

SECTION I - PURPOSE AND SCOPE

Field test support (subcontract) to the oxides of the nitrogen program now being conducted by Esso Research and Engineering Company under contract #CPA 70-90 at Boiler O.

SECTION II - PROGRESS

Laboratory Analysis

Ultimate coal analyses were performed on four composite and two single coal samples at the C-E Laboratory in Windsor, Connecticut. The samples were analyzed using the ASTM D271 procedure with the results tabulated on Sheet B1.

Unit Output, Efficiency, and Net Heat Input Calculations

Unit output was calculated by the heat balance method using test, board, and computer data. The method and results are listed on Sheets B2 and B3. The results of the unit efficiency calculations using the heat losses method are listed on Sheets B2 and B3 with the procedure explained on Sheets B4 thru B6. Unit efficiency was calculated with and without the reject loss included in the total losses.

Heat input from fuel was determined using the efficiency (W/O reject loss) divided into the unit output.

The net heat input to the furnace is the sum of the heat input from fuel and the heat credits and losses as listed on Sheets B2 and B3. A sample calculation of the credits and losses to the heat input from fuel is shown on Sheet B7.

A plot of efficiency (W/O reject loss) versus main steam flow (adjusted) is shown on Sheet B8. Test efficiencies are compared to the average efficiency (W/O reject loss) as calculated for the performance tests, Aug., 1962. The plot shows that two stage combustion does not adversly affect unit efficiency.

Board, Computer and Test Data

The test data is summarized on Sheets B9 and B10. The coal scales were only used to determine MW load output per furnace as they were not considered accurate enough to determine heat input to furnace. Reheat flow was determined by using the plot on Sheet B11 which was obtained from performance test data, Aug., 1962. Main steam flow and first stage pressure were adjusted to specified nozzle conditions and are plotted on Sheet B12. This plot was used as a check on the accuracy of the main steam flow. The values designated by the □ symbol fall significantly below the curve; this is due to the very low superheat outlet temperatures at which the boiler was operating during these tests. The gas and air flows are tabulated for each test with a sample calculation shown on Sheets B13 thru B16. Board and computer data are tabulated on Sheets B17 thru B22.

Carbon Heat Loss Variation

A plot of percent carbon heat loss on a test basis with respect to changes in percent O_2, degree nozzle tilt, and superheat outlet temperature is shown on Sheet B23. For all high load tests (four and five mill operation) except Test 20 the carbon heat loss is below .30 percent. The high carbon heat loss (.74 percent) obtained on Test 20 was due to the clean furnace walls (note drop in superheater outlet temperature) which allowed for an increase in furnace wall absorption rates and reduced flame temperature which reduced combustion efficiency.

Low load tests (three mill operation) were performed after the outage and the high carbon heat loss for Test 30 is due to the clean furnace walls. The carbon heat loss for Tests 31 thru 33 decreased to the expected level as the furnace became dirtier. Tests 34 and 35 were performed with the #1, 3 and 5 mills in service. Combustion efficiency decreased due to the large spacing between the fuel nozzles. The combustion efficiency improved on Test 35 when auxiliary and primary air was admitted between elevations #1 and 3.

Effect of Furnace Cleanliness on Four and Five Mill Operation

All furnace cleanliness data was obtained through visual observation of the furnace waterwalls. A plot on Sheet B24 shows superheat outlet temperature versus percent O_2 with changes in nozzle tilt, mills in service, and furnace cleanliness.

With heavy slag (3 to 4 inches) on the furnace walls, higher temperatures were obtained at horizontal tilt than at minus 30 degree tilt. In both cases, the temperature increased as percent O_2 increased due to an increased mass gas flow. There was no change in temperature between four and five mill operation as the heavy slag prevented a substantial increase or decrease in furnace absorption rates.

When the slag on the furnace walls was light (1 to 2 inches) and four mills in service at horizontal tilt, the outlet temperature increased as percent O_2 increased. At minus 30 degree tilt, a single point shows that at a high percent O_2 the mass gas flow effect overrides the minus 30 degree tilt effect as the temperature did not decrease. With five mill operation and low percent O_2, the spread between minus 30 degree and horizontal tilt is shown by single points. The effect shown here is that greater furnace absorption occurs with the minus 30 degree tilt due to the increased gas residence time in the furnace which decreases the temperature of the gas to the superheat sections.

During the short duration of each test in this test series, steam temperature characteristics and furnace slagging conditions were unaffected by four mill (with overfire air) operation.

Unit Inspection

An inspection of the nozzle compartments and the windbox was performed after the test period with the results shown on Sheets B25 - B28.

The nozzle tilt at horizontal and minus 30 degree positions were satisfactory although a few linkages were broken. A plus 30 degree tilt could be obtained in the rear corners but not in the front corners due to binding linkages. A majority of the tests were performed at either horizontal or minus 30 degree tilt, therefore the unavailability of the plus 30 degree tilt in the front corners is of no consequence.

The windbox dampers in the "full open" position were operating satisfactorily except the bottom five compartments in the right front corner which remained in a fixed position due to a broken linkage. The leakage gap measurement indicates that some of the dampers were not closing completely when the damper control was in the "full closed" position.

Nozzle Air Flow Distribution

A nozzle air flow distribution program was run with the results tabulated on Sheet B29. This calculation was made using design specifications for windbox and nozzle compartment geometry. The calculated percent theoretical air to the combustion zone is plotted versus [illegible] of NO, adjusted to 3 percent O_2, on Sheet B30. This plot shows that NO decreases as percent theoretical air to the burner zone decreases.

A tabulation of the windbox and nozzle compartment geometry used in the calculations are given on Sheet B31.

Pulverizer Fineness

A tabulation of pulverizer fineness at four classifier settings are shown on Sheet B32.

SECTION III - CURRENT PROBLEMS

At the present time there are no problems that will interfere with the completion of data analysis and reporting.

SECTION IV - FUTURE WORK

This is the final progress report on subcontract ESC-12. Although CE's commitment to this contract is finished, should there be need for clarification and/or interpretation of the test data or performance results, please contact the writer.

J. D. Cavers

J. D. Cavers

JDC/sl

Attachments

Boiler O
Contract 16357
Project 900096

Combustion Engineering, Inc.
Field Testing and
Performance Results

ULTIMATE FUEL ANALYSES

TESTS	Composite Proximate Analyses As Received: Moisture %	Volatile Matter %	Fixed Carbon %	Ash %	HHV BTU/LB	Composite Ultimate Analyses As Received: Moisture %	Carbon %	Hydrogen %	Oxygen %	Nitrogen %	Sulfur %	Ash %	HHV BTU/LB*
1,4,8,9, 12,16,17, 22,23	7.5	34.6	43.3	14.6	11,160	7.5	61.3	4.3	7.1	1.5	3.7	14.6	14,369
5,6,10,11, 13,14,18,19, 30,31,33	7.9	34.4	39.9	17.8	10,500	7.9	57.8	4.1	7.4	1.3	3.7	17.8	14,260
2,7,21,32	7.6	35.3	41.1	16.0	11,010	7.6	59.5	4.2	7.7	1.1	3.9	16.0	14,481
3,15,35	8.1	35.2	39.3	17.4	10,600	8.1	57.3	3.8	8.3	1.4	3.7	17.4	14,348
20	9.9	35.0	39.9	15.2	11,020	9.9	60.8	4.4	4.6	1.4	3.7	15.2	14,842
34	7.0	32.5	37.5	23.0	9,670	7.0	53.5	3.8	7.1	1.3	4.3	23.0	14,005

*HHV calculated on moisture and ash free basis.

UNIT EFFICIENCY AND NET HEAT INPUT CALCULATIONS

UNIT OUTPUT - HEAT BALANCE METHOD

TEST NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1. Feedwater Flow	10^3LB/HR	1703	1655	1605	1744	1734	1680	1670	1648	1635	1758	1760	1573	1552	1643	1638
2. FW Pressure	PSIG	2750	2750	2750	2780	2780	2750	2750	2750	2740	2800	2800	2265	2260	2300	2350
3. FW Temp. at Econ.	F	522	516	515	526	522	521	523	518	517	518	529	520	520	514	518
4. Enthalpy at Econ. 2, 3	BTU/LB	513	506	505	517	513	512	513	509	509	509	521	511	511	504	509
5. SHO Pressure	PSIG	2450	2450	2450	2450	2450	2440	2450	2440	2440	2450	2450	1970	1960	2010	2050
6. SHO Temp.	F	1037	1056	1032	1030	1046	1015	1060	1029	1037	1019	1064	1014	1019	992	1018
7. SHO Enthalpy 5, 6	BTU/LB	1484	1496	1481	1479	1489	1470	1499	1479	1484	1472	1501	1484	1487	1469	1484
8. Enthalpy Diff. 7 - 4	H	971	990	976	962	976	958	986	970	975	963	980	973	976	965	975
9. Total SH Abs. 8 X 1	10^6BTU/HR	1653.6	1638.5	1565.5	1677.7	1737.3	1609.4	1645.6	1598.6	1594.1	1693.0	1723.8	1530.5	1514.8	1585.5	1597.1
10. SH Spray Flow	10^3LB/HR	0	21.5	0	0	0	0	0	0	0	0	0	0	0	0	0
11. SH Spray Pressure	PSIG	2650	2650	2650	2680	2680	2650	2650	2650	2640	2700	2700	2165	2160	2200	2250
12. SH Spray Temp.	F	354	355	355	356	354	353	348	348	347	363	360	323	321	326	325
13. SH Spray Enthalpy 11, 12	BTU/LB	330	331	331	332	330	329	324	324	323	339	336	297	295	300	299
14. Enthalpy Diff. 8 - 13	H	1154	1165	1150	1147	1159	1141	1175	1155	1161	1133	1165	1187	1192	1169	1185
15. Total SH Spray Abs. 10 X 14	10^6BTU/HR	0	25.0	0	0	0	0	0	0	0	0	0	0	0	0	0
16. Cold RH Flow	10^3LB/HR	1277.5	1245	1210	1305	1292.5	1285	1242.5	1242.5	1222.5	1330	1297.5	1212.5	1200	1262.5	1257.5
17. Cold RH Pressure	PSIG	428	424	414	456	447	422	417	418	408	438	438	403	397	418	418
18. Cold RH Temp.	F	615	623	619	630	644	607	631	620	627	622	632	642	638	633	656
19. Cold RH Enthalpy 17, 18	H	1312	1317	1315	1319	1327	1308	1322	1315	1320	1316	1322	1330	1328	1324	1336
20. RHO Pressure	PSIG	367	370	362	378	380	365	365	355	350	375	375	345	345	360	365
21. RHO Temp.	F	1024	999	1000	1018	1011	986	1013	1000	995	991	1016	989	986	968	1000
22. RHO Enthalpy 20, 21	BTU/LB	1535	1523	1523	1532	1529	1516	1530	1521	1521	1518	1532	1518	1516	1506	1523
23. Enthalpy Diff. 22 - 19	H	223	206	208	213	202	208	208	206	201	202	210	188	188	182	187
24. Total RH Abs. 23 X 16	10^6BTU/HR	284.9	256.5	251.7	278.0	261.1	267.3	258.4	256.0	245.7	268.7	272.5	228.0	225.6	229.8	235.2
25. RH Spray Flow	10^3LB/HR	0	27.0	10.0	0	14.5	0	10.0	0	8.0	0	10.0	0	0	0	0
26. RH Spray Pressure	PSIG	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500
27. RH Spray Temp.	F	351	353	[illegible]	354	352	350	345	346	344	360	358	321	320	323	323
28. RH Spray Enthalpy 26, 27	BTU/LB	325	326	326	328	325	324	318	319	317	334	332	294	293	296	296
29. Enthalpy Diff. 22 - 28	H	1210	1197	1197	1204	1204	1192	1212	1202	1204	1184	1200	1224	1223	1210	1227
30. Total RH Spray Abs. 29 X 25	10^6BTU/HR	0	32.3	12.0	0	17.5	0	12.1	0	9.6	0	12.0	0	0	0	0
31. Total HT Absorbed by Boiler 9 + 15 + 24 + 30	10^6BTU/HR	1938.5	1952.3	1829.2	1955.7	2015.9	1876.7	1916.1	1854.6	1849.4	1961.7	2008.3	1758.5	1740.4	1815.3	1832.3

EFFICIENCY - HEAT LOSSES METHOD

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Dry Gas Loss	%	3.88	3.76	3.69	4.07	4.07	3.86	3.87	3.91	3.97	4.15	4.24	3.56	3.57	3.53	3.48
Moisture in Air Loss	%	.09	.09	.09	.10	.10	.09	.09	.09	.10	.10	.10	.09	.09	.08	.08
Moisture from Fuel Loss	%	4.62	4.58	4.42	4.59	4.73	4.73	4.57	4.59	4.59	4.78	4.77	4.56	4.70	4.70	4.39
Carbon Heat Loss	%	.27	.19	.14	.04	.05	.10	.06	.02	.08	.07	.07	.06	.10	.12	.14
Radiation Loss	%	.22	.22	.23	.22	.21	.22	.26	.23	.23	.21	.21	.24	.24	.23	.23
Heat Loss in Fly Ash	%	.05	.05	.06	.05	.06	.06	.05	.05	.05	.06	.07	.05	.06	.06	.06
Ash Pit Loss	%	.23	.23	.23	.22	.22	.22	.22	.23	.23	.22	.22	.23	.23	.22	.22
Total Losses	%	9.36	9.24	8.86	9.29	9.44	9.28	9.08	9.12	9.25	9.59	9.68	8.79	8.99	8.94	8.60
Reject Loss	%	.92	.92	.97	1.77	1.72	1.84	1.81	.96	.96	.79	.78	1.48	1.49	.86	.85
Total Losses (Incl. Reject Loss)	%	10.28	10.16	9.83	11.06	11.16	11.12	10.89	10.08	10.21	10.38	10.46	10.27	10.48	9.80	9.45
Efficiency (W/O Reject Loss)	%	90.64	90.76	91.14	90.71	90.56	90.72	90.92	90.88	90.75	90.41	90.32	91.21	91.01	91.06	91.40
Efficiency (W Reject Loss)	%	89.72	89.84	90.17	88.94	88.84	88.88	89.11	89.92	89.79	89.62	89.54	89.73	89.52	90.20	90.55

NET HEAT INPUT - 10^6BTU/HR

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Heat Input from Fuel [Unit Output/Eff. (W/O Reject Loss)]	2138.7	2151.1	2007.0	2156.0	2226.0	2068.7	2107.5	2040.7	2037.9	2169.8	2222.5	1928.0	1912.3	1993.5	2004.7
(+) Sensible Heat in Preheated Air	198.5	196.9	183.1	211.5	217.8	193.6	198.3	195.1	200.1	206.6	218.2	173.1	173.6	176.3	174.5
(+) Sensible Heat in Fuel	5.9	5.5	5.4	5.6	5.6	5.4	5.5	5.2	5.2	5.7	5.7	5.6	5.3	5.8	5.6
(-) Latent Heat of Vaporization	91.2	91.3	82.5	91.9	97.9	91.0	89.4	87.0	86.9	95.4	97.8	82.2	84.1	87.7	82.4
(-) Combustible Heat Loss	5.8	4.1	2.8	.9	1.1	2.1	1.3	.4	1.6	1.5	1.6	1.2	1.9	2.4	2.8
Net Heat Input	2246.1	2258.1	2110.2	2280.3	2350.4	2174.6	2220.6	2153.6	2154.7	2285.2	2348.0	2023.3	2005.2	2085.5	2099.6

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Project [illegible]

UNIT EFFICIENCY AND NET HEAT INPUT CALCULATIONS

TEST NO.		16	17	18	19	20	21	22	23	30	31	32	33	34	35
UNIT OUTPUT - HEAT BALANCE METHOD															
1. Feedwater Flow	10^3LB/HR	1648	1655	1587	1576	1660	1619	1708	1751	1242	1158	1240	1186	1171	1195
2. FW Pressure	PSIG	2450	2580	2320	2320	2780	2700	2790	2700	1650	1800	1900	1890	1890	1870
3. FW Temp. at Econ.	F	523	526	510	512	512	510	515	516	486	486	487	484	481	483
4. Enthalpy at Econ. 3, 2	BTU/LB	514	518	499	501	501	499	505	506	471	471	472	469	466	468
5. SHO Pressure	PSIG	2185	2290	2000	2005	2410	2420	2460	2520	1425	1590	1690	1650	1625	1650
6. SHO Temp.	F	1015	1034	978	1010	919	956	960	963	892	911	905	984	933	934
7. SHO Enthalpy 5, 6	BTU/LB	1478	1488	1460	1480	1405	1431	1432	1432	1427	1432	1426	1438	1445	1465
8. Enthalpy Diff. 7 - 4	"	964	970	961	979	904	932	927	926	956	961	954	969	979	977
9. Total SH Abs. 1 x 8	10^6BTU/HR	1588.7	1605.4	1525.1	1542.9	1500.6	1508.9	1583.3	1621.4	1187.4	1112.8	1183.0	1149.2	1146.4	1167.5
10. SH Spray Flow	10^3LB/HR	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11. SH Spray Pressure	PSIG	2390	2480	2220	2220	2620	2600	2690	2600	1550	1700	1800	1750	1750	1770
12. SH Spray Temp.	F	335	336	323	322	361	360	359	348	269	279	295	294	290	300
13. SH Spray Enthalpy 11, 12	BTU/LB	310	311	297	296	337	336	335	339	240	251	268	267	263	273
14. Enthalpy Diff. 7 - 13	"	1168	1177	1163	1184	1068	1095	1097	1093	1187	1181	1158	1171	1182	1172
15. Total SH Spray Abs. 10 x 14	10^6BTU/HR	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16. Cold RH Flow	10^3LB/HR	1250	1250	1270	1242.5	1265	1192.5	1290	1327.5	962.5	885	920	900	892.5	910
17. Cold RH Pressure	PSIG	415	412	411	412	400	420	409	422	297	300	304	293	293	299
18. Cold RH Temp.	F	628	649	641	656	537	552	598	551	547	540	533	549	563	570
19. Cold RH Enthalpy 17, 18	"	1321	1331	1329	1337	1267	1275	1280	1275	1284	1279	1276	1285	1294	1297
20. RHO Pressure	PSIG	357	362	353	352	345	330	354	379	240	240	295	250	265	290
21. RHO Temp.	F	982	1008	966	989	872	912	912	916	834	856	866	862	882	890
22. RHO Enthalpy 20, 21	BTU/LB	1514	1527	1504	1518	1456	1478	1477	1478	1440	1452	1446	1455	1465	1469
23. Enthalpy Diff. 22 - 19	"	193	196	175	181	189	203	197	203	156	173	170	170	171	172
24. Total RH Abs. 16 x 23	10^6BTU/HR	241.3	245.0	222.3	224.9	239.1	242.1	254.1	269.5	150.2	153.1	156.4	153.0	152.6	156.5
25. RH Spray Flow	10^3LB/HR	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26. RH Spray Pressure	PSIG	1900	1900	1900	1900	1900	1900	1900	1900	1900	1900	1900	1900	1900	1900
27. RH Spray Temp.	F	333	335	321	320	359	358	357	360	268	278	294	293	289	297
28. RH Spray Enthalpy 26, 27	BTU/LB	306	308	294	293	333	332	331	334	240	250	266	265	261	269
29. Enthalpy Diff. 22 - 28	"	1208	1219	1210	1225	1123	1146	1146	1144	1200	1202	1180	1190	1204	1200
30. Total RH Spray Abs. 25 x 29	10^6BTU/HR	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31. Total HT Absorbed by Boiler 9 + 15 + 24 + 30	10^6BTU/HR	1830.0	1850.4	1747.4	1767.8	1739.7	1751.0	1837.4	1890.9	1337.6	1265.9	1339.4	1302.2	1299.0	1324.0
EFFICIENCY - HEAT LOSSES METHOD															
Dry Gas Loss	%	3.71	3.70	3.48	3.70	3.38	3.36	3.50	3.48	3.06	2.90	2.73	3.01	3.00	2.98
Moisture in Air Loss	%	.09	.09	.08	.09	.08	.08	.08	.08	.07	.07	.07	.07	.07	.07
Moisture from Fuel Loss	%	4.56	4.55	4.68	4.69	4.94	4.53	4.56	4.55	4.69	4.64	4.47	4.63	4.63	4.34
Carbon Heat Loss	%	.06	.08	.07	.12	.74	.26	.21	.21	.65	.20	.28	.35	.67	.43
Radiation Loss	%	.23	.23	.24	.24	.24	.24	.23	.22	.31	.33	.31	.32	.32	.31
Heat Loss in Fly Ash	%	.05	.04	.06	.06	.04	.05	.04	.04	.05	.05	.04	.05	.07	.05
Ash Pit Loss	%	.23	.23	.22	.22	.23	.23	.23	.23	.22	.22	.25	.25	.22	.22
Total Losses	%	8.93	8.92	8.83	9.12	9.65	8.75	8.84	8.81	9.05	8.41	8.15	8.68	8.98	8.40
Reject Loss	%	1.42	1.40	.89	.88	1.02	1.48	1.41	.94	1.38	1.46	.86	.89	.88	.78
Total Losses (Incl. Reject Loss)	%	10.35	10.32	9.72	10.00	10.67	10.23	10.25	9.75	10.43	9.87	9.01	9.57	9.86	9.18
Efficiency (W/O Reject Loss)	%	91.07	91.08	91.17	90.88	90.35	91.25	91.16	91.09	90.95	91.59	91.85	91.32	91.02	91.60
Efficiency (W Reject Loss)	%	89.65	89.68	90.28	90.00	89.33	89.77	89.75	90.25	89.57	90.13	90.99	90.43	90.14	90.82
NET HEAT INPUT - 10^6BTU/HR															
Heat Input from Fuel [Unit Output/Eff. (W/O Reject Loss)]		2009.4	2031.6	1916.6	1945.2	1925.5	1918.9	2015.6	2075.9	1470.7	1382.1	1458.2	1426.0	1427.2	1444.2
(+) Sensible Heat in Preheated Air		188.6	193.5	170.2	178.9	167.8	166.5	177.0	185.6	114.5	112.1	114.3	120.5	118.8	115.9
(+) Sensible Heat in Fuel		5.3	5.2	5.5	5.5	4.8	4.9	5.2	5.2	4.1	4.0	3.7	4.3	3.1	3.6
(-) Latent Heat of Vaporization		85.7	86.6	84.3	85.6	89.0	81.4	85.9	88.5	64.7	60.8	61.9	62.7	62.6	59.4
(-) Combustible Heat Loss		1.2	1.6	1.3	2.3	14.2	5.0	4.2	4.4	9.6	2.8	4.1	5.0	9.6	6.2
Net Heat Input		2116.4	2142.1	2006.7	2041.7	1994.9	2003.9	2107.7	2173.8	1515.0	1434.6	1510.2	1483.1	1476.9	1498.1

SAMPLE CALCULATION OF EFFICIENCY - HEAT LOSSES METHOD

TEST #1

1. DRY GAS LOSS, DGL

$$DGL = (DP\ Lvg.\ AH)(.24)(T_{GL} - T_{AE}) \times 10^{-4}$$

Where: .24 = Instantaneous Specific Heat of Dry Products
T_{GL} = Temperature of Gas Lvg. AH
T_{AE} = Temperature of Air Ent. AH
DP Lvg. AH = Dry Products Lvg. AH

$$DGL = (956.52)(.24)(265 - 96) \times 10^{-4}$$
$$DGL = 3.88\%$$

2. MOISTURE IN AIR LOSS, MAL

$$MAL = (.013)(DA\ Lvg.\ AH)(.46)(T_{GL} - T_{AE}) \times 10^{-4}$$

Where: .013 = Standard Specific Humidity
.46 = Instantaneous Specific Heat of Water Vapor
DA Lvg. AH = Dry Air in Products Lvg. AH

$$MAL = (.013)(921.58)(.46)(265 - 96) \times 10^{-4}$$
$$MAL = .09\%$$

3. MOISTURE FROM FUEL LOSS, MFL

$$MFL = MF \left[1089 - T_{AE} + .46\ (T_{GL})\right] \times 10^{-4}$$

Where: $\left[1089 - T_{AE} + .46\ (T_{GL})\right]$ Accounts for Evaporating & Superheating the Moisture In & From the Fuel.

$$MFL = 41.40 \left[1089 - 96 + .46\ (265)\right] \times 10\text{-}4$$
$$MFL = 4.62\%$$

4. CARBON HEAT LOSS, CL

$$CL = \frac{\%\ Ash}{100\% - \%\ Carbon\ in\ Fly\ Ash}\left[\frac{\%\ Carbon\ in\ Fly\ Ash\ (14{,}450)}{HHV,\ Fuel}\right]$$

Where: 14,450 = HHV of Carbon

$$CL = \frac{14.6}{100 - 1.4}\left[\frac{1.4\ (14{,}450)}{11160}\right]$$

$$CL = .27\%$$

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5. RADIATION LOSS, RL

Determined From ABMA Curve.

RL = .22%

6. HEAT LOSS IN FLYASH, FAL

$$FAL = \frac{\%\ ASH}{HHV}(.22)(T_{GL} - T_{AE})$$

Where: .22 = Specific Heat of Fly Ash

$$FAL = \frac{14.6}{11160}(.22)(265 - 96)$$

FAL = .05%

7. ASH PIT LOSS, APL

Determined using curves on sheets B5-1 and B5-2.

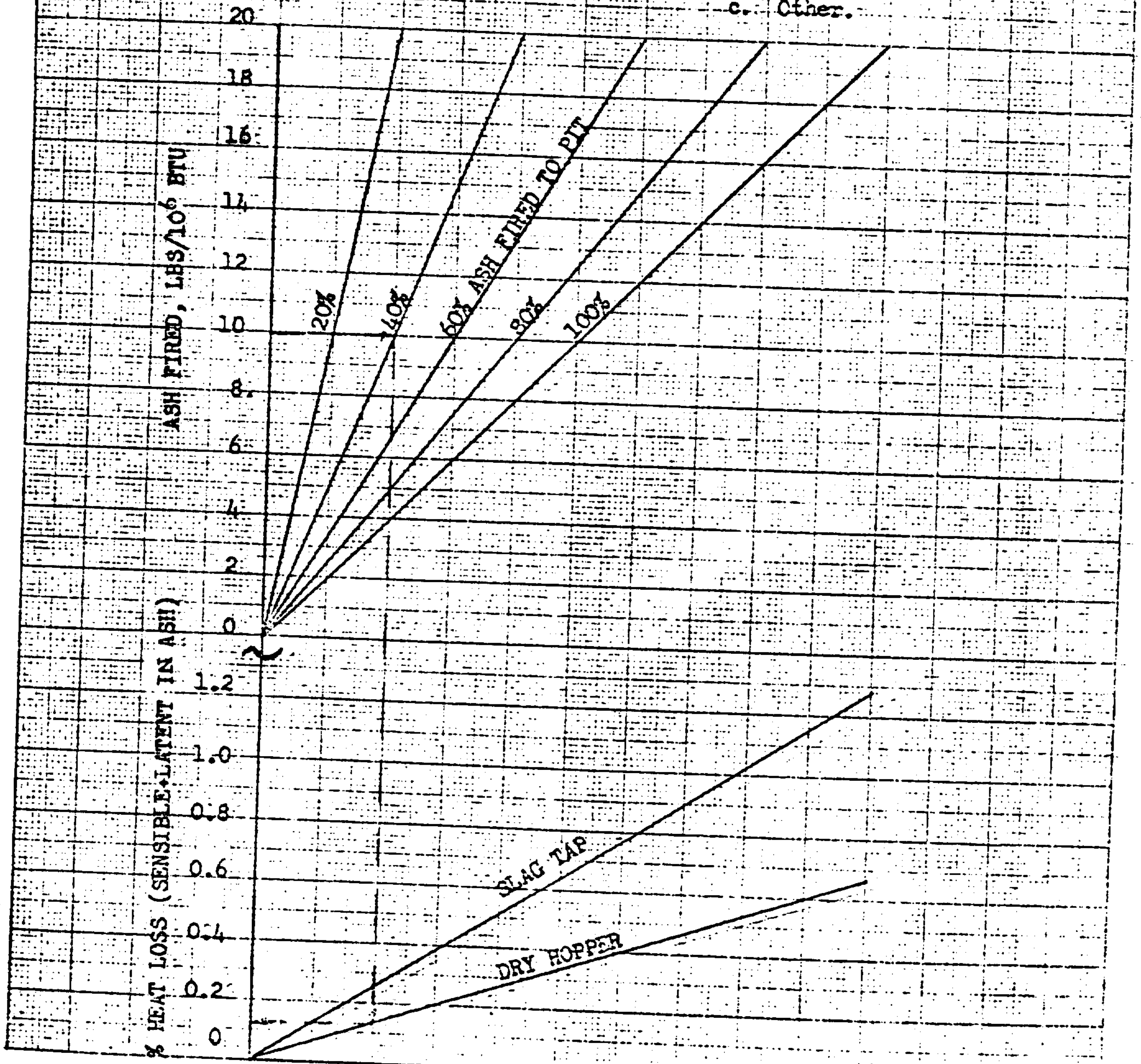
1. Furnace Width, Feet -40.167
2. Furnace Depth, Feet -40.167
3. Furnace Diagonal, Feet -57.0
4. Furnace Height, Feet -114.83
5. Distance Firing ℄ to Hopper Aperture - Feet -49.66
6. Ratio 5/3 -.87
7. Ashpit Aperture (Area), Feet^2 -100.42
8. Ratio 7/3 4 -.015
9. Curve Value of Radiation Thru Aperture (% Heat Loss) - .23
10. % Ash in Fuel, As Fired -14.6
11. HHV Fuel, as Fired, BTU/LB - 11160
12. 10 (10^4)/11, Ash Fired/10^6BTU -13.08
13. % Ash Fired Going to Ashpit -0
14. Slagging or Dry Ash Bottom ? - Dry Ash
15. Curve ValueSensible and Latent Heat of Ash (% Heat Loss) -0
16. Total Ash Pit Loss = 9 + 15 = .23 + 0 = .23%

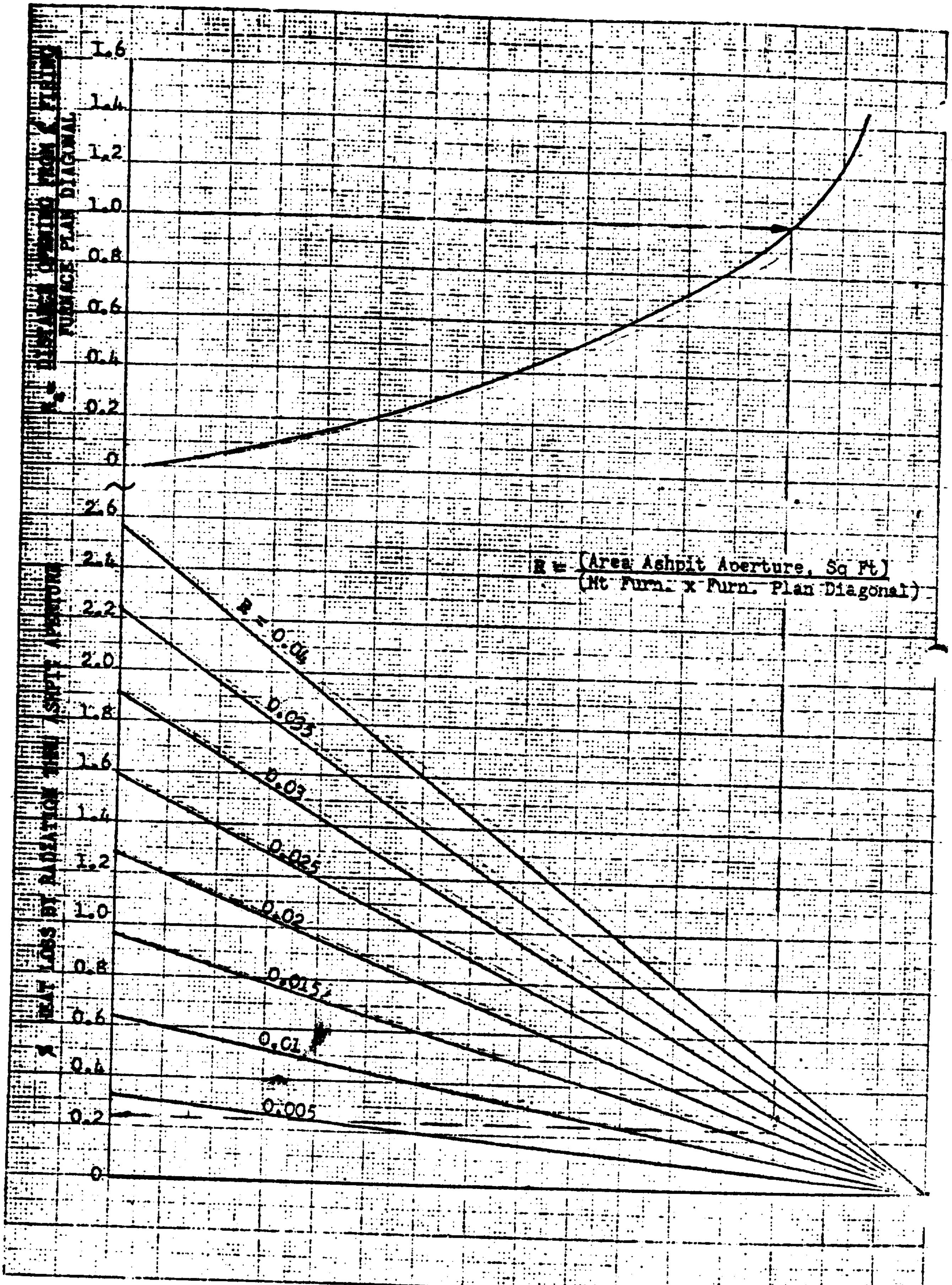
ASHPIT HEAT LOSS CORRELATION
(H.D. Mumper)

1. Furnace Width, Feet
2. Furnace Depth, Feet
3. Furnace Diagonal, Feet
   (Only one divided Furnace)
4. Furnace Height, Feet
5. Distance Firing ℄ to Hopper Aperture, Ft
6. Ratio (5) / (3)
7. Ashpit Aperture: Width, Ft
   Depth, Ft
   Area, Ft^2
8. Ratio (7) / (3) (4)
9. Curve Value of Radiation thru Aperture
   (% Heat Loss)

10. % Ash in Fuel, as Fired
11. HHV Fuel, as Fired, BTU/#
12. (10) x 10^4 / (11), Ash Fired/10^6 BTU
13. % Ash Fired going to Ashpit, %
14. Slagging or "dry ash" bottom?
15. Curve Value Sensible & Latent Heat of Ash, % Heat Fired.
16. TOTAL ASH PIT LOSS = (9) + (15)

NOTE any special circumstances, such as;
a. Water spray nozzles above surface of water pool and whether they are angled up toward aperture.
b. Lack of water sluice in ashpit.
c. Other.




K = DISTANCE OPENING FROM ¢ FIRING FURNACE PLAN DIAGONAL
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0
2.6
2.4
2.2
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0
% HEAT LOSS BY RADIATION THRU ASHPIT APERTURE
R = (Area Ashpit Aperture, Sq Ft) / (Ht Furn. x Furn. Plan Diagonal)
R = 0.04
0.035
0.03
0.025
0.02
0.015
0.01
0.005

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8. REJECT LOSS, RL

$$RL = \text{LB/HR Rejected} \left(\frac{\text{HHV, Rejects}}{\text{Total BTU/HR Input}}\right) \times 10^2$$

Where: Total BTU/HR Input is Estimated Using [Unit Absorption X 1.11]

$$RL = 3495 \left(\frac{5650}{2151.7 \times 10^6}\right) \times 10^2$$

$$RL = .92\%$$

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SAMPLE CALCULATION OF HEAT CREDITS
AND LOSSES TO HEAT INPUT FROM FUEL

TEST #1

CREDITS

1. Sensible Heat In Preheated Air, HPA

HPA = HT Content Air @ AH Out Temp. [WA (Flow) Ent. AH]

HPA = 107 (1855.3) = 198.5 X 10^6 BTU/HR

2. Sensible Heat in Fuel, HF

HF = Coal Flow (.3) (Coal Temp. - 80)

Where: .3 = Mean Specific Heat of Coal

80 = Datum Temperature

HF = 196,000 (.3) (181 - 80) = 5.9 X 10^6 BTU/HR

LOSSES

1. Latent Heat of Vaporization, HV

HV = MF (Heat Input From Fuel) (1030)

Where: 1030 = BTU/LB of Heat to Vaporize Water in Fuel & Water Formed by Combustion of Hydrogen

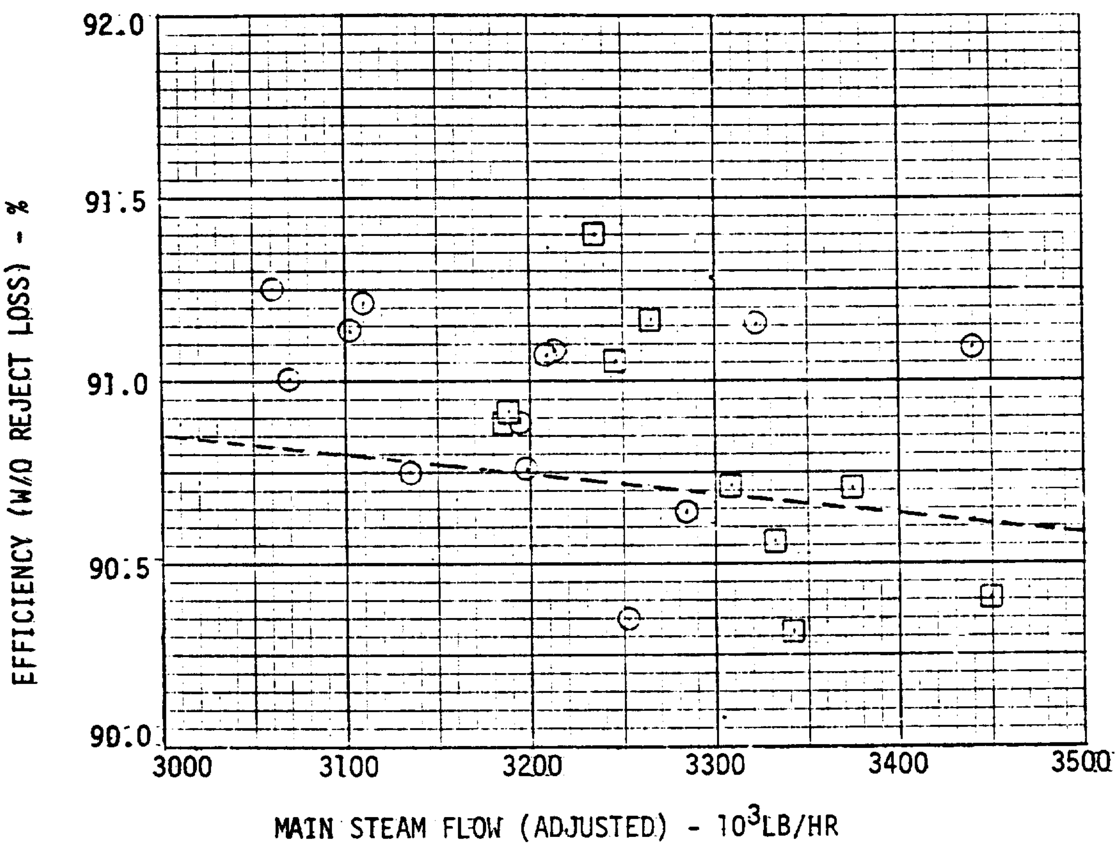
HV = 41.4 (2138.7) (1030) = 91.2 X 10^6 BTU/HR

2. Combustible Heat Loss, CHL

CHL = CL (Heat Input from Fuel)

CHL = .27 (2138.7) = 5.8 X 10^6 BTU/HR

EEFFICIENCY (W/O REJECT LOSS)
VERSUS
MAIN STEAM FLOW (ADJUSTED)



⊡ - 5 Mills In Service
⊙ - 4 Mills In Service

Dashed Line is Average Efficiency (W/O Reject Loss) As Determined For Performance Tests, Aug., 1962.

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SUMMARY OF TEST DATA

TEST NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Date	4/15/71	4/15/71	4/15/71	4/15/71	4/15/71	4/16/71	4/16/71	4/16/71	4/16/71	4/17/71	4/17/71	4/21/71	4/21/71	4/20/71	4/20/71
Gross Load MW	460	470	460	475	475	460	465	455	455	480	480	430	430	447	450
FLOWS - 10^3 LB/HR															
Main Steam (Integ.)	3253.8	3207.3	3057.0	3326.4	3405.4	3243.1	3187.7	3163.8	3120.0	3381.3	3360.0	3436.4	3410.5	3509.3	3498.8
Main Steam (Adjusted)	3286.3	3197.7	3102.9	3373.0	3332.4	3308.0	3187.7	3195.4	3135.6	3448.9	3343.2	3109.9	3069.5	3246.1	3236.4
Reheat Steam (Graph)	2555	2490	2420	2610	2585	2570	2485	2485	2445	2660	2595	2425	2400	2525	2515
Wet Products Ent. AH - B	2018.5	2004.0	1867.1	2141.1	2191.1	1954.7	1963.3	2092.1	2061.7	2137.5	2213.3	1796.3	1802.5	1835.2	1802.2
Dry Products Ent. AH - B	1906.2	1891.7	1765.0	2026.4	2070.2	1843.4	1853.3	1923.6	1952.9	2019.6	2092.3	1695.3	1699.8	1728.6	1701.2
Wet Air Ent. AH - B	1855.3	1840.3	1711.0	1976.2	2017.0	1792.9	1802.8	1876.0	1905.8	1967.8	2039.4	1648.8	1653.0	1679.3	1646.3
Dry Air Ent. AH - B	1831.4	1816.6	1688.9	1950.7	1990.9	1770.0	1779.6	1851.9	1881.4	1942.6	2013.2	1627.6	1631.8	1657.8	1625.2
Wet Products Lvg. AH - B	2159.9	2144.2	1997.8	2291.0	2344.4	2091.7	2100.8	2174.4	2206.0	2287.2	2348.2	1922.0	1928.7	1963.6	1928.5
Dry Products Lvg. AH - B	2045.7	2030.2	1894.0	2174.3	2221.5	1978.5	1989.1	2064.0	2095.4	2167.4	2245.3	1819.5	1824.3	1855.4	1825.7
Wet Air Lvg. AH - B	1996.5	1980.5	1841.6	2126.0	2170.4	1929.9	1940.2	2018.3	2050.1	2117.5	2194.4	1774.5	1779.2	1807.7	1772.4
Dry Air Lvg. AH - B	1970.8	1954.9	1817.9	2098.7	2142.1	1905.1	1915.3	1992.3	2023.8	2090.2	2166.1	1751.8	1756.4	1784.6	1749.7
PRESSURE - PSIG															
1st Stage	1562	1535	1524	1599	1581	1550	1542	1518	1491	1611	1607	1478	1468	1534	1548
1st Stage (Adjusted)	1559	1529	1538	1573	1564	1553	1545	1538	1524	1580	1575	1519	1515	1546	1553
TEMPERATURES - °F															
SH Outlet - B	1037	1056	1032	1030	1046	1015	1060	1029	1037	1019	1064	1014	1019	992	1018
RH Outlet - B	1024	999	1000	1018	1011	986	1013	1000	995	991	1016	989	986	968	1000
SH Outlet - A	1017	1019	1033	1064	1062	1031	1046	1053	1053	1041	1044	1030	1032	1016	1054
RH Outlet - A	985	998	1000	1025	1004	989	1019	1013	1011	1004	1013	985	990	980	1020
RH Inlet - B	598	542	585	605	593	605	600	619	598	608	609	642	645	624	650
Econ. In. - B	522	516	515	526	522	521	523	518	517	518	529	520	520	514	518
Gas Entering AH - C/D	610/632	612/632	614/631	615/632	617/634	609/623	613/630	612/627	612/626	617/633	624/640	602/611	602/610	604/613	601/605
MISCELLANEOUS															
O_2 - B %	2.62	2.68	2.89	3.59	3.36	2.55	2.66	3.64	3.95	3.38	3.58	2.32	2.50	2.01	2.19
Excess Air - B %	13.9	14.3	15.7	20.2	18.6	13.5	14.2	20.5	22.6	18.8	20.1	12.1	13.2	10.3	11.4
COAL SCALES															
Coal Flow - A 10^3 LBS/HR	192.3	178.6	177.6	182.2	186.8	185.6	188.4	180.0	177.9	198.2	190.7	181.3	167.6	187.8	194.0
Coal Flow - B 10^3 LBS/HR	196.0	187.4	186.8	189.0	195.5	194.1	197.6	189.8	184.5	198.9	200.7	182.8	174.8	198.8	195.7
Coal To Furnace - A %	49.5	48.8	48.7	49.1	48.9	48.9	48.8	48.7	49.1	49.9	48.7	49.8	49.0	48.6	49.8
Coal To Furnace - B %	50.5	51.2	51.3	50.9	51.1	51.1	51.2	51.3	50.9	50.1	51.3	50.2	51.0	51.4	50.2
MW Per Furnace - A %	227.7	229.4	224.0	233.2	232.3	224.9	226.9	221.6	223.4	239.5	233.8	214.1	210.7	217.2	224.1
MW Per Furnace - B %	232.3	240.6	236.0	241.8	242.7	235.1	238.1	233.4	231.6	240.5	246.2	215.9	219.3	229.8	225.9
MILL REJECTS - LB/HR															
Pulv. Reject Flow - B	3495	3495	3495	5625	5625	5625	5625	3495	3495	3615	3615	4905	4905	3615	3615

Boiler O

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Project 988096

Combustion Engineering, Inc.
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SUMMARY OF TEST DATA

TEST NO.		16	17	18	19	20	21	22	23	30	31	32	33	34	35
Date		4/21/71	4/21/71	4/20/71	4/20/71	4/22/71	4/22/71	4/22/71	4/22/71	4/19/71	4/19/71	4/19/71	4/19/71	4/19/71	4/19/71
Gross Load	MW	443	455	440	438	420	418	437	465	300	300	310	310	305	310
FLOWS - 10^3LB/HR															
Main Steam (Integ.)		3360.0	3329.2	3493.1	3482.2	3067.8	2929.2	3150.0	3229.5	3080.0	2700.0	2741.1	2710.6	2717.2	2756.9
Main Steam (Adjusted)		3208.8	3212.8	3266.0	3186.2	3251.9	3061.0	3323.3	3439.4	2479.4	2281.5	2371.1	2317.6	2296.0	2343.4
Reheat Steam (Graph)		2500	2500	2540	2485	2530	2385	2580	2655	1925	1770	1840	1800	1785	1820
Wet Products Ent. AH - B		1949.5	2015.8	1770.9	1839.6	1825.4	1778.1	1872.9	1943.0	1345.4	1288.1	1313.8	1367.1	1338.1	1294.9
Dry Products Ent. AH - B		1843.2	1907.9	1668.2	1734.9	1717.4	1677.9	1767.5	1834.1	1266.9	1213.9	1238.3	1290.1	1261.6	1222.1
Wet Air Ent. AH - B		1795.8	1860.5	1620.9	1687.5	1678.3	1632.0	1718.9	1784.4	1231.0	1180.0	1202.9	1255.7	1225.1	1182.8
Dry Air Ent. AH - B		1772.9	1836.6	1600.2	1665.7	1656.7	1611.1	1696.9	1761.6	1215.1	1165.0	1187.4	1239.6	1209.4	1167.6
Wet Products Lvg. AH - B		2086.0	2156.9	1894.8	1968.3	1953.2	1902.4	2003.9	2079.0	1439.5	1378.2	1405.9	1462.8	1431.8	1385.6
Dry Products Lvg. AH - B		1978.1	2047.2	1790.7	1861.9	1843.5	1800.9	1896.9	1968.4	1359.8	1302.9	1329.0	1384.5	1354.1	1311.6
Wet Air Lvg. AH - B		1932.2	2001.5	1744.9	1816.2	1805.9	1756.4	1850.1	1920.4	1325.1	1270.3	1294.9	1351.4	1318.9	1273.5
Dry Air Lvg. AH - B		1907.5	1975.9	1722.4	1792.9	1782.8	1733.9	1826.3	1895.7	1308.0	1254.0	1278.3	1334.0	1301.9	1257.0
PRESSURE - PSIG															
1st Stage		1526	1534	1511	1515	1435	1391	1494	1511	1094	1037	1103	1071	1063	1088
1st Stage (Adjusted)		1541	1545	1538	1536	1507	1481	1530	1599	1335	1296	1329	1317	1310	1327
TEMPERATURES - °F															
SH Outlet - B		1015	1034	978	1010	919	956	960	963	892	911	905	924	933	934
RH Outlet - B		982	1008	964	989	872	912	912	916	834	856	846	862	882	890
SH Outlet - A		1042	1061	1044	1053	968	990	984	982	914	933	916	944	958	973
RH Outlet - A		994	1018	1002	1022	894	936	919	920	853	862	849	870	907	918
RH Inlet - B		676	641	639	644	536	553	559	566	545	542	532	549	556	562
Econ. In. - B		523	526	510	512	512	510	515	516	486	486	487	484	481	483
Gas Entering AH - C/D		608/616	613/620	598/607	607/613	588/591	589/593	599/607	599/607	545/553	549/554	551/558	549/559	548/558	551/559
MISCELLANEOUS															
O_2 - B	%	3.14	3.58	2.08	2.57	2.36	2.58	2.29	2.44	1.96	2.28	2.00	2.88	2.27	2.18
Excess Air	%	17.2	20.1	10.7	13.6	12.3	13.7	12.0	12.8	10.1	11.9	10.3	15.5	11.8	11.4
COAL SCALES															
Coal Flow - A	10^3LBS/HR	182.1	182.2	180.0	191.1	171.7	168.0	180.0	171.4	152.3	137.1	144.5	138.5	138.5	148.8
B	10^3LBS/HR	181.7	179.7	186.5	186.1	166.5	165.2	174.3	178.4	151.9	152.6	153.1	148.6	133.9	141.5
Coal To Furnace - A	%	50.1	50.4	49.1	50.7	50.8	50.4	50.8	49.0	50.1	47.3	48.6	48.2	50.8	51.3
B	%	49.9	49.6	50.9	49.3	49.2	49.6	49.2	51.0	49.9	52.7	51.4	51.8	49.2	48.7
MW Per Furnace - A	%	221.9	229.3	216.0	222.1	213.4	210.7	222.0	227.9	150.3	141.9	150.7	149.4	154.9	159.0
B	%	221.1	225.7	224.0	215.9	206.6	207.3	215.0	237.1	149.7	158.1	159.3	160.6	150.1	151.0
MILL REJECTS - LB/HR															
Pulv. Reject Flow - B		4905	4905	3615	3615	3495	4905	4905	3495	2940	2940	1845	1845	1815	1815

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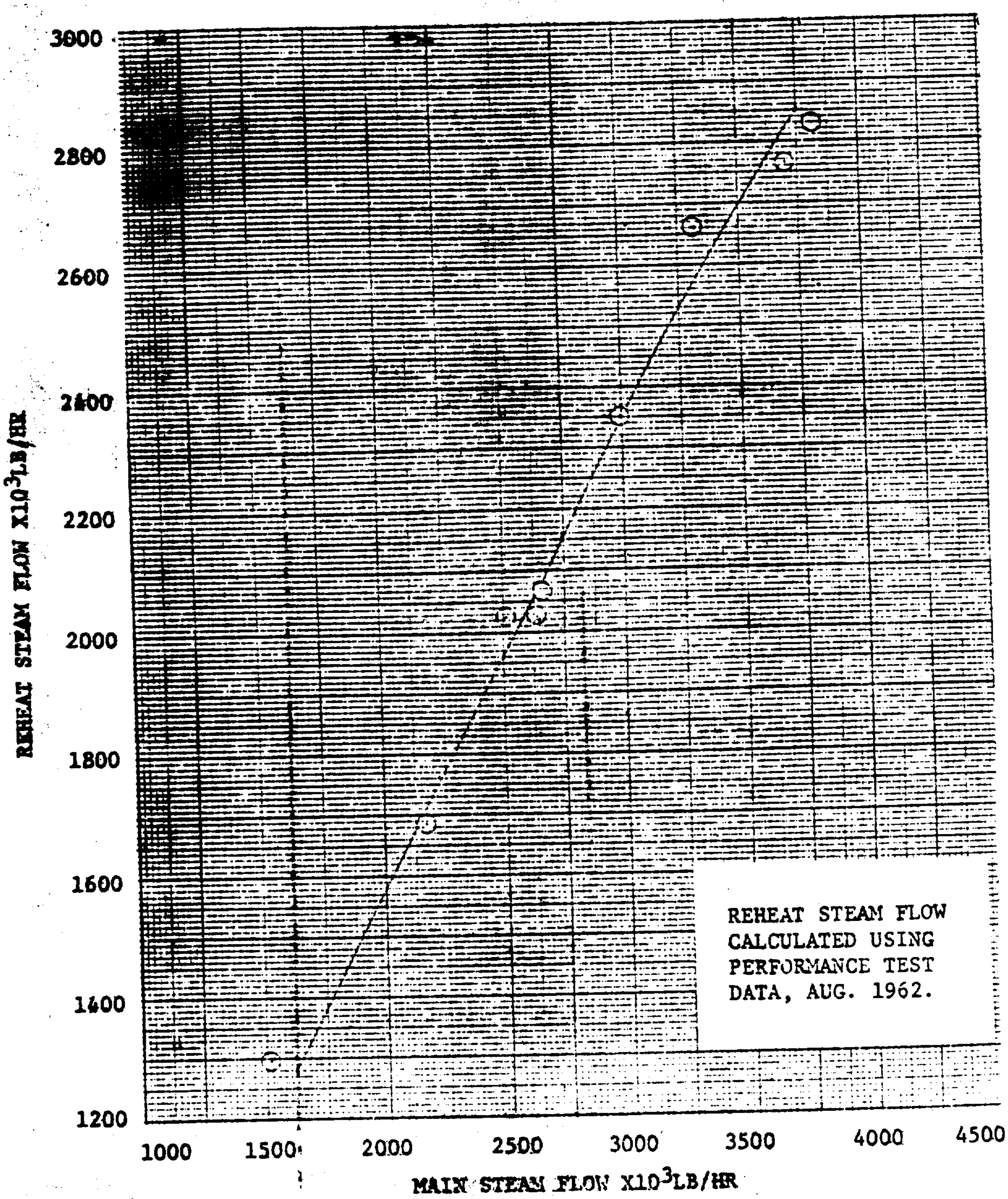
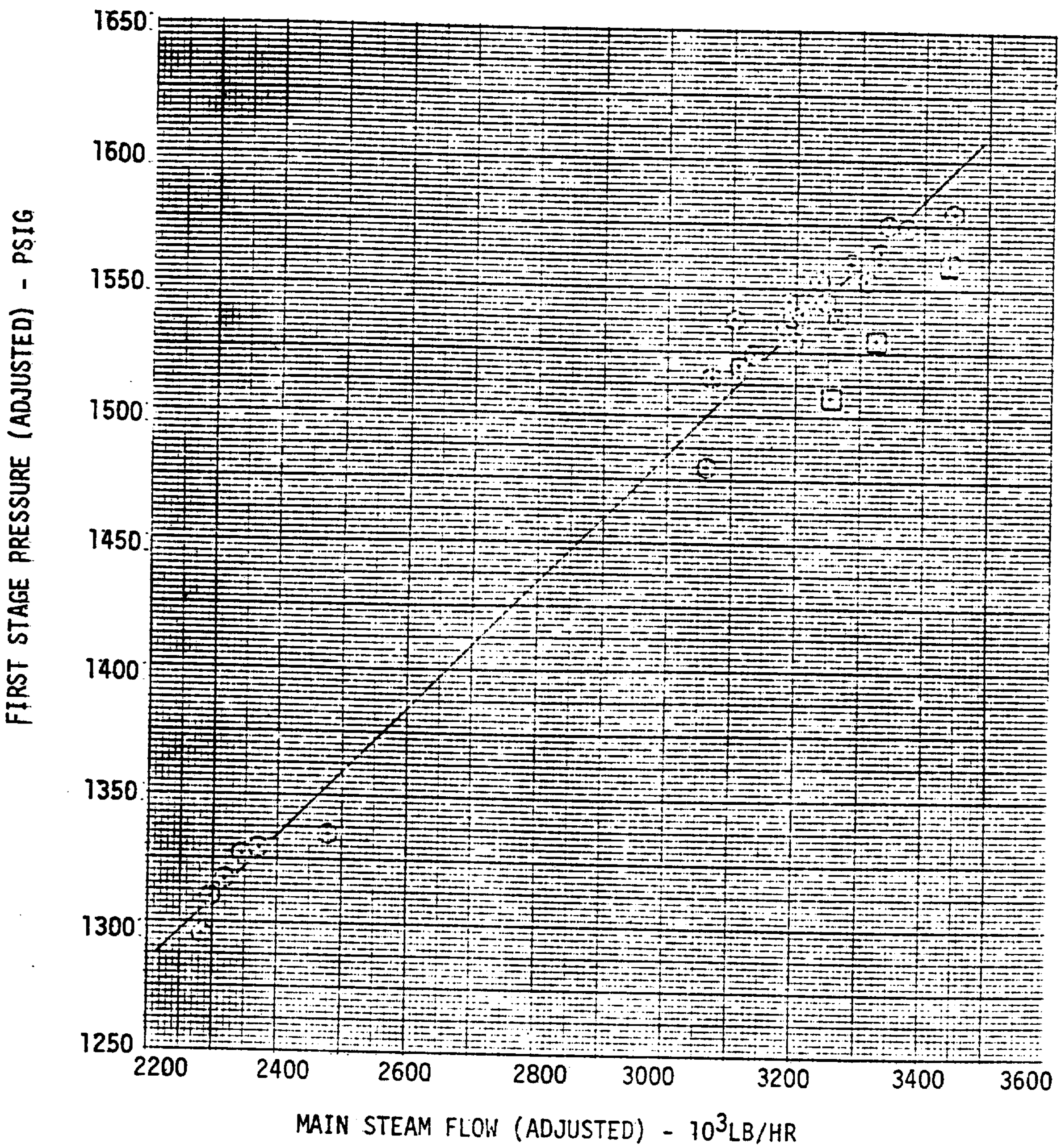
REHEAT STEAM FLOW
VERSUS
MAIN STEAM FLOW



MAIN STEAM FLOW (ADJUSTED)
VERSUS
FIRST STAGE PRESSURE (ADJUSTED)



Boiler O
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Combustion Engineering, Inc.
Field Testing &
Performance Results

SAMPLE CALCULATION OF GAS & AIR FLOWS

TEST #1

1. ULTIMATE COAL ANALYSIS

Carbon	-- 61.3%
Hydrogen	-- 4.3%
Nitrogen	-- 1.5%
Oxygen	-- 7.1%
Sulfur	-- 3.7%
Moisture	-- 7.5%
Ash	-- 14.6%
TOTAL	100.0%

HHV = 11,160 BTU/LB.

2. THEORETICAL DRY AIR, TDA

$$TDA = \left[\frac{11.54\ (\%\ C) + 34.34\ (\%\ H - \frac{\%\ O}{8}) + 4.32\ (\%\ S)}{HHV \times 10^6}\right] \times 10^4$$

Where: 11.54 = LBS. Air to Burn One Lb. C

34.34 = LBS. Air to Burn One Lb. H

4.32 = LBS. Air to Burn One Lb. S

$$TDA = \left[\frac{11.54\ (61.3) + 34.34\ (4.3 - \frac{7.1}{8}) + 4.32\ (3.7)}{11,160 \times 10^6}\right] \times 10^4$$

$TDA = 753.20\ LB/10^6 BTU$

3. MOISTURE IN AIR, MA

$MA = .013\ (TDA)$

Where: .013 = Standard Specific Humidity

$MA = .013\ (753.20) = 9.79\ LB/10^6 BTU$

4. THEORETICAL WET AIR, TWA

$TWA = TDA + MA$

$TWA = 753.20 + 9.79 = 762.99\ LB/10^6 BTU$

5. FUEL IN PRODUCTS, F

$$F = \frac{(100 - \%\ Ash - \%\ SCL)}{HHV \times 10^6}$$

Where: % SCL = CL (HHV, Fuel/14,450)

$$F = \frac{(100 - 14.6 - .2)}{11,160 \times 10^6} \times 10^4 = 76.34\ LB/10^6 BTU$$

6. MOISTURE FROM FUEL, MF

$$MF = \frac{(\%\ Moisture) + 9\ (\%\ H)}{HHV \times 10^6} \times 10^4$$

Where: 9 = LB Moisture Formed by Burning 1 LB Hydrogen

$$MF = \frac{(7.5) + 9\ (4.3)}{11{,}160 \times 10^6} \times 10^4 = 41.40\ LB/10^6 BTU$$

7. GAS FLOWS ENTERING AIRHEATER AT 13.9% EXCESS AIR

A. – Dry Air, DA

$$DA = \left[1 + \frac{\%\ Excess\ Air}{100}\right] (TDA)\ (K)$$

Where: K = 1 - (% SCL/100)

$$DA = \left[1 + \frac{13.9}{100}\right] (753.20)\ (.998) = 856.17\ LB/10^6 BTU$$

DA (Flow) = DA (Heat Input From Fuel)

DA (Flow) = 856.17 (2138.7) = 1831.4 X 10^3 LB/HR

B. Moisture In Air, MA

MA = .013 (DA)

MA = .013 (856.17) = 11.13 LB/10^6BTU

C. Wet Air, WA

WA = DA + MA

WA = 856.17 + 11.13 = 867.30 LB/10^6BTU

WA (Flow) = WA (Heat Input From Fuel)

WA (Flow) = 867.30 (2138.7) = 1855.3 X 10^3 LB/HR

D. Wet Products, WP

WP = F + WA

WP = 76.34 + 867.30 = 943.64 LB/10^6BTU

WP (Flow) = WP (Heat Input From Fuel)

WP (Flow) = 943.64 (2138.7) = 2018.5 X 10^3 LB/HR

E. Dry Products, DP

$DP = WP - MA - MF$

$DP = 943.64 - 11.13 - 41.40 = 891.11 \ LB/10^6BTU$

DP (Flow) = DP (Heat Input From Fuel)

DP (Flow) = 891.11 (2138.7) = 1906.2×10^3 LB/HR

8. GAS FLOWS LEAVING AIRHEATER AT 22.6 % EXCESS AIR

A. Dry Air, DA

$$DA = \left[1 + \frac{\%\ \text{Excess Air}}{100}\right](TDA)\ (K)$$

$$DA = \left[1 + \frac{22.6}{100}\right](753.20)(.998) = 921.58\ LB/10^6BTU$$

DA (Flow) = DA (Heat Input From Fuel)

DA (Flow) = 921.58 (2138.7) = 1970.8×10^3 LB/HR

B. Moisture in Air, MA

MA = .013 (DA)

MA = .013 (921.58) = 11.98 $LB/10^6BTU$

C. Wet Air, WA

WA = DA + MA

WA = 921.58 + 11.98 = 933.56 $LB/10^6BTU$

WA (Flow) = WA (Heat Input From Fuel)

WA (Flow) = 933.56 (2138.7) = 1996.5×10^3 LB/HR

D. Wet Products, WP

WP = F + WA

WP = 76.34 + 933.56 = 1009.90 $LB/10^6BTU$

WP (Flow) = WP (Heat Input From Fuel)

WP (Flow) = 1009.90 (2138.7) = 2159.9×10^3 LB/HR

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E. Dry Products, DP

$DP = WP - MA - MF$

$DP = 1009.90 - 11.98 - 41.40 = 956.52$ LB/10^6BTU

DP (Flow) = DP (Heat Input From Fuel)

DP (Flow) = 956.52 (2138.7) = 2045.7 X 10^3LB/HR

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BOARD AND COMPUTER DATA

TEST NO.	1	2	3	4	5	6	7	8	9	10
Date	4/15/71	4/15/71	4/15/71	4/15/71	4/15/71	4/16/71	4/16/71	4/16/71	4/16/71	4/17/71
Gross Load - MW	460	470	460	475	475	460	465	455	455	480
FLOWS - 10^3LB/HR										
Main Steam (Integ.)	3253.8	3207.3	3057.0	3326.4	3315.8	3243.1	3187.7	3163.8	3120.0	3381.3
Main Steam A/B	1690/1650	1680/1620	1640/1610	1720/1680	1710/1680	1680/1620	1660/1620	1640/1600	1620/1590	1750/1700
Main Steam Total	3400	3370	3310	3470	3420	3380	3350	3300	3280	3500
Air Flow A/B	1620/1580	1580/1560	1590/1550	1710/1700	1710/1680	1670/1500	1550/1500	1670/1620	1670/1620	1790/1710
Air Flow Total	3220	3200	3190	3500	3500	3200	3200	3300	3300	3500
Feedwater (Integ.)	3446.5	3417.9	3248.9	3528.0	3511.7	3420.0	3389.7	3335.8	3307.5	3564.9
Feedwater Total	3500	3480	3400	3520	3520	3450	3400	3350	3300	3525
SH DESH Spray B LS/RS	0/0	4/17.5	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0
RH DESH Spray B LS/RS	0/0	0/27	0/10	0/0	0/14.5	0/0	0/10	0/0	0/8	0/0
#3A Heater Drain	300	290	290	310	305	300	300	290	285	300
#3B Heater Drain	325	325	325	335	330	335	325	325	320	325
SH DESH Spray A LS/RS	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0
RH DESH Spray A LS/RS	0/0	0/0	0/0	0/0	0/0	0/0	0/2	0/0	0/0	0/0
Inj. Water Leakoff	52	52	52	52	52	51	51	51	51	52
Inj. Water	82	82	80	83	82	81	78	80	79	85
Soot Blowing Sta. (Integ.)	—	—	—	—	—	—	—	—	—	—
*Gas Flow A/B	1492/1524	1528/1490	1441/1474	1629/1604	1654/1594	1509/1463	1983/1512	1567/1546	1494/1533	1612/1626
PRESSURES - PSIG										
Drum	2550	2550	2550	2570	2570	2550	2550	2550	2550	2550
SH Outlet A/B	2450/2450	2450/2450	2450/2450	2450/2450	2450/2450	2450/2440	2450/2450	2450/2440	2450/2440	2450/2450
RH Outlet A/B	380/367	380/370	372/362	390/378	392/380	377/365	377/365	368/355	365/350	385/375
Main Steam	2400	2400	2400	2420	2420	2400	2400	2400	2400	2400
Feedwater	2750	2750	2750	2780	2780	2750	2750	2750	2740	2800
RH Inlet A/B	405/402	405/402	398/392	418/412	418/412	401/397	402/398	394/390	382/380	417/410
PRESSURES - IN. H_2O										
Furnace A/B	-0.70/-0.50	-0.70/-0.50	-0.70/-0.70	-0.60/-0.48	-0.60/-0.48	-0.65/-0.52	-0.75/-0.52	-0.62/-0.40	-0.55/-0.40	-0.70/-0.40
High Temp. SH Diff. A/B	0.90/0.85	0.90/0.90	0.90/0.90	1.2/1.2	1.0/1.0	0.75/0.80	0.75/0.90	0.80/0.90	0.80/0.90	0.80/1.0
RH Diff. A/B	0.12/0.10	0.13/0.10	0.13/0.10	0.16/0.12	0.15/0.11	0.14/0.09	0.13/0.07	0.14/0.10	0.14/0.10	0.18/0.18
Low Temp. SH Diff. A/B	2.7/2.3	2.7/2.2	2.7/2.2	3.2/2.5	3.2/2.4	2.8/2.2	2.8/2.2	3.0/2.3	2.8/2.3	3.2/2.5
Econ. Diff. A/B	0.95/1.3	0.95/1.3	0.95/1.25	1.1/1.4	1.1/1.35	1.0/1.2	0.95/1.25	1.0/1.3	1.0/1.3	1.15/1.40
AH Diff. A/B	2.8/1.8	2.7/2.0	2.7/2.0	3.0/2.4	3.0/2.3	2.6/2.2	2.7/2.3	2.7/2.2	2.7/2.2	3.0/2.5
C/D	2.5/3.5	2.6/3.5	2.7/3.6	3.0/4.0	2.8/3.8	2.6/3.5	2.5/3.5	2.7/3.7	2.7/3.7	2.5/4.0
Circ. Pump Diff. (PSID)	24	25	25	24	24	25	25	25	25	25
FD Fan Disch. A/B	5.2/5.8	5.2/5.5	5.2/5.5	6.0/6.0	6.0/6.0	5.2/5.5	5.0/5.5	5.2/6.2	5.2/6.2	6.0/6.0
C/D	6.5/7.0	6.5/7.0	6.2/7.0	6.8/7.2	6.8/7.2	6.2/7.0	6.0/6.5	7.0/7.2	6.8/7.5	7.3/8.0
Air Leaving AH A-B	3.2	2.9	2.9	3.2	3.2	3.0	2.7	3.2	3.0	3.5
C-D	3.7	3.7	3.5	4.0	4.0	3.6	3.3	4.0	3.8	4.5
Windbox A RS/LS	2.3/2.7	2.3/2.3	2.2/2.3	2.5/2.7	2.7/2.9	2.3/2.5	2.2/2.3	2.4/2.7	2.5/2.7	2.7/3.0
Windbox B RS/LS	2.7/2.5	2.7/2.4	2.3/2.3	2.7/2.5	2.7/2.7	2.3/2.3	2.3/2.0	2.8/2.8	2.8/2.8	3.3/3.3
ID Fan Inlet A/B	10.7/9.8	10.1/9.4	10.3/9.5	12.0/11.0	12.0/11.0	10.8/10.2	10.6/10.0	11.0/10.2	11.0/10.5	12.5/11.5
C/D	9.7/10.5	9.5/10.2	9.5/10.2	10.5/10.5	10.5/11.2	9.0/10.0	9.2/10.0	10.0/10.5	9.7/10.5	10.5/11.5
TEMPERATURES - °F										
SH Outlet A R/L	980/1035	995/1050	1000/1053	1015/1070	1025/1080	995/1050	1000/1055	1005/1065	1010/1070	1010/1065
RH Outlet A R/L	955/980	975/990	988/990	995/1005	975/995	955/975	985/1000	975/994	980/1005	980/1000
SH Outlet B R/L	1012/1050	1025/1070	1015/1045	1005/1030	1022/1050	1000/1020	1035/1065	1005/1030	1020/1045	1010/1080
RH Outlet B R/L	980/1090	965/1050	970/1010	980/1005	980/1012	970/975	990/1005	975/994	990/990	980/930
SH Outlet A	1010	1030	1038	1055	1060	1025	1030	1045	1050	1040
RH Outlet A	980	995	1010	1015	1000	980	1000	1000	1000	1010
SH Outlet B	1040	1055	1038	1025	1047	1015	1055	1026	1040	1025
RH Outlet B	1025	1055	1010	1013	1010	980	1010	995	990	995
Econ. Link Tubes A/B	—/—	—/—	—/—	—/—	—/—	620/620	625/630	625/625	625/625	625/630
Gas Leaving AH A/B	295/255	290/272	290/270	295/290	300/293	292/288	293/288	300/265	302/267	295/290
C/D	264/263	266/265	268/266	275/275	278/280	275/275	279/280	260/259	264/262	265/260
Air Entering AH A/B	92/95	96/99	100/105	103/107	105/108	103/106	106/109	97/98	100/102	90/95
C/D	97/95	101/98	105/102	108/105	110/107	109/105	110/107	98/100	103/100	90/90
*Gas Entering AH A/B	601/612	602/614	603/613	613/625	615/627	603/614	605/615	606/616	606/617	611/623
* C/D	614/620	618/626	613/617	619/622	623/627	612/613	619/621	616/614	617/617	621/621
*SH Platen Outlet Hdr. A/B	783/778	779/799	797/790	787/774	796/787	787/779	790/794	799/774	793/775	792/778
*Hor. SH Outlet Hdr. A/B	907/911	916/939	929/917	952/919	962/937	926/903	938/932	942/914	942/932	947/918
*SH Outlet Hdr.	1055/1041	1059/1059	1077/1066	1101/1065	1106/1090	1069/1062	1079/1087	1091/1050	1096/1064	1088/1058
*RH Outlet Hdr. A/B	1012/1050	1024/1037	1039/1040	1054/1047	1037/1049	1009/1016	1036/1045	1029/1029	1033/1034	1034/1030
*Air Leaving AH A/B	540/515	540/530	539/527	543/542	548/546	540/535	543/536	548/515	548/517	544/540
* C/D	510/530	514/535	513/531	516/536	521/541	519/534	526/542	504/522	507/526	509/526
*SH Spray Water B	354	355	355	356	354	353	348	348	347	363
*RH Spray Water B	351	353	353	354	352	350	345	346	344	360

*Computer

BOARD AND COMPUTER DATA

TEST NO.	1	2	3	4	5	6	7	8	9	10
Date	4/15/71	4/15/71	4/15/71	4/15/71	4/15/71	4/16/71	4/16/71	4/16/71	4/16/71	4/17/71
Gross Load - MW	460	470	460	475	475	460	465	455	455	480
MILL DATA										
Mill Amps A1/A2	0/98	0/96	0/61	54/54	53/56	54/54	55/54	0/98	0/98	55/55
A3/A4	52/53	53/53	53/53	50/50	52/52	50/50	51/51	54/54	51/53	50/52
A5/B1	54/0	54/0	54/0	52/62	54/63	52/64	52/65	56/0	54/0	50/64
B2/B3	54/61	55/62	54/61	57/60	58/61	58/62	61/61	56/64	54/62	53/61
B4/B5	59/61	58/64	60/64	63/60	62/60	54/56	54/56	58/58	56/54	55/55
Pulv. Supply Air - In. H_2O A1/A2	0/-1.1	0/-1.2	0/-1.4	-1.6/-1.3	-1.8/-1.3	-1.8/-1.4	-2.0/-1.4	0/-1.4	0/-1.4	-1.8/-1.2
A3/A4	-1.7/-1.6	-1.8/-1.7	-2.1/-2.1	-1.8/-1.6	-1.8/-1.7	-2.0/-1.6	-2.2/-1.9	-2.0/-2.0	-2.0/-1.5	-1.8/-1.8
A5/B1	-1.5/0	-1.8/0	-2.1/0	-1.6/-1.4	-1.7/-1.5	-1.8/-1.8	-1.8/-1.8	-1.6/0	-1.5/0	-1.5/-1.5
B2/B3	-2.1/-1.4	-2.0/-1.4	-2.6/-1.9	-2.3/-1.7	-2.2/-1.7	-2.4/-1.8	-2.3/-2.0	-2.1/-1.5	-2.2/-1.6	-1.8/-1.2
B4/B5	-1.0/-0.9	-1.0/-0.9	-1.3/-1.4	-1.0/-1.1	-1.5/-1.0	-1.8/-1.5	-1.9/-1.5	-1.7/-1.3	-1.9/-1.4	-1.6/-1.1
Pulv. Discharge - In. H_2O A1/A2	0/12.5	0/13.0	0/11.5	11.5/12.0	11.0/11.5	11.0/12.0	11.0/11.5	0/12.0	0/12.0	12.5/12.0
A3/A4	12.5/10.0	12.5/10.0	12.0/9.0	12.0/9.5	11.5/10.0	11.5/9.0	11.5/9.0	12.0/10.0	12.0/10.0	12.0/10.0
A5/B1	12.5/0	12.5/0	12.0/0	12.0/10.5	11.5/10.0	11.5/10.5	11.5/10.0	12.5/0	12.0/0	12.0/12.0
B2/B3	13.0/14.0	13.0/13.5	13.0/13.0	12.5/13.5	12.0/13.0	12.0/13.0	11.5/12.5	14.0/13.5	13.0/13.0	13.5/13.5
B4/B5	12.0/12.5	12.5/11.0	11.5/11.5	11.0/10.5	11.0/10.0	10.0/11.0	9.5/10.5	12.0/12.0	12.0/11.0	12.0/12.0
Pulv. Coal Air - °F A1/A2	92/165	94/172	97/172	182/174	182/176	183/175	182/175	105/176	102/170	181/178
A3/A4	178/174	177/178	177/174	180/174	180/176	178/174	178/174	181/177	180/170	178/170
A5/B1	174/88	176/90	175/92	176/168	176/168	173/164	175/164	174/103	170/98	172/166
B2/B3	192/176	185/176	178/177	185/178	185/176	180/174	180/175	172/176	174/178	167/178
B4/B5	180/174	180/167	168/164	178/186	178/174	166/176	165/176	166/173	164/174	168/179
Feeder RPM A1/A2	0/10.6	0/10.0	0/9.8	8.1/9.0	7.2/9.0	7.8/8.8	8.0/9.0	0/10.8	0/10.8	8.8/8.7
A3/A4	10.3/8.3	10.6/8.9	9.8/8.0	9.3/7.4	9.3/7.5	9.1/7.6	9.1/7.5	11.1/9.4	11.0/9.4	8.7/8.8
A5/B1	10.7/0	11.2/0	10.2/0	9.3/6.8	9.3/6.8	9.3/8.2	9.4/8.2	11.3/0	11.2/0	9.1/8.5
B2/B3	10.9/9.4	11.2/9.6	10.0/8.6	9.5/8.2	9.5/8.2	9.2/8.9	9.2/8.9	10.8/10.2	10.5/10.0	8.5/8.7
B4/B5	11.0/11.3	11.2/11.4	10.0/10.4	9.7/9.8	9.6/9.8	5.9/9.2	5.9/9.2	10.6/10.8	10.5/10.5	8.5/8.9
Exhauster - % Open A1/A2	0/88	0/89	0/84	65/80	60/80	64/80	65/80	0/95	0/96	79/80
A3/A4	83/94	82/95	89/91	73/86	74/86	86/98	86/98	98/100	99/100	94/99
A5/B1	94/0	88/0	84/0	67/55	78/95	86/67	88/68	100/0	100/0	79/77
B2/B3	82/91	82/90	89/88	71/83	71/82	84/79	85/81	94/91	94/98	98/81
B4/B5	80/83	80/83	78/82	73/76	84/74	64/96	66/97	96/100	96/100	83/82
MISCELLANEOUS										
Drum Level - In.	-1.5	-1.5	-1.5	-1.5	-1.5	-1.1	-1.0	-1.3	-1.5	-1.2
Fuel Nozzle Tilt A/B - Deg.	-30/-30	-15/+30	-5/0	-10/-30	0/0	+12/-30	+6/0	+25/-30	+12/0	+11.5/-30
O_2 A/B - %	3.3/2.7	3.3/3.4	3.8/3.6	3.9/4.8	4.3/3.8	3.5/3.2	3.5/3.0	3.0/4.8	3.5/4.0	4.0/4.6
FD Fan Amps A/B	74/73	73/72	72/72	77/75	77/75	73/73	72/73	72/77	72/77	78/77
C/D	75/82	75/82	74/82	78/85	78/85	73/81	73/80	78/85	78/84	80/88
ID Fan Amps A/B	160/140	150/151	152/145	182/180	180/180	155/161	155/160	158/158	155/157	180/175
C/D	143/147	141/148	142/147	157/162	158/164	139/142	139/142	146/150	144/150	161/165
Boiler Circ. Pump Amps A/B	42/40	42/41	42/40	42/40	42/40	43/41	42/41	43/41	43/41	42/41
C/D	41/41	41/42	41/42	41/41	41/41	41/41	42/42	41/41	41/42	42/42
FD Fan Inlet Vanes - % Open A/B	54/54	54/53	54/52	58/58	58/57	56/56	56/55	60/59	59/59	58/58
C/D	60/59	59/58	58/58	65/64	64/63	57/56	57/56	62/62	62/61	65/64
ID Fan - % Speed A/B	72/71	72/72	71/71	85/84	83/83	73/73	73/72	73/72	71/71	78/78
C/D	68/68	66/66	66/66	72/72	72/72	63/63	64/64	68/67	66/66	73/72
SH DESH Valve A/B - % Open	0/0	0/43	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0
RH DESH Valve A/B - % Open	0/0	0/48	0/12	0/0	0/37.5	0/0	11/25	0/0	0/5	0/0
Damper Pos. A - % Open Top Aux./Coal	6/6	6/6	6/6	6/3	3/6	3/6	6/3	6/6	6/6	3/6
Aux./Coal	6/6	6/6	6/3	6/3	3/6	3/6	6/3	6/4	6/6	3/6
Aux./Coal	3/6	3/6	4/3	4/3	4/6	4/6	3/3	4/4	3/6	4/6
Aux./Coal	3/6	3/6	3/3	4/3	4/6	3/6	3/3	3/4	3/6	4/6
Aux./Coal	3/6	3/6	3/3	3/3	4/6	3/6	3/3	3/4	3/6	4/6
Bot. Aux.	3	3	3	3	4	3	3	3	3	4
Damper Pos. B - % Open Top Aux./Coal	6/6	6/6	6/6	6/3	3/6	3/6	6/3	6/6	6/6	3/6
Aux./Coal	6/6	6/6	6/3	6/3	3/6	3/6	6/3	6/4	6/6	3/6
Aux./Coal	3/6	3/6	4/3	4/3	4/6	4/6	3/3	4/4	3/6	4/6
Aux./Coal	3/6	3/6	3/3	4/3	4/6	4/6	3/3	3/4	3/6	4/6
Aux./Coal	3/6	3/6	3/3	3/3	4/6	3/6	3/3	3/4	3/6	4/6
Bot. Aux.	3	3	3	3	4	3	3	3	3	4

Boiler O

Contract 16357
Project 900096

Combustion Engineering, Inc.
Field Testing and
Performance Results

BOARD AND COMPUTER DATA

TEST NO.	11	12	13	14	15	16	17	18	19	20
Date	4/17/71	4/21/71	4/21/71	4/20/71	4/20/71	4/21/71	4/21/71	4/20/71	4/20/71	4/22/71
Gross Load - MW	480	430	430	447	450	443	455	440	438	420
FLOWS - 10^3LB/HR										
Main Steam (Integ.)	3360.0	3436.4	3410.5	3509.3	3498.8	3360.0	3329.2	3493.1	3482.2	3067.8
Main Steam A/B	1725/1700	1790/1725	1790/1730	1810/1760	1810/1780	1720/1690	1740/1690	1800/1740	1790/1730	1600/1560
Main Steam Total	3500	3575	3400	3575	3650	3490	3500	3650	3600	3210
Air Flow A/B	1790/1700	1620/1585	1500/1490	1550/1520	1550/1520	1600/1500	1620/1620	1500/1490	1485/1480	1440/1380
Air Flow Total	3500	2960	2950	3050	3150	3160	3300	3000	3000	2890
Feedwater (Integ.)	3552.8	3210.7	3163.8	3334.7	3304.9	3325.4	3360.0	3233.2	3211.3	3360.0
Feedwater Total	3525	3140	3210	3350	3310	3210	3360	3250	3100	3490
SH DESH Spray B LS/RS	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0
RH DESH Spray B LS/RS	0/10	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0
#3A Heater Drain	300	290	310	320	310	290	300	320	295	270
#3B Heater Drain	325	345	335	350	335	310	340	350	330	350
SH DESH Spray A LS/RS	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0
RH DESH Spray A LS/RS	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0
Inj. Water Leakoff	52	57.5	57.5	61	60.5	68	59	59	59	65
Inj. Water	84	82	83	88	87	87	88	85	84	94
Soot Blowing Stm. (Integ.)	---	---	---	---	---	---	---	---	---	---
*Gas Flow A/B	1599/1631	1419/1369	1431/1371	1555/1495	1498/1451	1504/1465	1526/1500	1458/1391	1455/1374	1368/1341
PRESSURES - PSIG										
Drum	2550	2100	2090	2150	2190	2300	2350	2140	2145	2500
SH Outlet A/B	2450/2450	1990/1970	1960/1960	2010/2010	2050/2050	2200/2185	2240/2250	2010/2000	2010/2005	2420/2410
RH Outlet A/B	385/375	360/345	354/345	360/360	365/365	359/357	363/362	358/353	358/352	355/345
Main Steam	2400	1900	1910	2000	2000	2250	2170	1950	1995	2390
Feedwater	2800	2265	2260	2300	2350	2450	2580	2320	2320	2720
RH Inlet A/B	416/411	380/381	379/380	395/392	401/398	397/394	398/397	389/400	391/390	374/376
PRESSURES - IN. H_2O										
Furnace A/B	-0.50/-0.30	-0.69/-0.45	-0.60/-0.25	-0.55/-0.25	-0.68/-0.28	-0.60/-0.40	-0.65/-0.15	-0.50/-0.25	-0.55/-0.28	-0.70/-0.35
High Temp. SH Diff. A/B	0.80/1.0	0.50/0.65	0.50/0.65	0.60/0.60	0.60/0.70	0.55/0.70	0.60/0.75	0.55/0.55	0.55/0.62	0.50/0.55
RH Diff. A/B	0.18/0.13	0.12/0.30	0.12/0.15	0.13/0.08	0.15/0.07	0.15/0.50	0.60/0.70	0.15/0.70	0.14/0.70	0.11/0.03
Low Temp. SH Diff. A/B	3.1/2.5	2.4/1.9	2.4/1.8	2.5/2.0	2.5/2.0	2.5/2.0	2.8/2.1	2.5/1.9	2.5/1.9	2.2/1.7
Econ. Diff. A/B	1.20/1.45	0.90/1.0	0.90/1.1	1.0/1.4	1.0/1.2	1.0/1.4	1.1/1.3	0.95/1.2	0.95/1.2	0.9/1.1
AH Diff. A/B	2.9/2.5	2.4/1.9	2.2/2.0	2.3/2.1	2.4/2.3	2.4/2.2	2.5/2.3	2.3/2.0	2.4/2.0	2.2/2.0
C/D	3.0/4.0	2.3/2.9	2.1/2.9	2.4/2.6	2.5/3.2	2.5/3.2	2.5/3.5	2.3/3.0	2.5/3.1	2.3/2.6
Circ. Pump Diff. (PSID)	25	29.5	29.9	28	28	27.5	26.5	29	29	24.9
FD Fan Disch. A/B	5.9/6.0	5.0/5.2	5.0/5.4	5.0/5.5	6.0/6.0	5.9/6.1	5.0/5.3	5.0/5.0	4.5/4.5	5.5/5.5
C/D	7.0/7.5	6.1/6.1	5.9/6.5	6.8/7.0	7.2/7.5	7.0/7.0	6.5/7.0	6.0/7.0	6.0/6.1	6.0/6.1
Air Leaving AH A-B	3.0	3.0	3.1	3.4	3.8	3.5	2.8	3.3	2.6	3.0
C-D	3.9	3.6	3.8	4.3	4.5	4.2	3.8	4.0	3.6	3.6
Windbox A RS/LS	2.5/2.5	3.0/3.2	2.8/2.8	3.2/3.2	3.3/3.4	3.2/3.2	2.1/2.3	---/---	2.4/2.5	2.4/2.5
Windbox B RS/LS	2.5/2.5	3.2/3.2	2.8/2.8	3.0/3.0	3.9/3.9	3.2/3.1	2.6/2.5	3.3/3.3	2.6/2.5	2.6/2.6
ID Fan Inlet A/B	12.0/11.0	9.1/8.9	9.0/8.9	9.5/9.5	9.8/9.8	9.7/9.5	10.4/10.0	9.5/9.0	9.5/9.0	8.9/8.7
C/D	10.5/11.5	8.0/8.6	7.9/8.4	8.8/9.2	8.8/9.0	8.8/9.3	9.0/9.8	8.0/7.5	8.1/8.8	7.7/8.0
TEMPERATURES - °F										
SH Outlet A R/L	1005/1055	995/1035	993/1028	990/1030	1015/1055	1008/1038	1016/1060	1015/1065	1019/1060	938/985
RH Outlet A R/L	985/995	964/972	953/967	955/980	985/1012	973/967	976/1000	980/1000	990/1015	870/990
SH Outlet B R/L	1030/1055	996/1016	995/1013	985/1010	1005/1015	988/1012	1010/1026	980/995	1005/1018	924/930
RH Outlet B R/L	990/995	958/985	965/973	950/975	995/978	956/975	990/995	950/970	985/980	873/811
SH Outlet A	1035	1018	1020	1015	1050	1030	1045	1045	1060	964
RH Outlet A	1000	975	970	975	1012	980	1000	1000	1085	935
SH Outlet B	1060	1016	1016	1000	1020	1012	1030	985	1025	915
RH Outlet B	1010	985	977	970	995	976	1005	968	1000	867
Econ. Link Tubes A/B	625/640	604/607	604/606	610/612	607/610	605/608	610/612	610/610	610/612	600/600
Gas Leaving AH A/B	290/285	285/283	285/284	295/300	295/312	287/285	292/296	305/308	304/310	279/284
C/D	270/270	265/267	268/259	273/263	278/265	266/268	264/266	276/267	279/222	255/290
Air Entering AH A/B	95/100	104/109	104/107	110/107	112/113	107/110	106/110	114/116	116/118	103/106
C/D	95/95	111/107	109/106	113/107	115/111	113/107	113/111	118/115	120/116	108/104
*Gas Entering AH A/B	611/621	594/602	592/602	597/608	601/614	600/606	602/616	598/608	597/610	581/593
* C/D	624/627	603/601	604/600	604/604	612/604	603/606	614/608	601/600	608/602	590/584
*Air Leaving AH A/B	537/538	532/530	530/530	540/542	543/551	534/529	538/542	546/550	545/551	522/525
* C/D	515/535	506/525	510/518	510/521	514/523	504/524	501/522	512/522	516/528	493/504
*SH Platen Outlet Hdr. A/B	787/790	782/776	789/777	778/767	792/776	781/770	786/773	794/768	793/774	775/753
*Hor. SH Outlet Hdr. A/B	945/938	923/904	918/904	909/892	937/930	934/896	932/931	932/883	931/919	852/845
*SH Outlet Hdr. A/B	1079/1072	1073/1053	1057/1042	1067/1042	1103/1066	1082/1045	1101/1076	1095/1036	1100/1066	1012/953
*RH Outlet Hdr. A/B	1034/1039	1009/1010	1001/1003	1003/996	1037/1031	1015/1002	1034/1039	1032/995	1046/1028	916/900
*SH Spray Water B	360	323	321	326	325	335	336	323	322	361
*RH Spray Water B	358	321	320	323	323	333	335	321	320	359

*Computer

Boiler O
Contract 14357
Project 900096

Combustion Engineering, Inc.
Field Testing and
Performance Results

BOARD AND COMPUTER DATA

TEST NO.	11	12	13	14	15	16	17	18	19	20
Date	4/17/71	4/21/71	4/21/71	4/20/71	4/20/71	4/21/71	4/21/71	4/20/71	4/20/71	4/22/71
Gross Load - MW	480	430	430	447	450	443	455	440	438	420
MILL DATA										
Mill Amps A1/A2	54/54	0/55	0/53	55/54	55/55	0/58	0/60	54/54	54/54	0/56
A3/A4	50/53	54/55	51/55	50/53	50/53	54/52	54/53	50/52	50/52	53/52
A5/B1	52/64	54/0	54/0	50/65	50/65	56/0	56/0	49/63	48/62	55/0
B2/B3	54/60	56/61	57/61	53/61	53/63	57/60	57/61	54/60	54/60	54/61
B4/B5	55/54	61/54	60/54	54/49	54/49	61/61	61/61	53/47	53/48	57/54
Pulv. Supply Air - In. H_2O A1/A2	-2.2/-1.4	0/-1.0	0/-0.9	-2.0/-1.2	-1.5/-1.0	0/-0.3	0/-1.3	-1.9/-1.4	-2.5/-1.9	0/-1.7
A3/A4	-2.0/-1.8	-2.7/-1.1	-1.8/-1.5	-2.0/-1.5	-1.8/-1.0	-1.1/-0.9	-1.9/-1.5	-2.2/-1.8	-2.2/-1.9	-2.3/-1.6
A5/B1	-2.0/-1.8	-1.7/0	-1.5/0	-2.0/-1.3	-1.5/-1.0	-1.0/0	-1.9/0	-2.1/-1.3	-2.1/-1.8	-2.7/0
B2/B3	-2.2/-1.8	-2.0/-1.5	-2.0/-1.4	-2.1/-1.5	-1.4/-1.0	-2.1/-1.3	-1.9/-1.3	-1.9/-1.2	-2.1/-1.8	-2.5/-1.9
B4/B5	-2.0/-1.7	-1.1/-1.5	-1.1/-1.0	-1.6/-1.2	-1.3/-0.8	-1.2/-0.5	-1.3/-0.9	-1.5/-1.0	-2.8/-1.4	-1.7/-1.4
Pulv. Discharge - In. H_2O A1/A2	12.0/11.5	0/12.5	0/12.1	12.5/11.0	12.5/12.0	0/13.0	0/12.0	12.0/11.0	12.5/12.0	0/12.0
A3/A4	11.0/10.0	12.0/10.5	12.0/11.5	10.0/10.0	11.5/10.0	12.9/11.5	12.0/10.5	11.5/10.0	11.5/10.0	12.0/10.0
A5/B1	12.0/12.0	12.5/0	12.5/0	12.0/12.0	11.5/11.5	13.0/0	12.5/0	11.5/11.5	11.5/11.5	12.0/0
B2/B3	13.0/13.0	12.0/13.5	13.0/13.5	13.0/13.0	13.0/13.0	12.5/13.5	12.5/13.5	13.5/13.5	13.0/13.0	12.5/12.5
B4/B5	11.0/11.0	12.0/12.0	11.5/11.5	11.0/10.0	11.5/10.5	11.5/11.5	11.0/11.5	11.0/11.0	11.0/10.0	11.0/11.0
Pulv. Coal Air - °F A1/A2	182/170	102/170	108/170	178/169	176/169	102/170	102/169	177/166	175/169	105/168
A3/A4	180/165	178/165	178/167	178/161	178/166	178/166	177/166	178/164	178/166	178/167
A5/B1	170/163	177/103	177/106	175/167	175/168	176/104	178/106	174/166	174/168	176/104
B2/B3	185/175	195/175	190/176	190/171	170/170	176/176	170/175	188/172	186/172	163/175
B4/B5	168/180	184/175	184/175	186/174	178/189	183/176	184/175	177/188	178/186	183/177
Feeder RPM A1/A2	9.0/8.8	0/9.7	0/9.6	9.0/8.7	9.2/8.8	0/10.3	0/10.4	8.8/8.5	8.6/8.2	0/10.8
A3/A4	8.8/8.7	9.8/10.0	9.8/10.0	8.4/8.3	8.6/8.5	11.2/10.6	11.2/10.6	8.2/8.0	8.0/7.9	11.2/12.0
A5/B1	8.9/8.5	10.3/0	10.3/0	7.9/9.2	6.1/9.3	11.7/0	11.7/0	7.8/8.1	7.6/7.9	11.8/0
B2/B3	8.5/8.6	10.6/9.2	9.8/9.2	8.8/8.9	9.2/9.3	11.2/10.5	11.1/10.5	8.1/8.4	8.0/8.2	12.4/10.9
B4/B5	8.5/8.9	9.8/10.3	9.9/10.3	8.0/8.1	7.7/7.4	10.1/11.5	10.1/11.6	7.6/7.7	7.5/7.7	10.9/12.7
Exhauster - % Open A1/A2	78/79	0/90	0/90	82/78	83/80	0/95	0/95	80/77	79/77	0/100
A3/A4	93/99	92/96	92/98	79/88	80/89	98/100	97/100	78/87	77/86	98/100
A5/B1	79/77	98/0	98/0	71/100	73/100	100/0	100/0	57/100	69/100	100/0
B2/B3	97/82	100/86	100/87	100/84	100/88	97/96	86/95	100/82	82/83	100/82
B4/B5	83/83	94/100	94/100	80/70	78/66	98/100	96/100	77/62	77/61	86/100
MISCELLANEOUS										
Drum Level - In.	-1.1	-1.6	-1.4	-1.8	-1.6	-1.6	-1.5	-1.5	-1.6	-1.8
Fuel Nozzle Tilt A/B - Deg.	+3/0	-30/-30	0/0	+15/-30	+12.5/0	-30/-30	0/0	+20/-30	-14/0	0/0
O_2 A/B - %	3.9/4.4	2.7/2.7	2.5/2.5	3.2/2.4	2.7/2.7	3.4/3.4	3.6/3.6	2.5/2.5	2.5/2.5	2.7/2.4
FD Fan Amps A/B	78/75	72/71	72/71	71/75	74/72	73/74	73/73	72/70	71/69	70/70
C/D	79/87	73/77	72/78	75/81	76/84	76/81	76/82	73/80	72/79	72/77
ID Fan Amps A/B	178/170	134/137	134/137	139/151	140/156	142/154	152/165	139/145	140/142	130/138
C/D	160/167	125/125	125/125	135/133	135/134	137/140	141/144	127/125	132/128	120/122
Boiler Circ. Pump Amps A/B	43/42	47/45	48/46	46/45	47/44	44/43	44/42	45/45	46/46	43/43
C/D	41/42	45/45	45/46	44/44	44/44	43/44	42/43	45/45	44/45	42/44
FD Fan Inlet Vanes - % Open A/B	56/56	53/52	53/52	55/54	54/54	57/57	56/56	51/50	51/50	50/50
C/D	64/63	57/57	55/55	60/59	63/62	62/62	66/65	58/58	57/57	56/55
ID Fan - % Speed A/B	76/73	66/66	65/65	70/70	73/72	72/72	76/76	71/70	69/68	63/63
C/D	73/72	56/55	55/55	62/62	63/63	63/63	67/67	58/58	59/59	51/50
SH DeSH Valve A/B - % Open	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0
RH DeSH Valve A/B - % Open	0/25	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0
Damper Pos. A - % Open Top Aux./Coal	6/3	6/6	6/6	3/3	2/6	6/6	6/6	2/6	4/3	6/6
Aux./Coal	6/3	6/2	6/6	3/3	2/6	6/6	6/6	2/6	3/3	2/6
Aux./Coal	4/3	3/2	2/6	3/3	3/6	2/6	4/2	3/6	3/3	3/6
Aux./Coal	4/3	3/2	2/6	3/3	3/6	3/6	4/2	3/6	3/3	3/6
Aux./Coal	3/3	3/2	2/6	3/3	3/6	3/6	4/2	3/6	3/3	3/6
Bot. Aux.	3	3	3	3	4	3	4	4	4	3
Damper Pos. B - % Open Top Aux./Coal	6/3	6/6	6/6	4/3	2/6	6/6	6/6	2/6	4/3	6/6
Aux./Coal	6/3	6/2	6/6	3/3	2/6	6/6	6/6	2/6	3/3	2/6
Aux./Coal	4/3	3/2	2/6	3/3	3/6	2/6	4/2	3/6	3/3	3/6
Aux./Coal	4/3	3/2	2/6	3/3	3/6	3/6	4/2	3/6	3/3	3/6
Aux./Coal	3/3	3/2	2/6	3/3	3/6	3/6	4/2	3/6	3/3	3/6
Bot. Aux.	3	3	3	4	3	3	4	3	4	3

Boiler O
Contract 14857
Project 900096

Combustion Engineering, Inc.
Field Testing and
Performance Results

BOARD AND COMPUTER DATA

TEST NO.	21	22	23	30	31	32	33	34	35
Date	4/22/71	4/22/71	4/22/71	4/19/71	4/19/71	4/19/71	4/19/71	4/19/71	4/19/71
Gross Load - MW	418	437	465	300	300	310	310	305	310
FLOWS - 10^3LB/HR									
Main Steam (Integ.)	2929.2	3150.0	3229.5	3080.0	2700.0	2741.1	2710.6	2717.2	2756.9
Main Steam A/B	1520/1485	1620/1590	1700/1650	1550/1490	1410/1380	1430/1390	1425/1390	1400/1375	1425/1400
Main Steam Total	3050	3250	3400	2990	2710	2850	2900	2850	2730
Air Flow A/B	1420/1385	1620/1480	1600/1520	1150/1125	1090/990	1120/1000	1120/1000	1000/975	1080/980
Air Flow Total	2880	3080	3130	2100	2080	2000	2120	2000	1990
Feedwater (Integ.)	3273.8	3446.2	3552.0	2543.6	2346.2	2520.0	2408.5	2366.6	2415.9
Feedwater Total	3175	3410	3460	2450	2400	2390	2410	2300	2330
SH DSH Spray B LS/RS	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0
RH DSH Spray B LS/RS	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0
#3A Heater Drain	253	270	300	290	225	225	210	210	215
#3B Heater Drain	340	340	340	—	275	270	250	290	250
SH DSH Spray A LS/RS	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0
RH DSH Spray A LS/RS	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0
Inj. Water Leakoff	69	70	74	50	54	54	55	54	55
Inj. Water	89	95	96	60	63	65	64	63	65
Soot Blowing Stm. (Integ.)	—	—	—	9.21	9.52	8.21	6.05	—	—
*Gas Flow A/B	—/—	1398/1420	1491/1451	1145/1040	1063/1044	1106/1064	1120/1048	993/965	971/1048
PRESSURES - PSIG									
Drum	2510	2560	2625	1525	1650	1740	1750	1710	1750
SH Outlet A/B	2440/2420	2460/2460	2520/2520	1425/1425	1990/1990	1650/1650	1650/1650	1625/1625	1660/1650
RH Outlet A/B	344/330	368/354	390/379	235/240	290/240	265/255	255/250	260/245	257/250
Main Steam	2400	2420	2500	1360	1550	1600	1610	1600	1625
Feedwater	2700	2790	2700	1690	1800	1900	1890	1890	1870
RH Inlet A/B	363/362	387/384	385/383	278/278	270/270	283/281	280/279	279/278	281/282
PRESSURES - IN. H_2O									
Furnace A/B	-0.65/-0.25	-0.65/-0.30	-0.70/-0.30	-0.65/-0.10	-0.60/-0.20	-0.55/-0.20	-0.70/-0.25	-0.65/-0.45	-0.70/-0.40
High Temp. SH Diff. A/B	0.50/0.60	0.50/0.60	0.50/0.60	0.30/0.30	0.35/0.30	0.65/0.70	0.65/0.65	0.30/0.30	0.30/0.30
RH Diff. A/B	0.11/0.05	0.12/0.04	0.14/0.90	0.04/0.02	0.08/0.04	0.08/0.04	0.07/0.04	0.65/0.30	0.35/0.35
Low Temp. SH Diff. A/B	2.2/1.7	2.3/1.9	2.5/2.0	1.5/1.1	1.5/1.1	1.5/1.6	1.5/1.5	1.4/1.1	1.4/1.1
Econ. Diff. A/B	0.85/1.0	0.9/1.2	1.0/1.2	0.55/1.5	0.5/0.75	0.5/0.65	0.5/0.75	0.45/0.55	0.5/0.7
AH Diff. A/B	2.1/1.9	2.3/2.0	2.2/2.1	1.8/1.8	1.6/1.2	1.6/1.1	1.6/1.1	1.6/1.1	1.3/1.0
C/D	2.1/2.8	2.3/3.1	2.5/3.4	1.5/2.0	1.5/1.9	1.5/2.1	1.4/2.0	1.4/1.7	1.5/1.9
Circ. Pump Diff. (PSID)	24.8	26.0	21.0	34	35.5	34.5	35	35	34
FD Fan Disch. A/B	4.5/4.5	5.5/6.0	5.9/6.3	5.0/5.0	4.3/4.3	5.5/5.4	4.5/4.5	4.3/4.5	4.0/4.0
C/D	5.9/6.0	7.0/7.0	7.1/7.2	6.0/6.0	4.5/4.3	6.2/6.5	5.5/5.5	5.0/5.5	5.0/5.0
Air Leaving AH A-B	2.6	3.6	4.0	3.5	1.9	4.0	3.0	3.1	3.5
C-D	3.3	4.3	4.5	4.4	2.3	4.8	4.0	3.9	2.5
Windbox A RS/LS	2.0/2.3	3.2/3.3	3.3/3.5	3.4/3.4	1.5/1.6	3.8/3.6	2.8/3.0	2.9/3.0	2.6/2.6
Windbox B RS/LS	2.3/2.3	3.3/3.3	3.6/3.5	3.4/3.4	1.6/1.6	3.9/4.2	3.0/3.0	2.9/3.2	2.5/2.5
ID Fan Inlet A/B	8.7/8.2	9.0/9.8	9.5/9.1	5.9/5.9	6.5/5.5	6.5/5.5	6.5/5.5	6.1/5.3	6.0/5.3
C/D	7.4/8.0	8.1/8.9	8.5/9.2	5.0/5.7	5.0/5.7	5.2/6.0	5.3/6.0	5.0/5.6	5.1/5.8
TEMPERATURES - °F									
SH Outlet A R/L	953/995	960/985	955/982	885/905	900/926	900/922	909/930	925/960	945/975
RH Outlet A R/L	890/917	900/900	900/905	805/845	822/851	826/844	827/872	855/905	875/920
SH Outlet B R/L	945/955	947/915	945/960	875/895	885/904	893/914	906/921	915/960	925/990
RH Outlet B R/L	915/905	890/918	895/910	815/835	817/843	819/830	826/872	845/880	865/905
SH Outlet A	970	975	960	910	920	913	932	930	920
RH Outlet A	905	905	995	840	846	840	864	895	910
SH Outlet B	955	968	940	890	903	905	924	935	940
RH Outlet B	908	908	895	830	845	840	859	880	895
Econ. Link Tubes A/B	601/604	600/609	600/605	595/580	594/597	590/593	595/597	585/590	590/600
Gas Leaving AH A/B	281/286	285/280	288/283	260/265	264/269	270/272	268/272	283/283	280/280
C/D	254/259	262/267	263/269	240/235	239/243	244/238	247/245	249/246	249/250
Air Entering AH A/B	106/108	107/111	108/112	95/100	109/112	112/115	113/116	116/118	116/118
C/D	109/107	110/109	114/111	100/100	114/112	117/114	118/116	118/116	118/116
*Gas Entering AH A/B	—/—	590/594	593/599	547/551	545/550	548/553	549/556	547/558	553/561
* C/D	—/—	598/590	603/556	546/549	548/551	552/556	552/564	551/557	554/560
*Air Leaving AH A/B	—/—	529/522	533/523	486/494	489/498	492/498	490/902	503/508	504/508
* C/D	—/—	496/518	499/519	463/470	464/487	487/483	471/486	476/491	476/501
*SH Platen Outlet Hdr. A/B	774/765	781/776	765/756	761/741	762/750	754/747	774/753	799/773	804/775
*Hor. SH Outlet Hdr. A/B	870/873	897/890	889/855	815/800	828/805	830/805	828/812	837/822	853/887
*SH Outlet Hdr. A/B	1021/990	1027/1000	1028/995	940/—	962/915	957/940	972/960	999/971	1018/975
*RH Outlet Hdr. A/B	930/940	943/938	943/937	—/—	870/855	844/865	878/876	911/898	928/912
*SH Spray Water B	—	359	363	269	279	295	294	290	300
*RH Spray Water B	—	357	360	268	278	294	293	289	297

*Computer

Boiler O
Contract 14097
Project 900096

Combustion Engineering, Inc.
Field Testing and
Performance Results

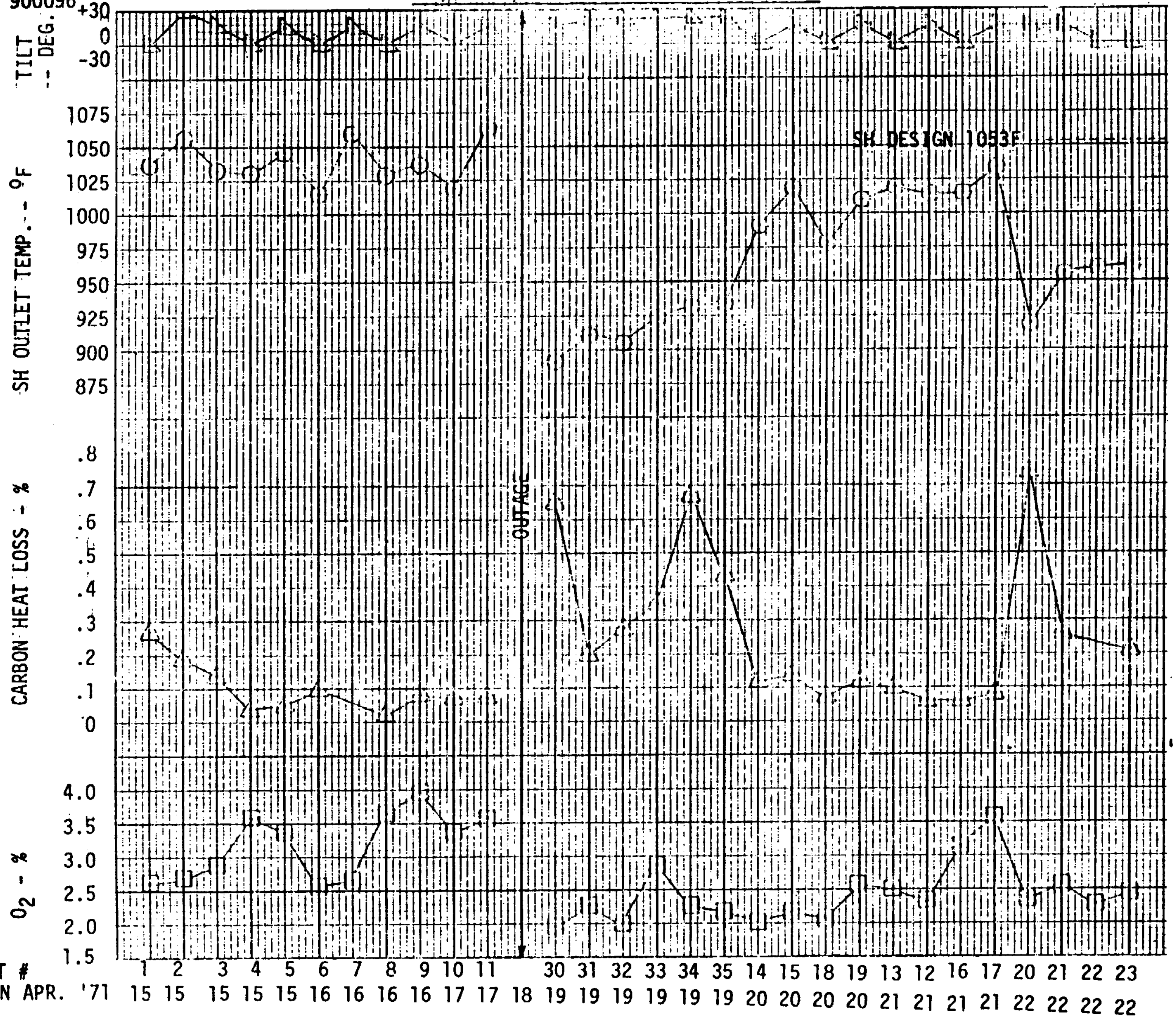
BOARD AND COMPUTER DATA

TEST NO.	21	22	23	30	31	32	33	34	35
Date	4/22/71	4/22/71	4/22/71	4/19/71	4/19/71	4/19/71	4/19/71	4/19/71	4/19/71
Gross Load - MW	418	437	465	300	300	310	310	305	310
MILL DATA									
Mill Amps A1/A2	0/59	0/57	0/57	0/60	0/56	0/0	0/0	59/0	60/0
A3/A4	54/54	54/53	52/53	55/58	52/55	52/55	52/55	53/0	53/0
A5/B1	56/0	56/0	55/0	0/0	0/0	53/0	54/0	52/67	52/67
B2/B3	59/62	58/61	54/61	55/62	56/62	0/65	0/65	0/65	0/64
B4/B5	61/62	61/62	58/60	60/0	58/0	58/59	58/55	0/54	0/55
Pulv. Supply Air - In. H_2O A1/A2	0/-1.6	0/-1.0	0/-0.5	0/-0.9	0/-2.1	0/0	0/0	-1.0/0	-1.7/0
A3/A4	-2.4/-1.9	-1.5/-0.9	-1.3/-0.7	-1.0/-1.2	-2.4/-2.3	-1.1/-0.9	-1.7/-1.8	-1.5/0	-1.7/0
A5/B1	-2.1/0	-1.0/0	-0.7/0	0/0	0/0	-1.1/0	-1.7/0	-1.5/-0.8	-1.7/-1.0
B2/B3	-2.3/-2.0	-1.1/-1.1	-1.0/-0.9	-1.9/-1.0	-3.0/-2.2	0/-0.5	0/-1.2	0/-1.4	0/-1.6
B4/B5	-1.7/-1.1	-1.0/-0.4	-0.9/-0.5	-1.2/0	-2.3/0	-1.0/-0.3	-1.4/-0.9	0/-0.8	0/-1.1
Pulv. Discharge - In. H_2O A1/A2	0/12.0	0/12.5	0/13.0	0/12.0	0/11.0	0/0	0/0	13.0/0	13.0/0
A3/A4	11.5/10.0	12.5/10.0	12.5/10.5	12.5/10.0	11.5/10.0	12.5/11.0	11.5/10.0	12.0/0	12.0/0
A5/B1	12.0/0	12.0/0	13.8/0	0/0	0/0	12.0/0	12.5/0	12.5/11.5	12.0/11.5
B2/B3	12.0/12.1	13.0/13.0	14.0/13.5	13.0/13.5	12.5/13.0	0/14.0	0/13.0	0/13.0	0/13.5
B4/B5	10.0/11.5	13.0/12.5	12.0/12.0	13.0/0	11.5/0	13.0/11.0	13.0/11.0	0/12.0	0/12.0
Pulv. Coal Air - °F A1/A2	103/167	105/178	108/177	92/178	95/185	100/95	102/150	175/143	178/144
A3/A4	174/166	178/164	180/165	178/175	178/160	165/181	178/190	175/118	178/111
A5/B1	172/100	171/102	170/100	83/88	85/92	169/95	169/98	176/163	172/160
B2/B3	184/172	186/174	179/174	164/172	158/172	75/140	120/185	112/171	110/170
B4/B5	179/176	179/179	180/178	170/106	173/109	178/165	176/170	110/138	126/162
Feeder RPM A1/A2	0/9.5	0/9.7	0/10.0	0/11.2	0/9.7	0/0	0/0	11.0/0	11.2/0
A3/A4	10.2/10.9	10.5/11.3	10.2/11.0	11.0/11.0	9.7/9.8	10.5/10.0	10.4/9.9	10.4/0	10.3/0
A5/B1	10.8/0	11.0/0	10.8/0	0/0	0/0	10.6/0	10.5/0	10.5/10.3	10.5/10.3
B2/B3	11.5/9.7	12.2/10.5	12.2/10.4	11.6/9.8	11.1/9.2	0/10.9	0/10.7	0/10.8	0/10.7
B4/B5	9.3/11.8	9.9/12.4	9.8/12.4	11.5/0	11.0/0	10.8/10.9	10.8/10.8	0/10.5	0/10.6
Exhauster - % Open A1/A2	0/92	0/93	0/95	0/81	0/83	0/0	0/0	100/0	100/0
A3/A4	90/100	94/100	92/100	94/100	89/100	94/100	93/72	94/0	95/0
A5/B1	97/0	100/0	98/0	0/0	0/0	85/0	86/0	85/100	85/100
B2/B3	100/72	100/78	100/77	98/88	94/84	0/94	0/94	0/93	0/93
B4/B5	73/91	79/98	78/96	97/0	93/0	93/86	93/86	0/85	0/86
MISCELLANEOUS									
Drum Level - In.	-1.5	-1.7	-2.0	-1.5	-1.7	-1.8	-1.6	-1.6	-1.5
Fuel Nozzle Tilt A/B - Deg.	0/0	-22/-30	-22/-30	0/0	-12/+10.5	-12/+10	-12/+10	-12/+10	-12/+10
O_2 A/B - %	2.0/2.0	2.6/2.6	2.8/2.8	2.4/2.5	2.6/2.6	2.0/2.0	2.6/2.6	2.4/2.4	2.5/2.5
FD Fan Amps A/B	70/69	72/72	73/73	70/65	64/62	69/64	68/63	64/63	65/63
C/D	71/76	75/80	76/81	66/72	65/70	69/64	67/72	66/72	65/72
ID Fan Amps A/B	139/134	132/140	137/145	120/115	115/112	116/113	116/113	105/110	105/110
C/D	119/120	127/131	131/135	100/102	100/102	102/104	102/104	100/102	100/102
Boiler Circ. Pump Amps A/B	44/42	41/40	44/44	53/51	54/53	52/51	53/51	53/50	52/50
C/D	42/42	41/41	43/44	52/52	53/54	50/52	51/52	50/51	50/51
FD Fan Inlet Vanes - % Open A/B	50/49	54/54	56/55	40/41	36/36	39/39	37/38	37/38	37/56
C/D	55/53	59/59	62/62	43/42	42/41	47/46	44/44	43/42	55/42
ID Fan - % Open A/B	63/63	65/65	69/68	63/63	61/61	61/60	60/60	54/54	56/55
C/D	51/51	57/57	60/60	35/34	42/41	37/37	37/38	32/32	33/32
SH DESH Valve A/B - % Open	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0
RH DESH Valve A/B - % Open	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0
Damper Pos. A - % Open Top Aux./Coal	6/6	6/6	6/6	1/1	4/6	1/1	6/6	4/3	2/3
Aux./Coal	4/2	6/6	4/2	1/3	2/3	1/1	1/1	1/1	3/6
Aux./Coal	3/2	2/6	3/2	3/3	3/3	2/4	2/3	2/3	2/3
Aux./Coal	3/2	2/6	3/2	3/3	3/3	3/4	2/3	2/1	2/1
Aux./Coal	3/2	2/6	3/2	4/1	3/1	3/4	2/3	1/3	1/3
Bot Aux.	3	2	3	1	1	4	3	3	2
Damper Pos. B - % Open Top Aux./Coal	6/6	6/6	6/6	1/1	4/6	1/1	6/6	4/3	2/3
Aux./Coal	4/2	6/6	4/2	1/3	2/3	1/1	1/1	1/1	3/6
Aux./Coal	3/2	2/6	3/2	3/3	3/3	2/4	2/3	2/3	2/3
Aux./Coal	3/2	2/6	3/2	3/3	3/3	3/4	2/3	2/1	2/1
Aux./Coal	3/2	2/6	3/2	4/1	3/1	3/4	2/3	1/3	1/3
Bot. Aux.	3	2	3	1	1	4	3	3	2

Boiler O
CONTRACT 16357
PROJECT 900096

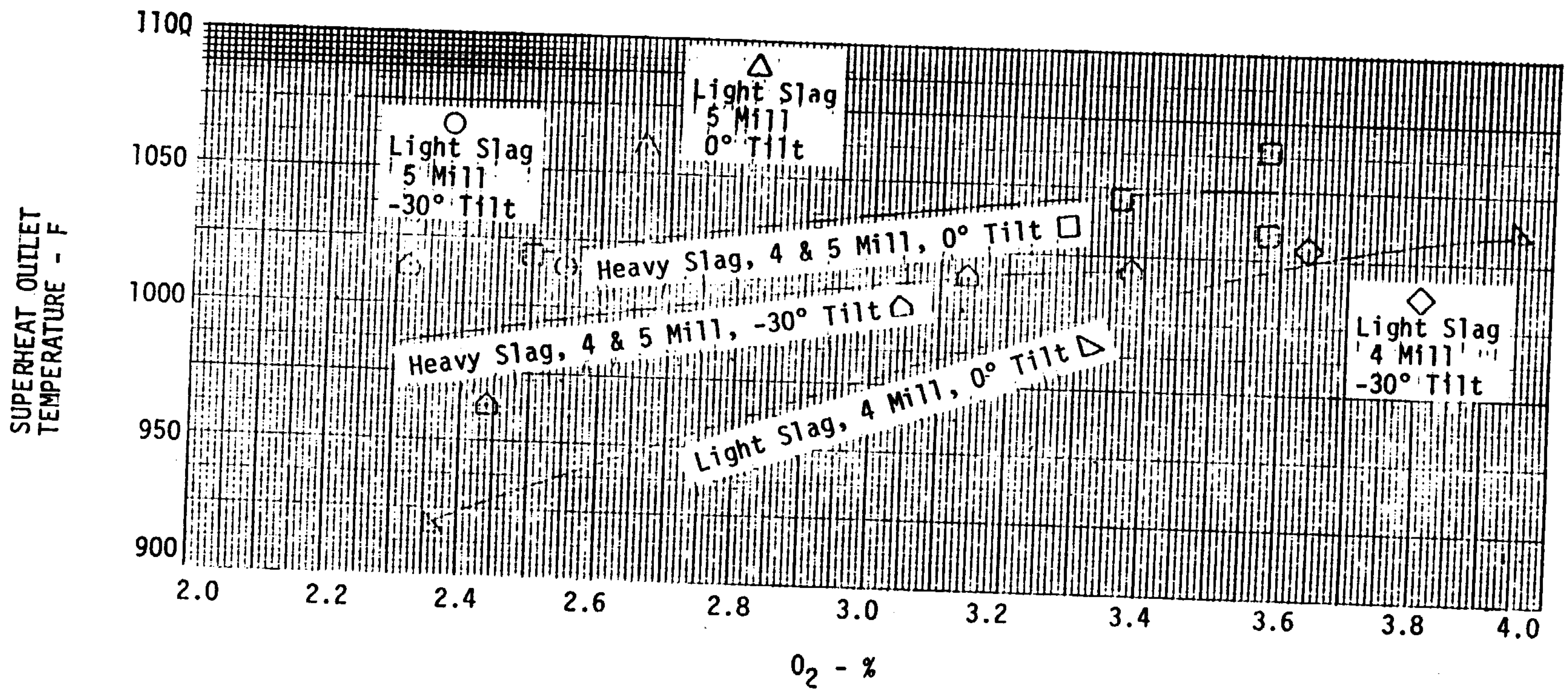
CARBON HEAT LOSS VARIATION
WITH CHANGES IN OPERATING PARAMETERS
AND SUPERHEATER OUTLET TEMPERATURE

FIELD TESTING &
PERFORMANCE RESULTS



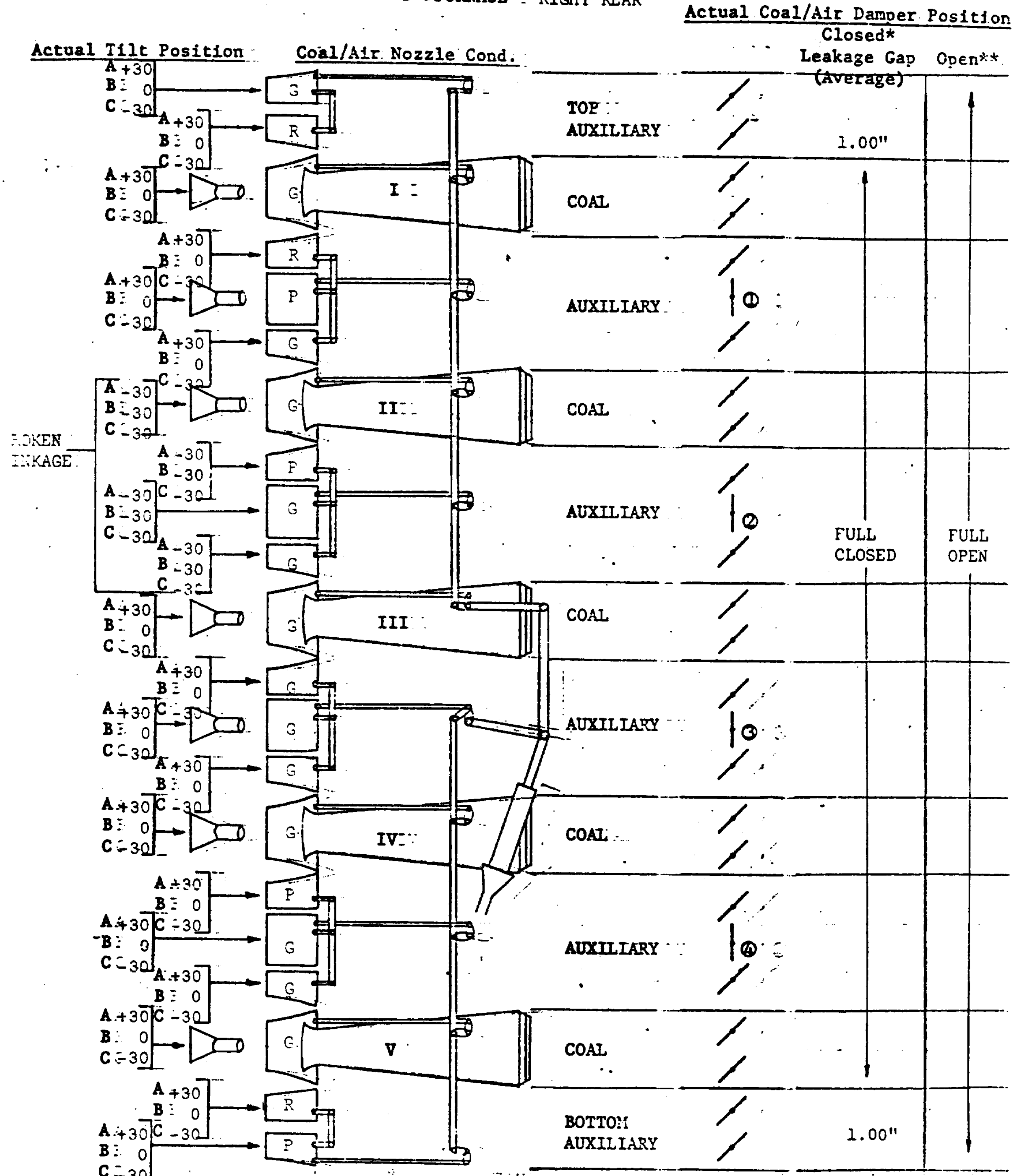
Sheet B23

SUPERHEAT OUTLET TEMPERATURE VERSUS O_2



INSPECTION OF NOZZLE COMPARTMENT AND WINDBOX

"B" FURNACE - RIGHT REAR



Control Room Tilt Indicator	Condition of Coal/Air Nozzles
A - (+30)	G - Good
B - (0)	P - Plugged

①,②,③,&④ dampers are disconnected and remain in closed position.

*Damper leakage gap when damper control in "full closed" position.

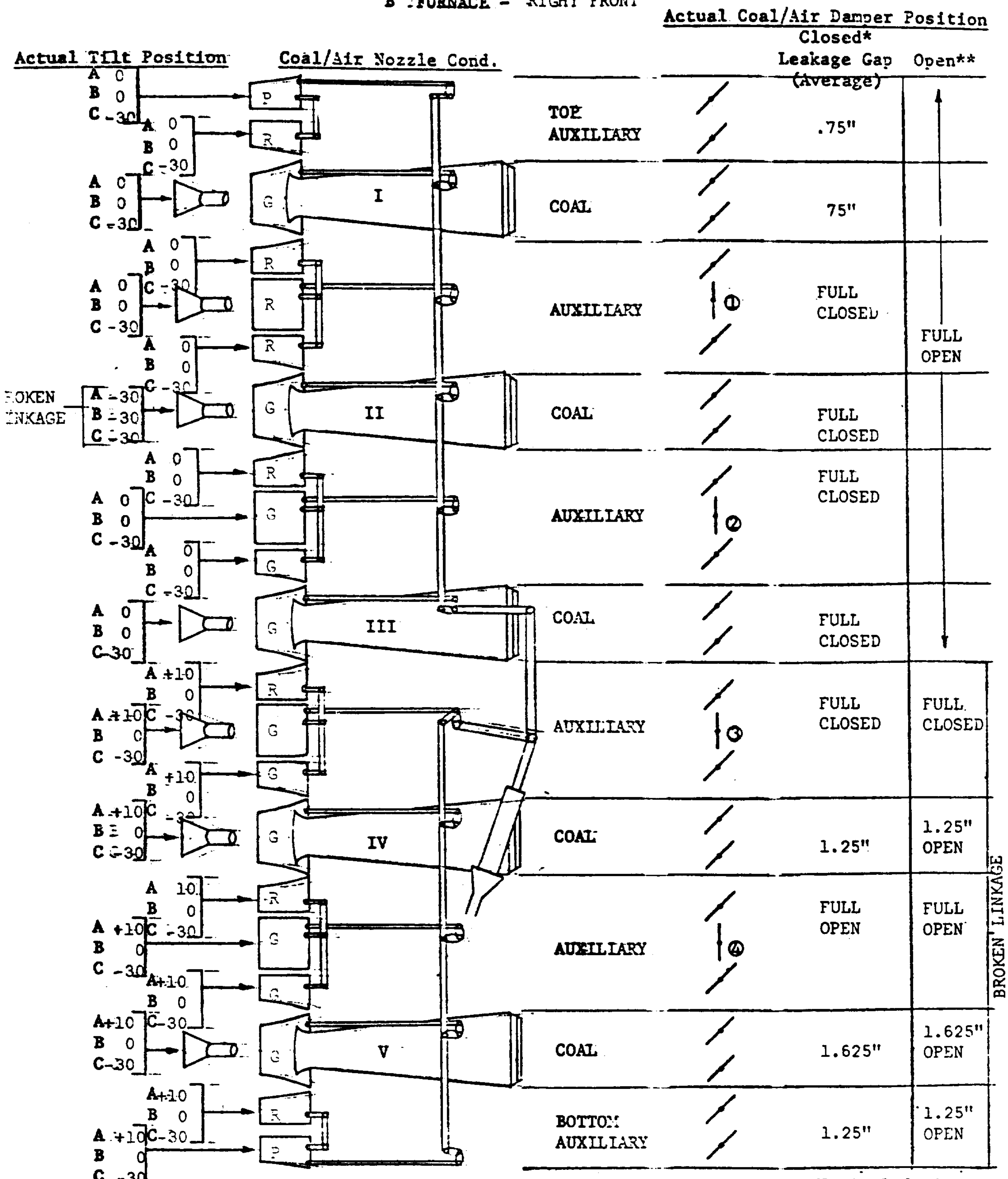
Nominal design gap is .25" - .50"

Sheet B25

Leakage gap measurement

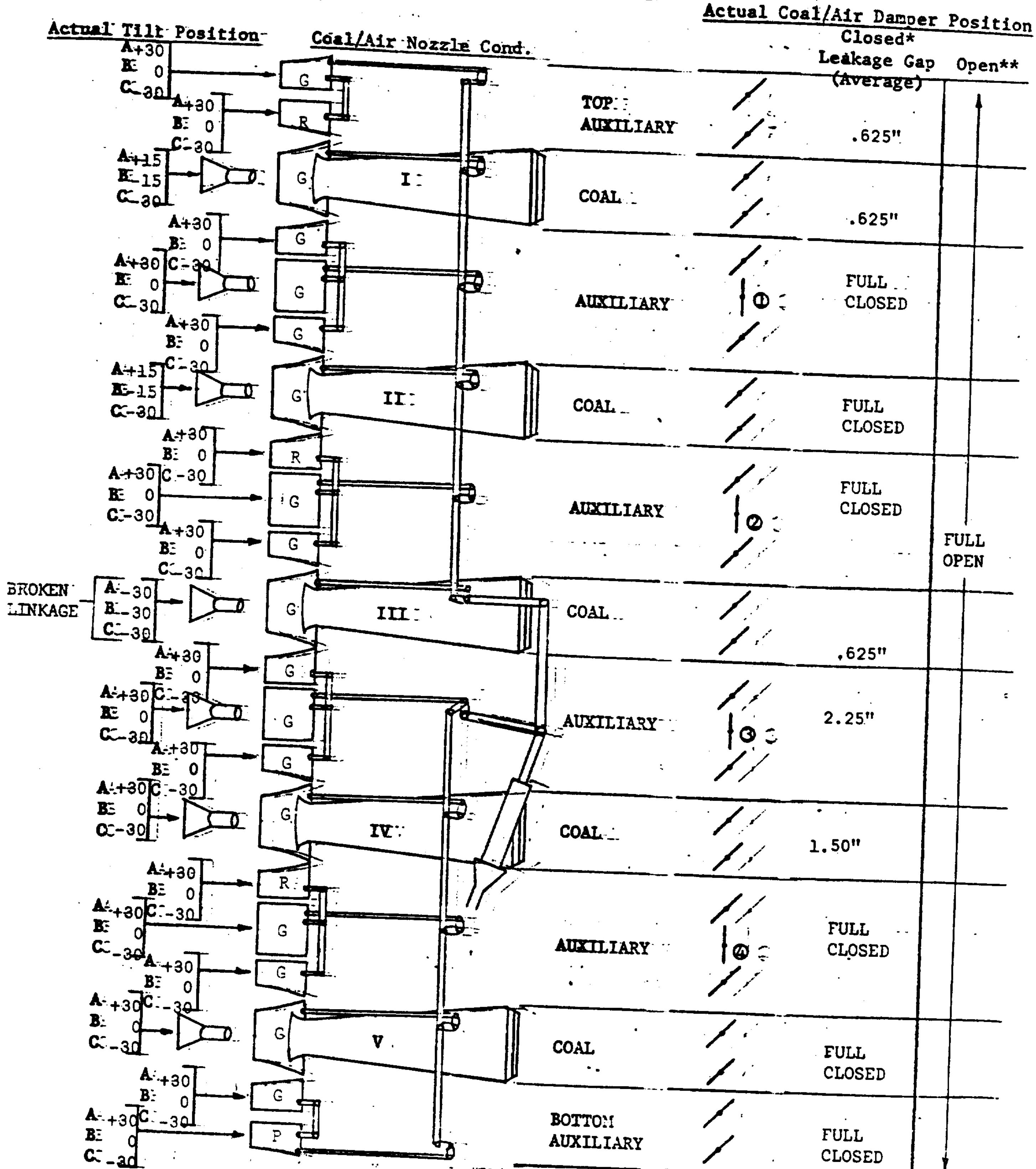
INSPECTION OF NOZZLE COMPARTMENT AND WINDBOX

"B" FURNACE - RIGHT FRONT



Control Room Tilt Indicator	Condition of Coal/Air Nozzles	①,②,③,&④ dampers are disconnected and remain in closed position.	Nominal design gap is .25" - .50"
A - (+30)	G - Good	*Damper leakage gap when damper control in "full closed" position.	Sheet B26
B - (0)	P - Plugged	**D... position when control in	Leakage gap measurement

INSPECTION OF NOZZLE COMPARTMENT AND WINDBOX
"B" FURNACE - - LEFT REAR



Control Room Tilt Indicator
A -- (+30)
B -- (0)

Condition of Coal/Air Nozzles
G -- Good
P -- Plugged

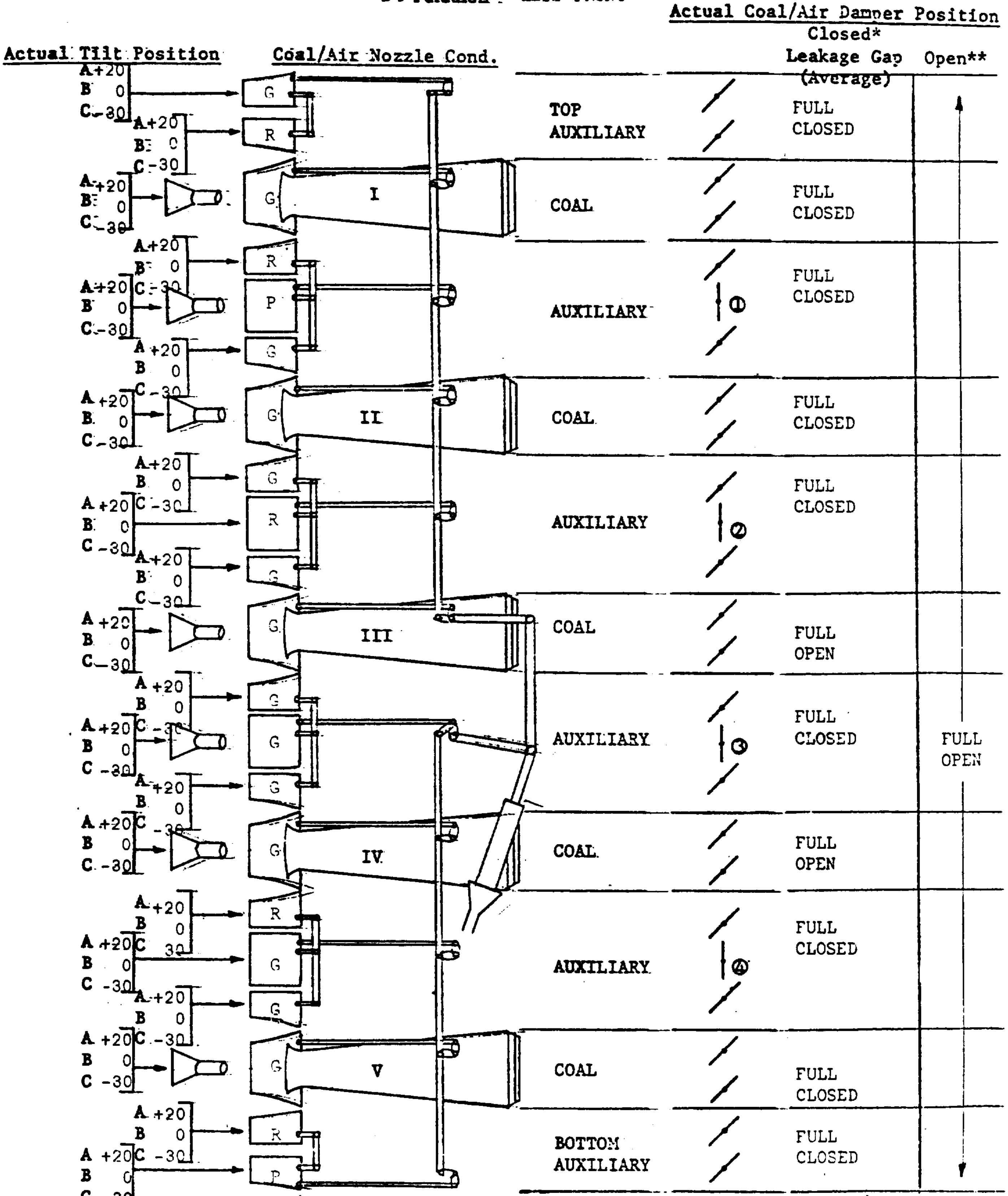
①,②,③,&④ dampers are disconnected and remain in closed position.
*Damper leakage gap when damper control in "full closed" position.
**Damper position when control in

Nominal design gap is .25" - .50"

Sheet B27

Leakage gap measurement

INSPECTION OF NOZZLE COMPARTMENT AND WINDBOX
"B" FURNACE - LEFT FRONT



Control Room Tilt Indicator

A - (+30)
B - (0)

Condition of Coal/Air Nozzles

G - Good
P - Plugged

①,②,③,&④ dampers are disconnected and remain in closed position.
*Damper leakage gap when damper control in "full closed" position.
**Damper position when control in

Nominal design gap is .25" - .50"

Sheet B28

Leakage gap measurement

Boiler O
CONTRACT 16357
PROJECT 900096

NOZZLE AIR FLOW DISTRIBUTION

FIELD TESTING & PERFORMANCE RESULTS

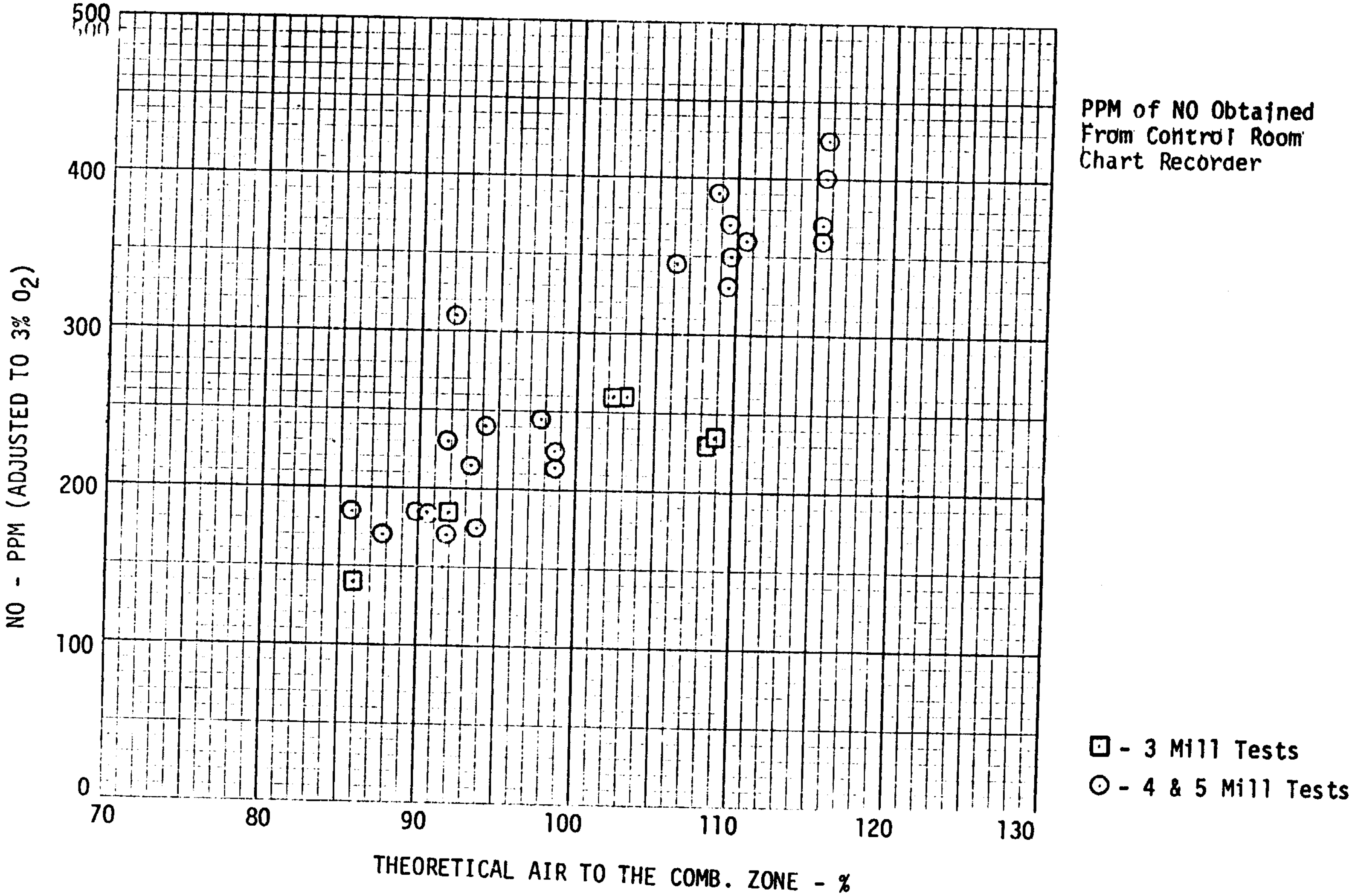
TEST NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Compartment Flow-1 Aux.	%	8.36	8.34	8.01	7.58	5.21	5.01	7.89	8.11	8.42	5.15	7.65	8.48	9.67	7.19	3.47
2 Coal	%	3.38	3.38	3.24	7.57	7.77	8.23	8.15	3.28	3.40	7.87	7.44	3.43	3.90	8.58	9.38
3 Aux.	%	15.38	15.36	14.71	13.92	10.25	9.86	14.51	14.94	15.49	10.16	14.07	15.61	17.77	10.68	7.42
4 Coal	%	8.45	8.48	8.47	7.57	7.77	8.23	8.15	8.23	8.33	7.87	7.44	8.21	9.58	8.58	9.38
5 Aux.	%	11.14	11.12	13.44	12.72	12.93	12.44	10.50	13.64	11.22	12.83	12.85	11.30	7.93	10.68	12.04
6 Coal	%	8.45	8.48	8.47	7.57	7.77	8.23	8.15	8.23	8.33	7.87	7.44	8.21	9.58	8.58	9.38
7 Aux.	%	11.14	11.12	10.65	12.72	12.93	12.44	10.50	10.81	11.22	12.83	12.85	11.30	7.93	10.68	12.04
8 Coal	%	8.45	8.48	8.47	7.57	7.77	8.23	8.15	8.23	8.33	7.87	7.44	8.21	9.58	8.58	9.38
9 Aux.	%	11.14	11.12	10.65	10.08	12.93	12.44	10.50	10.81	11.22	12.83	10.19	11.30	7.93	10.68	12.04
10 Coal	%	8.45	8.48	8.47	7.57	7.77	8.23	8.15	8.23	8.33	7.87	7.44	8.21	9.58	8.58	9.38
11 Aux.	%	5.66	5.64	5.42	5.13	6.90	6.65	5.35	5.49	5.71	6.85	5.18	5.74	6.55	7.19	6.09
Fuel Compartment Flow	%	33.82	33.90	33.88	37.86	38.83	41.16	40.76	32.94	33.32	39.33	37.21	32.82	38.31	42.90	46.88
Flow Above Center of Firing	%	60.73	60.71	61.65	53.13	47.80	47.89	53.27	61.86	60.80	47.82	53.17	60.88	62.39	50.00	46.38
Theoretical Air to Comb. Zone	%	91.80	92.13	94.18	115.63	115.52	110.66	109.75	97.73	98.57	115.71	115.54	90.02	87.84	106.33	109.51

TEST NO.		16	17	18	19	20	21	22	23	30	31	32	33	34	35
Compartment Flow-1 Aux.	%	8.76	7.62	3.45	7.22	9.12	8.63	10.13	8.83	.36	9.38	.34	13.50	15.38	5.50
2 Coal	%	3.54	3.08	9.44	8.56	3.68	3.48	4.09	3.57	.37	4.22	.35	5.46	14.03	13.23
3 Aux.	%	16.13	14.01	7.38	10.69	7.48	14.48	18.63	14.83	.78	8.57	.76	.76	.97	18.98
4 Coal	%	8.77	8.13	9.44	8.56	9.28	8.29	9.57	7.88	12.73	11.85	.36	.36	.46	5.76
5 Aux.	%	7.20	12.80	11.97	10.69	12.14	11.47	8.32	11.76	18.26	13.91	11.01	11.08	14.05	11.69
6 Coal	%	8.77	7.30	9.44	8.56	9.28	8.29	9.57	7.88	12.73	11.85	13.13	12.52	14.02	13.23
7 Aux.	%	11.68	12.80	11.97	10.69	12.14	11.47	8.32	11.76	18.26	13.91	17.87	11.08	14.05	11.69
8 Coal	%	8.77	7.30	9.44	8.56	9.28	8.29	9.57	7.88	12.73	11.85	13.13	12.52	.46	.38
9 Aux.	%	11.68	12.80	11.97	10.69	12.14	11.47	8.32	11.76	23.05	13.91	17.87	11.08	.97	.81
10 Coal	%	8.77	7.30	9.44	8.56	9.28	8.29	9.57	7.88	.37	.28	13.13	12.52	14.03	13.23
11 Aux.	%	5.93	6.86	6.06	7.22	6.18	5.84	3.91	5.97	.36	.27	12.05	9.12	11.57	5.50
Fuel Compartment Flow	%	35.07	30.02	47.18	42.82	37.14	33.16	38.27	31.51	38.20	35.55	39.38	37.55	42.09	39.69
Flow Above Center of Firing	%	59.01	59.34	46.40	50.00	57.05	60.37	64.46	60.62	38.86	53.85	50.39	61.01	51.89	61.77
Theoretical Air to Comb. Zone	%	93.29	98.84	108.82	109.51	93.77	91.76	85.68	90.47	108.89	91.87	102.25	85.93	103.19	108.39

Boiler O
Contract 16357
Project 9000096

Combustion Engineering
Field Testing &
Performance Results

NO (ADJUSTED TO 3% O_2)
VERSUS
THEORETICAL AIR TO COMBUSTION ZONE



Boiler O
TRACT 16357
OJECT 900096

COMBUSTION ENGINEERING, INC.
FIELD TESTING & PERFORMANCE
RESULTS

WINDBOX AND NOZZLE COMPARTMENT GEOMETRY
USED IN NOZZLE AIR FLOW DISTRIBUTION PROGRAM

Nozzle Compartment #	Nozzle Compartment Height - Ins.	# of Dampers Per Compartment	Free Area at Nozzle - FT2	Duct Area at Damper - FT2
1	19.25	2	1.74	4.61
2	20.00	2	0.70	4.76
3	35.25	3	3.20	8.38
4	20.00	2	0.70	4.76
5	35.25	3	3.20	8.38
6	20.00	2	0.70	4.76
7	35.25	3	3.20	8.38
8	20.00	2	0.70	4.76
9	35.25	3	3.20	8.38
10	20.00	2	0.70	4.76
11	19.25	2	1.74	4.61

Boiler O
Contract 16357
Project 900096

Combustion Engineering, Inc.
Field Testing and
Performance Results

PULVERIZER FINENESS TEST
"B" FURNACE

Classifier Setting - 0

Mill	B-1	B-2	B-3	B-4	B-5
% - 200 Mesh	70.8	71.0	79.2	65.8	82.6

Classifier Setting - 1

Mill	B-1	B-2	B-3	B-4	B-5
% - 200 Mesh	74.6	69.2	71.8	65.8	80.2

Classifier Setting - 2

Mill	B-1	B-2	B-3	B-4	B-5
% - 200 Mesh	74.2	73.0	72.0	71.8	82.6

Classifier Setting - 3

Mill	B-1	B-2	B-3	B-4	B-5
% - 200 Mesh	79.6	78.0	84.0	75.6	85.8

APPENDIX B-2

BOILER Q

Final Report

to

ESSO RESEARCH AND ENGINEERING

FOR

ENGINEERING AND CONSULTING SERVICES
PROVIDED
IN CONNECTION WITH A FIELD TEST PROGRAM
TO MEASURE GASEOUS EMISSIONS FROM
A BABCOCK & WILCOX STEAM GENERATOR

July 16, 1971

OBJECTIVE

The objective of this contract was to measure boiler thermal performance in connection with an ESSO Research and Engineering Company field test program to measure gaseous emissions from a Babcock & Wilcox steam generator. The gaseous emission of prime concern during these tests was the measurement of nitric oxide (NO) in the flue gas.

BACKGROUND AND SCOPE OF WORK

This report covers the results of the engineering and consulting services provided by B&W to ERE in connection with an ERE field test program to measure gaseous emissions from steam generators of various boiler manufacturers.

The Air Pollution Control Office of the Environmental Protection Agency and ERE requested that the Babcock & Wilcox Company provide engineering and consulting services to aid APCO and ERE in a field test program (Systems Study of Nitrogen Oxide Control Methods for Stationary Sources Phase II, CPA 70-90).

This program was to determine the level of nitric oxide emitted from several B&W steam generators. Testing of one B&W steam generator was done under B&W's contract with ERE.

The scope of test work for which B&W proposed to supply engineering services was:

1. Help the contractor select the boilers, negotiate with the utility owner-operators, plan the testing, and set the experimentation limits for safe and proper testing.
2. Perform a pre-testing check-out of the boiler to assure that it is in proper operating condition for the testing.
3. Acquire data on the thermal performance of the boiler while the contractor measures the NO_x and other emissions.
4. Help the contractor and boiler operators to solve any problems which might be encountered during testing.
5. Monitor the boiler operation during testing to assure that unsafe or unacceptable operation is avoided.
6. Evaluate thermal performance data and assist the contractor in evaluating the NO_x and other emissions data, as required.

PERFORMANCE OF THE SCOPE OF WORK

PERFORMANCE OF ITEM 1

It was decided to test a coal fired once through Universal Pressure Steam Generator designated as Boiler Q, Figure 1. The steam generator has the following full load design conditions:

Main Steam Flow	-	4,900,000 pounds per hour
Main Steam Pressure	-	2,400 pounds per square inch
Main Steam Temperature	-	1,053°F
Reheat Steam Flow	-	3,450,000 pounds per hour
Reheat Steam Pressure	-	305 pounds per square inch
Reheat Steam Temperature	-	1,003°F

The steam generator is fired by 14 Babcock & Wilcox cyclone burners which are arranged as shown in Figure 2. Seven cyclones are on the front wall and seven are on the rear wall. Each cyclone is 10 feet in diameter and 12 feet long. Coal preparation for firing requires a minimum of 90% by weight passing through a Number 4 mesh sieve. Coal flow to each cyclone is controlled by its own coal feeder. The steam generator was put in commercial operation on May 19, 1963, with a nominal full load electrical output of 650 megawatts (650,000 kilowatts).

A meeting was held with ERE, the boiler owner-operator and B&W at the steam plant on April 27, 1971 to discuss the test program and set experimentation limits. The prime concerns of the Babcock & Wilcox Company for these tests were; the maintaining of a minimum limit on total air of 122% to prevent iron sulfide formation, and the preventing of slag chilling to limit slag tapping problems. Load changes were dependent upon operation requirements.

A proposed test program was formulated by ESSO following the meeting and the proposed test program was submitted to the boiler-operator. A copy of this proposed test program is included as Figure 5. Test runs which could not be made were deleted and the resulting test schedule consisted of 6 test runs. These test runs are tabulated in Figure 6.

PERFORMANCE OF ITEM 2

Pre-testing consisted of a test run designated as "A" on May 10, 1971. Data accumulated during this run were compared with the design data and previous test data; it was found that the boiler was operating near design temperatures, pressures and flows. From this comparison it was determined that the steam generator was in proper operating condition for testing.

PERFORMANCE OF ITEM 3

In preparation for determining thermal performance it was decided that the following items would be desirable indications of equipment operation during test runs:

1. Panel board or computer data points indicating temperatures, pressures and flows affecting the boiler.

2. Panel board indications of damper positions.

3. Boiler efficiency as calculated by the ASME Short Form (including air heater leakage).

4. Reheat flow calculated by heat balance.

5. Coal flow.

6. Recirculated flue gas in pounds per hour.

7. Flue gas flow in pounds per hour.

The above data would permit the evaluation of changes in thermal and operating performance if major changes occurred during nitric oxide testing. Operating performance for long term effects under various operating conditions could not be evaluated with the short duration of testing.

PERFORMANCE OF ITEMS 4 AND 5

No problems were encountered with boiler operation during testing and no unsafe operations were performed.

PERFORMANCE OF ITEM 6

SUMMARY OF PERFORMANCE OF ITEM 6

Thermal performance was evaluated using the data acquired during testing on May 10, 1971 and May 11, 1971. A summary sheet showing the results is listed in Figure 4. Included in the summary are significant items to compare test results.

No significant changes in thermal performance can be noted in comparing test runs 1 to 3 and test runs 4 to 6. No significant reductions in nitric oxide production were made by changing operating variables at each of the 2 separate boiler loads; however, reducing generator output and hence boiler loading produced a reduced nitric oxide production.

TEST NUMBER	BOILER EFFICIENCY	MEGAWATT LOADING MW	% OF FULL LOAD STEAM FLOW %	NITRIC OXIDE AVERAGE PPM	NITRIC OXIDE HIGH VALUE PPM
1	91.13	670	96.2	992	1063
4	91.61	542	76.8	731	793
Change	+.48	-128	-19.4	-261	-270
% Reduction	-	19.1%	19.4%	26.3%	25.4%

DETAILS OF PERFORMANCE OF ITEM 6

TEST CONDITIONS

Test conditions for the 6 test runs are tabulated in Figure 6.

Test run 1 and test run 2 vary gas tempering and gas recirculation to determine the effect on nitric oxide production. The location of admission of gas recirculation and tempering gas to the boiler is shown on Figure 1.

Test run 1 and test run 3 vary coal feeder bias to determine the effect on nitric oxide production. In test run 3 coal flow was reduced in the upper row of cyclones, and increased in the lower row while maintaining constant boiler load.

Test run 1 and test run 4 vary boiler load to determine the effect on nitric oxide production. In test run 5 coal flow was reduced in the upper row of cyclones and increased in the lower row of cyclones.

Test run 5 and test run 6 vary secondary air to the upper cyclones to determine the effect on NO production. During test run 6 secondary air was increased to the upper row of cyclones until the boiler excess O_2 increased from 3.9 to 4.9%.

The overall effect created in Tests 3, 5, and 6 was to produce a staging of the burners--a method found to reduce nitric oxide production in gas and oil fired boilers. Increased flue gas recirculation (test run 2) was found helpful in reducing NO in boilers equipped with cell type burners on gas and oil.

TEST PROCEDURE

When test conditions were obtained and the boiler had reached steady state conditions test data were recorded. Coal samples were obtained by the boiler-operator at a location immediately above the coal feeders. Fly-ash samples were obtained by the boiler-operator at the economizer. Figure 1 indicates the locations of coal and ash samples. Ash samples from the slag tank were not obtained. Flue gas analysis to determine air heater leakage was made at the air heater inlet and outlet at the two load conditions.

Coal analysis was performed by ERE and the boiler-operator. Proximate analysis was determined for each of the 6 test runs. Ultimate analysis was determined for a composite sample of test runs 1, 2, and 3; and test runs 4, 5, and 6.

Per cent combustibles in the flue dust samples were determined by the boiler-operator for each of the test runs.

TEST EQUIPMENT

Test equipment to obtain data for thermal performance consisted of:

Panel board and computer logged data points.

Water manometers (when available) to determine gas recirculation fan static pressure.

Coal and ash sampling equipment supplied by the boiler-operator.

Gaseous emission analyzers supplied by ESSO Research and Engineering Company.

Gas analysis of flue gas entering and leaving the air heater by TVA.

Coal and ash analysis by ESSO and TVA laboratories.

TEST CALCULATIONS

Boiler efficiency was calculated by the ASME Abbreviated Efficiency Test Method. This method determines boiler efficiency by heat loss. The heat losses are recorded in the ASME test forms. Calculations were based on flue gas analysis from the boiler-operator because the higher values of excess oxygen in the ESSO analysis indicated possible leakage of air into the sampling lines. Dry refuse calculations were based on the assumption of 70% of the ash went to the slag tank and 30% passed through the boiler. Combustibles in the slag tank were assumed to be zero. Unmeasured losses were assumed to be 0.6%. These assumptions were based on the test results of the acceptance test run by the boiler-operator on this boiler. The as fired heating value of the coal was used for efficiency calculation. The ultimate analysis was used for the heat loss due to dry gas and the heat loss due to H_2O from the combustion of H_2.

The two composite ultimate analyses by ESSO were converted to 6 as fired ultimate analyses using the moisture content as determined by the boiler-operator. The boiler-operator analyses had a higher mositure content. This ultimate analysis was then used in calculations.

Reheat flow was determined by heat balance around the parallel flow high pressure feedwater heaters which take extraction steam from the high pressure turbine and the cold reheat steam. Losses from the main steam flow are tabulated in the reheat flow calculation summary.

Coal flow was determined by using total heat output in the steam, boiler efficiency and the heating value of the coal.

Recirculated gas flow was calculated by using the fan characteristic curves, motor horsepower, and static pressure where available. The recirculated gas flow was proportioned into gas recirculation and tempering gas flow by assuming flow to be a function of damper position.

Nitric oxide data reduction of the ESSO test data consisted of averaging the results of each individual probe for each test run. All probes were averaged to obtain a test run average. Results shown in Figure 4 indicate test run averages and the high probe average. Nitric oxide values in this report are as recorded and no corrections to a uniform oxygen have been made. The higher values of excess oxygen of the ESSO data compared with the boiler-operator's data indicated possible leakage of air into the ESSO sampling lines and thus lowering the concentration of nitric oxide in the sample.

DISCUSSION OF RESULTS

The change in operating conditions of the boiler during the first three test runs indicate almost no change in boiler efficiency. The criterion used is that during normal boiler efficiency testing two of three test runs must fall within a plus or minus 0.25 percentage point band. During the first 3 test runs no significant reduction in nitric oxide production was made by changing the gas recirculation and tempering gas or the feeder bias of the upper and lower cyclones.

The change in operating conditions during the last 3 tests indicated almost no change in boiler efficiency during these tests. Only slight variations in nitric oxide production were made during the last 3 tests when feeder bias and increased air to the upper cyclones were the operating variables that were changed.

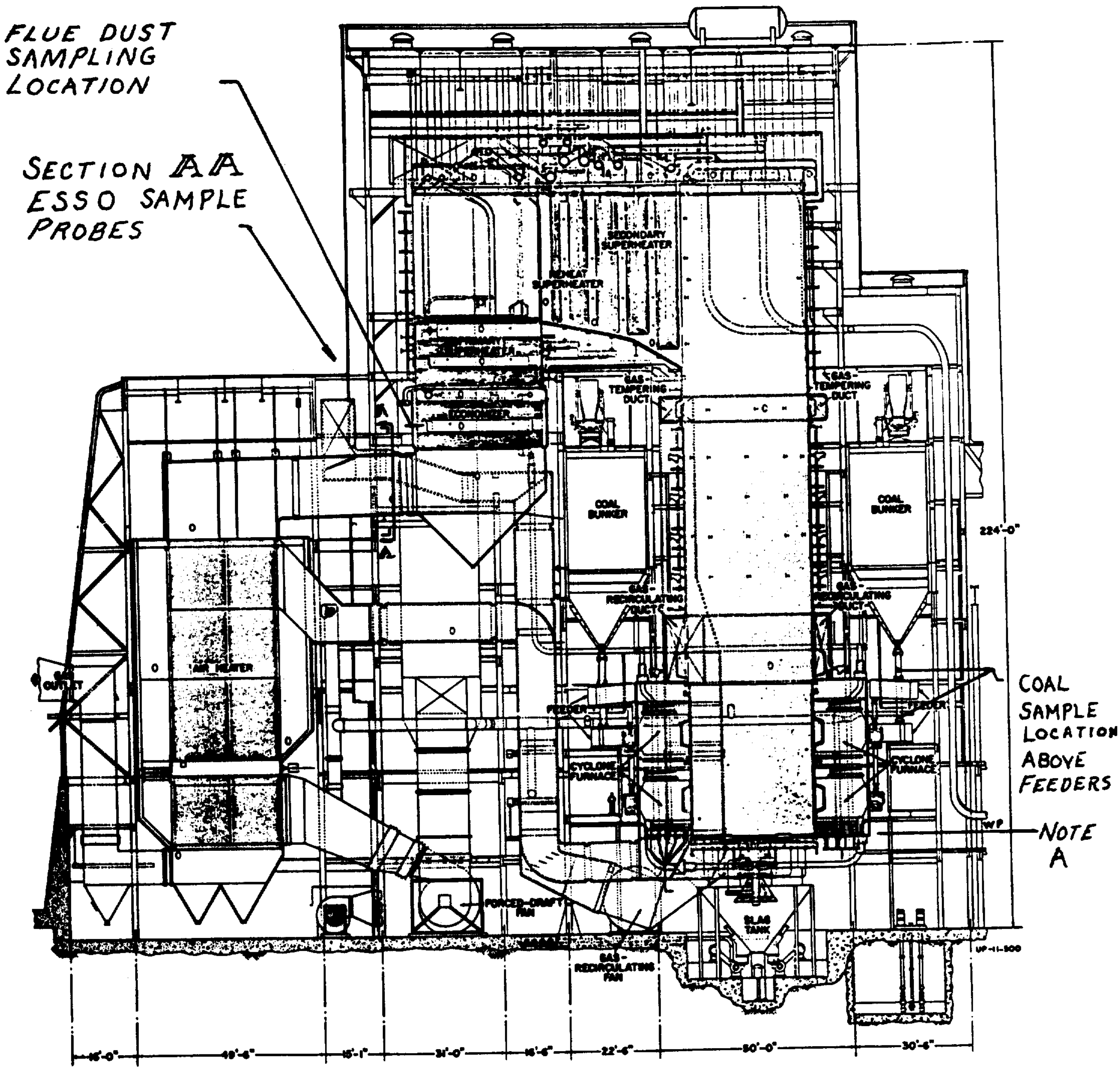
The change in boiler load from test 1 to test 4 indicated a 25% reduction in nitric oxide when boiler load was reduced 19.4%. Boiler efficiency changed from 91.13 per cent at the high load to 91.61 per cent at the low load. A slight increase in efficiency at some lower loads is not unusual.

CONCLUSIONS

No significant change in boiler efficiency was experienced during the tests and nitric oxide production was only decreased significantly by reducing boiler load.

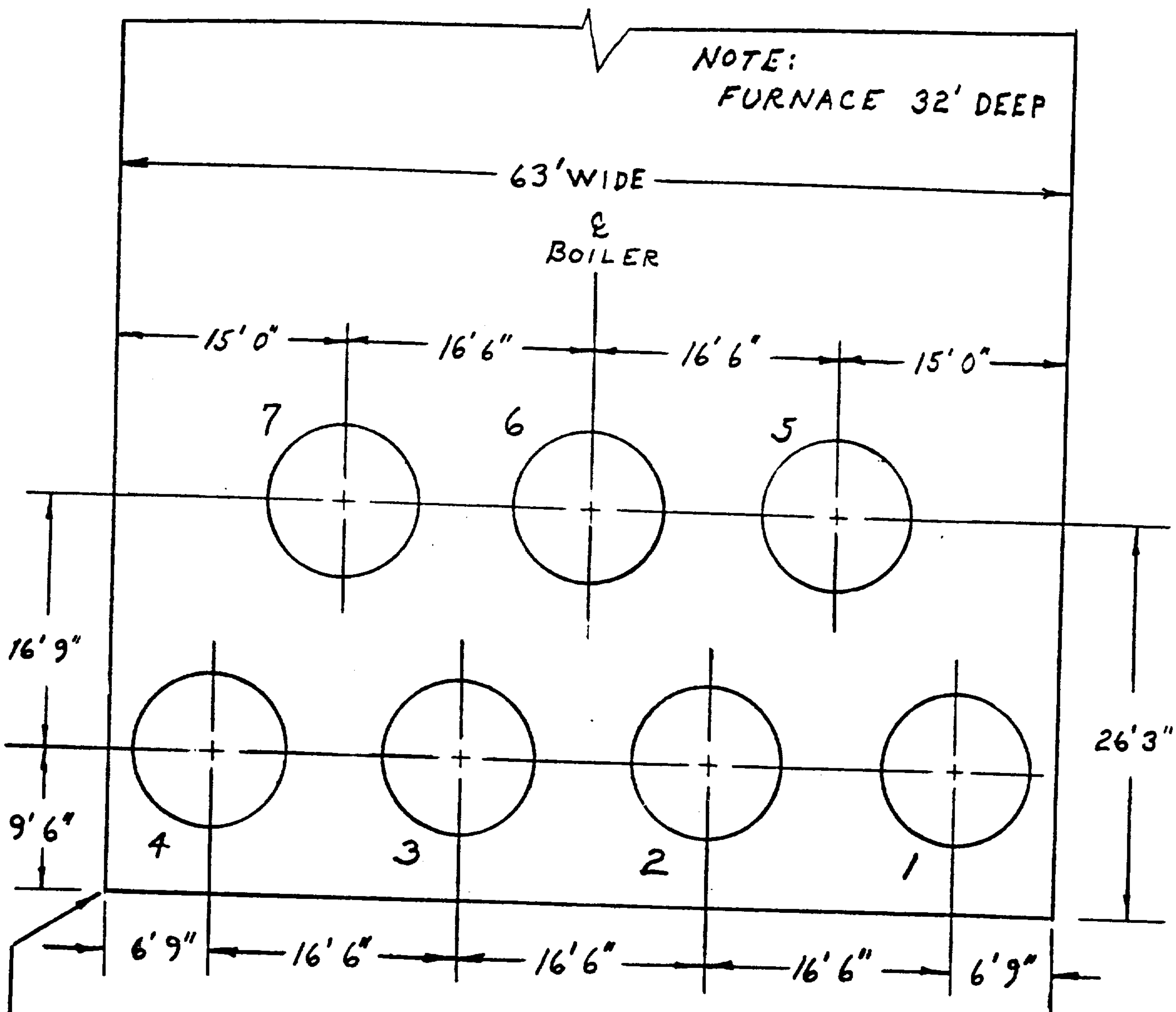
FIGURE 1

BOILER Q



NOTE A
WORK POINT ELEVATION
FOR CYCLONE DRAWING

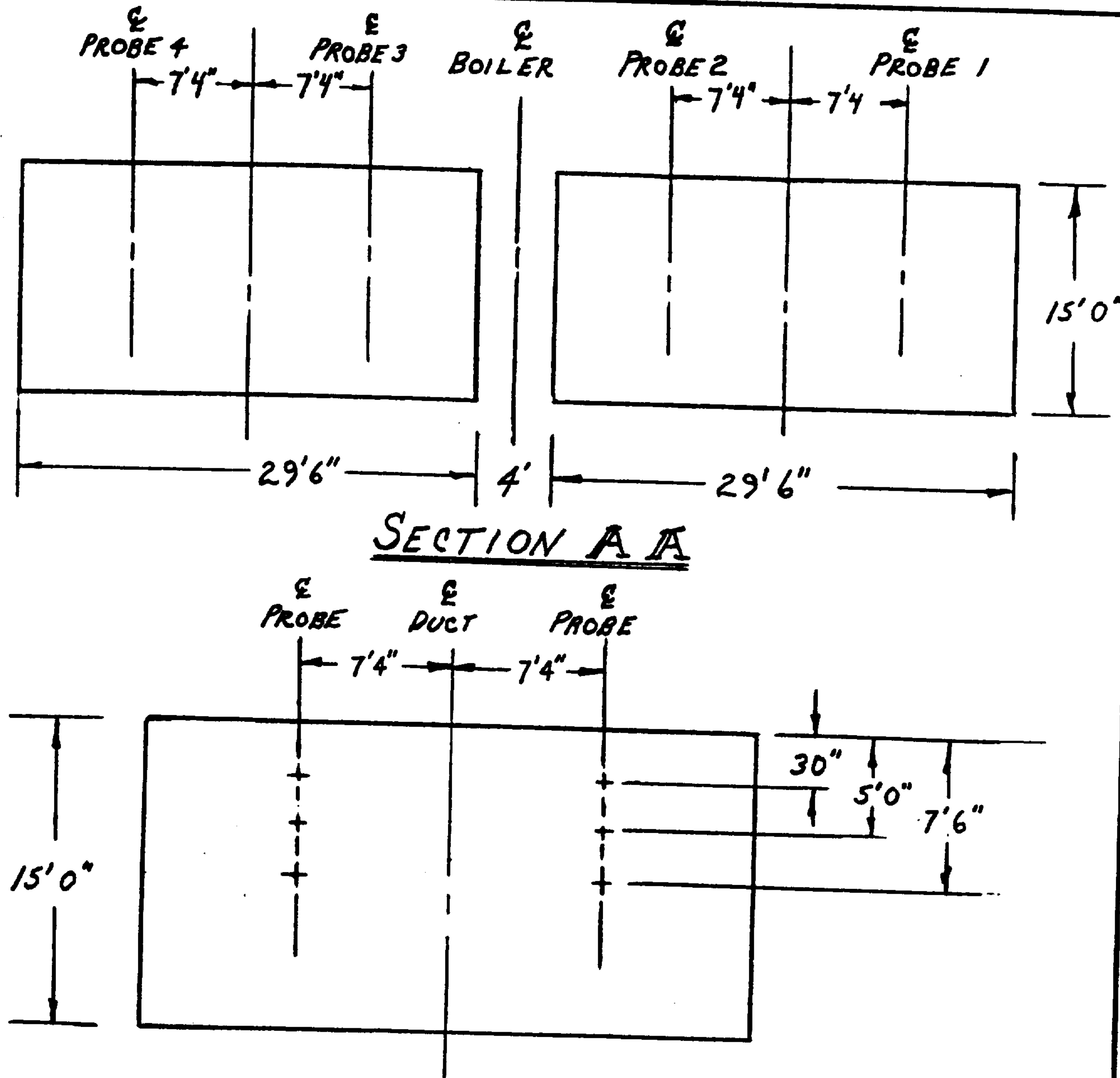
THE BABCOCK & WILCOX COMPANY



CYCLONE ARRANGEMENT
14 TOTAL 7 SHOWN
VIEW FACING FRONT OR REAR WALL
EACH CYCLONE 10' DIAMETER 12' LONG

CUSTOMER ESSO	
SUBJECT CYCLONE ARRANGEMENT	JOB No. B&W UP-10
	FIGURE 2
	BY E.P.SZMANIA
	DATE 6-3-71

THE BABCOCK & WILCOX COMPANY



ECONOMIZER OUTLET DUCT
ONE SHOWN
LOCATION OF 2 VERTICAL PROBES MARKED
DEPTH OF 3 SAMPLE PROBE TUBES SHOWN
FOR ONE PROBE

CUSTOMER ESSO
SUBJECT GAS PROBE SAMPLE LOCATIONS
JOB No. B&W UP-10
FIGURE 3
BY EPS
DATE 6-3-71

RDG 3027

BBS 120-1

THE BABCOCK & WILCOX COMPANY

TEST	NUMBER	1	2	3	4	5	6
DATE	Mo DA YR	5-10-71	5-10-71	5-10-71	5-11-71	5-11-71	5-11-71
MEGAWATTS	MW	670	668	660	542	550	550
MAIN STEAM FLOW	1000#/hr	4713.	4778.	4786.	3752.	3793.	3792.
REHEAT FLOW	1000#/hr	3434	3485	3494	2677	2708	2731
TOTAL COAL FLOW	1000#/hr	559	556	595	445.5	474.5	480.5
HEAT INPUT	10^6 BTU/hr	5925	6130	6185	4680	4625	4610
HEAT OUTPUT	10^6 BTU/hr	5397	5602	5612	4288	4257	4277
EFFICIENCY	%	91.13	91.47	90.76	91.61	92.02	91.73
AS FIRED HEAT. VALUE	BTU/#	10,600	11 030	10410	10 500	9750	9600
FLUE GAS RECIRC	1000#/hr	415	1150	450	435	440	410
GAS TEMPERING	1000#/hr	925	400	970	1075	1080	1010
OXYGEN**	% VOL	4.0	4.0	4.0	3.8	3.9	4.9
CO_2**	% VOL	14.6	14.6	14.6	14.8	14.8	13.8 *
BURNERS IN SERVICE	NUMBER	14	14	14	14	14	14
AIR HEATER LEAKAGE	%	8.3	8.3	8.3	12.2	12.2	11.0 *
MEASURED EXIT GAS T.	°F	298	299	299	290	290	292
CORRECTED EXIT GAS T	°F	309	310	310	306	306	308
GAS FLOW TO AHTR	1000#/hr	6223	6200	6600	4395	4640	5000
AVERAGE FEEDER SPEED	BY ROWS						
CYCLONES 1-4 BOTTOM	RPM	1195	1205	1362	985	1272	1274
CYCLONES 5-7 TOP	RPM	1235	1242	1096	1036	785	781
AVE NO PPM MEASURED	PPM VOL	992	924	1002	731	773	690
AVE O_2 % MEASURED	% VOL	5.4	5.4	5.4	5.3	4.8	5.51
AVE CO_2 % MEASURED	% VOL	13.0	13.2	13.0	13.3	13.5	12.9
HIGH PROBE NUMBER	NUMBER	3	3	3 & 4	2	4	4
HIGH NO VALUE	PPM VOL	1063	981	1042	793	848	776

* CALCULATED

** Measured by boiler-operator

CUSTOMER ESSO

SUBJECT TEST RESULTS SUMMARY SHEET

JOB NO. B&W UP-10

FIGURE 4

BY EPS

DATE 6-8-71

FIGURE 5

BOILER Q

PROPOSED NO_x TEST PROGRAMS

PLAN I 4 TEST RUNS PER DAY (REPEAT RUN 1 IF TIME PERMITS)

		L_1 (700 MW)	L_2 (550 MW)		L_3 (400 MW)	
		S_1 (ALL CYCLONES FIRING COAL)	S_1	S_2 (TOP ROW 50% COAL RATE HI AIR)	S_3 (TOP ROW AIR ONLY)	S_4 (ALT. CYCLONES AIR ONLY) XOX OXO O OXO XOXO
D_1 (PRIM TEST AIR DAMP NORMAL)	R_1 MAX	1	5		9	
	R_2 MIN	2		8		11
D_2 (WIDE OPEN)	R_1 MAX	3		7		12
	R_2 MIN	4	6		10	

PLAN II 4 TEST RUNS PER DAY (REPEAT RUN 1 IF TIME PERMITS)

		L_1	L_2		L_3	
		S_1	S_1	S_2	S_3	S_4
D_1	R_1	1		5	(11)	9
	R_2		3		7	
D_2	R_1		4		8	
	R_2	2		6	(12)	10

PLAN III DAY 1 (RUNS 1–5), DAY 2 (RUNS 6–10), DAY 3 (RUNS 11–16)

		L_1	L_2		L_3	
		S_1	S_1	S_2	S_3	S_4
D_1	R_1	1, 10, (11)	2	(15)	6	
	R_2	(12)		4		8
D_2	R_1	(13)		5		9
	R_2	(14)	3	(16)	7	

5/5/71 A.R.C.

FIGURE 6

BOILER Q NO PROGRAM

RUN NO.	LOAD	EXCESS AIR LEVEL	FLUE GAS RECIRCULATION	TEMPERING	CYCLONE FEEDER BIAS	CYCLONE AIR BIAS
1	Max.	120%	Minimum	Maximum	Zero	Zero
2	Max.	120%	Increase	Decrease	Zero	Zero
3	Max.	120%	Minimum	Maximum	+Bottom -Top	Zero
4	550 mw	120% +	Minimum	Maximum	Zero	Zero
5	550 mw	120% +	Minimum	Maximum	Bottom Normal -Top (50%)	Zero
6	550 mw	120 +	Minimum	Maximum	Bottom Normal -Top (50%)	Zero-Bottom + - Top

5-6-71
O.S. Office

APPENDIX C

Representative samples of fuels fired were obtained from the boilers tested in this study. This section of the report presents a summary of the fuel compositions determined for coal, oil and gas fired boilers.

APPENDIX C-1

COAL ANALYSES

Boiler	Run No.	Proximate Analysis, % By Weight: Moisture As Rec'd	Moisture Dry	Ash As Rec'd	Ash Dry	Volatile Matter As Rec'd	Volatile Matter Dry	Ultimate Analysis, % By Weight: Carbon As Rec'd	Carbon Dry	Hydrogen As Rec'd	Hydrogen Dry	Nitrogen As Rec'd	Nitrogen Dry	Sulfur As Rec'd	Sulfur Dry	Oxygen (by diff.) As Rec'd	Oxygen (by diff.) Dry	HHV BTU/lb As Rec'd	HHV BTU/lb Dry	Wt. % Carbon in Fly Ash
C	1-6	7.78		12.0				78.06		4.70		1.60		1.82				12921		
C	1-6	8.14		12.69				73.01		4.44		1.09		2.21				13214		
C	1-6	6.95		14.2				67.02		4.22		1.38		1.59				12802		
C	1-6	5.98		16.65				68.63		4.48		1.09		2.97				12596		
F	1-2	1.14		14.23	14.39	29.0	29.3	73.4	74.2	4.55	4.61	1.38	1.39	1.17	1.18	4.13	4.18	12719	12866	
F	3-4	1.41		14.00	14.20	30.3	30.7	72.6	73.6	4.61	4.68	1.37	1.39	1.14	1.16	4.87	4.94	12875	13059	
P	1-4	5.29		12.81	13.53	33.5	35.3	69.2	73.1	4.52	4.77	1.31	1.38	0.72	0.76	6.15	6.49	12322	13010	
P	1-4	6.64		14.06	15.06	32.4	34.7	66.7	71.5	4.28	4.58	1.36	1.46	0.67	0.72	6.29	6.74	11674	12504	
				17.93																
O	Comp. of 27,21,32	6.94		16.87		32.49		60.58		5.06		1.24		3.98		14.32		10922		
O	Comp. of 3,15,35	6.75		17.93		32.57		59.51		4.97		1.27		3.82		12.50		10761		
O		7.45		12.69	13.71	35.40	38.25	63.97	69.12	5.33	4.86	1.24	1.34	3.38	3.65	15.42	9.52	11646	12583	
O	Reject 4	1.48		55.47	56.31									40.36	40.96			3973	4033	
O		8.15		20.35	22.16	31.36	34.15	56.64	61.67	4.86	4.29	1.15	1.25	4.17	4.54			10232	11140	
O	Reject 33	3.56		40.19	41.67									40.02	41.50			6691	6938	
O		6.82		16.42	17.62	32.55	34.94	61.39	65.88	5.03	4.57	1.18	1.27	3.42	3.67			11055	11664	
O	Reject 13	2.50		47.10	48.31									28.92	29.66			5807	5956	
O	Coal 9	8.80		16.69	18.30	33.14	36.34	59.55	65.30	5.15	4.56	1.21	1.32	3.80	4.17	13.61	6.35	10795	11837	
O	Reject 9	1.79		56.13	57.15									41.21	41.96			3774	3843	
O	1	6.28	2.18	14.74	15.38	33.96	35.45	45.02	46.99					2.47	2.58			11550	12055	1.44
O	2	8.53	2.06	15.65	16.76	35.91	38.45	39.91	42.73					4.18	4.48			10914	11687	0.86
O	3	8.47	1.53	13.40	14.42	37.18	40.00	40.95	44.05					3.62	3.89			11044	11882	0.58
O	4	8.50	1.37	12.94	13.95	36.65	39.50	41.91	45.18					3.59	3.87			11334	12217	0.16
O	5	8.51	1.71	13.52	14.53	37.17	39.93	40.80	43.83					3.30	3.54			11126	11953	0.18
O	Reject 5													23.03				68.32		
O	6	7.99	1.44	17.02	18.23	35.06	37.56	39.93	42.77					3.54	3.79			10655	11414	0.42
O	7	8.47	1.66	16.77	18.02	34.58	37.15	40.18	43.17					4.03	4.33			10686	11482	--
O	8	8.29	1.24	15.41	16.60	35.92	38.68	40.38	43.48					3.67	3.95			10988	11833	0.14
O	Reject 8													32.48				56.50		
O	9	8.54	1.52	16.15	17.39	35.04	37.73	40.27	43.36					3.66	3.94			10898	11735	0.40
O	10	7.65	1.70	17.09	18.19	33.84	36.02	41.42	44.09					4.19	4.46			10715	11405	0.33
O	11	8.51	1.46	18.17	19.57	33.44	36.02	39.88	42.95					4.04	4.35			10382	11181	0.32
O	12	7.76	1.24	16.96	18.16	34.46	36.90	40.82	43.70					3.73	3.99			10789	11551	0.29
O	13	8.10	1.52	17.24	18.48	32.90	35.25	41.76	44.75					3.66	3.92			10590	11348	0.39
O	Reject 13													24.63				58.10		
O	14	9.14	1.61	19.08	20.66	32.78	35.50	39.00	42.23					3.39	3.67			10156	10997	0.48
O	15	8.10	1.50	19.87	21.30	33.81	36.24	38.22	40.96					4.03	4.32			10131	10858	0.58
O	16	7.38	1.22	16.65	17.76	33.52	35.75	42.45	45.27					3.45	3.68			10898	11623	0.30
O	17	7.54	1.26	15.78	16.85	34.12	36.44	42.56	45.45					3.47	3.71			11023	11772	0.38
O	18	7.94	1.33	16.86	18.07	34.12	36.57	41.08	44.03					3.54	3.79			10672	11438	0.32
O	Reject 18													24.28				47.78		
O	19	8.71	1.49	15.70	16.94	35.69	38.51	39.90	43.06					3.16	3.41			10803	11658	0.50
O	20	9.88	1.53	15.22	16.63	35.05	38.30	39.85	43.54					3.68	4.02			11027	12049	3.62
O	21	6.45	1.36	12.54	13.22	37.87	39.93	43.14	45.49					3.45	3.64			11632	12265	1.21
O	Reject 21													29.48				59.37		
O	22	7.59	1.14	13.52	14.47	35.75	38.24	43.14	46.15					3.65	3.90			11415	12211	--
O	23	6.88	1.35	13.63	14.44	35.54	37.65	43.95	46.56					3.83	4.06			11514	12197	1.09
O	30	7.38	1.58	22.19	23.58	32.07	34.08	38.36	40.76					4.22	4.48			9914	10535	2.61
O	31	8.08	1.84	20.21	21.58	32.65	34.87	39.06	41.71					3.72	3.97			10193	10885	0.79
O	32	7.48	1.79	20.81	22.09	32.22	34.20	39.49	41.92					3.75	3.98			10222	10850	1.27
O	Reject 32													27.41				69.74		
O	33	6.26	1.65	20.19	21.18	34.30	35.99	39.25	41.18					4.28	4.49			10421	10934	1.39
O	34	7.02	1.82	22.98	24.26	32.53	34.35	37.47	39.57					4.20	4.44			9675	10216	1.90
O	35	7.89	1.85	19.76	21.06	34.03	36.26	38.32	40.83					3.83	4.08			10185	10852	1.80
M	Comp. of 11 12,13,14,15	7.87		15.75		31.60		61.45		5.04		1.30		3.30		13.16		11035		
M	Comp. of 16 17,18,19,20	8.00		15.99		32.62		61.16		5.14		1.35		3.32		13.03		10900		
M	Comp. of 8,6A,9,11A	7.58		14.48		32.06		62.82		5.12		1.40		2.53		13.64		11217		
M	Comp. of 1,7,6	7.29		13.98		32.21		63.87		5.08		1.39		2.29		13.38		11356		
M	1	9.3	9.3	14.3	15.8	33.6	37.1	42.8	47.1					2.4	2.7			10870	11990	
M	7	9.3	9.3	14.0	15.4	33.6	37.1	43.1	47.5					2.4	2.6			10940	12060	
M	10	9.4	9.4	13.9	15.3	33.6	37.1	43.1	47.6					2.4	2.6			10970	12110	
M	6	9.8	9.8	14.2	15.7	32.1	35.6	43.9	48.7					2.5	2.8			10900	12080	
M	11	9.9	9.9	14.5	16.1	33.2	36.9	42.4	47.0					3.1	3.4			10820	12010	
M	12	9.7	9.7	14.6	16.2	32.1	35.6	43.6	48.2					3.1	3.4			10830	11990	
M	13	9.5	9.5	16.2	17.9	32.8	36.2	41.5	45.9					3.5	3.9			11620	11730	
M	14	10.0	10.0	15.8	17.5	32.0	35.5	42.2	47.0					3.2	3.5			10620	11800	
M	8	9.7	9.7	14.2	15.7	33.0	36.6	43.1	47.7					2.3	2.6			11094	12120	
M	6A	9.5	9.5	13.1	14.5	33.8	37.3	43.6	48.2					2.4	2.7			11130	12300	
M	9	9.4	9.4	14.5	16.0	33.7	37.2	42.4	46.8					2.8	3.1			11850	11980	
M	11A	9.2	9.2	13.8	15.2	33.8	37.2	43.2	47.6					2.5	2.7			10930	12040	
M	15	9.9	9.9	15.0	16.6	32.4	36.0	42.7	47.4					3.5	3.9			10800	11990	
M	17	9.7	9.7	16.4	18.2	33.6	37.2	40.3	44.6					3.1	3.4			10550	11680	
M	18	10.2	10.2	14.7	16.4	34.8	38.8	40.3	44.8					3.1	3.5			10700	11920	
M	16	10.3	10.3	15.7	17.5	33.7	37.6	40.3	44.9					3.3	3.7			10560	11770	
M	19	9.5	9.5	15.8	17.5	34.3	37.9	40.4	44.5					3.6	4.0			10660	11780	
M	20	9.4	9.4	12.4	13.7	35.8	39.5	42.4	46.8					2.3	2.5			11230	12390	
Q	Comp. of 1,2 & 3	6.76		15.62		31.02		61.64		5.05		1.30		3.60		14.95		11090		
Q	Comp. of 4,5 & 6	8.44		21.91		30.36		54.39		4.71		1.08		4.45		13.47		9765		
Q	1	8.6			17.7	36.8			45.5						4.1				11600	
Q	2	8.8			15.5	39.2			45.3						3.9				12090	
Q	3	9.3			19.6	37.3			43.1						4.3				11470	
Q	4	10.4			21.2	36.9			41.9						4.5				11170	
Q	5	11.2			22.9	36.3			40.8						4.9				10970	
Q	6	11.3			23.3	35.7			41.0						4.8				10830	
N	4	5.45		12.21		35.36		67.37		5.31		1.17		4.12		9.82		12191		

APPENDIX C-2

OIL ANALYSES

Boiler	Run No.	Ash Wt. %	C Wt. %	H Wt. %	N Wt. %	Sulfur Wt. %	Fe ppm	Ni ppm	V ppm	HHV BTU/lb	Kin. Vis. at 210°F
J	1-4	0.04	86.3	11.6	0.29	0.94	8	7	56	18,820	
J		0.09	87.8	11.4	0.32	0.60	48	9	18	18,817	
L	1-5	0.02	85.15	11.76	0.53	0.46	2.0	7.5	29	19,185	35.86
K	1-15	0.04	86.49	12.06	0.62	0.99	12	23	100	18,921	303
A	11	0.011	85.16	11.82	0.36	0.45	6.5	25	19	18,989	6.22
A	15-18	0.015	86.30	12.45	0.21	0.18	2.5	16	3.0	19,725	9.26
B	1-8	0.009	88.07	11.38	0.31	0.24	1.0	4	3	18,946	16.97
B	17-24	0.10	87.77	11.33	0.41	0.31	4.0	7.0	3.0	18,795	39.12
D	1-8	0.35	88.15	11.13	0.46	0.42	7	12	11	18,773	45.05
H	9-16	0.010	86.51	12.24	0.30	0.44	5	20	12	19,235	8.72
F	1-5,8-10	0.007	86.02	12.62	0.25	0.46	8	11	2.5	19,315	7.58
G	1,. 2 & 7	0.022	86.29	12.06	0.42	0.44	14	24	21	18,990	17.63
G	7,12,15-20	0.025	86.35	11.68	0.42	0.44	11	34	20	18,966	16.73

APPENDIX C-3

TYPICAL GAS ANALYSIS

Components	Mole %	HHV BTU/ft^3
O_2	.02	0
N_2	1.01	0
CH_4	91.41	927
C_2H_6	4.49	80
CO_2	1.40	0
C_3H_8	1.32	33
$i-C_4H_{10}$	0.09	3
$n-C_4H_{10}$	0.17	6
$i-C_5H_{12}$	0.05	2
$n-C_5H_{12}$	0.04	2
Total	100.00	1053

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13. ABSTRACT

As a major part of Esso's "Systems Study of Nitrogen Oxide Control Methods for Stationary Sources in Phase II," funded by the EPA under Contract No. CPA 70-90, a utility boiler field test program was conducted. The objectives of this study were to determine new or improved NO_x emission factors by fossil fuel type and boiler design, and to assess the scope of applicability of combustion modification techniques for controlling NO_x emissions from such installations. In addition, the concentrations of other combustion flue gas species were also determined, to evaluate the effect of combustion modification techniques on the emission of other potential pollutants, such as unburned combustibles.

A specially designed mobile sampling-analytical van was assembled for the purpose of this boiler test program. This system was equipped with continuous monitoring instrumentation for the measurement of NO, NO_2, CO_2, O_2, CO and hydrocarbons, with the later addition of an SO_2 monitor. Probing of the flue gases from boiler duct-work was accomplished by simultaneously withdrawing sample streams from 12 different locations, varied as dictated by the duct configuration. Usually, four sample streams compositing the contents of three probes each were monitored during test runs.

(Continued)

ABSTRACT (Continued)

A statistically designed test program was conducted with the cooperation of utility owner-operators. Boilers to be tested in the program were selected based on fuel type fired, boiler size and design, and special features of interest to NO_x emission control. The objective was to make the boilers selected a reasonable "micro-sample" of the U.S. boiler population. Wall-fired, tangentially-fired, cyclone-fired, and vertically-fired boilers were tested in the program. Altogether, 17 boilers and 25 boiler-fuel combinations were tested.

The NO_2 portion of the total NO_x content in the flue gas was found to average five per cent or less, whenever NO_2 could be measured. For test data which did not include NO_2 measurements, the NO_x was calculated as 105% of the NO measured.

Major combustion operating parameters investigated included the variation of boiler load, level of excess air, firing pattern (staged, "off-stoichiometric", or "biased firing"), flue gas recirculation, burner tilt, and air preheat temperature. It was found that while NO_x emission levels reached very high levels (on the order of 1000 ppm) in large gas fired boilers, combustion modifications, particularly low excess air firing and staged air supply resulted in some cases in emission reductions at full load on the order of 80%. However, even for gas fired boilers, the degree of effectiveness of combustion modifications varied with individual boiler characteristics, such as burner design and spacing. Load reductions resulted in large reductions in NO_x emissions for gas fired boilers.

Similar trends on the effectiveness of combustion modifications were observed with fuel oil firing, albeit with a lesser degree of effectiveness. NO_x emission reduction from oil firing is less responsive to load changes and the application of combustion modification techniques is somewhat more difficult than in gas firing.

In coal firing, promising exploratory data were obtained on two of the seven coal fired boilers tested. For coal, the key to NO_x reductions (apart from operating under reduced load) appears to be the firing of burners with substoichiometric quantities of air, followed by second stage air injection for the burn-out of combustibles. This was accomplished in a 175 MW front wall fired boiler and in a 575 MW tangentially fired boiler with better than 50% reductions in NO_x, operating at 80-85% of full load. Boiler manufacturers participated in testing three coal fired boilers manufactured by them to assess the steam-side consequences (i.e., effects on thermal performance, slagging characteristics, coal in the fly-ash, and other boiler operability features) of applying combustion modifications. In the short-term tests conducted in this program, the boiler manufacturers (Babcock and Wilcox, Combustion Engineering and Foster-Wheeler) did not find undue problems caused by combustion modifications.

ABSTRACT (Continued)

Unburned combustible emissions, i.e., CO and hydrocarbons were found to be very low under base-line boiler operating conditions for all boilers tested. However, using low excess air firing, the CO levels can increase sharply, and in fact, set the lower limit on excess air. In tests where unburned carbon in the fly ash was measured by boiler manufacturers, combustion modifications (staging with low excess air firing) did not result in increased carbon in the fly ash. More detailed testing will be needed under carefully controlled conditions.

The emission factors established in this study in conjunction with the overall correlations developed for NO_x emissions will allow making better estimates for individual boilers, according to fuel type fired, boiler size and design.

It is concluded that modification of combustion operating conditions offers good promise for the reduction of NO_x emissions from utility boilers. Further cooperative testing with boiler owner-operators and manufacturers are required to optimize and demonstrate the general applicability of these techniques to the control of NO_x emissions from gas and oil fired installations and to establish their real potential for coal fired boilers.