EPA-450/3-74-063

Section 1.3

-#7

PARTICULATE EMISSION CONTROL SYSTEMS FOR OIL-FIRED BOILERS

GCA Corporation
Technology Division
Burlington Road
Bedford, Massachusetts 01730

Contract No. 68-02-1316

EPA Project Officer: Edwin J. Vincent

Prepared for

ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Waste Management
Office of Air Quality Planning and Standards
Research Triangle Park, N. C. 27711

December 1974

Ref 7

FUEL OIL
COMBUSTION
AP-42 Section 1.3
Reference Number
7

EPA-450/3-74-063

PARTICULATE EMISSION CONTROL SYSTEMS FOR OIL-FIRED BOILERS

GCA Corporation
Technology Division
Burlington Road
Bedford, Massachusetts 01730

Contract No. 68-02-1316

EPA Project Officer: Edwin J. Vincent

Prepared for

ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Waste Management
Office of Air Quality Planning and Standards
Research Triangle Park, N. C. 27711

December 1974

This report is issued by the Environmental Protection Agency to report technical data of interest to a limited number of readers. Copies are available free of charge to Federal employees, current contractors and grantees, and nonprofit organizations - as supplies permit - from the Air Pollution Technical Information Center, Environmental Protection Agency, Research Triangle Park, North Carolina 27711; or, for a fee, from the National Technical Information Service, 5285 Port Royal Road, Springfield, Virginia 22161.

This report was furnished to the Environmental Protection Agency by GCA Corporation, in fulfillment of Contract No. 68-02-1316. The contents of this report are reproduced herein as received from GCA Corporation. The opinions, findings, and conclusions expressed are those of the author and not necessarily those of the Environmental Protection Agency. Mention of company or product names is not to be considered as an endorsement by the Environmental Protection Agency.

Publication No. EPA-450/3-74-063

ABSTRACT

The results of this study have been reported in three sections: (1) a listing of oil-fired combustion units including their size, fuel rate and composition, type and performance of particulate control equipment, and the methodology used to procure these data; (2) an assessment of the effectiveness of the particulate control equipment and the impact of coal-to-oil conversions, sulfur and ash content, fuel additives, sootblowing, base or peak load operations on equipment performance; and (3) the technical feasibility and cost of installing particulate controls on existing and proposed oil-fired systems.

CONTENTS

FIGURES

TABLES

SECTION I

SUMMARY AND CONCLUSIONS

The combustion of residual and distillate oils in stationary boilers represents an important source of fine particles in the atmosphere. Utilities and industry are the principal consumers of residual oil for electric power, heating and steam production whereas commercial and domestic heating systems are the main users of distillate oils.

The quantity, type and size of particulate emissions from oil-fired combustion operations are presumed to depend mainly upon the following factors:

- Overall fuel consumption rate
- Ash and sulfur content of fuel
- Use of mineral fuel additives
- Combustion efficiency for fuel
- Plant age and operating procedures-archaic to modern
- Use and effectiveness of particulate control devices.

The resultant impact of these combustion operations upon any geographical area must be assessed not only in terms of sources strength(s) but also in terms of climatological and topographical factors that control the meteorological transport of the particulates.

The first objective of this study was to provide a general listing of oil-fired combustion facilities within the U.S.A. with respect to the key parameters defining particulate emission levels. This was accomplished through analyses of data excerpted from: (1) NEDS files prepared by EPA;

(2) past and present stack sampling programs conducted by GCA/Technology Division and other private agencies; and (3) stack test data made available by the Massachusetts Bureau of Air Quality.

A second objective of this study was to determine what degree of control was now provided by various types of particulate collectors so that an assessment of the feasibility of installing more and better control devices might be made. At this time, it appears that the necessity for controlling particulate emissions from present or future combustion systems must be judged first upon best estimates of particle toxicity. Secondary criteria should include how large a reduction in solids emissions can be attained for any one type of oil-fired combustion unit compared to the total emission potential for all classes of oil-fired systems. Additionally, the feasibility of regulating emissions from oil-fired boilers must also be examined on a cost basis relative to the selection of alternate methods of energy production.

CONCLUSIONS

General

1. NEDS data provide a useful information source from which parameters can be developed to assist in estimating particulate emissions potential and emission control needs for large geographical areas.
2. Particulate emission rates based upon actual stack sampling indicate that use of EPA emission factors for stationary, oil-fired combustion systems in conjunction with commonly accepted efficiency values for electrostatic precipitators (or those suggested by the manufacturer) can lead to erroneously low projections for emission rates.
3. The general scatter observed in the actual sampling data used in preparing this report indicates that considerably more than 100 samples are needed to establish precise estimates of current emissions and the feasibility of their control.

Applications/NEDS Data

1. NEDS sources currently report emission data that, based upon estimated fuel consumption from independent surveys, represent about 75 percent of existing stationary oil-fired, external combustion boiler capacity in the U.S.A.

2. Boilers are grouped according to three fuel consumption classes (utility, industrial and commercial), rated capacity, fuel type and fuel usage. Where multiple fuel usage (e.g., oil-coal or oil-gas) is indicated, one can establish emission statistics only on a yearly average basis.

3. Exclusion of multiple-fueled boilers from statistical averaging processes does not appear to bias NEDS data with respect to number of boilers versus size, boiler size versus use of control equipment, or boiler size versus estimated particulate emissions.

4. NEDS emission statistics for most boilers are based upon emission factors established by prior EPA studies and dust collector efficiency data either provided by the manufacturer or estimated by the user or polling group. They may apply only to a single fuel type; e.g., coal, and to but one method of boiler operation; e.g., base load. Few data reported in NEDS files are based upon current stack sampling carried out in accordance with compliance procedures. Therefore NEDS emission statistics are essentially a reflection of existing emission factors and depict no new data.

5. Generally, NEDS data permit no evaluations of the effect of fuel additives, method of boiler operation and the performance potential of particulate control equipment. The age of a boiler, which may have a significant impact on the emissions characteristics, can only be inferred indirectly on the basis of size.

Analyses of Field Measurements

1. Stack sampling measurements indicate that particulate emissions per 1000 gallons of fuel fired generally decrease as boiler size increases. Emission levels were found to range from 13.1 to 6.9 lb/1000 gal. for boiler capacities of 1 to 500 Mw. With regard to boiler size, EPA has proposed an average emission factor of 8 lb/1000 gal.

2. A decrease in emission rate as a function of boiler capacity was also observed for systems using additives.

3. A decrease in particulate emission rate was noted for uncontrolled systems as well as controlled systems when boiler capacity was increased.

4. A reduced emission rate for large boilers is attributed mainly to the fact that boiler larger than 200 Mw in capacity are usually newer units with more sophisticated combustion control.

5. Electrostatic precipitators are by far the predominant collector types for control of emissions from oil-fired units.

6. Those precipitators designed expressly for oil-fired systems provide better collection than units designed for coal-fired boilers and not modified for oil-firing.

7. Inertial collectors of the multicyclone type generally have little value as control units for oil-fired emissions except to capture gross particulate (> 10 μm diameter) in the acid smut category.

8. Particulate emissions for oil-fired systems with electrostatic precipitators appear to decrease slowly once a 300 Mw capacity is reached suggesting that a steady state discharge may be approached that depends upon: (1) the intensity and frequency of plate rapping and its effects upon dust reentrainment; and (2) the intensity, duration, and general programming of soot blowing operations.

9. Collection efficiencies for electrostatic precipitators will usually increase with inlet dust loading for a given boiler operation. The reason for this behavior is that high loadings are usually associated with coarse particulates produced by: (1) massive soot discharge resulting from poor combustion; (2) excessive soot blowing; or, (3) excessive use of coarse mineral additives.

10. Current field sampling data (exclusive of NEDS sources) indicate that emission rates for boilers controlled by electrostatic precipitation average about 3.8 lb/1000 gal for units $>$ 100 Mw capacity. On this basis the "effective" efficiency for the ESP units is roughly 50 percent or less for boilers that are well controlled from the combustion standpoint.

11. Limited measurements indicate that use of fuel additives to regulate ash slagging and cold-end corrosion produced higher particulate emission.

12. Limited data indicate that wet scrubbing systems developed mainly for sulfur oxides removal provide high particulate collection. Unfortunately, power requirements to achieve > 90 percent removal and the plume reheating necessary to provide for vapor plume rise and dissipation may not be acceptable.

13. Limited tests indicate that normal variations in fuel oil sulfur and ash content exert no significant effect on particulate emission rates. It is recognized, however, that any real emission variations that might have been attributable to sulfur content could have been observed by variations in other system operating parameters. Further tests should be made to determine whether the components of the mineral ash, particularly catalyzing elements such as vanadium, may affect emissions rate.

SECTION II

SURVEY OF OIL-FIRED COMBUSTION SYSTEMS EMPLOYING PARTICULATE EMISSION CONTROL DEVICES

The contribution of particulate emissions from oil-fired combustion systems to total atmospheric loadings must be appraised within the context of current fuel consumption policies. In Table 1,[1,2] a breakdown of fuel usage is provided with respect to fuel type (distillate or residual) and plant operation (industrial or electrical power). In 1971, electric power generating utilities consumed approximately 396 million barrels of fuel oil.[3] This was more than 1.5 times that consumed by industry for the production of heat and power[1] while it was considerably less than the combined domestic and commercial fuel oil consumption for the same year.[4] The terms domestic and commercial as used in this report refer, respectively, to private residence and public buildings and/or apartments.

Oil-fired electric utilities employ particulate emission controls far more frequently than their industrial or commercial counterparts. Use of particulate control equipment on domestic combustion systems is virtually unheard of. For this reason, the primary focus of this study has been upon power generating utilities.

The data presented in Table 2, Appendix A, Appendix B, and in other sections of this report were obtained from a number of sources. In this report, the basis for particulate emission analyses was the stack test data in Table 2 and Appendix B. These are the data that are illustrated in various figures throughout the text. The information used to

Table 1. INDUSTRIAL AND ELECTRIC UTILITY FUEL OIL CONSUMPTION (FOR THE PRODUCTION OF HEAT AND POWER) BY GEOGRAPHIC REGION AND STATE[1,2]

Geographic region and state	Industrial[a]		Utility[b]	
	Distillate (1000 BBL/yr)	Residual (1000 BBL/yr)	Distillate (1000 BBL/yr)	Residual (1000 BBL/yr)
New England				
Connecticut	2,731.0	7,297.5	1.0	29,753.0
Maine	1,546.8	9,190.8	0.0	4,713.3
Massachusetts	4,556.1	7,370.4	65.0	45,050.0
New Hampshire	635.1	2,620.8	0.0	1,725.7
Rhode Island	725.4	1,317.0	10.0	2,419.4
Vermont	211.2	419.8	0.0	0.0
TOTALS	10,405.6	28,216.3	76.0	83,661.4
Middle Atlantic				
New Jersey	15,085.5	13,765.5	18.9	34,376.6
New York	9,407.9	11,044.0	47.0	92,390.9
Pennsylvania	11,084.0	15,581.4	830.0	14,582.8
TOTALS	35,577.4	40,390.4	895.9	141,350.3
East North Central				
Illinois	5,053.0	4,073.4	1,602.2	6,825.1
Indiana	4,054.4	5,404.3	342.1	0.0
Michigan	1,945.8	2,574.4	1,388.7	6,957.5
Ohio	4,471.2	1,760.1	364.2	1,186.1
Wisconsin	1,418.3	1,059.7	273.9	2,534.4
TOTALS	16,942.7	14,871.9	3,971.1	17,503.1
West North Central				
Iowa	1,082.0	352.9	79.2	0.0
Kansas	175.2	220.3	230.6	781.5
Minnesota	959.6	1,847.8	750.5	841.3
Missouri	648.7	325.7	192.1	830.2
Nebraska	305.7	122.9	154.0	203.7

Table 1 (continued). INDUSTRIAL AND ELECTRIC UTILITY FUEL OIL CONSUMPTION (FOR THE PRODUCTION OF HEAT AND POWER) BY GEOGRAPHIC REGION AND STATE[1,2]

Geographic region and state	Industrial[a] Distillate (1000 BBL/yr)	Industrial[a] Residual (1000 BBL/yr)	Utility[b] Distillate (1000 BBL/yr)	Utility[b] Residual (1000 BBL/yr)
North Dakota	109.4	15.2	7.1	0.0
South Dakota	47.6	102.0	0.0	277.0
TOTALS	3,328.2	2,986.8	1,413.5	2,933.7
South Atlantic				
Delaware	784.0	2,853.4	0.0	589.1
District of Columbia	13.9	37.3	0.0	5,309.0
Florida	3,974.4	6,916.0	85.7	59.622.3
Georgia	4,225.8	4,638.7	847.2	3,245.0
Maryland	2,450.3	6,937.8	0.0	25,079.6
North Carolina	3,405.5	7,859.6	401.1	3,588.8
South Carolina	3,552.4	3,042.4	334.5	2,446.5
Virginia	4,444.6	4,521.5	118.3	20,465.5
West Virgina	730.5	124.4	0.0	2,105.5
TOTALS	23,581.4	36,931.1	1,786.8	122,451.3
East South Central				
Alabama	1,634.3	1,525.7	10.2	0.0
Kentucky	351.0	291.6	24.4	0.0
Mississippi	477.9	262.6	3,432.8	1,541.9
Tennessee	972.4	1,165.2	0.0	0.0
TOTALS	3,440.6	3,245.1	3,467.4	1,541.9
West South Central				
Arkansas	338.2	1,592.1	297.0	1,058.5
Louisiana	1,473.5	808.3	4,239.9	2,369.1
Oklahoma	31.9	27.3	68.3	49.3
Texas	690.2	1,817.1	4,125.5	1,679.9
TOTALS	2,533.8	4,244.8	8,730.7	5,156.8

Table 1 (continued). INDUSTRIAL AND ELECTRIC UTILITY FUEL OIL CONSUMPTION (FOR THE PRODUCTION OF HEAT AND POWER) BY GEOGRAPHIC REGION AND STATE[1,2]

Geographic region and state	Industrial[a]		Utility[b]	
	Distillate (1000 BBL/yr)	Residual (1000 BBL/yr)	Distillate (1000 BBL/yr)	Residual (1000 BBL/yr)
Mountain				
Arizona	116.7	54.5	4,170.4	4,029.7
Colorado	646.6	1,197.8	15.5	475.0
Idaho	196.4	58.2	0.0	0.0
Montana	99.0	157.8	0.0	0.0
Nevada	121.5	20.0	81.5	522.8
New Mexico	17.2	15.9	258.4	363.5
Utah	678.7	95.5	4.0	373.0
TOTALS	2,092.8	1,599.7	4,529.8	5,728.0
Pacific				
California	3,093.8	1,309.8	69.3	81,622.8
Oregon	1,111.0	2,066.1	200.4	0.0
Washington	1,971.1	3,572.1	0.0	440.6
TOTALS	6,175.9	6,948.0	269.7	82,063.4
Non-Contiguous U.S.				
Alaska	630.5	355.0		
Hawaii	203.8	820.3		
TOTALS	834.3	1,175.3		
U.S. TOTALS	104,912.7	140,617.4	25,140.9	462,390.0

[a]Figures based on 1972 Census of Manufacturers; Fuels and Electric Energy Consumed in 1971 for the Production of Heat and Power.

[b]Figures based on FPC Form No. 423; Monthly Reports of Cost and Quantity of Fuels for Steam Electric Plant 1973.

Table 2. OIL-FIRED COMBUSTION SYSTEMS WITH PARTICULATE EMISSION CONTROL DEVICES (STACK TEST DATA)

Company name	Plant name	Boiler No.	Boiler capacity (Mw)[a]	Sulfur content (%)	Ash content (%)	Additives	Fuel consumption rate (gph)	Particulate emission control device[b]	Particulate emission control efficiency (%)[c]	Particulate emissions (lb/MM Btu)
Company A	1		30			Yes	2870	ESP		0.136
			30			Yes	2870	ESP		0.149
			30	0.87		Yes	2870	ESP		0.084
			30	0.93		Yes	2870	ESP	--	0.132
			30	0.89		Yes	2870	ESP		0.094
			30			Yes	2870	ESP		0.188
			30			Yes	2870	ESP		0.130
			30			Yes	2870	ESP		0.132
			30			Yes	2870	ESP		0.078
			30			Yes	2870	ESP		0.099
			18			Yes	2100	ESP		0.176
			18			Yes	2100	ESP		0.187
			18			Yes	2100	ESP		0.157
			18			Yes	2100	ESP		0.160
			18	0.86		Yes	2100	ESP		0.074
			18	1.18		Yes	2100	ESP		0.142
			18	1.13		Yes	2100	ESP		0.150
			20	1.00		Yes	2200	ESP		0.097
			40	1.00		Yes	3200	ESP		0.140
			10			Yes	900	ESP		0.096
			10			Yes	900	ESP		0.099
			10			Yes	1100	ESP		0.136
			10			Yes	1100	ESP		0.149
	2		600	1.00		Yes	35000	ESP		0.021
Company B	1		70	1.00		No	4640	Cyclone		0.064
			85	1.00		No	5980	Cyclone		0.053
Polaroid Corp.	New Bedford	1	10	0.70		No	390	ESP	40	0.055
		2	10	0.70		No	340	ESP	51	0.070
Boston Edison	Mystic	3	48	2.40		Yes	3600	ESP	38	0.113
		3	48	2.40		No	3600	ESP	57	0.150
		3	48	2.40		Yes	3600	ESP	71	0.033
		3	48	2.40		No	3600	ESP	34	0.148
		3	48	2.30		Yes	3600	ESP		0.244
		3	48	2.30		Yes	3600	ESP		0.154
		3	48	2.30		No	3600	ESP		0.154
		6	146	2.15	0.09	Yes	11256	Scrubber	69.5	0.085
		6	144	2.10	0.10	Yes	9593	Scrubber	50.5	0.085
		6	151	1.89	0.07	Yes	9268	Scrubber	62.4	0.106
		6	148	2.04	0.07	Yes	8211	Scrubber	45.7	0.059
Hartford Electric Light	Middletown	2	119	1.95	0.09	Yes	7800	ESP		0.070
		2	117	1.84	0.07	Yes	7800	ESP		0.057
		2	119	1.79	0.07	Yes	7800	ESP		0.067
United Illuminating	Bridgeport	3	405	1.80	0.08	Yes	26000	ESP		0.150
		3	405	1.77	0.09	Yes	26000	ESP		0.126
Consolidated Edison	Ravenswood	30	600	0.30	0.02	No	37000	ESP	16	0.017
	Astoria	50	320	0.30		No	19000	ESP	51	0.008
		30	350	0.37		No	19000	ESP	54	0.012
		40	355	0.30		No	19000	ESP	48	0.012
		50	385	0.37		No	19000	ESP	45	0.012
Company C			185	2.5		Yes		ESP & Cyclone	63.0	0.083
			185	2.5		Yes		ESP & Cyclone	72.0	0.062
			185	2.5		Yes		ESP & Cyclone	86.0	0.049
			367	2.45	0.28	Yes		ESP	90.0	0.015
			367	2.45	0.28	Yes		ESP	73.3	0.022
			368	2.5	0.12	No	22560	ESP		0.0103
			368	2.5	0.12	No	22560	ESP		0.0113
			368	2.5	0.12	No	22560	ESP		0.0348
			368	2.5	0.12	No	22560	ESP		0.0197
			363	2.5	0.12	No	22620	ESP		0.0132
			363	2.5	0.12	No	22620	ESP		0.0097
			370		0.15	Yes	22040	Cyclone	19.4	0.092
			372		0.16	Yes	23262	Cyclone	7.4	0.085
			363		0.15	Yes	21687	Cyclone	71.	0.042
			368		0.16	Yes	21360	Cyclone	71.6	0.034
			370	0.5		Yes		Cyclone		0.048
			370	0.7		Yes		Cyclone		0.046
			370	1.0	0.1	Yes		Cyclone		0.052
			370	2.7	0.2	Yes		Cyclone		0.080
Company D			600	0.9	.06	No	36425	ESP		0.0060
			600	0.9	.06	No	36425	ESP		0.0034
			600	0.9	.06	No	36425	ESP		0.0058
			600	0.9	.06	No	36425	ESP		0.0062

[a] Mw ≅ 9.4 MM Btu/hr

[b] ESP - Electrostatic precipitator

[c] Many of the stack tests did not include upstream particulate measurements. Therefore, control device collection efficiencies could not be determined.

formulate Appendix A was obtained from the National Emissions Data System (NEDS). Since most NEDS data were computed on the basis of emission factors rather than actual stack measurements, the NEDS information has been used mainly to furnish system and operating parameters. NEDS data have not been used in subsequent analyses of emissions. Procedures used to process NEDS data are described below.

Figure 1 illustrates the manner in which the data from NEDS were handled. Initially, a tape was received containing information for electric utility, industrial and commercial boilers firing oil, coal and natural gas. Due to the nature of the retrieval program used to prepare this tape, the information was stored by fuel type rather than by source. This created process complications because the fractions of oil coal, or gas consumed at multiple fuel use locations were often not clearly identified. A program was developed to extract the oil-fired system data from the initial tape for both printout and storage on another tape. From this second tape, those systems employing emission control equipment were identified and printed. Since many of the systems on the list of controlled oil-fired boilers also fired other fuels, it is necessary to identify and print a list of these multiple fueled systems. Once identified, a manual sorting process was employed to eliminate the multiple fueled systems from the list of controlled boilers. Further complications arose when it was realized that some of the boilers which were thought to be fired solely by oil might also be fueled with wood, bagasse, coke, process gas, LPG, etc. Due to the fact that these fuels were not included on the initial NEDS tape received by GCA, these multiple fueled sources had to be manually identified by personnel at the NADB. This permitted a listing of controlled boilers fueled solely by oil in Appendix A.

The data presented in Table 2 include the results of stack tests provided by the Massachusetts Bureau of Air Quality Control and the results of emissions compliance tests performed by GCA/Technology Division at several oil-fired power plants. Several large utilities also provided

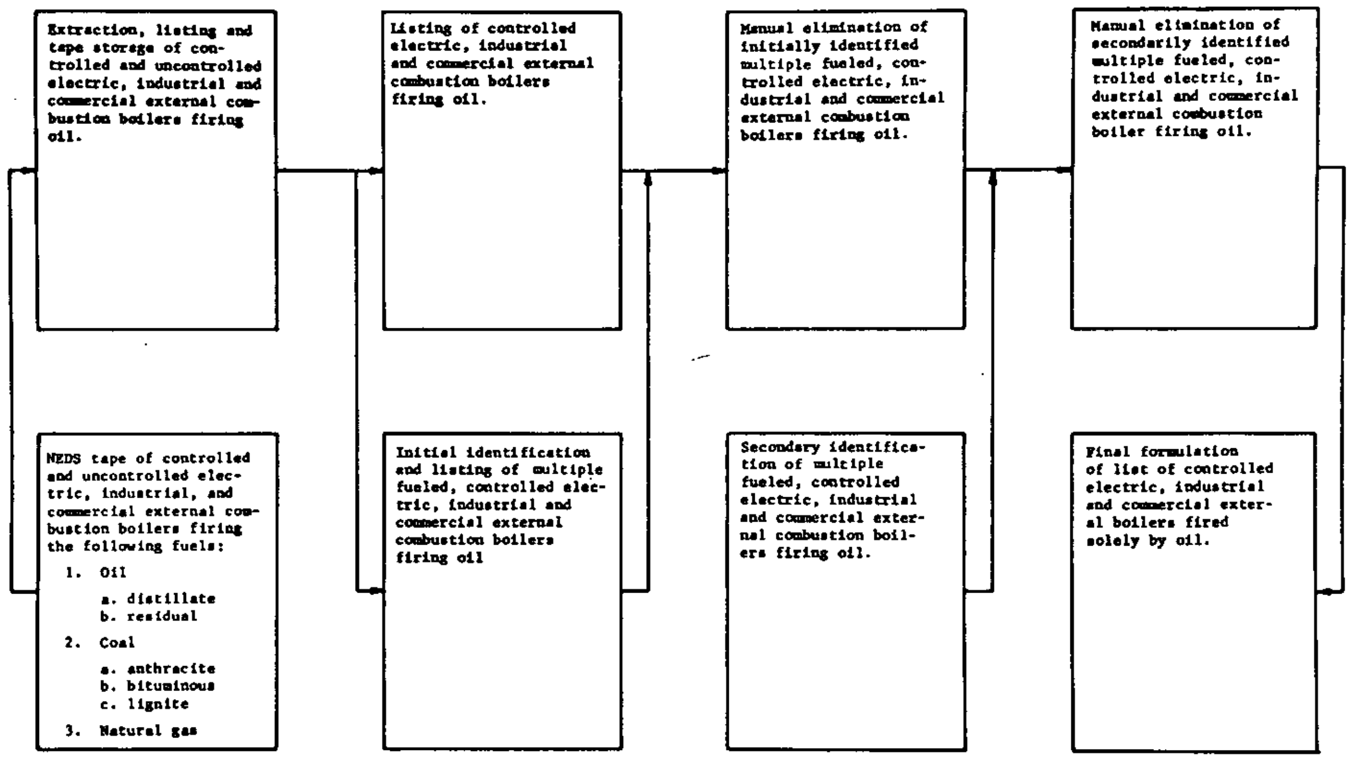

Figure 1. Outline of processing procedure used on NEDS data

results of stack measurements on their systems with the proviso, in some cases, that their plants not be identified.

Table 3 was developed from the NEDS list of controlled and uncontrolled oil-fired external combustion boilers. Only oil-fired electric utility boilers were considered since, as stated earlier, their emissions are the primary concern of this study. The hourly heat input rate was calculated for these boilers by assuming continuous operation. Since some of these boilers were multiple fueled, only those using more than 10 percent oil were used to formulate the table. This procedure was followed in order to avoid including boilers that use oil only for startup operations. The total annual distillate and residual fuel oil consumptions for the boilers used to develop Table 3 are 12,235,000 bbls and 363,735,000 bbls, respectively. These figures represent 48.7 and 78.7 percent of the total national distillate and residual fuel oil consumption by electric utilities (Table 1). In GCA's estimation, the NEDS data presented in Table 3 provides a representative cross section of oil-fired electric utility boilers. In Table 4, the total national fuel oil consumption by electric utilities is apportioned using the categorical distribution of fuel oil consumption presented in Table 3.

In both Tables 3 and 4, the boiler size category of >1000 MM Btu/hr appears while this size category does not appear in the NEDS. Boilers in this category are usually relatively new power utility boilers. Due to technological advances, these new boilers have more sophisticated combustion controls than older boilers that are generally smaller in size. It is GCA's contention that this additional boiler size category will add valuable detail to this study, especially when considering the formulation of particulate emission factors.

Table 3. SIZE BREAKDOWN OF CONTROLLED AND UNCONTROLLED ELECTRIC UTILITY EXTERNAL COMBUSTION BOILERS LISTED IN NEDS THAT SATISFY MORE THAN 10 PERCENT OF THEIR FUEL DEMANDS WITH OIL

Boiler size categories (MM Btu/hr[a])	Number of boilers in each size range category	Annual distillate fuel oil consumption of boilers in each size range category (1000 gal)	% of total annual distillate fuel oil consumption by both controlled and uncontrolled boilers in all size range categories	Boiler size range category (MMBtu/hr) ≅ (10⁻¹Mw)	Number of boilers in each size range category	Annual residual fuel oil consumption of boilers in each size range category (1000 gal)	% of total annual residual fuel oil consumption by both controlled and uncontrolled boilers in all size range categories
Controlled electric utility oil-fired external combustion boilers							
Distillate oil				Residual oil			
< 10	0	0	0	< 10	2	52	0
10 - 100	0	0	0	10 - 100	2	7,922	0.1
100 - 1000	1	17,573	3.4	100 - 1000	135	2,722,051	17.8
> 1000	2 3	88,034	17.1	> 1000	159 /298	4,063,668	26.6
Uncontrolled electric utility oil-fired external combustion boilers							
< 10	15	1,582	0.3	< 10	25	6,375	0
10 - 100	7	3,370	0.7	10 - 100	134	210,628	1.4
100 - 1000	47	282,102	54.9	100 - 1000	339	3,310,050	21.7
> 1000	3 72	121,191	23.6	> 1000	84 582	4,956,136	32.4

[a] $9.4 \frac{MM\ Btu}{hr} \cong 1$ Mw

300 controlled

654 uncontrolled utility

Table 4. ESTIMATED ANNUAL ELECTRIC UTILITY FUEL OIL CONSUMPTION BY BOILER SIZE FOR THE U.S.

Boiler size categories (MM Btu/hr)[a]	Annual distillate oil consumption (1000 gal)	Annual residual oil consumption (1000 gal)
Controlled boilers		
< 10	0	0
10 - 100	0	19,420
100 - 1000	35,901	3,456,828
> 1000	180,562	5,165,821
Uncontrolled boilers		
< 10	3,168	0
10 - 100	7,391	271,885
100 - 1000	579,699	4,214,222
> 1000	249,197	6,292,203

[a] $9.4 \frac{\text{MM Btu}}{\text{hr}} \cong 1$ Mw

SECTION III

CONTROL OF PARTICULATE EMISSIONS FROM OIL - FIRED COMBUSTION SYSTEMS

FUEL AND EMISSION CHARACTERIZATION

Residual oil typically has an ash content of 0.1 percent[5] while bituminous coal, which is the most widely used of all coals, may contain anywhere from 3 to 20 percent ash.[6] The particulate emissions resulting from efficient coal combustion are composed almost entirely of mineral and metallic oxides and a very small percentage of combustible carbonaceous materials. When residual oil combustion is highly efficient, the resulting particulate emissions are constituted almost entirely of inorganic ash which occurs as oxides, chlorides or sulfates.[5,7] A typical residual fuel oil ash analysis appears in Table 5. Residual oil combustion products, however, are more often found to contain about 50 percent by weight of sooty organic material. Frequently this material consists of unburned carbonaceous solids which tend to be sticky and hygroscopic.[5] The latter condition probably arises from the presence of calcination products and condensed sulfuric acid.

On a mass basis, the particulate emissions from an uncontrolled residual oil-fired boiler are of the same order as those from a highly controlled (> 95 percent removal efficiency) coal-fired boiler. Stack tests have indicated that between 85 and 90 weight percent of the particles liberated by uncontrolled residual oil combustion are less than 1 micron in diameter while usually less than 10 percent of those liberated by coal combustion are in the < 1 μm category.[5,9] Because submicron particles are highly efficient light scatterers, uncontrolled residual oil-fired boilers often have high plume opacities. The new source performance standards for oil-fired power plants not only require that particulate emissions do not exceed 0.10 lb/MM Btu but also that plume opacity not be greater than 20 percent.[10] This particulate emission level excludes condensables. It is unlikely that high efficiency particulate collection equipment will be required for new oil-fired utility boilers to comply with particulate emission regulations. However, due to the submicron size of the particles emitted, relatively efficient particulate collection equipment may be necessary in order to improve plume appearance. As well as reducing plume opacity, a high efficiency collector reduces the chance of acid smut discharge during sootblowing operations.[11] Smuts are created by the formation and/or collection of sulfuric acid upon particle deposits which lie on furnace, duct, and stack liner surfaces.[12] The sulfuric acid dew point of a stack gas increases with increasing sulfur trioxide and, to a lesser extent, increasing water vapor concentration.[13] Generally speaking, the higher the sulfur content of a fuel oil, the more SO_3 is formed, and subsequently, the higher the sulfuric acid dew point.[14]

Smut buildup can occur on any cool boiler surface. Periodically, patches of agglomerated material become resuspended by vibrations and aerodynamics and are carried up the stack. Oftentimes, duct and stack linings are insulated in order to keep their temperature above the acid dew point. Another acid smut reduction technique is to periodically wash the stack interior. This is usually accomplished by installing a spray ring at the top of the stack and a drain at the bottom.[12] In addition to being responsible for the formation of acid smut, SO_3, upon emerging from a stack, forms a fine aerosol mist and subsequently causes increased plume opacity.

Table 5. TYPICAL RESIDUAL OIL ASH ANALYSIS[8]

Constituent	Weight %
Iron	22.99
Aluminum	21.90
Vanadium	19.60
Silicon	16.42
Nickel	11.86
Magnesium	1.78
Chromium	1.37
Calcium	1.14
Sodium	1.00
Cobalt	0.91
Titanium	0.55
Molybdenum	0.23
Lead	0.17
Copper	0.05
Silver	0.03
Total	100.00

EMISSION FACTORS FOR UNCONTROLLED OIL-FIRED BOILERS

In order to assess the effectiveness of particulate emission control equipment for residual oil combustion, it is first necessary to establish the relationship between particulate concentration and boiler size for uncontrolled effluents. For reasons mentioned in Section II, this study focuses on power plant boilers. It is our impression that emissions from industrial boilers are comparable to those from utility boilers of a corresponding capacity. In Figure 2, all particulate emission data that were compiled for uncontrolled, base loaded residual oil-firing power plant boilers are presented. Each point represents either a single or the average of replicate boiler tests. Replicate tests were averaged to avoid assigning too much weight to the performance of any one boiler. In order to characterize these emission data, a linear regression analysis was carried out. In Figure 2, the envelope lines about the regression line represent the 50 percent confidence limits. The regression line may be described by the following equation:

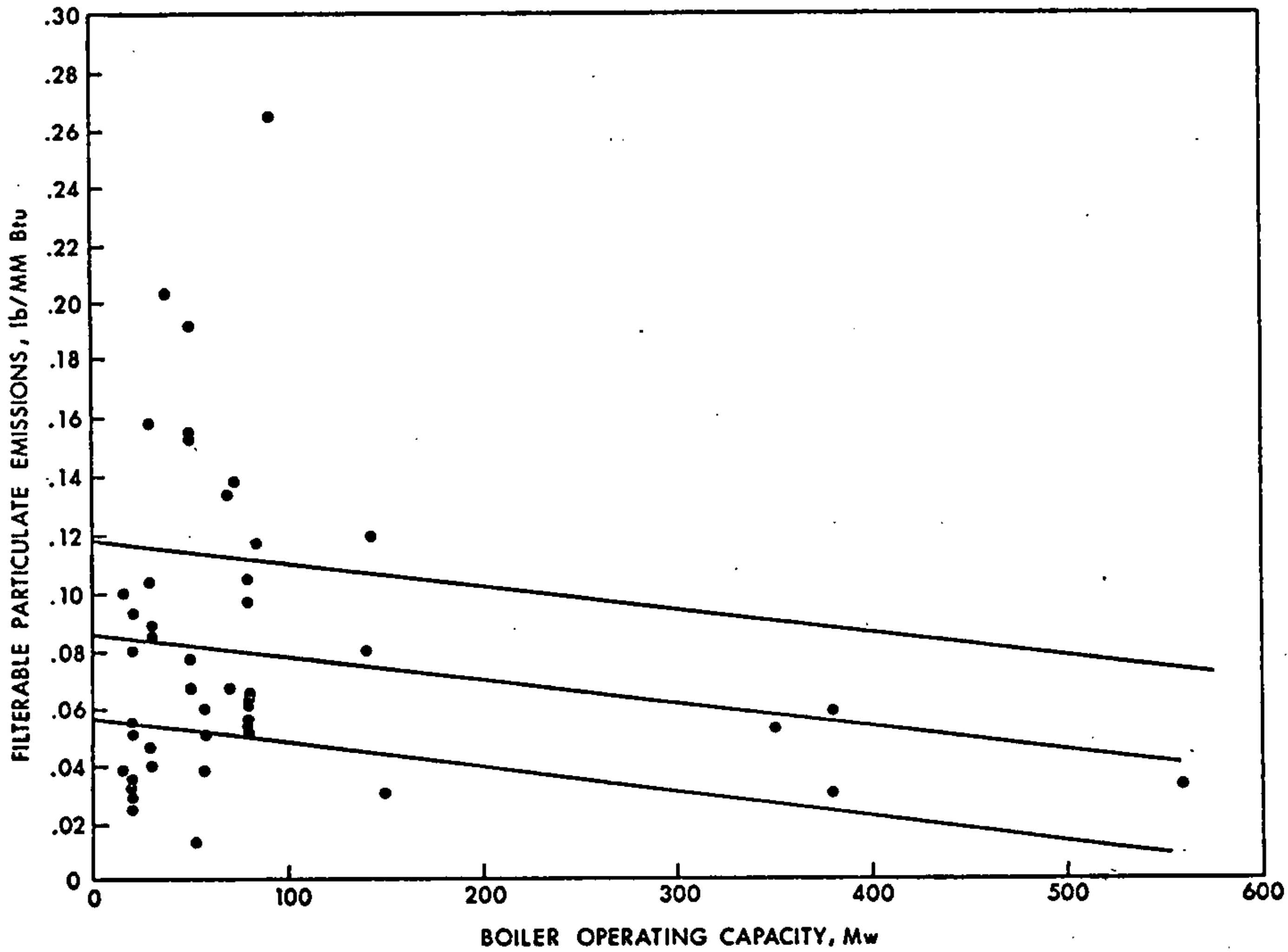

Figure 2. Uncontrolled electric utility emissions vs. capacity

$$y = -(7.82 \times 10^{-5})x + 0.0876 \quad (1)$$

where y = filterable particulate emissions (lb/MM Btu)

x = boiler operating capacity (Mw).

The negative slope of the regression line indicates that an inverse proportionality exists between particulate release and boiler size. The superior performance of large utility boilers is attributed to more sophisticated combustion controls and properly functioning system components. Thus better regulation of excess air, flame temperature, atomizing conditions and gas mixing patterns leads to more efficient combustion and lower particulate emissions. Equation (1) can be readily modified to express emissions in terms of gallons of fuel consumed, rather than the equivalent Btu rate.

$$y = -0.0117\,x + 13.1 \quad (2)$$

where y = filterable particulate emission factor (lb/1000 gal)

x = boiler operating capacity (Mw).

In Table 6, the emission factors predicted by Equation (2) for various size utility boilers are contrasted with those reported by other sources. A fuel input/boiler capacity conversion ratio of 9.4 $\frac{\text{MM Btu}}{\text{hr}}$: 1 Mw was used in the preparation of this table.[15,16] The emission factors presented in Table 6 are plotted in Figure 3 to facilitate visual comparison. As shown in Figure 3, the variable emission factor proposed by GCA is greater than the MRI value when considering boilers of less than 270 Mw capacity and is greater than the EPA emission factor for boilers smaller than 430 Mw. The variable emission factor proposed here more accurately depicts the actual performance of uncontrolled residual oil-firing base loaded utility boilers.

Table 6. EMISSION FACTORS VERSUS SIZE FOR RESIDUAL OIL-FIRED UTILITY BOILERS

Boiler capacity rating		Boiler fuel consumption (gal/hr)	Predicted emission factors (lb/1000 gal)			Total emissions rate calculation basis (lb/hr)		
10^6 Btu/hr	Mw		Equation (2)[a]	MRI study[b]	EPA[c]	Eq. (2) E.F.[d]	MRI E.F.	EPA E.F.
10	1.06	66.7	13.1	10	8	0.873	0.666	0.533
100	10.6	667.0	13.0	10	8	8.67	6.66	5.33
1000	106.0	6,670.0	11.9	10	8	79.3	66.6	53.3
5000	530.0	33,300.0	6.9	10	8	230.0	333.0	267.0

[a] Emission factor by GCA analysis, Equation (2) and Figure 3.

[b] Emission factor based on MRI study, Reference 9.

[c] Emission factor from EPA document AP-42, Reference 17.

[d] E.F. = emission factor.

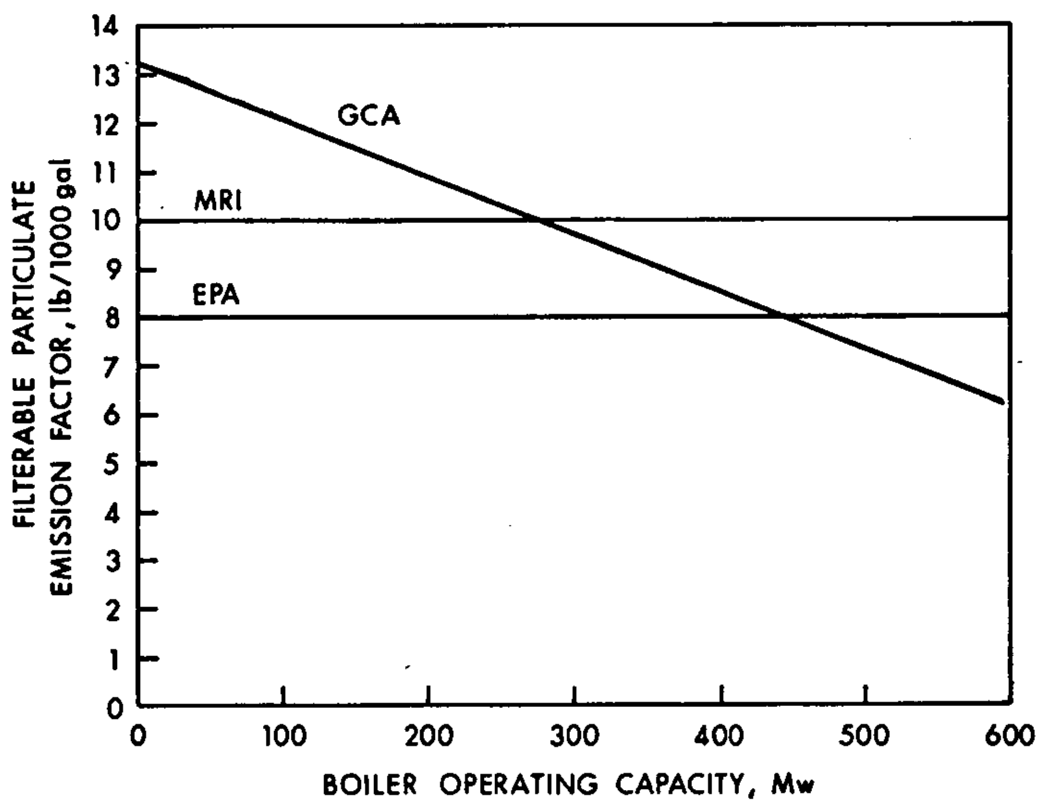

Figure 3. Filterable particulate emission factors vs. capacity for uncontrolled residual oil-fired base loaded utility boilers

PARTICULATE EMISSION CONTROL EQUIPMENT PERFORMANCE ON RESIDUAL OIL-FIRED UTILITY BOILERS

The forthcoming discussion deals mainly with electrostatic precipitators since there are not as yet sufficient data on wet scrubbers and fabric filters to establish reliable performance parameters. A few comments are made with respect to inertial collectors because they still remain in some systems that were designed initially for coal combustion.

Inertial Dust Collectors

Centrifugal collectors (cyclones) are not effective in removing particulates smaller than 5 microns in diameter.[5] Since it is the particles in this size range that are the most effective light scatterers, a cyclone will not appreciably reduce the opacity of a plume from a residual oil-fired boiler. Though ineffective on fine particles, cyclones may be effective in reducing emissions of agglomerated acid smut.[12]

Cyclones generally have low maintenance and operational costs, but for oil-fired boilers, their limited removal efficiency may not economically justify the increased pressure loss. It appears that cyclones would not be effective in the reduction of plume opacities for subsequent compliance with federal regulations.

Fabric Filters

Though relatively untried, baghouses have been shown to be effective in the reduction of particulate emissions from oil-fired boilers. As demonstrated by the tests conducted by Southern California Edison, a baghouse is capable of virtually eliminating visible emissions from an oil-fired utility boiler. They reported a particulate removal efficiency of 88 percent with moderate reductions of sulfur oxides also noted.[18]

Though effective for particulate emission control, baghouses tend to be troublesome from the standpoint of operation and maintenance. The two major drawbacks are high pressure drop and bag failure. Baghouses have a moderately high pressure drop that increases as the filter cake builds up. This necessitates periodic cleaning in order to remove the filter cake and thus reduce the pressure drop. Bag failures, which are by far the worst problem, are oftentimes caused by bag collapse during cleaning operations. Wire cages, which prevent bags from collapsing completely, are sometimes employed to prevent this type of failure. Corrosion of cloth bags due to the acidity of the filter cake is another cause of bag failure. This problem is especially prevalent when temperatures are below the sulfuric acid dew point.[19] Alkaline additives have been employed in an attempt to reduce the hygroscopicity of the filter cake, giving it better releasing qualities, and to lessen the acidity of the cake, thereby reducing the rate of cloth bag deterioration.[18]

Scrubbers

The use of scrubbers to remove SO_2 from boiler stack gases has been an area of considerable research and debate. Boston Edison has recently completed a series of scrubber performance tests on Mystic Station Boiler No. 6. Results of these tests, which were performed on a residual oil-firing base loaded utility boiler, are presented in Table 7. A conversion factor of 9.4 $\frac{\text{MM Btu/hr}}{\text{Mw}}$ was used in the development of this table.

A magnesium oxide additive was used with the oil in order to reduce slagging and corrosion of boiler heat transfer surfaces. This explains the high inlet and outlet particulate loadings. In tests 1, 2, and 4, some of the stack gas bypassed the scrubber in order not to exceed the control device's design capacity. In test 3, however, the scrubber was receiving the system's full flow.[20]

Table 7. BOSTON EDISON SCRUBBER TESTS - MYSTIC STATION BOILER NO. 6[20]

Performance factor	Test number 1	2	3	4
Sulfur content of fuel (wt %)	2.15	2.10	1.89	2.04
Ash content of fuel (wt %)	0.09	0.10	0.07	0.07
Boiler operating capacity (Mw)	146.0	144.0	151.0	148.0
Inlet particulate loading (lb/MM Btu)	0.277	0.171	0.281	0.108
Outlet particulate loading (lb/MM Btu)	0.085	0.085	0.106	0.059
Particulate removal efficiency (wt %)	69.5	50.5	62.4	45.7
Sulfur dioxide removal efficiency (wt %)	92.7	91.4	93.4	89.2

additive used

During these tests, a magnesium oxide scrubbing solution was used to remove SO_2 and SO_3, respectively, by forming $MgSO_3$ and $MgSO_4$. It was found that a 4-inch pressure drop was sufficient to satisfactorily remove sulfur oxides. In order to realize higher particulate emission reduction, the pressure drop would have to be increased.

Although scrubbers can be used successfully to remove particulate emissions from oil-fired boilers, some potential problems must be faced and rectified. Since the stack gas is brought into contact with a cooler liquid medium, the gas temperature is lowered and subsequently its buoyancy is reduced. This restricts upper atmosphere diffusion, thereby increasing ground level concentration. Moisture from the scrubbing solution is picked up by the stack gas and results in a visible water vapor plume that eventually dissipates. This visible plume, though innocuous, often causes public concern. It seems that in order to realize efficient particulate removal, high pressure drops through the scrubber must be maintained. This in turn is responsible for high operational costs. Finally, proper treatment of the scrubber solution presents a very real ecological and economic problem.[21]

Electrostatic Precipitators

Electrostatic precipitators are the most commonly used particulate emission control devices on oil-fired boilers. This can be attributed partly to the fact that many utility boilers that were at one time burning coal and abating fly ash emissions with an electrostatic precipitator have since converted to fuel oil and kept their precipitators in operation. In order for these precipitators to operate efficiently, certain modifications must be made.

Figure 4 presents the particulate emission reductions that are typically obtained on oil-fired boilers employing electrostatic precipitators without additives. It is obvious that the particulate emission values for the 48 Mw unit are quite high, probably due to improper boiler operation. As a result, these points have not been heavily weighted. The average efficiency of the units shown in Figure 2 is 43.5 percent. This figure is lower than would be expected for precipitators designed especially for oil since some of the units in the plot were designed for coal firing and were never modified.

In Figure 5 the cumulative particle size distribution of the exit gas from an electrostatic precipitator is presented. This precipitator was being used on a 365 Mw oil-fired utility boiler. The count median diameter was about 0.2 microns and approximately 93 percent of the particles were less than 1 micron in diameter.[22]

When designing an electrostatic precipitator to control the particulate emissions from oil-fired boilers, the hygroscopicity, resistivity and size distribution of the particulate must be considered. Due to hygroscopicity, solids build up in hoppers, on high tension electrodes, insulators and collecting curtains are a problem. These solids, when allowed to contact cool surfaces, absorb moisture, becoming difficult to remove and cause arcing and shorts. These problems can be remedied

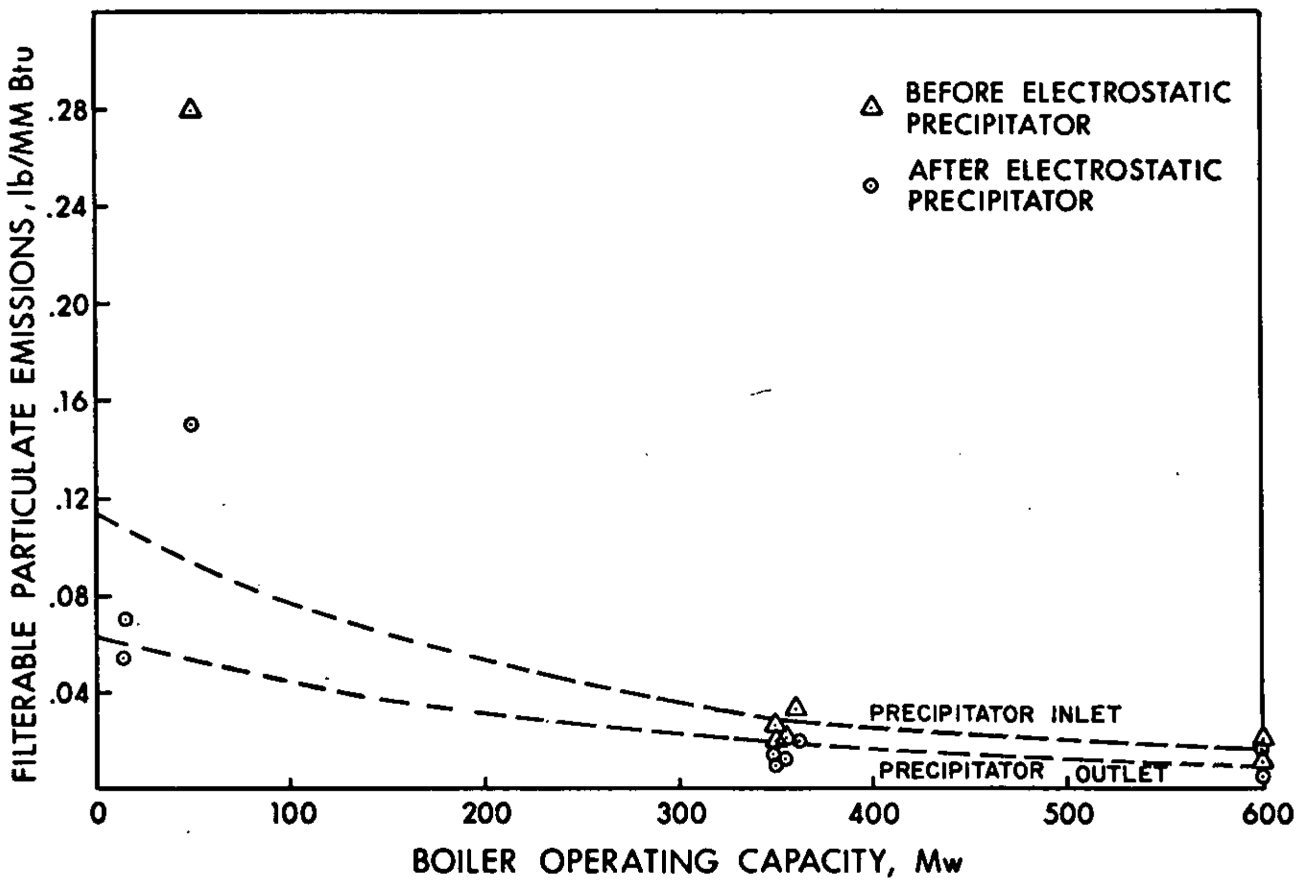

Figure 4. Particulate emissions before and after an electrostatic precipitator for base loading residual oil-firing utility boilers

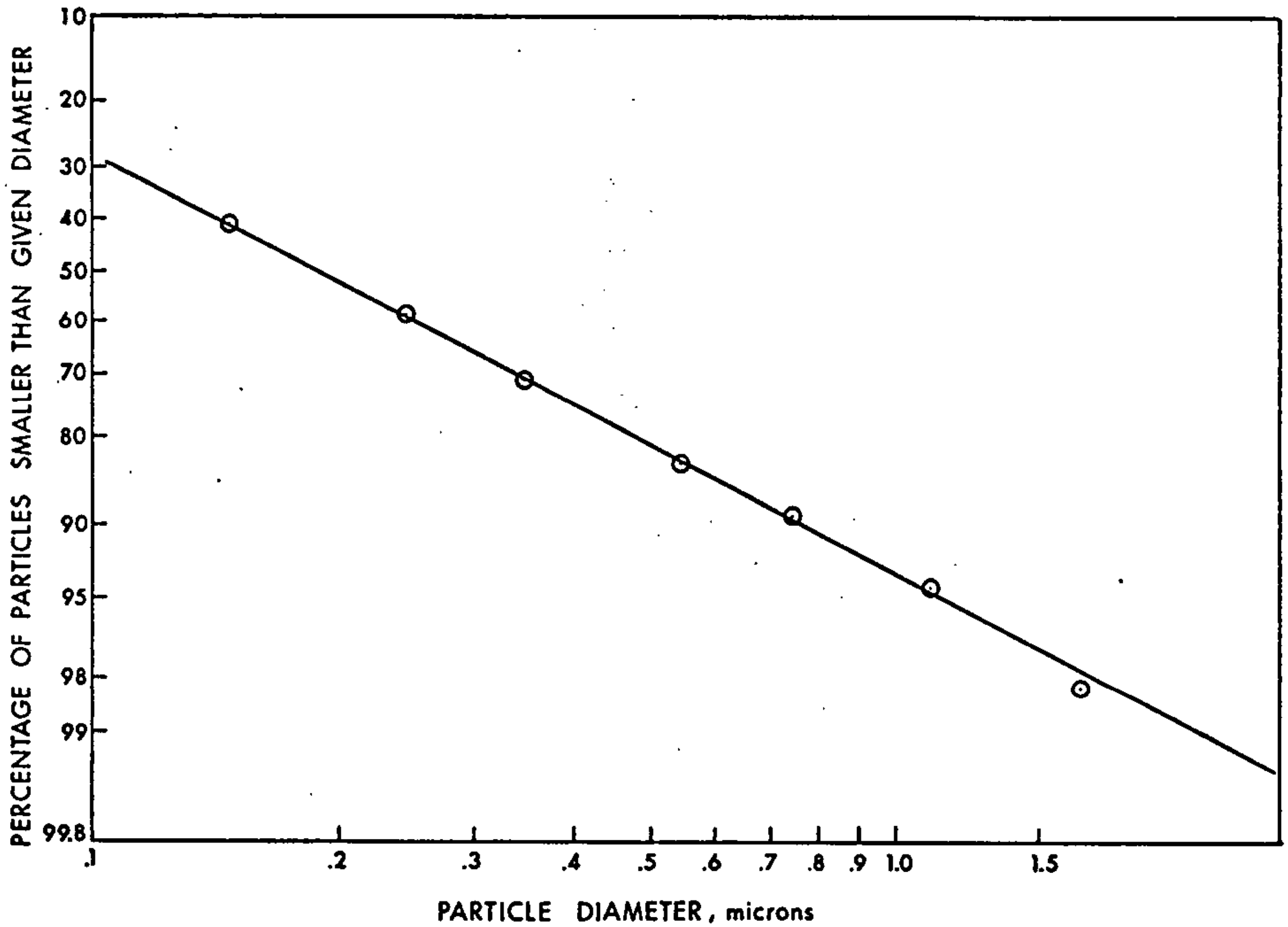

Figure 5. Cumulative particle size distribution of the exit gas from an electrostatic precipitator used on a 365 Mw oil-fired boiler[21]

by keeping deposition surfaces hot and preventing the solids from "setting up." By locating the precipitator on the hot side of the air preheater, ash buildup on high tension wires and collection curtains is minimized. Buildup on insulator bushings can be avoided by the use of hot air ventilation. Solids in hoppers can be kept mobile either by heating the wall surfaces or using a wet bottom flushout system.

With respect to particulate emissions from oil-fired boilers, stack gas temperature and sulfur content of the oil affect the resistivity of the noncombustible portion of these solids; however, the balance of these solids are composed of highly conductive combustible carbonaceous solids. As a result of these carbonaceous solids, the resistivity of the particulate matter emitted from oil-fired boilers is relatively lower, usually run on the order of 10^7 to 10^9 ohm-cm.[5,23] In some cases, these solids are so conductive that they do not retain a charge and subsequently prevent the field from becoming saturated. Another problem that has been encountered is that these solids, upon deposition on collecting curtain surfaces, sometimes lose their charge to the curtain and become reentrained in the gas stream. The extremely fine size of the particles liberated by oil combustion make efficient collection by electrostatic precipitation difficult. Collection efficiency is improved through the employment of high voltage, large collection curtains, lower superficial gas velocity and high retention times.[5,23]

Corrosion due to high dew point, reentrainment of collected particulate matter and fire hazards due to the combustible solids in ash hoppers are three problems that must also be considered. Reentrainment of particulate matter can be abated by optimizing rapping frequency and intensity. Problems associated with the hygroscopicity and combustibility of the collected particulate matter can be eliminated with a fly ash injection system that keeps hot gas going through the hopper. The problem of solids combustion can also be combatted by using steam quenching devices that are activated by temperature.[5] Corrosion problems can be eliminated by locating the precipitator on the hot side of the air preheater and by heating precipitator surfaces.

COAL TO OIL CONVERSIONS

As mentioned previously, the particulate emissions from an uncontrolled oil-fired boiler are comparable to those of a highly controlled coal-fired boiler. In order for a particulate control device to perform as well on an oil-fired boiler as on a coal-fired, certain modifications are usually necessary. Often times, even after modification, performance cannot be duplicated.

Table 8 presents some representative particulate emission factors for large uncontrolled coal-fired boilers that will be used throughout this discussion. The average values of 10 percent ash and 12,000 Btu/lb heating value for bituminous coal were used in the development of this table. Due to the tangential firing pattern, cyclone pulverized coal boilers retain a higher percentage of the ash in their furnaces and subsequently have lower particulate emissions. This particulate emission reduction is due to the contact between the molted slag on boiler walls and the solids entrained in flue gas. These emissions, however, tend to be composed of smaller particles since it is the larger particles that settle out in the furnace.

Inertial Collectors

The particulate emission control efficiency of a multicyclone is dependent upon the size and density of the particulates in the gas stream. On coal-fired cyclone furnaces the efficiency usually ranges from 30 to 40 percent, while on a pulverized unit it ranges from 65 to 75 percent.[17] These range differences can be attributed to the fact that the mean particle diameter of the emissions from a cyclone furnace is usually lower than that of the emissions from a pulverized unit.

Table 8. PARTICULATE EMISSION FACTORS FOR UNCONTROLLED BITUMINOUS COAL-FIRED BOILERS GREATER THAN 100 MM Btu/hr[22]

Boiler type	Particulate emissions (lb/ton of coal burned)	Particulate emissions (lb/MM Btu input)[a]
General pulverized	16A[b]	6.66
Cyclone pulverized	2A	0.88

[a]Based on the average values of 10 percent ash and 12,000 Btu/lb.

[b]The letter A represents the ash content of the coal.

When these multi-cyclone efficiencies are superimposed upon the coal emission factors in Table 8, particulate emission ranges of 1.66 to 2.33 lb/MM Btu for pulverized units and 0.528 to 0.616 lb/MM Btu for cyclone furnaces are obtained. The efficiency of cyclones on oil-fired boilers, however, is appreciably lower than on coal-fired boilers since the particulate emissions from a properly operated oil-fired boiler has a smaller mean particle diameter. GCA estimates that a maximum efficiency of 40 percent might be obtained for small oil-fired boilers and that this efficiency would decrease as the boiler size increased. Though they are not efficient in the reduction of fine particulate emissions, mechanical collectors could help reduce acid smut emissions since smut is composed of agglomerated solids and is usually large in diameter. When converting from coal to oil on a system already employing a centrifugal collector, the reduction of acid-smut emissions might justify keeping the collector in operation if its resistance is less than a few inches of water.

Eff. of mech. collector on oil fired boiler

If the temperature of the combustion gas is below the SO_3 dew point, the hygroscopicity and corrosiveness of the oil ash can cause centrifugal collector operational and maintenance problems. Buildup of cement-like ash on tube and hopper surfaces results in increased pressure drop, as well as corrosion and cleaning problems. These problems can be satisfactorily eliminated by frequent washing of the collector and oil ash hopper. Tube surfaces could be kept clean by locating the collector on the hot side of the air preheater. This will usually keep these surfaces above the SO_3 dew point. However, the acid smut that is formed and periodically liberated from air preheater surfaces would not be controlled.

Fabric Filters

Emission tests have been recently performed on two 80 Mw low sulfur anthracite coal-fired boilers using fabric filters. These filters operated at greater than 99 percent particulate removal efficiency having a maximum outlet loading of 0.047 lb/MM Btu fired. A pressure drop of approximately 3.0 inches at H_2O was experienced and no major maintenance or operational problems were noted.[24]

As mentioned in an earlier section of this text, fabric filters whose performance was enhanced with alkaline additives were used to control emissions from a 320 Mw residual oil-firing boiler. These filters operated at 88 percent particulate removal efficiency and SO_3 reductions were also noted. As a result of this reduction of particulate and SO_3 emissions, plume opacity was virtually eliminated. An alkaline additive was used to neutralize SO_3 in the flue gas, reduce the hydroscopicity of the particulates and to improve the cleanability of the bags. Pressure drops as high as 9.5 inches of H_2O and deterioration of the bags due to the acidic nature of the solids were encountered.[18]

The results of the two aforementioned test programs as well as those of other researchers[25] indicate that for fabric filters the magnitude of the average outlet particulate concentration is nearly independent of the inlet dust concentration. Thus, an order of magnitude rise in the inlet loading may result in a corresponding rise in collection efficiency but a negligible change in the mass or size of the discharged particles.[25]

In regard to coal-to-oil conversions, an appreciable change in the particulate concentration at the outlet of the baghouse would not be expected. However, due to the hygroscopic nature of the oil ash and the corrosiveness of acid smut, operational and maintenance problems could be encountered. Difficulties with bag cleaning and bag deterioration due to these troublesome solids can be reduced through the use of an alkaline additive. Increased pressure drop as a result of this fuel conversion would result in increased operational costs.

Scrubbers

When applied to 170 Mw bituminous coal-fired boilers, scrubbers have demonstrated the capability of removing an average of 96 percent of the particulate and subsequently reducing emissions to 0.050 lb/MM Btu fired.[26] A pressure drop of 20 in. H_2O was experienced, however. The results of a recent scrubber test on a 155 Mw residual oil-fired boiler showed that when operating at a 4-inch pressure drop, particulate removal efficiencies averaging 57 percent could be achieved.[20] Since this scrubber was installed primarily to remove sulfur oxides, a high pressure drop was not necessary. If this pressure drop were increased, a corresponding increase in removal efficiency could be expected.

Electrostatic Precipitators

When applied to cyclone-fired, coal-burning boilers, electrostatic precipitators have demonstrated particulate collection efficiencies ranging from 65 to 99.5 percent. On general pulverized coal boilers, control efficiencies are usually between 80 and 99.5 percent.[17] When a coal-fired boiler with an electrostatic precipitator is converted to oil with the precipitator unmodified, particulate control efficiency will usually fall in the 45 percent range. If the precipitator is modified, however, control efficiencies approaching 90 percent can be realized.[5] The following discussion deals with the problems and some rectifying modifications that should be considered when converting from coal to oil-firing on precipitator controlled boilers.

Compared to coal fly ash, the solids emitted by fuel oil combustion are more hygroscopic, have a high combustible content and have a lower resistivity. The lower resistivity of the particulate matter from oil firing is due to the highly conductive nature of the carbonaceous portion of these solids. Compared to the effect of these conductive carbonaceous solids, sulfur content of the oil and stack gas temperature have an insignificant effect on the resistivity of these solids.

The solids liberated by ~~coal~~ oil combustion are much smaller than those from coal combustion. As a result, collection efficiency usually drops considerably upon conversion from coal to oil. This efficiency can be improved by enlarging collection curtains, employing higher voltages, lowering superficial gas velocity and increasing retention time.[5]

The hygroscopicity of the particulate matter causes a solids buildup on high tension electrodes, insulators, and collection curtains. When allowed to cool, these solids absorb moisture, become difficult to remove and cause arcing and shorts. By locating the precipitator on the hot side of the air preheater, solids build up on high tension wires and collection curtains are minimized. Buildup on insulator bushings can be prevented by using hot air ventilation. Hopper plugging can be avoided by either heating the hopper or employing a wet bottom system. Fly ash reinjection is also an alternative solution.[5]

The high combustible content of the particulates resulting from oil firing presents a potential fire hazard in collection hoppers. This problem can be remedied by using steam quenching devices that are activated by temperature sensors or by using fly ash reinjection. Corrosion problems associated with high sulfuric acid dew point temperatures can be reduced by locating the precipitator upstream of the air preheater. Reentrainment of collected particulate matter can be reduced by optimizing rapping intensity and frequency as well as employing a low superficial gas velocity.[5]

EFFECTS OF SULFUR AND ASH CONTENT OF FUEL OIL ON PLUME OPACITY, PARTICULATE EMISSIONS, AND CONTROL EQUIPMENT PERFORMANCE

Stack sampling data from power plant boilers operating at a capacity greater than or equal to 70 Mw were used to establish relationships between particulate emission rates and fuel ash content as well as between particulate emission rate and fuel sulfur. This boiler size range was chosen in order to limit the variability of the data due to improper operation or differences in operating methods. Test data from boilers using additives were not included because they represented a different test population.

A graphing of particulate emissions versus fuel sulfur content, Figure 6, shows too broad a point scatter to propose any relationship. It has been postulated that increased sulfur can lead to increased SO_3 adsorption, and hence a greater mass accumulation, on sampling filters. The net result would appear as an increased solids emission rate. Figure 7 illustrates no positive correlation between fuel ash content and particulate emissions. This is due to the fact that generally the majority of the particulate matter emitted from oil-fired boilers is composed of combustible organic material rather than mineral ash.

ASA not important

Sulfates (measured as SO_4) have been noted to constitute approximately 35 percent of the filterable solids generated by the combustion of high

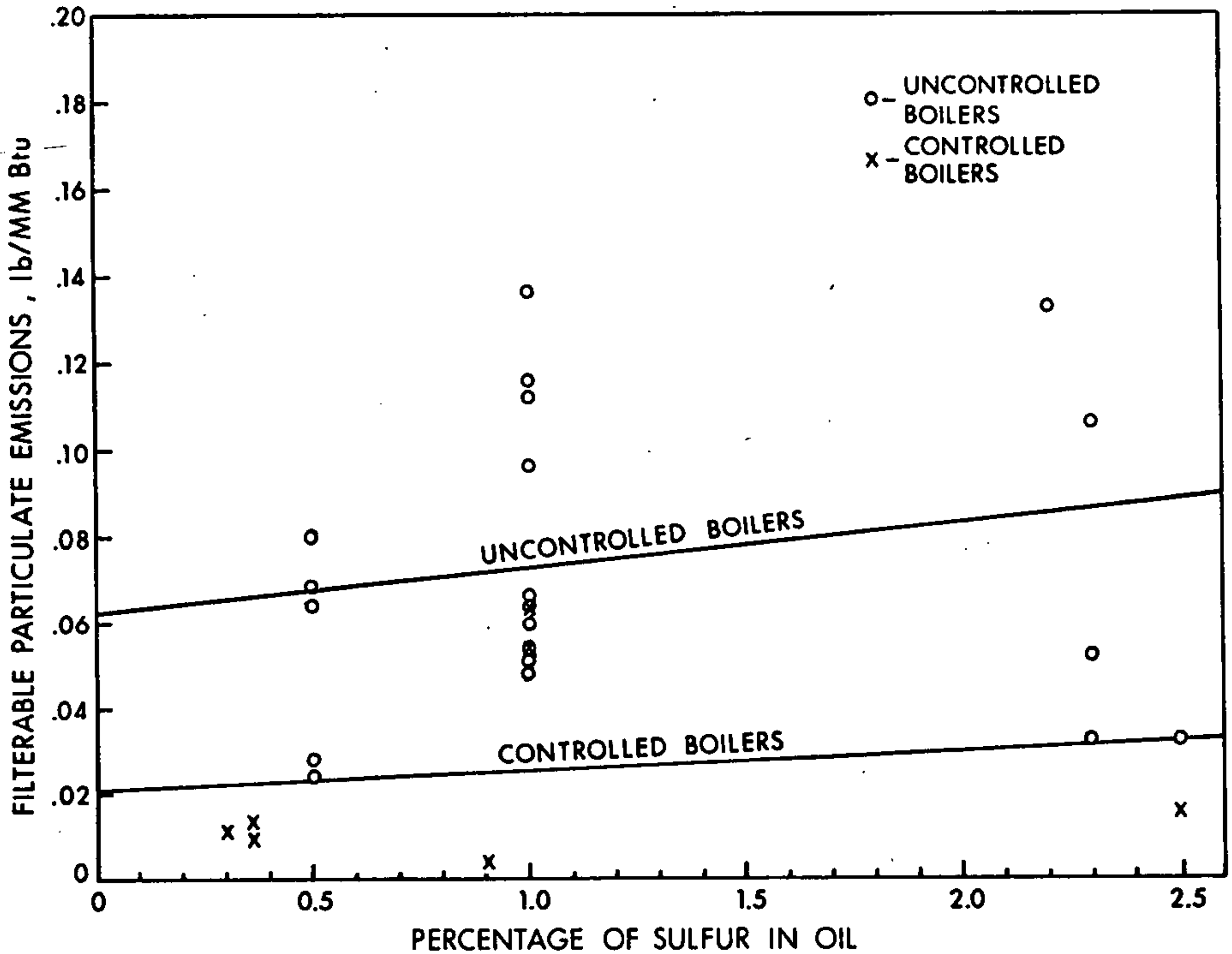

Figure 6. Controlled and uncontrolled particulate emissions for residual oil burning base loaded power plant boilers operating at $\geq$ 70 Mw capacity

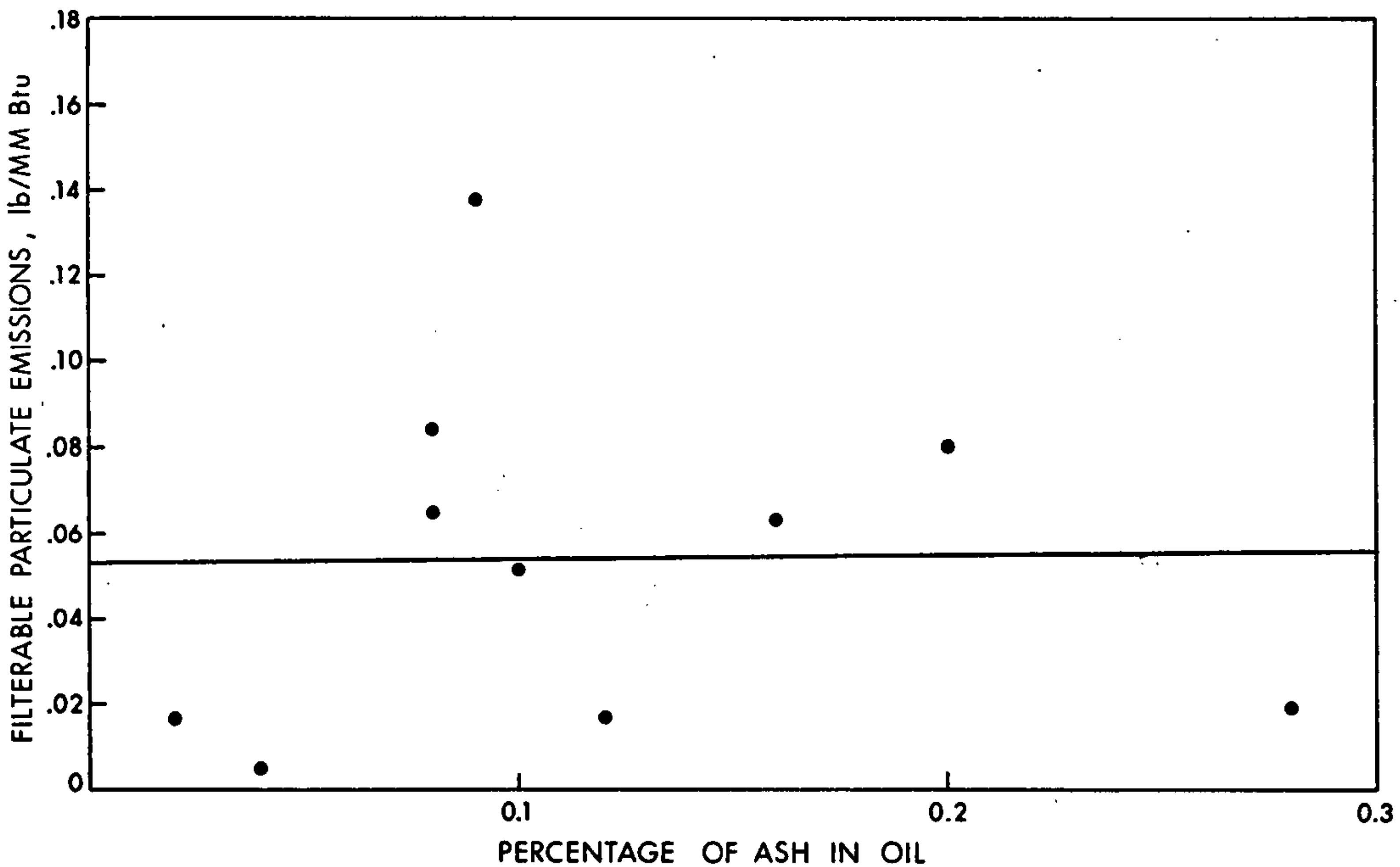

Figure 7. Controlled particulate emissions vs. ash content for residual oil burning base loaded power plant boiler operating at $\geq$ 70 Mw capacity

sulfur (> 2.5 percent) residual oil in large utility boilers using magnesium oxide fuel additives.[22,27] As a result of using this additive, most of the sulfate was present as $MgSO_4$ with a small fraction occurring as H_2SO_4 (sulfuric acid). If no additive were used, the total sulfate catch would probably decrease due to SO_3 penetrating the filter and the sulfate that was captured would probably occur as sulfuric acid.

Since the increase in filterable particulate emissions as the sulfur content of an oil increases is partly due to the formation of sulfates, some sulfur trioxide and sulfate removal will be realized when particulate control equipment is used. This has been demonstrated during the use of fabric filters on an oil-fired boiler.[18] One might make a general statement that the removal of sulfur trioxide and sulfates emitted from oil-fired systems is roughly proportional to the removal of particulates from the flue gas. If a piece of control equipment is located on the cold end of the air preheater, this removal will be further enhanced through the reduction of acid smut emissions.

In addition to contributing to mineral sulfate formation, sulfur trioxide forms sulfuric acid mist which is partially responsible for plume opacity. Table 9 presents the results of some plume opacity tests conducted on a 370 Mw boiler using additives and an inertial collector.[22] It can be readily seen that as the sulfur content of the fuel increases, particulate emissions, sulfur trioxide concentration and plume opacity also increase. The increase in plume opacity can be attributed to the increase in emissions of both particulate and sulfuric acid mist.

Reports that mechanical collectors do not noticeably reduce plume opacity are entirely consistent with the inability of these devices to efficiently remove the submicron sized particles that cause plume opacity.[22] Both electrostatic precipitators[22] and fabric filters[18] have been shown capable of virtually eliminating the plume opacity resulting from residual oil combustion. If the gas temperature is allowed to fall below the dew point, high sulfur oil can cause damage to baghouse structures and filter media. On the other hand, as the sulfur content of an oil increases, the conductivity of the particulate emissions increases, thus improving electrostatic precipitator performance.[28] Based upon their potential for removing both particulates and sulfur oxides, scrubbers seem capable of satisfactorily reducing plume opacity. The vaporization of scrubber water and cooling of stack gas, however, creates a low level vapor billow of reduced buoyancy that can generate public complaints despite the fact that it will eventually dissipate.[21]

Table 9. AVERAGED RESULTS OF PLUME OPACITY TESTS CONDUCTED ON A 370 Mw BASE LOADED RESIDUAL OIL-FIRING POWER PLANT BOILER USING MgO ADDITIVES AND A MECHANICAL COLLECTOR[22]

Sulfur content of fuel oil fired (% wt)	SO_2 emissions (lb/MM Btu)	Particulate emissions (lb/MM Btu)	SO_3 concentration (ppm)	Plume opacity (%)
0.48	0.452	0.048	3.09	2.5
0.70	0.642	0.046	4.83	3.3
1.05	0.848	0.052	5.92	7.1
2.70	2.577	0.080	14.90	36.9

ADDITIVES AND THEIR IMPACT ON PARTICULATE EMISSION CONTROL EQUIPMENT PERFORMANCE

The fouling and corrosion of high temperature waterwall, superheater and reheater surfaces along with low temperature gas passes and air heaters is a common problem when firing residual oil. Magnesium and calcium additives are commonly used to improve boiler heat transfer characteristics and reduce corrosion problems. Heat transfer is improved by the conversion of low melting point ash components which adhere to heat exchanger surfaces into high melting point, powdery compounds that can be easily removed by sootblowing.[30] Low temperature corrosion is caused by SO_3 reacting with water in the vapor phase to form sulfuric acid mist which condenses on boiler surfaces whose temperatures are below the dew point. Additives reduce this corrosion by coupling with sulfur trioxide to form sulfates.[29] Concurrently, reduction of the sulfur trioxide concentration also reduces the sulfuric acid dew point of the flue gas such that less H_2SO_4 will condense on heat transfer surfaces.[30]

By virtue of the fact that they are ash-forming substances, fuel additives increase the particulate emissions from oil-fired boilers. In order to estimate the contribution of fuel additives to total particulate emissions, the following simplifying assumptions have been made: (1) 150,000 Btu/gal oil, 8 lb/gal oil, 0.1 percent ash in oil, 200 ppm Vanadium in oil, (2) magnesium oxide additive dosing rate of 1.5 pounds of magnesium per pound of vanadium, (3) upon combustion, the additive is completely converted to magnesium sulfate, (4) half of the solids liberated via combustion (including $MgSO_4$) become particulate emissions while the remaining half are retained in the boiler, and (5) excluding the contribution made by the $MgSO_4$, equal masses of combustible solids and ash solids are liberated via combustion. Based upon these simplifying assumptions we find that particulate emissions increased from 0.053 lb/MM Btu to 0.094 lb/MM Btu due to the use of a magnesium oxide additive and that this additive was responsible for 43.6 percent of the total particulate emissions.

If one assumes that the efficiencies of the electrostatic precipitators used to control particulate emissions from oil-fired systems are essentially constant, the higher effluent concentrations (roughly twice as large) shown in Figure 8 for systems using additives are readily explained. The data in Figure 8 further suggests that the use of an alkaline additive does not alter significantly either the resistivity or the size properties of the precipitated dust.

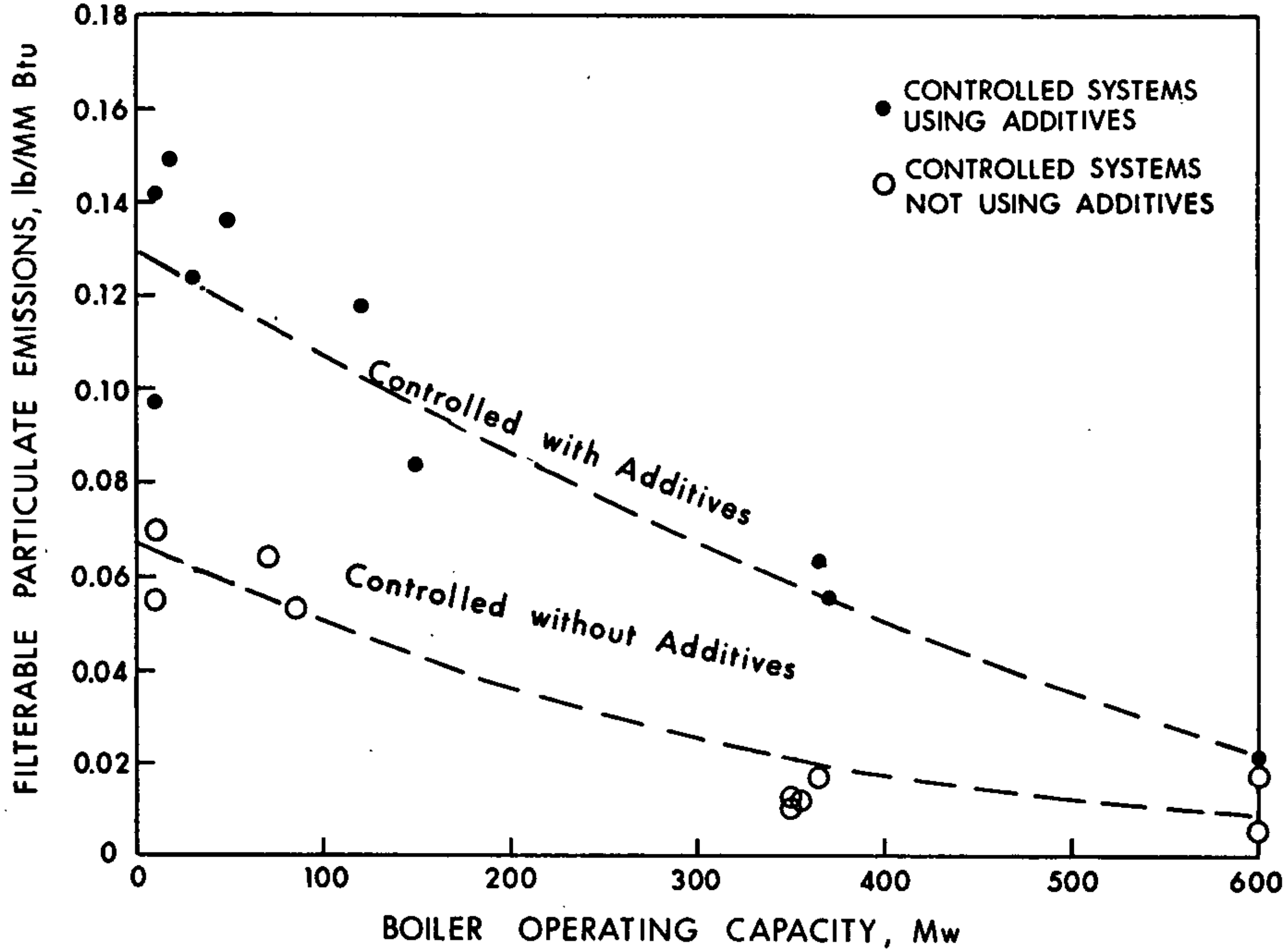

Figure 8. Particulate emissions from controlled residual oil-firing boilers with and without additives

PARTICULATE EMISSIONS FROM OIL-FIRED BOILERS DURING SOOTBLOWING OPERATIONS

Sootblowing in boilers is usually accomplished via one of the following two techniques: (1) sequential cleaning of internal surfaces starting first at the hot end of the boiler and gradually working toward the cold end, or (2) simultaneous cleaning of all heat transfer surfaces. Large utility boilers usually employ the first technique on a continuous basis. When the cold end of the boiler is being cleaned, particulate emissions are heaviest due to the entrainment of coarse accumulated solids from air preheater surfaces.

The second sootblowing technique is employed mainly by industrial and small utility boilers. In these cases, sootblowing consists of brief intermittent cleanings typically occurring once every 8 hours for periods of 10 minutes or less. During these short sootblowing periods, particulate emissions have been reported to be as much as 40 times greater than those for non-cleaning intervals.[31]

During sootblowing operations, particle size and gas stream loadings are greater than during normal operation due to the dislodgement of agglomerated solids from internal boiler surfaces. Since these particles are considerably larger in diameter than those emitted during normal operation, the use of simple inertial control devices will collect a large fraction of these emissions on a mass basis. If particulate control equipment is not employed, a visible plume will always result during sootblowing operations.

EFFECTS OF PEAKING OPERATIONS ON THE CONTROL OF PARTICULATE EMISSIONS FROM RESIDUAL OIL-FIRED BOILERS

Variations in consumer power demands are often handled by peaking boilers which typically operate between 60 and 100 percent of their design capacity. Table 10 presents the results of load variance tests performed on

250 and 600 Mw peaking utility boilers employing fuel additives and controlled by electrostatic precipitators. The precipitator used with the 250 Mw boiler was originally designed for coal firing but had been modified for oil firing. The absolute amount of particulates discharged from the 250 Mw system increased with load level except that the emission at 44 percent load was greater than at full load (possibly due to poorly regulated combustion).

Table 10. PARTICULATE EMISSIONS FROM PEAK LOADED RESIDUAL OIL-FIRING UTILITY BOILERS

Load (%)	Particulate emissions (lb/MM Btu)	Excess air at point of sampling (%)
250 Mw design capacity using additives and ESP[32,a]		
44	0.0473	38.3
52	0.0118	27.3
64	0.0141	20.8
84	0.0178	15.5
100	0.0197	15.8
600 Mw design capacity using additives and ESP[16,b]		
60	0.0029	111.4
70	0.0056	120.9
80	0.0065	10.7
90	0.0071	18.7
100	0.0054	4.2

[a]Originally designed for coal but later modified for oil.
[b]Designed for coal and left unmodified.

The precipitator used with the 600 Mw system was designed for coal firing and had been left unmodified. The 600 Mw system appeared to discharge the same total amount of solids over the load level range

70 to 100 percent. The very low emission at 60 percent load is not readily explained. Generally, inspection of Table 10 indicates that the larger boiler produces a proportionately cleaner effluent. Actually, it would appear that the 600 Mw system discharges less particulate on an absolute basis than the 250 Mw boiler.

Gas turbines used in conjunction with base loaded boilers are also used to handle variations in power demand. Depending on the power demand, these turbines operate at one of the following output levels: (1) spinning reserve, (2) base loaded, and (3) peak loaded. The data analyzed by GCA indicates that the particulate emissions from gas turbines burning distillate oil decrease as turbine loading increases. This can generally be attributed to more efficient fuel combustion.

In Figure 9, particulate emissions from gas turbines have been characterized individually since each turbine exhibited unique emission characteristics. Since distillate oil is inherently low in ash and sulfur, gas turbine particulate emissions are relatively low and are composed mainly of combustible solids. Because gas turbines usually burn distillate oil, emission control equipment is almost never required.

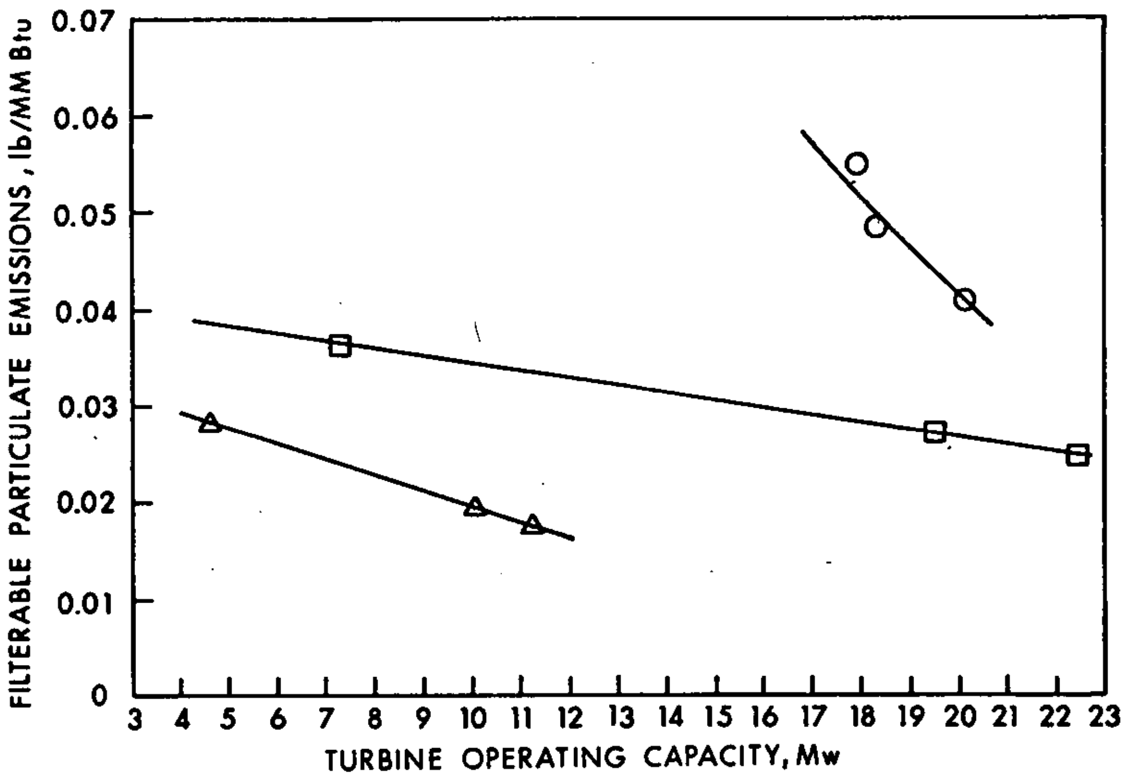

Figure 9. Particulate emissions from uncontrolled distillate oil-fired gas turbines[27, 33]

SECTION IV

COST AND EFFECTIVENESS OF PARTICULATE EMISSION CONTROLS ON OIL-FIRED BOILER

The forthcoming discussion centers upon electrostatic precipitators since they are the most common of all devices used on oil-fired boilers. Figure 10 characterizes the emissions from controlled and uncontrolled oil-fired boilers based upon the empirical data that were collected during this study. The boilers used to construct this figure were not utilizing additives. These data indicate that the effluent quality improves as the boiler size increases irrespective of whether particulate control apparatus is used, presumably due to better combustion as a result of more sophisticated combustion controls.

On the basis of continuous operation, annual particulate emissions versus boiler capacity are plotted in Figure 11 for controlled and uncontrolled systems. As for Figure 10, additives were not employed by these boilers. The annual particulate emission reduction achieved by the employment of control equipment is illustrated in Figure 12.

Based upon an analysis of stack test data, Figure 13 indicates the average stack gas flow rates that can be expected from oil-fired utility boilers. GCA has elected to represent this curve by the following two linear equations:

$$\text{when } P \leqslant 200$$

$$Q = 2300P \qquad (3)$$

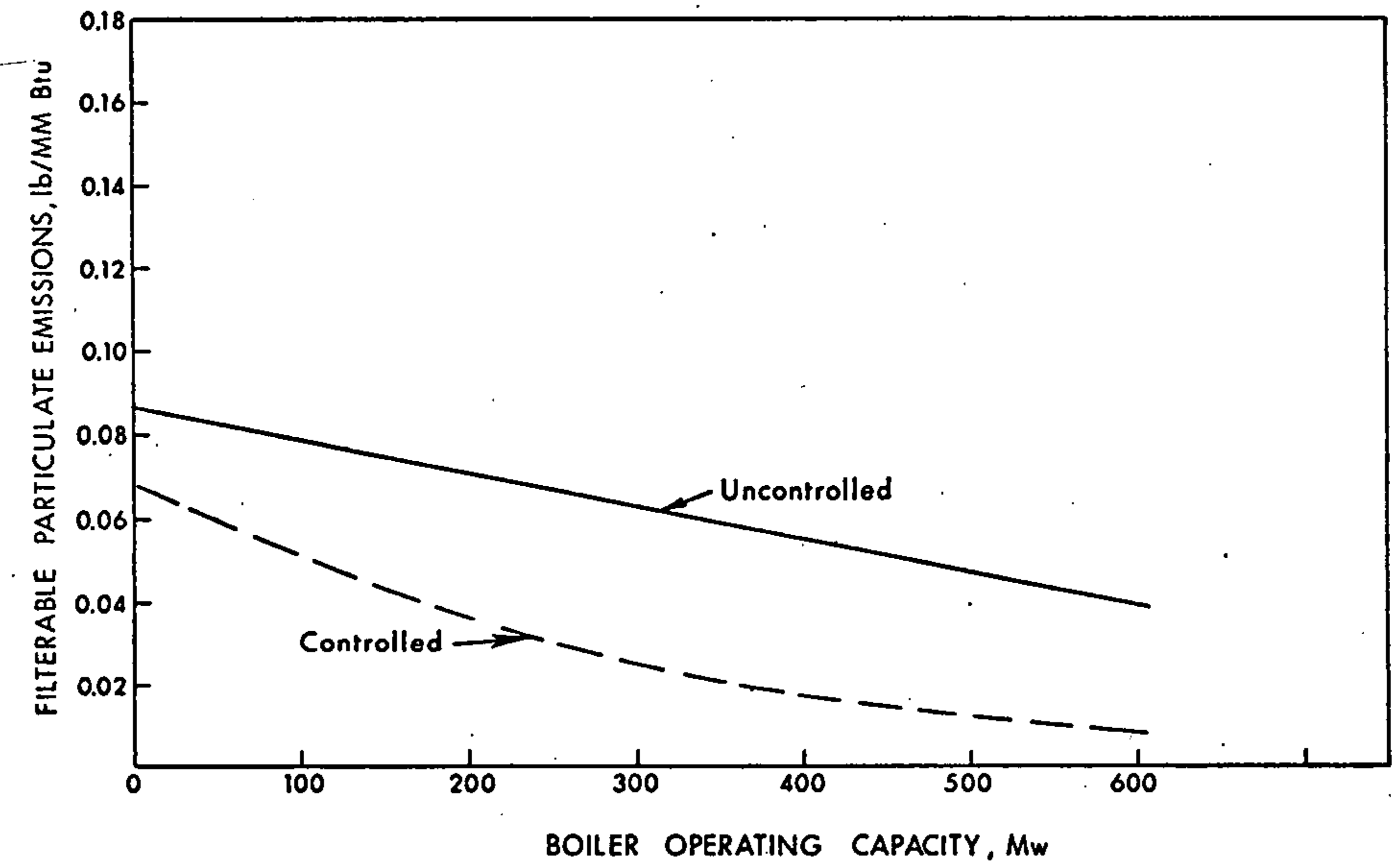

Figure 10. Controlled vs. uncontrolled particulate emission from residual oil-fired boilers

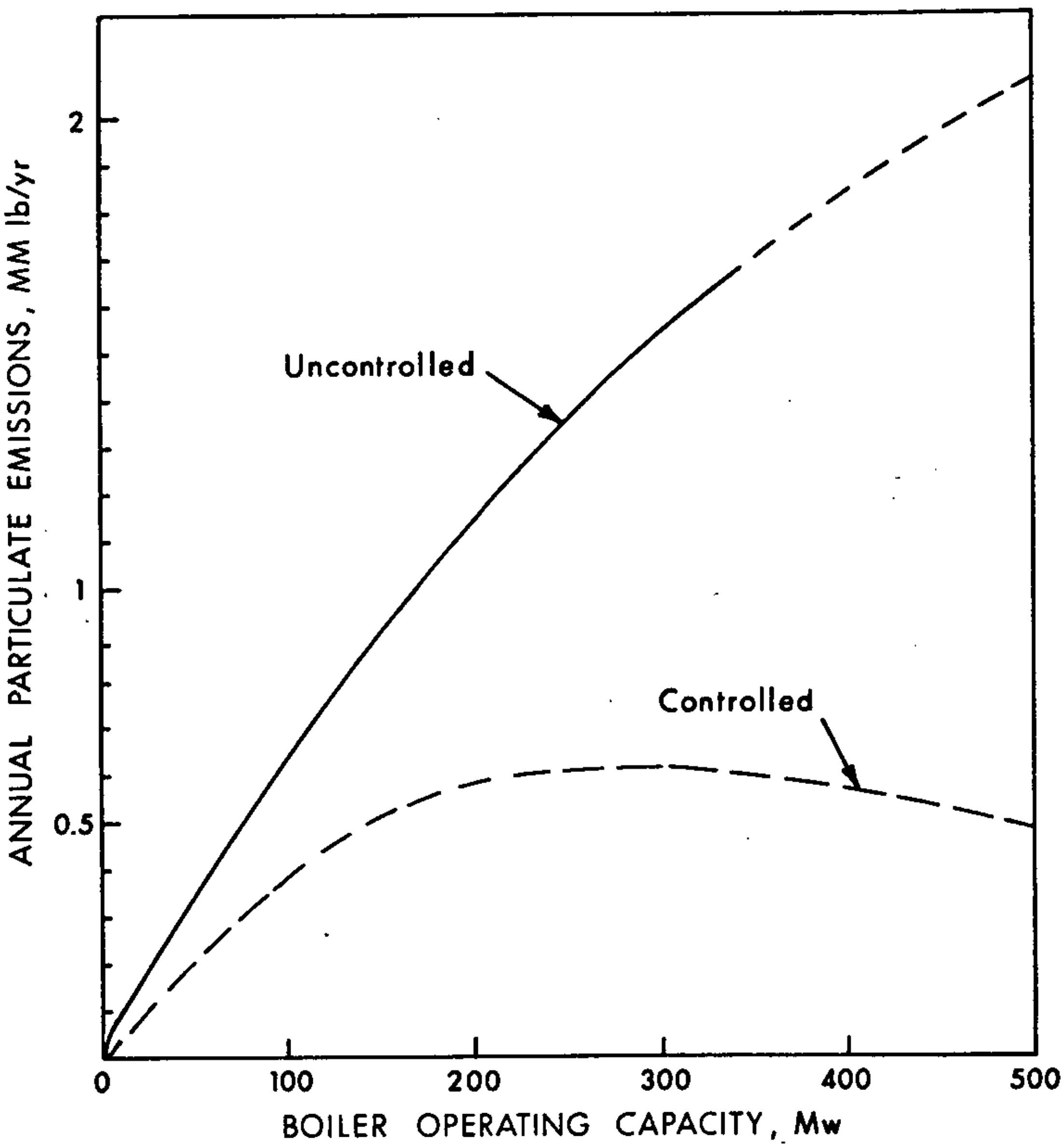

Figure 11. Annual particulate emissions from controlled and uncontrolled residual oil-firing boilers

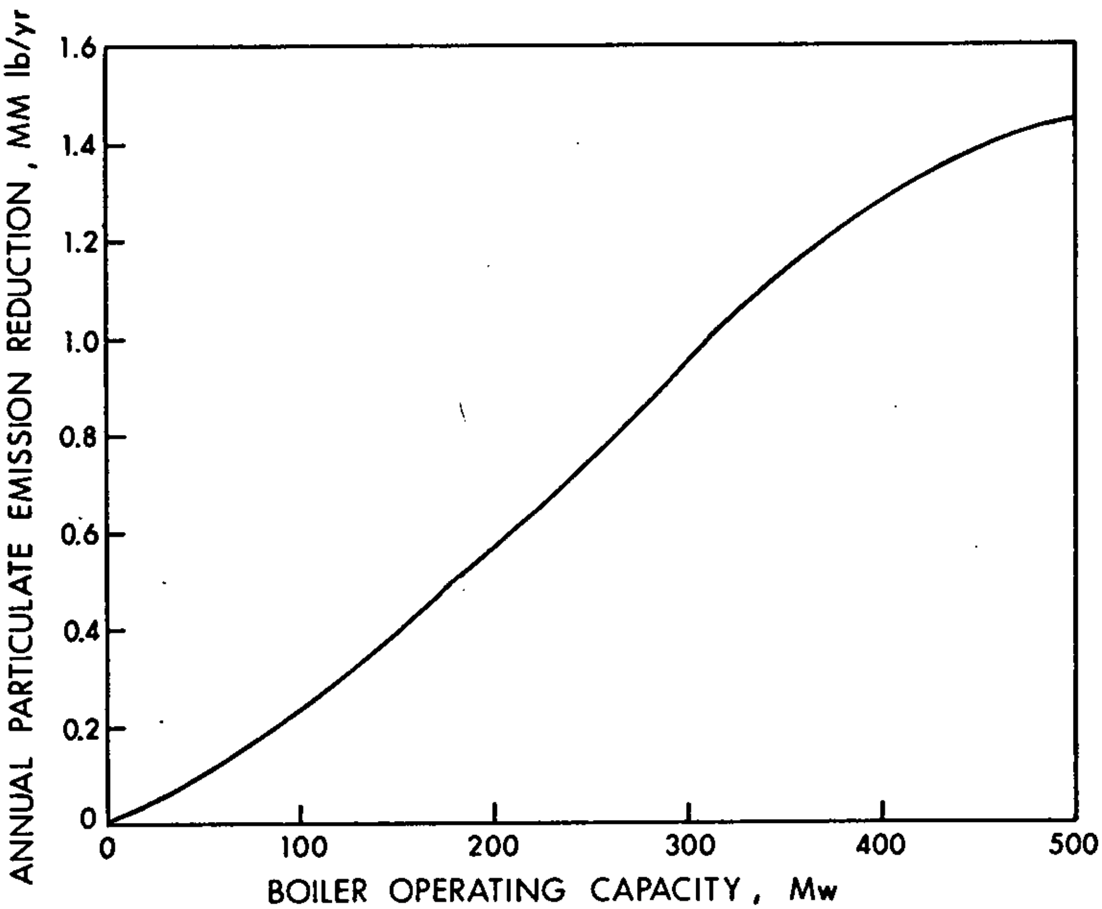

Figure 12. Annual particulate emission reduction for controlled residual oil-firing boilers

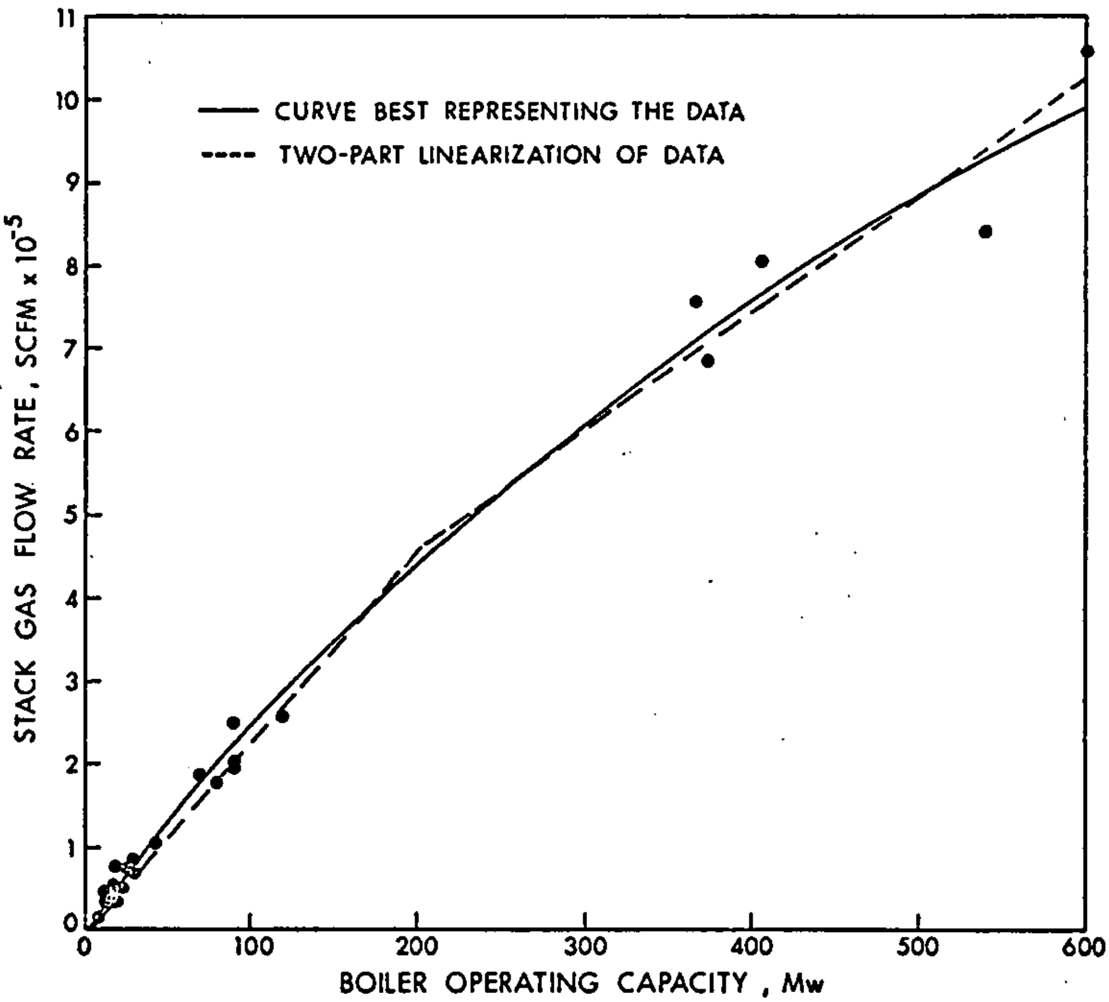

Figure 13. Stack gas flow rate vs. operating capacity for oil-fired utility boilers

when $P > 200$

$$Q = 1412.5\ P + 177{,}500 \qquad (4)$$

where Q = flue gas flow rate (SCFM)

P = boiler capacity (Mw).

Based upon the stack gas flow rates from Figure 13 and recent cost data,[5,34] Figure 14 presents the erected costs for both new and modified electrostatic precipitators as a function of boiler size. Total erected cost is the fixed capital investment necessary to either build a new electrostatic precipitator or to modify an existing installation. This investment is composed of both direct costs (materials, including duct work) and indirect costs (construction and installation labor and engineering services). The cost data to determine erected costs was obtained from engineering design cost estimates provided by the Research Cottrell Company. In generating these cost estimates, the following ESP parameters were used:

1,000,000 ACFM

0.5 % Sulfur

300° F Stack gas temperature.

It was found that for systems with stack gas flow rates in excess of 250,000 ACFM the erected costs were $6.70/ACFM for ESP's designed specifically for oil and $2.35/ACFM for coal-to-oil conversion. Operating costs for electrostatic precipitators are about $0.03 per year per ACFM and maintenance costs range from $0.02 to $0.03 per year per ACFM.[5]

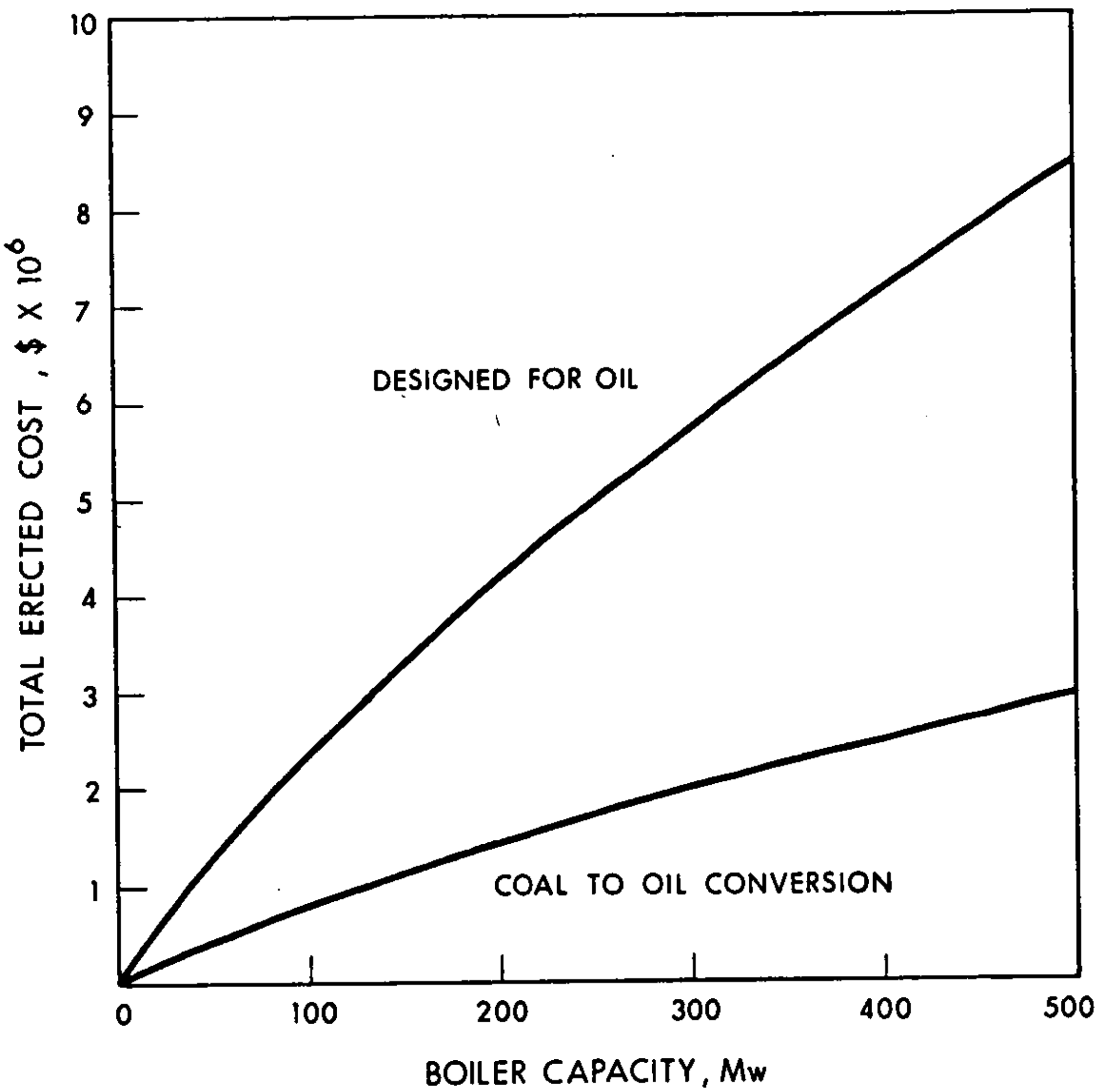

Figure 14. Total erected cost for electrostatic precipitators[5,34]

SECTION V

REFERENCES

1. Fuels and Electric Energy Consumed. U.S. Department of Commerce, Census of Manufacturers, 1972.

2. Monthly Reports of Cost and Quality of Fuels for Steam Electric Plants. Federal Power Commission, (F.P.C. Form No. 423), 1973.

3. Statistical Abstract of the United States. U.S. Department of Commerce, 1973.

4. United States Energy Facts Sheets; by States and Regions. Department of the Interior, 1971.

5. State of the Art: Oil Fired Precipitator Applications. Research-Cottrell, Inc., Air Pollution Control Division.

6. Waste Automotive Lubricating Oil Reuse as a Fuel. GCA/Technology Division.

7. Atmospheric Emissions from Fuel Oil Combustion, An Inventory Guide. U.S. Department of Health, Education and Welfare, 1962.

8. Air Pollution Engineering Manual. U.S. Environmental Protection Agency

9. Particulate Pollutant System Study. Midwest Research Institute, 1971

10. Standard for Particulate Matter. Federal Register, Dec. 1971, paragraph 60.42.

11. Walker, A.B. Status of Technology for Control of Pollutants from Fossil Fuel Fired Power Plants. Cottrell Environmental Systems, Inc.

12. Pinheiro, G. Precipitators for Oil - Fired Boilers. Power Engineering, April 1971.

13. Strauss. Industrial Gas Cleaning. 1966.

14. Tankha. Try Fabric Dust - Collectors on Small Boilers. Power, August 1973.

15. Exhaust Gases from Combustion and Industrial Processes. Engineering Science, Inc., 1971.

16. Personal Communications. Frank Govan, York Research Corporation, Stamford, Conn., June 1974.

17. Compilation of Air Pollutant Emission Factors. U.S. Environmental Protection Agency. Second Edition, AP-42, 1973.

18. Bagwell, F.A., L. F. Cox and E. A. Pirsh. Design and Operating Experience; A Filterhouse Installed on an Oil Fired Boiler. Journal of the Air Pollution Control Association. Vol. 19, No. 3, March 1969.

19. Billings, C. E. and J. E. Wilder. Handbook of Fabric Filter Technology. Contract No. CPA-22-69-38. GCA Corporation, Bedford, Mass. (December 1970). Document PB 200-648, National Technical Information Service, U.S. Dept. of Commerce, Springfield, Va. 22151.

20. Personal Communications. James Burns, Boston Edison Co., June 1974.

21. Bagwell, F.A. and R. G. Velte. New Developments in Dust Collecting Equipment for Public Utilities. Journal of the Air Pollution Control Association. Vol 21, No. 12, Dec. 1971.

22. Confidential Communications. March 1974.

23. Personal Communications. Research Cottrell. September 1974.

Get 24. Janoso, R. P. Baghouse Dust Collectors on a Low Sulfur Coal Fired anthracite Utility Boiler. Pennsylvania Power and Light Company. (Presentation at the 67th Annual APCA Meeting) June 1974.

25. Dennis, R., G. A. Johnson, M. W. First, and M. W. Silverman. How Dust Collectors Perform. Chem. Eng. 59, 196. 1952.

26. Scrubber Test Summary; Cherokee No. 3. Public Service Company of Colorado, June and August 1973.

27. Field Measurements File. GCA/Technology Division. 1969.

28. A Manual of Electrostatic Precipitator Technology. Southern Research Institute. 1970.

29. A Review Study of Fire-Side Corrosion In Utility and Industrial Boilers. Combustion Engineering Inc., 1966.

30. Babcock and Wilcox. Steam: Its Generation and Use. 1972.

31. Emissions from Oil-Fired Boilers. E.I. Dupont De Nemours & Co. Wilmington, Delaware. 1971.

32. Relationship of Particulate Emissions Versus Partial to Full Load Operations for Utility-Sized Boilers. York Research Corporation. 1973.

33. Personal Communications. Consolidated Edison Company. March 1974.

34. Personal Communications. Research Cottrell Company. May 1974.

SECTION VI

APPENDICES

APPENDIX A

Table 11. OIL-FIRED COMBUSTION SYSTEMS WITH PARTICULATE EMISSION CONTROL DEVICES (NEDS)

State	County	Plant ID	Point ID	Boiler type	Boiler design capacity (MM Btu/hr)	Boiler size category (MM Btu/hr)	Fuel type	Sulfur content (% wt)	Ash content (% wt)	Fuel consumption rate (1000 gal/yr)	Primary particulate emission control device	Secondary particulate emission control device	Particulate emission control efficiency (%)	Particulate emission estimation method	Reported particulate emissions (tons/yr)	Calculated particulate emissions before control device using EPA emission factor (tons/yr)	Calculated particulate emissions after control device using EPA emission factor (tons/yr)
10	860	1	1	Elect	469	100-1000	Resid	1.0	0	16,632	009	-	20	1	132	67	53
10	1160	2	1	Indus	28	10-100	Resid	–	–	4,314	008	-	78.5	1	44	50	11
23	1700	11	3	Indus	80	10-100	Resid	1.0	0	3,500	007	000	93	1	43	40	3
23	3360	3	1	Indus	192	100-1000	Resid	0.7	0	10,046	006	000	50	1	60	116	58
48	1660	1	1	Indus	217	100-1000	Resid	2.1	0.1	5,869	009	-	64	1	28	67	24
48	1660	1	3	Indus	464	100-1000	Resid	2.1	0.1	23,535	009	-	64	1	61	271	97
48	2500	3	1	Indus	141	100-1000	Resid	2.1	0	8,580	007	-	87	1	195	99	13
48	2500	3	2	Indus	198	100-1000	Resid	2.1	0	11,583	007	-	87	1	195	133	17
48	2500	3	3	Indus	391	100-1000	Resid	2.1	0	22,730	007	-	87	1	173	261	34
7	265	6	1	Elect	763	100-1000	Resid	0.5	0	39,871	012	030	60	3	64	159	64
7	265	6	2	Elect	1475	> 1000	Resid	0.5	0	74,714	012	030	60	3	119	299	120
7	265	6	3	Elect	3522	> 1000	Resid	0.5	0	162,465	012	030	75	3	162	650	162
7	265	7	21	Elect	175	100-1000	Resid	0.6	0	2,970	012	-	60	3	4	12	5
7	265	7	22	Elect	175	100-1000	Resid	0.6	0	2,970	012	-	60	3	4	12	5
7	265	7	23	Elect	196	100-1000	Resid	0.6	0	5,750	012	-	60	3	23	23	9
7	265	7	24	Elect	196	100-1000	Resid	0.6	0	5,750	012	-	60	3	23	23	9
7	265	7	25	Elect	219	100-1000	Resid	0.6	0	5,350	012	-	60	3	13	21	9
7	265	7	26	Elect	219	100-1000	Resid	0.6	0	5,350	012	-	60	3	13	21	9
7	265	7	27	Elect	383	100-1000	Resid	0.6	0	14,790	012	-	60	3	59	59	24
7	425	15	4	Elect	560	100-1000	Resid	0.9	0	18,145	009	-	33.3	3	48	73	48
7	425	15	5	Elect	564	100-1000	Resid	0.9	0	16,737	009	-	30	3	47	67	47
7	425	15	6	Elect	664	100-1000	Resid	0.9	0	18,081	009	-	30.5	3	50	72	50
7	565	7	1	Elect	769	100-1000	Resid	0.9	0	26,769	012	-	33	3	74	111	74
7	565	7	2	Elect	1143	> 1000	Resid	0.9	0	51,745	012	-	30	3	145	207	145
7	565	7	3	Elect	201[illegible]	> 1000	Resid	0.9	0	96,467	012	-	33	3	257	346	254
7	705	8	5	Elect	888	100-1000	Resid	0.9	0	28,883	012	–	33.6	3	77	116	77
7	705	8	10	Elect	888	100-1000	Resid	0.9	0	28,203	012	–	33.6	3	75	113	75
7	705	12	4	Elect	–	10-100	Resid	0	0	–	008	–	90	3	1	–	–
7	705	12	6	Elect	–	10-100	Resid	0	0	–	003	–	80	3	27	–	–
7	705	12	7	Elect	–	10-100	Resid	0	0	–	008	–	90	3	1	–	–
7	705	17	13	Elect	385	100-1000	Resid	0.9	0	12,941	012	030	60	3	21	50	20
7	705	17	14	Elect	445	100-1000	Resid	0.9	0	12,362	012	030	60	3	20	49	20
10	2280	2	2	Elect	4640	> 1000	Resid	1.0	0	143,447	009	–	20	3	574	574	459
20	277	18	1	Elect	602	100-1000	Resid	2.1	0	24,000	009	006	85	3	14	96	14
20	277	18	2	Elect	602	100-1000	Resid	2.1	0	24,700	009	006	85	3	15	99	15
20	277	18	3	Elect	1132	> 1000	Resid	2.1	0	52,900	009	006	85	3	32	212	32
20	645	1	1	Elect	176	100-1000	Resid	2.0	0	3,885	008	–	85	3	–	16	2
20	645	1	2	Elect	176	100-1000	Resid	2.0	0	3,885	008	–	85	3	–	16	2
20	645	1	3	Elect	176	100-1000	Resid	2.0	0	3,528	008	–	85	3	–	14	2
20	645	1	4	Elect	170	100-1000	Resid	2.0	0	3,528	008	–	85	3	–	14	2
20	645	1	5	Elect	413	100-1000	Resid	2.0	0	17,094	011	008	95	3	–	68	3
20	645	1	6	Elect	413	100-1000	Resid	2.0	0	18,816	011	008	95	3	-	75	4
20	645	1	7	Elect	413	100-1000	Resid	2.0	0	16,080	008	–	85	3	–	5	10

007-009 — mech collector

010-012 ESP

004-006 - gravity

88 mechanical only
63 Esp only
14 Mechanical + Esp -
4 gravity + mechanical
5 gravity + Esp

19 m
17 E
3 gr + m
2 m + E

8 industrial

104 mechanical's
75 ESP's

Table 11 (continued). OIL-FIRED COMBUSTION SYSTEMS WITH PARTICULATE EMISSION CONTROL DEVICES (NEDS)

State	County	Plant ID	Point ID	Boiler type	Boiler design capacity (MM Btu/hr)	Boiler size category (MM Btu/hr)	Fuel type	Sulfur content (% wt)	Ash content (% wt)	Fuel consumption rate (1000 gal/yr)	Primary particulate emission control device	Secondary particulate emission control device	Particulate emission control efficiency (%)	Particulate emission estimation method	Reported particulate emissions (tons/yr)	Calculated particulate emissions before control device using EPA emission factor (tons/yr)	Calculated particulate emissions after control device using EPA emission factor (tons/yr)
21	140	4	6	Elect	2	< 10	Resid	0.8	0	26	011	-	95	3	0	0	0
21	140	4	8	Elect	2	< 10	Resid	0.8	0	26	011	-	95	3	0	0	0
21	140	21	3	Elect	707	100-1000	Resid	1.6	0	28,009	012	-	84	3	18	112	18
21	140	21	4	Elect	825	100-1000	Resid	1.6	0	42,036	009	-	65	3	59	168	59
21	140	21	5	Elect	825	100-1000	Resid	1.6	0	43,562	009	-	65	3	61	174	61
22	369	26	3	Elect	179	100-1000	Resid	2.4	0	3,320	008	060	90	3	1	13	1
22	1291	194	1	Elect	700	100-1000	Resid	2.1	0	31,357	011	000	35	3	82	125	82
22	1291	194	2	Elect	700	100-1000	Resid	2.1	0	32,075	011	000	35	3	83	128	83
22	1291	194	3	Elect	1120	> 1000	Resid	2.1	0	57,242	011	000	35	3	147	229	149
22	1798	39	1	Elect	218	100-1000	Resid	2.2	0	8,295	008	000	94	3	2	33	2
22	2121	61	1	Elect	2200	> 1000	Resid	2.0	0	104,202	012	000	35	3	271	417	271
22	2121	61	2	Elect	2200	> 1000	Resid	2.0	0	108,335	012	000	35	3	281	433	282
22	2121	61	3	Elect	5600	> 1000	Resid	2.0	0	191,293	012	000	35	3	497	765	497
26	4280	38	3	Elect	404	100-1000	Resid	2.1	0	197	011	-	97	3	33	1	0
31	660	3	2	Elect	630	100-1000	Resid	0.9	0	28,745	012	-	95	3	6	115	6
31	660	3	3	Elect	630	100-1000	Resid	0.9	0	28,745	012	-	95	3	6	115	6
31	660	3	4	Elect	630	100-1000	Resid	0.9	0	30,970	012	-	95	3	6	115	6
31	660	3	5	Elect	630	100-1000	Resid	0.9	0	30,970	012	-	95	3	6	115	6
31	660	3	6	Elect	1595	> 1000	Resid	0.9	0	77,960	011	-	97	3	9	312	9
31	1380	16	3	Elect	750	100-1000	Resid	0.9	0	17,320	010	-	90	3	66	69	9
31	1380	16	4	Elect	750	100-1000	Resid	0.9	0	17,320	010	-	90	3	66	69	7
31	2240	22	1	Elect	1513	> 1000	Resid	0.9	0	56,280	010	-	97	3	7	227	7
31	2240	22	2	Elect	1513	> 1000	Resid	0.9	0	59,178	010	-	97	3	7	227	7
31	2240	23	1	Elect	630	100-1000	Resid	0.8	0	27,132	010	-	95	3	5	109	5
31	2240	23	2	Elect	630	100-1000	Resid	0.8	0	27,132	010	-	95	3	5	109	5
31	3060	7	3	Elect	973	100-1000	Resid	0.3	0	44,800	008	-	86	3	25	179	25
31	3060	7	4	Elect	973	100-1000	Resid	0.3	0	44,800	008	-	86	3	25	179	25
31	3060	7	6	Elect	1125	> 1000	Resid	0.3	0	61,600	011	-	90	3	26	246	25
31	4900	1	1	Elect	743	100-1000	Resid	1.3	0	37,101	010	-	90	3	15	148	15
31	4900	1	3	Elect	728	100-1000	Resid	1.3	0	30,050	008	-	83.4	3	20	120	20
31	4900	1	4	Elect	728	100-1000	Resid	1.3	0	27,920	008	-	83.4	3	19	112	19
31	4900	1	5	Elect	644	100-1000	Resid	1.3	0	34,200	008	-	88	3	16	137	16
31	4900	1	6	Elect	1032	> 1000	Resid	1.3	0	58,080	008	-	82.2	3	42	232	41
39	1660	3	2	Elect	1850	> 1000	Resid	1.0	0	111,252	008	011	98.5	3	7	445	7
39	2360	11	1	Elect	752	100-1000	Resid	1.0	0	45,552	008	-	85	3	27	182	27
39	2360	11	2	Elect	752	100-1000	Resid	1.0	0	45,552	008	-	85	3	27	182	27
39	6000	3	1	Elect	730	100-1000	Resid	1.0	0	84,096	008	011	96.2	3	13	336	13
39	7160	4901	13	Elect	1123	> 1000	Resid	0.7	0	38,031	008	011	96	3	18	152	6
39	7160	4901	14	Elect	1130	> 1000	Resid	0.7	0	38,031	008	011	96	3	18	152	6
39	7160	4902	1	Elect	281	100-1000	Resid	0.6	0	3,265	009	-	76.5	3	9	13	3
39	7160	4902	2	Elect	281	100-1000	Resid	0.6	0	3,265	009	-	76.5	3	9	13	3
39	7160	4902	3	Elect	337	100-1000	Resid	0.7	0	3,963	008	-	85	3	7	2	0
39	7160	4902	4	Elect	337	100-1000	Resid	0.7	0	3,963	008	-	85	3	7	2	0

15 m
22E
1 g+m
4 mitgp

Table 11 (continued). OIL-FIRED COMBUSTION SYSTEMS WITH PARTICULATE EMISSION CONTROL DEVICES (NEDS)

State	County	Plant ID	Point ID	Boiler type	Boiler design capacity (MM Btu/hr)	Boiler size category (MM Btu/hr)	Fuel type	Sulfur content (% wt)	Ash content (% wt)	Fuel consumption rate (1000 gal/yr)	Primary particulate emission control device	Secondary particulate emission control device	Particulate emission control efficiency (%)	Particulate emission estimation method	Reported particulate emissions (tons/yr)	Calculated particulate emissions before control device using EPA emission factor (tons/yr)	Calculated particulate emissions after control device using EPA emission factor (tons/yr)
39	7160	4903	9	Elect	789	100-1000	Resid	0.7	0	32,349	009	011	93	3	25	129	9
39	7160	4903	10	Elect	789	100-1000	Resid	0.7	0	32,349	009	011	93	3	25	129	9
39	7160	4903	11	Elect	924	100-1000	Resid	0.7	0	39,338	008	011	96	3	17	157	6
39	7160	4903	12	Elect	924	100-1000	Resid	0.7	0	39,338	008	011	96	3	17	157	6
39	7160	4904	3	Elect	1542	> 1000	Resid	0.7	0	72,064	009	-	76	3	184	288	69
39	7160	4904	4	Elect	270	100-1000	Resid	0.7	0	11,378	008	-	85	3	20	46	7
39	7160	4904	5	Elect	270	100-1000	Resid	0.7	0	11,378	008	-	85	3	20	46	7
39	7160	4904	6	Elect	751	100-1000	Resid	0.7	0	37,928	008	-	85	3	56	152	23
39	7160	4905	1	Elect	1031	> 1000	Resid	0.7	0	44,909	008	010	99.2	3	4	180	0
39	7160	4905	2	Elect	1031	> 1000	Resid	0.7	0	44,909	008	010	99.2	3	4	180	0
39	7160	4905	3	Elect	1031	> 1000	Resid	0.7	0	44,909	008	010	99.2	3	4	180	0
39	7160	4905	4	Elect	1031	> 1000	Resid	0.7	0	44,909	008	010	99.2	3	4	180	0
39	7160	4906	1	Elect	162	100-1000	Resid	0.7	0	2,549	008	-	85	3	5	10	2
39	7160	4906	3	Elect	162	100-1000	Resid	0.7	0	2,549	008	-	85	3	5	10	2
39	7160	4906	4	Elect	211	100-1000	Resid	0.7	0	3,642	008	-	85	3	6	15	2
39	7160	4906	6	Elect	211	100-1000	Resid	0.7	0	3,642	008	-	85	3	6	15	2
41	320	37	1	Elect	807	100-1000	Resid	2.4	0	22,201	011	000	40	3	54	89	53
41	320	37	2	Elect	807	100-1000	Resid	2.4	0	21,483	011	-	40	3	52	86	52
42	420	3	1	Elect	529	100-1000	Resid	1.9	0	22,806	008	-	85	3	14	91	14
42	420	3	2	Elect	529	100-1000	Resid	1.9	0	22,806	008	-	85	3	14	91	14
48	720	2	2	Elect	725	100-1000	Resid	2.5	0	47,158	012	-	70	3	56	189	57
48	720	2	3	Elect	838	100-1000	Resid	2.5	0	54,285	004	012	80	3	43	217	43
48	720	2	4	Elect	1340	> 1000	Resid	2.5	0	65,373	012	-	70	3	78	752	226
48	720	2	5	Elect	2574	> 1000	Resid	2.5	0	101,854	012	-	70	3	122	1171	351
48	2440	4	1	Elect	1013	> 1000	Resid	2.2	0	42,231	004	-	87.2	3	22	486	57
48	2440	4	2	Elect	1013	> 1000	Resid	2.2	0	44,449	004	-	87.2	3	23	511	60
48	2440	4	3	Elect	1535	> 1000	Resid	2.2	0	70,316	004	-	85.5	3	41	109	117
48	2440	4	4	Elect	2102	> 1000	Resid	2.2	0	92,215	012	-	92	3	30	1060	85
6	600	7	1	Elect	350	100-1000	Dist	1.0	0	17,573	009	-	85	3	79	202	30
31	3060	7	5	Elect	1125	> 1000	Dist	0.3	0	53,400	011	-	90	3	21	614	61
7	705	40	1	Indus	250	100-1000	Resid	0.8	0	5,642	009	030	21	3	51	65	51
7	725	2	3	Indus	161	100-1000	Resid	0.9	0	2,400	009	-	25	3	21	28	21
7	725	2	5	Indus	197	100-1000	Resid	0.9	0	6,700	009	-	63	3	29	77	29
7	725	2	6	Indus	160	100-1000	Resid	0.9	0	3,850	009	-	25	3	33	44	33
16	400	30	2	Indus	—	—	Resid	0.3	0	175	008	-	80	3	—	2	0
20	445	1	2	Indus	73	10-100	Resid	2.0	0	1,030	011	-	92	3	1	12	1
20	445	1	3	Indus	73	10-100	Resid	2.0	0	1,030	011	-	92	3	1	12	1
20	445	1	4	Indus	73	10-100	Resid	2.0	0	1,030	011	-	92	3	1	12	1
20	547	14	3	Indus	290	100-1000	Resid	2.4	0	13,500	005	-	85	3	23	155	23
21	40	4	13	Indus	135	100-1000	Resid	0.8	0	4,800	007	-	85	3	12	55	8
21	40	4	14	Indus	135	100-1000	Resid	0.8	0	4,800	008	-	75	3	12	55	14
21	40	4	15	Indus	135	100-1000	Resid	0.8	0	4,800	007	-	85	3	12	55	14

12 industrial

78 m
10 E
8 m+ESP
1 op+ESP

Table 11 (continued). OIL-FIRED COMBUSTION SYSTEMS WITH PARTICULATE EMISSION CONTROL DEVICES (NEDS)

State	County	Plant ID	Point ID	Boiler type	Boiler design capacity (MM Btu/hr)	Boiler size category (MM Btu/hr)	Fuel type	Sulfur content (% wt)	Ash content (% wt)	Fuel consumption rate (1000 gal/yr)	Primary particulate emission control device	Secondary particulate emission control device	Particulate emission control efficiency (%)	Particulate emission estimation method	Reported particulate emissions (tons/yr)	Calculated particulate emissions before control device using EPA emission factor (tons/yr)	Calculated particulate emissions after control device using EPA emission factor (tons/yr)
21	120	26	1	Indus	13	10-100	Resid	0.8	0	250	011	–	95	3	3	3	0
21	120	26	2	Indus	13	10-100	Resid	0.8	0	250	011	–	95	3	3	3	0
21	120	26	3	Indus	13	10-100	Resid	0.8	0	250	011	–	95	3	3	3	0
21	120	26	4	Indus	13	10-100	Resid	0.8	0	250	011	–	95	3	3	3	0
21	120	39	1	Indus	44	10-100	Resid	0.8	0	1,410	010	–	90	3	16	16	2
21	120	39	2	Indus	44	10-100	Resid	0.8	0	1,410	010	–	90	3	16	16	2
21	120	44	1	Indus	14	10-100	Resid	0.8	0	200	004	–	60	3	2	2	1
21	120	48	2	Indus	7	< 10	Resid	0.8	0	20	011	–	95	3	2	2	1
21	120	48	3	Indus	8	< 10	Resid	0.8	0	288	011	–	75	3	–	3	0
21	120	49	2	Indus	125	100-1000	Resid	0.9	0	3,360	008	–	75	3	9	39	10
21	120	50	1	Indus	5	< 10	Resid	0.8	0	60	011	–	95	3	1	1	0
21	120	56	2	Indus	76	10-100	Resid	0.8	0	250	008	–	99.3	3	3	3	0
21	140	1	3	Indus	5	< 10	Resid	0.8	0	12	011	–	95	3	–	0	0
21	140	1	4	Indus	41	10-100	Resid	0.8	0	441	010	–	99	3	5	5	0
21	140	1	6	Indus	5	< 10	Resid	0.8	0	19	010	–	99	3	–	0	0
22	187	24	1	Indus	75	10-100	Resid	2.0	0	2,800	008	000	17.8	3	27	32	26
22	1278	31	4	Indus	38	10-100	Resid	2.0	0	135	008	000	95	3	2	2	0
22	1291	58	2	Indus	41	10-100	Resid	2.1	0	809	013	000	23.5	3	7	9	7
22	1291	58	3	Indus	41	10-100	Resid	2.1	0	809	013	000	23.5	3	7	9	7
22	1291	58	4	Indus	80	10-100	Resid	2.1	0	1,559	013	000	23.5	3	18	18	14
22	1291	58	5	Indus	152	100-1000	Resid	2.1	0	2,944	013	000	23.5	3	34	34	26
22	1291	58	6	Indus	123	100-1000	Resid	2.1	0	3,305	013	000	23.5	3	29	38	29
22	1291	58	7	Indus	95	10-100	Resid	2.1	0	2,569	013	000	40	3	22	30	22
22	1291	79	1	Indus	12	10-100	Resid	2.1	0	173	018	000	40	3	1	2	1
22	1291	79	2	Indus	12	10-100	Resid	2.1	0	173	018	000	30	3	1	2	1
22	1291	234	4	Indus	150	100-1000	Resid	2.3	0	2,519	008	000	30	3	20	29	20
22	1291	234	5	Indus	144	100-1000	Resid	2.3	0	2,414	008	000	58.6	3	19	28	19
22	1798	27	1	Indus	20	10-100	Resid	2.0	0	916	005	000	93	3	4	11	4
23	1700	11	1	Indus	170	100-1000	Resid	1.0	0	7,400	007	000	93	3	6	85	6
23	1700	11	2	Indus	170	100-1000	Resid	1.0	0	7,400	007	000	93	3	6	85	6
23	1700	11	4	Indus	170	100-1000	Resid	1.0	0	7,400	007	000	50	3	60	85	6
23	3360	3	2	Indus	192	100-1000	Resid	0.7	0	10,046	006	000	75	3	7	116	58
23	4620	3	1	Indus	65	10-100	Resid	0.7	0	2,380	008	000	75	3	11	27	7
23	4780	13	1	Indus	60	10-100	Resid	0.7	0	3,880	008	000	75	3	11	45	11
23	4780	13	2	Indus	60	10-100	Resid	0.7	0	3,880	008	000	99	3	1	45	11
31	300	14	4	Indus	168	100-1000	Resid	0.4	0	7,200	010	–	78	3	15	83	1
31	660	7	1	Indus	148	100-1000	Resid	0.4	0	600	008	–	87	3	5	7	2
31	3260	7	1	Indus	72	10-100	Resid	0.5	0	3,600	008	–	85	3	59	41	5
31	3260	7	2	Indus	6	< 10	Resid	0.5	0	34,000	008	–	86	3	27	391	59
31	3260	7	3	Indus	4	< 10	Resid	0.5	0	1,700	008	–	88	3	10	196	27
31	4120	11	1	Indus	182	100-1000	Resid	0.4	0	7,500	008	–	85	3	0	86	10
31	4900	5	16	Indus	7	< 10	Resid	0.5	0	300	002	–	85	3	0	3	1
31	4900	5	17	Indus	7	< 10	Resid	0.5	0	300	002	–	85	3	0	3	1

17m
13E

Table 11 (continued). OIL-FIRED COMBUSTION SYSTEMS WITH PARTICULATE EMISSION CONTROL DEVICES (NEDS)

State	County	Plant ID	Point ID	Boiler type	Boiler design capacity (MM Btu/hr)	Boiler size category (MM Btu/hr)	Fuel type	Sulfur content (% wt)	Ash content (% wt)	Fuel consumption rate (1000 gal/yr)	Primary particulate emission control device	Secondary particulate emission control device	Particulate emission control efficiency (%)	Particulate emission estimation method	Reported particulate emissions (tons/yr)	Calculated particulate emissions before control device using EPA emission factor (tons/yr)	Calculated particulate emissions after control device using EPA emission factor (tons/yr)
31	4900	5	18	Indus	7	< 10	Resid	0.5	0	300	002	–	85	3	0	3	1
31	4900	5	19	Indus	7	< 10	Resid	0.5	0	300	002	–	85	3	0	3	1
31	4900	5	20	Indus	7	< 10	Resid	0.5	0	300	002	–	85	3	0	3	1
31	5440	17	1	Indus	50	10-100	Resid	0.5	0	598	001	–	97	3	2	7	0
31	5440	17	2	Indus	30	10-100	Resid	0.5	0	1,195	001	–	97	3	4	14	0
31	5440	17	3	Indus	18	10-100	Resid	0.5	0	358	001	–	97	3	1	4	0
31	5440	17	4	Indus	12	10-100	Resid	0.5	0	239	001	–	97	3	1	3	0
31	5660	3	1	Indus	120	100-1000	Resid	0.8	0	500	005	–	60	3	2	6	2
31	5660	3	2	Indus	120	100-1000	Resid	0.8	0	1,700	005	–	60	3	7	20	8
34	2560	6	3	Indus	334	100-1000	Resid	2.0	0	12,453	007	–	95	3	7	143	7
34	2560	6	4	Indus	334	100-1000	Resid	2.0	0	12,351	007	–	95	3	7	142	7
39	516	10	10	Indus	100	10-100	Resid	2.4	0	5,317	001	–	98	3	61	61	1
39	516	10	11	Indus	100	10-100	Resid	2.4	0	5,317	001	–	98	3	61	61	1
39	516	10	12	Indus	100	10-100	Resid	2.4	0	5,317	001	–	98	3	61	61	1
39	516	10	13	Indus	201	100-1000	Resid	2.4	0	11,712	001	–	98	3	135	135	3
39	516	10	14	Indus	56	10-100	Resid	2.4	0	438	001	–	98	3	5	5	0
39	720	36	1	Indus	83	10-100	Resid	2.2	0	1,716	008	–	85.4	3	1	20	3
39	720	36	2	Indus	83	10-100	Resid	2.2	0	1,716	008	–	85.4	3	1	20	3
39	1660	12	1	Indus	275	100-1000	Resid	2.4	0	13,860	007	–	95	3	8	159	8
39	2360	30	2	Indus	490	100-1000	Resid	2.2	0	25,300	011	–	86.5	3	39	291	39
39	4700	21	44	Indus	177	100-1000	Resid	2.3	0	4,800	008	–	87.8	3	7	55	7
39	4700	21	45	Indus	200	100-1000	Resid	2.3	0	4,800	008	–	87.8	3	7	55	7
39	6000	41	1	Indus	432	100-1000	Resid	1.8	0	21,623	009	–	65	3	87	249	87
39	6000	50	1	Indus	553	100-1000	Resid	2.3	0	2,592	004	–	98	3	0	30	1
41	60	2	1	Indus	108	100-1000	Resid	2.2	0	2,042	002	000	96	3	1	23	1
41	320	9	3	Indus	4	< 10	Resid	2.2	0	55	060	000	0.6	3	1	1	1
48	720	1	1	Indus	112	100-1000	Resid	2.3	0	4,845	007	–	84	3	9	56	9
48	720	1	2	Indus	112	100-1000	Resid	2.3	0	4,845	007	–	84	3	9	56	9
48	720	1	3	Indus	112	100-1000	Resid	2.3	0	4,845	007	–	84	3	9	56	9
48	720	1	5	Indus	195	100-1000	Resid	2.3	0	6,715	007	–	84	3	12	77	12
48	720	1	6	Indus	195	100-1000	Resid	2.3	0	8,116	007	–	84	3	15	93	15
48	720	1	7	Indus	195	100-1000	Resid	2.3	0	8,116	007	–	84	3	15	93	15
48	720	1	8	Indus	195	100-1000	Resid	2.3	0	8,116	007	–	84	3	15	93	15
16	340	105	4	Indus	15	10-100	Dist	0	0	12	018	–	62.5	3	0	0	0
16	780	30	1	Indus	–	–	Dist	0.2	0	30	001	–	99.5	3	0	0	0
16	780	30	2	Indus	–	–	Dist	–	0	–	001	–	98.1	3	16	0	0

15 m
1E

Table 11 (continued). OIL-FIRED COMBUSTION SYSTEMS WITH PARTICULATE EMISSION CONTROL DEVICES (NEDS)

State	County	Plant ID	Point ID	Boiler type	Boiler design capacity (MM Btu/hr)	Boiler size category (MM Btu/hr)	Fuel type	Sulfur content (% wt)	Ash content (% wt)	Fuel consumption rate (1000 gal/yr)	Primary particulate emission control device	Secondary particulate emission control device	Particulate emission control efficiency (%)	Particulate emission estimation method	Reported particulate emissions (tons/yr)	Calculated particulate emissions before control device using EPA emission factor (tons/yr)	Calculated particulate emissions after control device using EPA emission factor (tons/yr)
23	2360	5	3	Indus	166	100-1000	Dist	0.7	0	9700	007	000	94.5	3	5	73	4
23	2360	5	4	Indus		100-1000	Dist	0.7	0	9700	007	000	94.5	3	5	73	4
23	2360	5	5	Indus	197	100-1000	Dist	0.7	0	11000	007	000	94	3	6	83	5
34	940	57	1	Indus	3	< 10	Dist	1.5	0	40	002	–	85	3	0	0	0
34	2060	53	1	Indus	10	< 10	Dist	1.0	0	5	008	–	90	3	0	0	0
39	4840	5	2	Indus	139	100-1000	Dist	0.2	0	2069	004	–	95	3	1	16	1
39	4840	5	4	Indus	139	100-1000	Dist	0.2	0	4645	004	–	95	3	2	35	2
21	80	2	1	Commer	30	10-100	Resid	0.8	0	1050	004	–	90	3	12	12	1
21	80	2	2	Commer	30	10-100	Resid	0.8	0	1050	004	–	90	3	12	12	1
21	80	13	2	Commer	10	< 10	Resid	2.0	0	315	011	–	99	3	4	4	0
21	80	13	3	Commer	4	< 10	Resid	2.0	0	125	011	–	98	3	1	1	0
21	1160	18	1	Commer	101	100-1000	Resid	0.9	0	1263	011	–	99	3	15	15	0
21	1160	18	2	Commer	18	10-100	Resid	0.9	0	222	011	–	99	3	3	3	0
22	1291	36	2	Commer	50	10-100	Resid	2.1	0	2028	011	000	40	3	14	23	14
41	320	36	1	Commer	75	10-100	Resid	2.2	0	726	001	000	90	3	0	8	1
41	320	43	1	Commer	178	100-1000	Resid	2.2	0	1501	003	000	70	3	5	17	5
20	45	35	1	Commer	63	10-100	Dist	0.3	0	2370	011	–	90	3	18	27	3
20	45	35	2	Commer	63	10-100	Dist	0.3	0	2370	011	–	90	3	18	27	3
20	45	35	3	Commer	63	10-100	Dist	0.3	0	2370	011	–	90	3	18	27	3
31	2240	29	1	Commer	12	10-100	Dist	0.3	0	250	011	–	46	3	1	3	2
31	2240	29	2	Commer	1	< 10	Dist	0.1	0	7	011	–	46	3	0	0	0
34	120	18	1	Commer	2	< 10	Dist	0.1	0	36	002	–	80	3	0	0	0

4m
10E

Legend to Table 11.

EQUIPMENT IDENTIFICATION CODES FOR
PRIMARY AND SECONDARY CONTROL EQUIPMENT

Identification Number	Control Device/Method[a]
000	No equipment
001	Wet scrubber - high efficiency
002	Wet scrubber - medium efficiency
003	Wet scrubber - low efficiency
004	Gravity collector - high efficiency
005	Gravity collector - medium efficiency
006	Gravity collector - low efficiency
007	Centrifugal collector - high efficiency
008	Centrifugal collector - medium efficiency
009	Centrifugal collector - low efficiency
010	Electrostatic precipitator - high efficiency
011	Electrostatic precipitator - medium efficiency
012	Electrostatic precipitator - low efficiency
013	Gas scrubber (general, not classified)
014	Mist eliminator - high velocity
015	Mist eliminator - low velocity
016	Fabric filter - high temperature
017	Fabric filter - medium temperature
018	Fabric filter - low temperature
019	Catalytic afterburner
020	Catalytic afterburner with heat exchanger
021	Direct flame afterburner
022	Direct flame afterburner with heat exchanger
023	Flaring
030	Discontinued; previously meant that no fuel was used with a sulfur content over that specified on the coding sheet
039	Catalytic oxidation - flue gas desulfurization
040	Alkalized alumina
041	Dry limestone injection
042	Wet limestone injection
043	Sulfuric acid plant - contact process
044	Sulfuric acid plant - double contact process
045	Sulfur plant
046	Process change
047	Vapor recovery system (including condensers, hooding, and other enclosures)
048	Activated carbon adsorption
049	Liquid filtration system
050	Packed-gas absorption column
051	Tray-type gas absorption column
052	Spray tower (gaseous control only)
053	Venturi scrubber (gaseous control only)

[a]Efficiency: High ($95-99^{+}$), medium (80-93), low (80).

Legend to Table 11.

STATE IDENTIFICATION NUMBER

State	Number	State	Number
Alabama	01	Nebraska	28
Alaska	02	Nevada	29
Arizona	03	New Hampshire	30
Arkansas	04	New Jersey	31
California	05	New Mexico	32
Colorado	06	New York	33
Connecticut	07	North Carolina	34
Delaware	08	North Dakota	35
District of Columbia	09	Ohio	36
Florida	10	Oklahoma	37
Georgia	11	Oregon	38
Hawaii	12	Pennsylvania	39
Idaho	13	Puerto Rico	40
Illinois	14	Rhode Island	41
Indiana	15	South Carolina	42
Iowa	16	South Dakota	43
Kansas	17	Tennessee	44
Kentucky	18	Texas	45
Louisiana	19	Utah	46
Maine	20	Vermont	47
Maryland	21	Virginia	48
Massachusetts	22	Washington	49
Michigan	23	West Virginia	50
Minnesota	24	Wisconsin	51
Mississippi	25	Wyoming	52
Missouri	26	American Samoa	53
Montana	27	Guam	54
		Virgin Islands	55

Legend to Table 11.

EMISSION ESTIMATION METHODS

Code	Description of Method
0	Not applicable (if emissions are negligible)
1	Stack-test results or other emission measurements
2	Material balance using engineering knowledge and past experience
3	Emissions calculated using EPA emission factors
4	Guess
5	Alternative emission factor (other than EPA)
6	New installation
7	Out of business

APPENDIX B

Per June 8, 1975 phone conversation with Jim Sabogin of GCA:
(1) all Bos. Ed. + Braintree plants burn #6 - believes most others do also
(2)

B — high eff. filter alone
A — alundum ~~[illegible]~~ thimble + high efficiency filter

all burning #6

Table 12. UNCONTROLLED OIL-FIRED BOILER EMISSIONS (NO ADDITIVES EMPLOYED)

Company Name	Plant	Boiler No.	Boiler Capacity (Mw)	Fuel Rate (gph)	Sulfur (%)	Ash (%)	Emissions (lb/MM Btu)
Boston Edison Co.	L Street	68	15	790	0.50	---	0.0391
		74	40	3,300	0.50	---	0.1923
		75	75	5,350	0.50	---	0.0675
		75	40	3,300	0.50	---	0.1546
		76	40	3,300	0.50	---	0.1521
	N. Boston	1	354	26,400	2.25	---	0.0529
		1	380	26,400	0.50	---	0.0653
		2	361	26,400	2.25	---	0.0319
		2	380	26,400	0.50	---	0.0309
	Kneeland St.	1	55	3,500	1.00	---	0.0600
		2	55	3,500	1.00	---	0.0490
		4	55	3,500	0.50	---	0.0128
		4	55	3,500	0.50	---	0.0385
		4	55	3,500	0.50	---	0.012
	Minot St.	6	25	1,600	0.50	---	0.0218
		7	25	1,600	0.50	---	0.0256
		7	25	1,600	0.50	---	0.060
	Edgar Station	9	80	6,000	2.17	---	0.131
		9	80	6,000	2.34	---	0.136
		9	80	6,000	1.00	---	0.0590
		9	80	6,000	1.00	---	0.0967
		9	80	6,000	1.00	---	0.0872
		9	80	6,000	1.00	---	0.0825
		9	80	6,000	1.00	---	0.0930
		9	80	6,000	1.00	---	0.0777
		9	80	6,000	1.00	---	0.0631
		9	80	6,000	1.00	---	0.0431
		9	80	6,000	1.00	---	0.0517
		9	80	6,000	1.00	---	0.0519
		9	80	6,000	1.00	---	0.0554
		10	80	6,000	1.00	---	0.0505
		10	80	6,000	1.00	---	0.1150
		10	80	6,000	1.00	---	0.0475
		10	80	6,000	1.00	---	0.0394
		10	80	6,000	1.00	---	0.0682

Table 12 (continued). UNCONTROLLED OIL-FIRED BOILER EMISSIONS (NO ADDITIVES EMPLOYED)

Company Name	Plant	Boiler No.	Boiler Capacity (Mw)	Fuel Rate (gph)	Sulfur (%)	Ash (%)	Emissions (lb/MM Btu)
Boston Edison Co.	Edgar Station (cont)	10	80	6,000	1.00	---	0.0828
		10	80	6,000	1.00	---	0.0675
		10	80	6,000	1.00	---	0.0568
		10	80	6,000	1.00	---	0.0781
		10	80	6,000	1.00	---	0.0689
		10	80	6,000	1.00	---	0.0567
		10	80	6,000	1.00	---	0.0701
		10	80	6,000	1.00	---	0.0409
		10	80	6,000	1.00	---	0.0630
		10	80	6,000	1.00	---	0.0494
		11	80	6,000	2.4	---	0.267
		11	80	6,000	2.34	---	0.111
		11	80	6,000	2.34	---	0.10
		11	80	6,000	1.00	---	0.0485
	Mystic Station	3	50	3,500	1.00	---	0.167
		3	50	3,500	2.3	---	0.244
		3	50	3,500	0.5	---	0.0465
		3	50	3,500	0.5	---	0.1057
		5	145	10,000	0.5	---	0.0263
		5	145	10,000	0.5	---	0.0935
		5	145	10,000	0.5	---	0.0646
		5	145	10,000	0.5	---	0.0406
		5	145	10,000	0.5	---	0.1225
		6	145	10,000	1.0	---	0.131
		6	145	10,000	1.0	---	0.106
Company A	1	4	20	1,250	---	---	0.042
	2	5 & 6	15	800	0.47	0.021	0.1172
		5 & 6	15	800	0.47	0.021	0.1053
		5 & 6	15	800	0.47	0.021	0.0785
		11 & 12	20	1,200	0.47	0.021	0.0308
		11 & 12	20	1,200	0.47	0.021	0.0489
		11 & 12	20	1,200	0.47	0.021	0.0518

oil burning #6

#6

Table 12 (continued). UNCONTROLLED OIL-FIRED BOILER EMISSIONS (NO ADDITIVES EMPLOYED)

Company Name	Plant	Boiler No.	Boiler Capacity (Mw)	Fuel Rate (gph)	Sulfur (%)	Ash (%)	Emissions (lb/MM Btu)
Dupont	Chestnut Run	--	10	475	2.19	0.06	0.0549
Bethlehem Steel	East Boston	2	<5	160	---	---	0.067
		2	<5	160	---	---	0.036
		2	<5	160	---	---	0.033
Borden Chemical	Leominster	1	10	500	---	---	0.21
		1	10	500	---	---	0.10
		1	10	500	---	---	0.099
		2	10	500	1.01	---	0.070
		2	10	500	1.03	---	0.074
		3	10	500	1.54	---	0.052
Company B	1	1	20	1,300	---	---	0.093
		2	25	1,750	---	---	0.046
		3	25	1,600	---	---	0.040
		4	30	1,950	---	---	0.103
		5	30	1,800	---	---	0.159
		5	30	2,050	---	---	0.085
		6	80	6,150	---	---	0.088
Braintree Elec.	Allen St. Sta.	2 & 3	20	1,150	0.89	---	0.1240
		2 & 3	20	1,200	0.84	---	0.0556
		2 & 3	20	1,170	0.88	---	0.0594
		4 & 5	20	1,170	0.89	0.03	0.0654
		4 & 5	20	1,220	0.92	0.038	0.0458
		4 & 5	20	1,190	0.85	0.035	0.0445
Eastman Gelatin	Peabody	1	10	500	---	---	0.158
		1	10	500	---	---	0.084
		1	10	500	---	---	0.084
		2	10	530	---	---	0.162
		2	10	530	---	---	0.195
		2	10	530	---	---	0.162
		3	10	570	1.11	0.044	0.079
		3	10	570	1.11	0.044	0.124
		3	10	570	---	---	0.105
		4	10	530	0.89	0.043	0.067
		4	10	530	0.89	0.043	0.067
		4	10	530	0.89	0.043	0.086

#6

June 9, 1975 phone conversation with Jim Sabogan: ①

Table 12 (continued). UNCONTROLLED OIL-FIRED BOILER EMISSIONS (NO ADDITIVES EMPLOYED)

Company Name	Plant	Boiler No.	Boiler Capacity (Mw)	Fuel Rate (gph)	Sulfur (%)	Ash (%)	Emissions (lb/MM Btu)
Eastman Gelatin (cont)	Peabody	5	10	540	0.93	0.034	0.052
		5	10	540	0.93	0.034	0.050
		5	10	540	0.93	0.034	0.104
		1,2,3	25	1,400	1.07	0.052	0.117
		1,2,3	25	1,400	1.07	0.052	0.100
		1,2,3	25	1,400	1.07	0.052	0.208
		1,2,3	20	1,050	1.04	0.030	0.145
		1,2,3	20	1,050	1.04	0.030	0.123
General Dynamics	Quincy		10	600	1.0	---	0.102
			10	600	1.0	---	0.082
			10	600	1.0	---	0.073
Plymouth Rubber	Canton		5	300	---	---	0.0232
			5	300	---	---	0.0456
			5	300	---	---	0.0376
			5	300	---	---	0.0441
Howard Johnsons	Wollaston	1 & 2	<5	100	---	---	0.106
		1 & 2	<5	100	---	---	0.145
Harvard Medical	Boston	2	5	300	---	---	0.065
		3	5	300	---	---	0.029
		4	5	300	---	---	0.032
Monsanto	Everett	2	5	460	0.45	---	0.067
		2	5	460	0.45	---	0.046
Univ. of Mass.	Amherst	8	10	650	1.06	0.30	0.0724
Montreal Urban Comm. (EPA-RTP has data)	Industrial	--	<5	130	---	---	0.031
		--	<5	120	---	---	0.030
		--	<5	115	---	---	0.026
		--	<5	125	---	---	0.057
		--	<5	90	---	---	0.071
		--	5	90	---	---	0.043
		--	13	730	---	---	0.078
		--	13	740	---	---	0.060
		--	13	730	---	---	0.054
		--	12	660	---	---	0.058
		--	12	670	---	---	0.039
		--	12	665	---	---	0.058

Table 12 (continued). UNCONTROLLED OIL FIRED BOILER EMISSIONS (NO ADDITIVES EMPLOYED)

Company Name	Plant	Boiler No.	Boiler Capacity (Mw)	Fuel Rate (gph)	Sulfur (%)	Ash (%)	Emissions (lb/MM Btu)
Montreal Urban Comm. (cont)		--	12	690	---	---	0.061
		--	12	700	---	---	0.062
		--	12	680	---	---	0.063
		--	13	720	---	---	0.055
		--	13	710	---	---	0.040
		--	13	710	---	---	0.041
Emission measurements made upstream of control equipment							
Polaroid	New Bedford	1	5	390	0.70	---	0.0917
		2	5	340	0.70	---	0.1429
Boston Edison	Mystic	3	50	3,600	2.40	---	0.2242
Con Edison	Ravenswood	30	600	57,000	0.30	0.02	0.0202
	Astoria	30	350	19,000	0.37	---	0.0261
		40	355	19,000	0.30	---	0.0231
		50	385	19,000	0.37	---	0.0218
		50	320	19,000	0.30	---	0.0163

Table 13. UNCONTROLLED OIL-FIRED BOILER EMISSIONS (ADDITIVES EMPLOYED)

Company Name	Plant	Boiler No.	Boiler Capacity (Mw)	Fuel Rate (gph)	Sulfur (%)	Ash (%)	Emissions (lb/MM Btu)
Braintree Electric	Potter Station	1	20	1,150	0.79	---	0.0544
		1	20	1,140	0.89	---	0.0746
		1	20	1,120	1.04	---	0.0710
		2	12	680	0.92	---	0.2295
		2	12	680	0.90	---	0.0925
		2	12	680	0.85	---	0.1218
		4	5	460	0.88	0.047	0.1008
		4	5	440	0.89	0.059	0.1313
		4	5	440	0.92	---	0.1414
Company A	1	1 & 2	25	1,670	0.39	0.045	0.0292
		1 & 2	25	1,670	0.41	0.047	0.0466
		1 & 2	25	1,670	0.44	0.042	0.0481
	3	8	20	1,080	---	---	0.044
		8	20	1,080	---	---	0.044
		10	10	450	---	---	0.075
		10	10	450	---	---	0.068
	4	7	20	1,100	---	---	0.068
		7	20	1,100	---	---	0.048
HELCO	Middletown		119	1,625	1.95	0.09	0.070
			117	7,625	1.86	0.07	0.057
			119	7,625	1.79	0.07	0.067

Table 13 (continued). UNCONTROLLED OIL-FIRED BOILER EMISSIONS (ADDITIVES EMPLOYED)

Company Name	Plant	Boiler No.	Boiler Capacity (Mw)	Fuel Rate (gph)	Sulfur (%)	Ash (%)	Emissions (lb/MM Btu)
Emission measurements made upstream of control equipment							
Boston Edison	Mystic	3	40	3,200	2.3	---	0.345
		3	40	3,200	2.3	---	0.238
		3	40	3,200	2.4	---	0.1823
		3	40	3,200	2.4	---	0.1138
		6	146	11,260	2.15	0.09	0.2780
		6	144	9,595	2.10	0.10	0.1717
		6	151	9,270	1.89	0.07	0.2819
		6	148	8,210	2.04	0.07	0.1087
Company C			185	11,800	2.5	---	0.2243
			185	11,800	2.5	---	0.1632
			185	11,800	2.5	---	0.3500
			367	22,000	2.45	0.28	0.1500
			367	22,000	2.45	0.28	0.0824
			370	22,040	---	0.15	0.1141
			372	23,260	---	0.16	0.0918
			363	21,690	---	0.15	0.1448
			368	21,360	---	0.16	0.1197