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Overview of Pollution from Combustion of Fossil Fuels in Boilers of the United States

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Overview of Pollution from Combustion of Fossil Fuels in Boilers of the United States

by

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ABSTRACT

The report describes the fossil-fuel-fired boiler population of the United States, presenting data on the number and capacity of boilers for categories with most relevance to production of pollution. This information includes:

- Type of fuel burned
  (coal, residual oil, distillate oil, natural gas)

- Usage sector
  (utility, industrial, commercial)

- Size category
  ($<25 \times 10^6$ Btu/hr, $25\text{-}250 \times 10^6$ Btu/hr, $>250 \times 10^6$ Btu/hr)

- Heat transfer configuration
  (water tube, fire tube, cast iron)

Fuel consumption data are presented for each type of fuel burned in each usage sector. These data are used to make estimates for the amount of sulfur oxide, nitrogen oxide, and particulate air emissions produced by boilers operation. Other air pollutants are discussed qualitatively. Solid waste and water pollution from boiler operation are discussed generally.

CONTENTS

FIGURES

TABLES

CONVERSION TABLE

ENGLISH TO METRIC

English Unit	Multiplier	To Metric Unit
British thermal unit (Btu)	1,055.056	joule (J)
Btu/hour	0.2931	watt (W)[1]
10^6 Btu/hour	0.2931	megawatt (MW)[1]
Ton	907.185	kilogram (kg)
Gallon	0.003785	cubic meter (m^3)

[1] Thermal units not to be confused with electrical.

SECTION 1

INTRODUCTION

BACKGROUND

Annual consumption of fossil fuels in the United States in recent years has totalled about 75×10^{15} Btu. One-third of this total was consumed in boilers. This exceeds even transportation (19×10^{15} Btu/yr) which is by far the next largest usage. Other major categories for consumption of fossil fuels are residential usage (about 14.4×10^{15} Btu) and fuel for direct heating of processes (about 8.6×10^{15} Btu). These four categories account for some 89 percent of all fossil fuel consumption. The balance is used for feedstocks, raw materials, and other miscellaneous uses. Further, most of the "dirty" fuels (coal and residual oil) go into boilers. Hence boilers are, by virtue of amount and type of fuel burned, by far the largest single source of air pollution from sulfur oxides and are a significant source of particulate matter and nitrogen oxides. While the contribution of other sources to environmental pollution is recognized as important, the present study is limited to the development of background information on boiler combustion which is sufficiently important to warrant the effort to analyze the complex nature of the problems presented.

Fuel consumption in boilers is divided into three sectors: utility boilers producing steam for generation of electricity (59%); industrial boilers generating steam or hot water for process heat, generation of electricity, or space heat (24%); and boilers for space heating for commercial and institutiononal facilities (17%). Some space heating for the residential sector takes place in boilers, and some fuel burned in boilers classified as institutional is probably providing heat for multi-family dwellings. No attempt was made to correct these minor departures from complete accuracy in boiler classification because they probably have no significant impact on the results of the investigation.

The fuels consumed in boilers in large quantities are natural gas, distillate oil, residual oil, and coal. Additional energy is derived from the burning of waste fuels such as bark, bagasse, liquid hydrocarbon waste materials, etc. These fuels contribute only a small percentage to energy needs. They may, however, present environmental problems out of proportion to the Btu's supplied especially in the immediate future when high fuel costs and increasing cost to dispose of waste materials will provide new incentives to burn them. Problems in this area have not been addressed because of the need to focus on more fundamental boiler-fuel-pollution relationships which are not presently understood. New Source Performance Standards (NSPS) for boilers burning waste are to be developed in the near future.

Further information on present and projected waste burning practices will be developed in connection with this activity.

For the fossil fuels being considered, various combinations of consuming sectors (i.e., utility, industrial, and commercial), types of application (i.e., generation of electricity, process steam and space heat) and type of fuel, have independent and significant environmental consequences. An overall analysis of pollution from boiler operation is complicated by the fact that boilers employed are of three basically different types, i.e. watertube, firetube and cast iron. In addition, each type varies in size, predominant type of fuel fired, combustion conditions, type of application, and other factors influencing the character and quantity of environmental discharges.

The complexity of analyzing the impacts of boiler operation in the United States has given rise to a series of studies by the U.S. Environmental Protection Agency. These studies have assessed various aspects of the environmental consequences of boiler operation and have progressively advanced our overall understanding of the impacts of specific pollutants and the control technology appropriate for different boilers. This overview is intended to place these findings in perspective and to suggest priorities for developing control systems and strategies. No attempt was made to include detailed economic analyses or in-depth evaluations of pollution control technology since such information is not needed to develop the perspective that this study is attempting to provide.

REPORT ORGANIZATION

This report is organized into seven sections which discuss the general character of the boiler population, the environmental impacts from boiler operation, and recommended future actions. Section 2 presents information on the estimated fuel burning capacity of each important type of boiler. The values presented are derived from previous boiler studies by updating earlier estimates with boiler sales data for the past 10 years. Section 3 presents estimates for amount and type of fuel actually consumed in different types of boiler service, and discusses capacity factors derived from the total capacity and fuel consumption figures. Data are presented for coal, residual oil, distillate oil and natural gas burned in the utility, industrial and commercial sectors.

Section 4 discusses potential discharges and emission estimates for sulfur oxides, nitrogen oxides, particulate matter, carbon monoxide, and hydrocarbons, 5 of the 7 criteria pollutants. Section 5 discusses trace metals (including lead, a criteria pollutant), polycyclic organic matter, and sulfates. Section 6 discusses the impact of wastewater and solid waste associated with boiler operation.

Section 7 presents conclusions of the report and recommendations for further work in four areas.

- Improvement of the information on application, operating practices, etc. for existing boilers

- Obtaining better data for characterization of boiler air emissions
- R&D to control environmental discharges
- Work to anticipate environmental problems which may accompany future changes in boiler and fuel usage patterns

SECTION 2

BOILER POPULATION OF THE UNITED STATES

For this analysis, the boiler population of the United States has been divided into categories which are considered most significant for determining potential environmental impact. These categories are:

(1) Type of fuel burned
(coal, residual oil, distillate oil, natural gas)

(2) Usage sector
(utility, industrial, commercial)

(3) Size category
(less than 25×10^6 Btu/h, $25\text{-}250 \times 10^6$ Btu/h, more than 250×10^6 Btu/h)

(4) Heat transfer configuration
(watertube, firetube, cast iron)

The population (number of boilers) and total fuel burning capacity (10^6 Btu/h) have been estimated for each category. Data were taken from a report by Walden (Ehrenfeld et al., 1970), and two reports by Battelle (Locklin et al., 1974), and (Putnam et al., 1975). These data were refined and updated using boiler sales data for the past 10 years which were supplied by the American Boiler Manufacturers Association and the Hydronics Institute. The procedures used to develop the estimates are described in a recent PEDCo report (Devitt et al., 1979). Tables showing the detailed estimates are also contained in the PEDCo report.

The distribution of boiler capacity by fuel type is shown in Table 1. Totals are shown for the utility sector, and for the industrial and commercial sectors combined, to permit comparison of utility and non-utility boilers. Total capacity of commercial and industrial boilers is shown to be roughly equivalent to that of utility boilers. Further, the total capacity for units consuming "dirty fuels" (coal and residual oil) is roughly equivalent. Natural gas is the dominant fuel in the industrial and commercial sectors. Replacement of large parts of this capacity by additional coal- and oil-fired units would greatly increase the pollution from boilers in these sectors. Conversely, the present trend towards firing more natural gas in lieu of oil is an improvement from an environmental perspective. The long-term trend away from oil and natural gas to coal-firing may be an environmental improvement to the extent that well controlled coal-fired units might emit less offensive pollution than uncontrolled oil-fired units which are typical of those in commercial and industrial service.

The distribution of boilers among the commercial and industrial sectors is shown in Table 2, along with average capacities for all sectors.

TABLE 1. SUMMARY OF THE TOTAL BOILER POPULATION BY TYPE OF FUEL, 1977

Utility Boilers	Number of boilers	Capacity (10^6 Btu/h)
Coal	1,533	1,833,000
Residual oil	1,038	743,600
Distillate oil	196	57,300
Natural gas	984	1,013,700
Total Utility	3,751	3,647,600
Industrial/Commercial		
Coal	214,400	815,800
Residual oil	389,104	1,223,800
Distillate oil	244,206	433,600
Natural gas	954,350	2,008,800
Total Industrial/Commercial	1,802,060	4,482,000
All Boilers		
Coal	215,933	2,648,800
Residual oil	390,142	1,967,400
Distillate oil	244,402	490,900
Natural gas	955,334	3,022,500
Total All Boilers	1,805,811	8,129,600

TABLE 2. SUMMARY OF TOTAL BOILER POPULATION BY CONSUMING SECTOR, 1977

Usage sector	No. of Boilers	Total capacity, (10^6 Btu/hr)	Average capacity, (10^6 Btu/h)
Utility	3,751	3,647,500	972
Industrial	506,930	3,107,400	6.1
Commercial	1,295,130	1,374,700	1.1
	1,805,811	8,129,600	

Although the total capacity of utility boilers is roughly equivalent to that of industrial and commercial boilers, there is a great disparity in terms of numbers. The greater number of industrial and commercial boilers, combined with their smaller average size and greater proximity to population centers, complicates controlling their emissions and increases their environmental impact potential. The variation in average size is extreme, being almost 1000 x 10^6 Btu/h for utility boilers versus about 6 x 10^6 Btu/h for industrial boilers and 1 x 10^6 Btu/h for commercial boilers. Assessing the environmental impact potential of industrial and commercial boilers is made more difficult by differences in heat transfer configuration, i.e. watertube, firetube or cast iron versus watertube only for utilities. Furthermore the industrial boilers may be used to generate electricity, to produce process steam, or for space heating; all of these uses call for different load swings and variation in other operating conditions that can influence both the rate and type of emissions as well as their resulting impact.

The distribution of boilers by size category is shown in Table 3. Boiler size is of great importance as far as relative impact of boiler operation is concerned. Pollution from larger boilers may often, despite the much greater amount being generated, produce relatively modest environmental impacts. Installation of environmental control equipment is generally required; and the combustion process is better controlled, burning the fuel more completely and forming fewer potentially hazardous air pollutants per unit of fuel burned.

The data in Table 3 show that a little over half of the existing boiler capacity and well under 1 percent of the boilers by number are subject to the size limitations (250×10^6 Btu/h or greater) of the New Source Performance Standard (NSPS) promulgated December 23, 1971. However, NSPS are currently being considered for the industrial boiler population. These standards are only in the formulative stage, but it is possible that a lower cutoff limit of 25×10^6 Btu/h may be established. The speculation concerning the lower size limit is based upon the almost even distribution of boiler capacity between those less than 25×10^6 Btu/h and those between 25×10^6 Btu/h and 250×10^6 Btu/h. Those having a capacity less than 25×10^6 Btu/h are mostly cast iron or firetube boilers (about 90 percent), whereas those between 25×10^6 Btu/h and 250×10^6 Btu/h are mostly watertube boilers. This is illustrated by Figure 1 which shows boiler capacity distribution by size and boiler type.

TABLE 3. SUMMARY OF TOTAL BOILER CAPACITY BY SIZE, 1977

Utility Size (10^6 Btu/h)	Number of Boilers	Total Capacity (10^6 Btu/h)
< 25	193	2,200
25-250	1,183	160,700
> 250	2,375	3,484,600
	3,751	3,647,500
Industrial/Commercial Size (10^6 Btu/h)	Number of Boilers	Total Capacity (10^6 Btu/h)
< 25	1,773,135	1,979,400
25-250	27,589	1,743,700
> 250	1,336	759,000
	1,802,060	4,482,100
All Boilers	Number of Boilers	Total Capacity (10^6 Btu/h)
< 25	1,773,328	1,981,600
25-250	28,772	1,904,400
> 250	3,711	4,243,600
	1,805,811	8,129,600

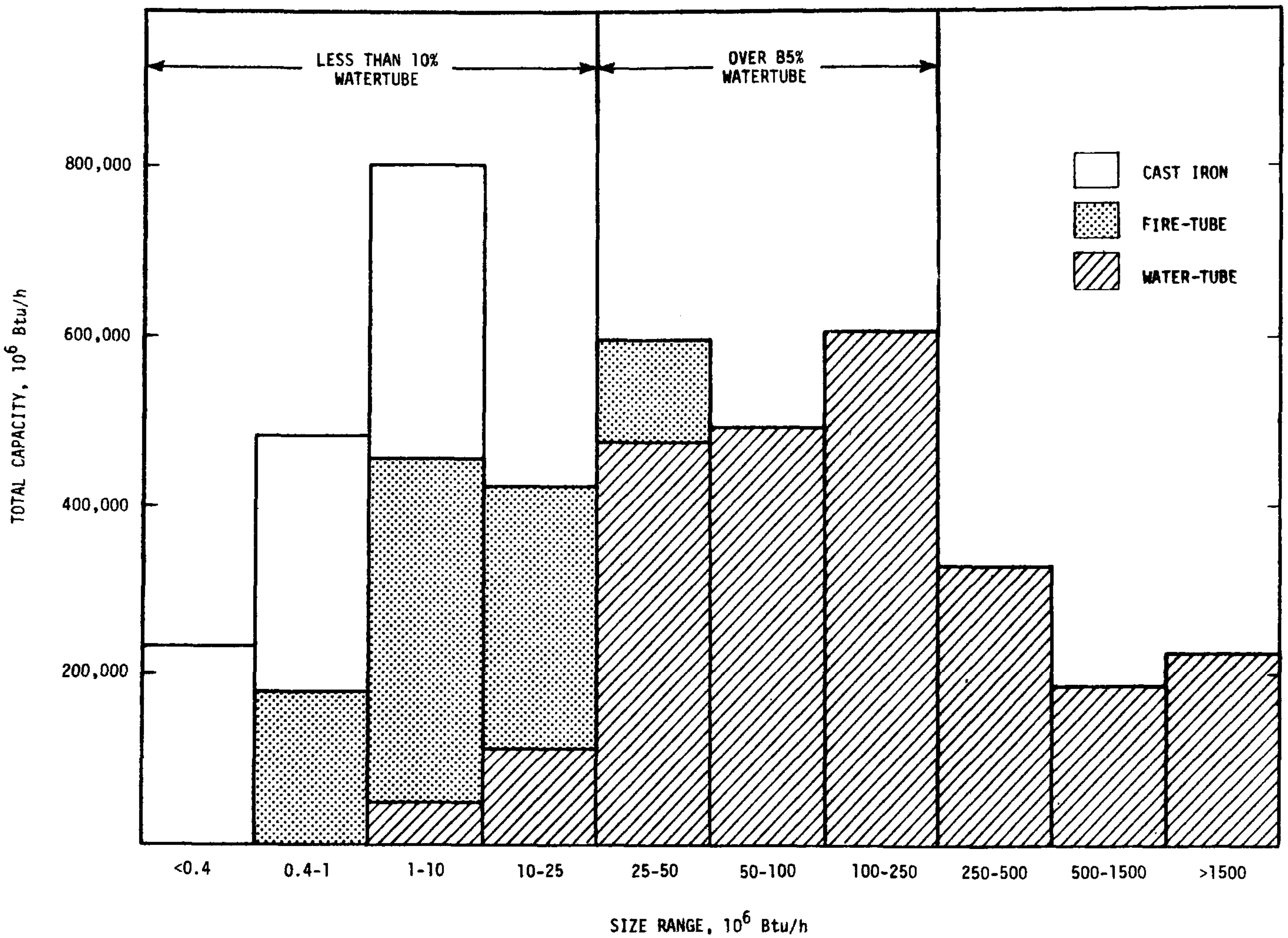

Figure 1. Relative distribution of the capacity of the industrial/commercial boiler population by type and size.

Classification by heat transfer configuration is an important consideration in evaluation of environmental impacts of the boiler population, partly because configuration has a direct effect on combustion conditions (and resulting emissions) but also because there is a great difference in size of boilers using the three basic types of heat transfer configuration. The distribution of the boiler population by type of heat transfer configuration is shown in Table 4.

TABLE 4. SUMMARY OF THE TOTAL BOILER CAPACITY BY TYPE OF HEAT TRANSFER CONFIGURATION, 1977

Heat transfer configuration	Number of boilers	Total capacity, (10^6 Btu/h)	Average size (10^6 Btu/h)
Watertube (Utility)	3,751	3,647,500	972
Watertube (Non-utility)	50,495	2,552,500	50
Firetube	275,075	1,033,300	3.7
Cast Iron	1,476,490	896,200	0.6
	1,805,811	8,129,500	

These data show that watertube boilers make up over 80 percent of the total estimated capacity. The smaller firetube and cast iron boilers do however, constitute a significant part of the capacity and amount to over 95 percent of the total population. It is interesting to note that the average size for watertube non-utility boilers is about 50 x 10^6 Btu/h as compared to about 6 x 10^6 Btu/h for all industrial boilers. This difference reflects the use of a significant number of firetube boilers in industrial applications and is another illustration of the wide variety of boiler practices in the industrial sector.

In summary, boilers can be classified in a number of ways. Their characteristics by configuration can best be summarized as follows:

Utility Watertube

- These boilers account for 45 percent of the total boiler capacity.
- Over 95 percent are above 250 x 10^6 Btu/h in capacity.
- The average size is much greater than that of industrial or commercial boilers (almost 20 times greater than the largest industrial category).
- Almost all units are field-erected.
- About half of the total capacity is designed to burn coal.

Industrial/Commercial Watertube

- These boilers make up the majority of total industrial/commercial capacity.
- They represent the least number of industrial/commercial boilers.
- The average boiler size is the largest of the three types used in industrial/commercial applications.
- Field-erected units represent the majority of the total capacity.
- Most units are industrial rather than commercial.
- They may be used for generation of process steam, electricity, or space heat.

Firetube

- These boilers represent 13 percent of the total boiler capacity and 25 percent of the industrial/commercial boiler capacity.
- The average boiler size is small compared with watertube boilers.

- They represent 15 percent of the total number of boilers.

- All units are package (shop fabricated).

- Very few fire coal.

Cast Iron

- These boilers comprise 11 percent of the total boiler capacity and 20 percent of the industrial/commercial boiler capacity.

- They represent the largest number of boilers (81%).

- The average boiler size is the smallest of all the categories.

- All units are package.

- Most are used for generation of space heat and hot water.

- Most are commercial rather than industrial.

SECTION 3

ANNUAL FUEL CONSUMPTION

Ideally, analysis of boiler fuel consumption in the evaluation of environmental impacts would begin with study of the important combinations of consuming sector, boiler type and application. These combinations are:

Sector	Boiler type	Application
Utility	Watertube	Electric generation
Industrial	Watertube	Electric generation
Industrial	Watertube	Process steam
Industrial	Watertube	Space heat
Industrial	Firetube	Process steam
Industrial	Firetube	Space heat
Commercial	Watertube	Space heat
Commercial	Firetube	Space heat
Commercial	Cast iron	Space heat

Each of these groups, for a given fuel type, would be expected to have unique process-discharge characteristics which would be reasonably uniform within the group. Collectively, the groups would represent essentially all boiler combustion. Given details on type and amount of fuel burned in each category, it would be possible to make a definitive comparison of environmental discharges.

Unfortunately data on fuel consumption are not sufficiently detailed to permit such an analysis. In fact, considerable investigation was required to develop reasonable estimates for amounts of each type of fuel used in each of the three basic consuming sectors. The details of this investigation were reported by PEDCo (Devitt et al., 1979). Data from the Federal Power Commission were the primary data source for utility boiler consumption (Federal Power Commission, 1976a). For the industrial and commercial sectors, reports from the Department of Energy (Bureau of Mines, 1976 a, b, and c) contained basic data. The data reported for utilities were specific and detailed. For the industrial and commercial sectors considerable analysis was necessary to estimate the amount of the total fuel consumption which was attributable to boiler operation. For example, data were available for total industrial fuel usage but secondary sources of information were needed to estimate boiler fuel consumption. The supplementary sources included the Survey of Major Fuel Burning Installations (Department of Energy, 1975) and the Stanford Research report on energy patterns of the United States (Stanford Research Institute, 1972). For the commercial sector similar problems of data interpretation were encountered e.g., figures for total gas consumption were available (Bureau of Mines, 1976 c) but the distribution among boiler fuel and other uses such as water heating, cooking, etc., was not given. Percentages from the Stanford study were used to estimate the space heat fraction and it was assumed that this represented boiler fuel.

Although interpretations and assumptions have undoubtedly led to some inaccuracies, the results provide a reasonable basis for analysis of the environmental impacts of boiler operation in all consuming sectors. This is illustrated by a comparison made between the boiler fuel consumption patterns by sector and boiler capacity by sector. Consumption data are shown in Table 5 for categories comparable to those used for capacity in Table 1. For all categories, there is reasonable agreement in the distribution between sectors for capacity and consumption. This is illustrated by the values in Table 6.

Using these data, overall annual capacity factors* were developed. These factors are shown in Table 7.

TABLE 7. OVERALL ANNUAL CAPACITY FACTOR FOR BOILERS IN THE UNITED STATES, 1975

Sector/Fuel Type	Capacity factor
Utility	
Coal	0.580
Residual oil	0.396
Distillate oil	0.258
Natural gas	0.340
Industrial/Commercial	
Coal	0.154
Residual oil	0.164
Distillate oil	0.297
Natural gas	0.322

*The capacity factor was derived by (1) dividing the total national capacity (in 10^6 Btu/h) into the fuel consumption for 1975 (in Btu) to calculate hours of operation possible for all boilers on the amount of fuel consumed; and (2) dividing this value by the total number of hours in a year.

TABLE 5. FUEL CONSUMPTION FOR BOILERS IN THE UNITED STATES, 1975

Sector/Fuel Type	Quantity	Fuel Consumption (10^{12} Btu)
Utility		
Coal (10^3 tons)	431,075	9,310.0
Residual oil (10^3 bbl)	446,699	2,590.8
Distillate oil (10^3 bbl)	22,245	129.7
Natural gas (10^6 ft^3)	2,945,969	3,016.7
		15,047.2
Industrial/Commercial		
Coal (10^3 tons)	44,417	1,101.6
Residual oil (10^3 bbl)	280,170	1,762.3
Distillate oil (103 bbl)	193,758	1,129.6
Natural gas (10^6 ft^3)	6,231,641	6,381.2
		10,374.7
All Boilers		
Coal (10^3 tons)	475,492	10,411.6
Residual oil (10^3 bbl)	726,869	4,353.1
Distillate oil (10^3 bbl)	216,003	1,259.3
Natural gas (10^6 ft^3)	9,776,610	9,397.9
		25,421.9

TABLE 6. DISTRIBUTION OF BOILER CAPACITY AND FUEL CONSUMPTION BY SECTOR AND FUEL TYPE

	Percent of total capacity	Percent of total consumption
Utility		
Coal	22.6	36.6
Residual oil	9.1	10.2
Distillate oil	0.7	0.5
Natural gas	12.5	11.9
Industrial/Commercial		
Coal	10.0	4.3
Residual oil	15.1	6.9
Distillate oil	5.3	4.4
Natural gas	24.7	25.1

The capacity factor for some categories is lower than reported in previous studies, e.g., Battelle (Putnam et al., 1975) reported factors ranging from 0.206 to 0.524 for commercial and industrial boilers burning coal, oil or natural gas. Also the weighted average of 26.1 percent from this study is lower than the estimate of 35 percent from a previous boiler study (Ehrenfeld et al., 1971). The Battelle estimates were derived from data contained in the EPA National Emissions Data System (NEDS). These data have known limitations (e.g., New York State is not included), and contain some errors. Battelle reported, for example, that for some boilers the capacity and fuel consumption values produced a load factor much greater than 1.0. Nevertheless some of the values derived here for industrial units appear to be low. This bias may be caused by assumptions concerning replacement rates, as discussed in the PEDCo report (Devitt, et al., 1979).

On the other hand, the figures may indicate, at least in part, that a substantial number of boilers are on standby. A brief survey in connection with this study identified a number of sites with 100 percent excess steam-raising capacity. In the opinion of several industry representatives, this is a common practice in the chemical and petroleum refining industries. Information on specific plants indicates that not only are there many spare or stand-by boilers, but also that individual boilers are sized in excess of demand. Several instances were found where only 50 to 75 percent of boiler capacity was required for plant needs. Another factor having a large impact on overall capacity factor is the seasonal operation of many boilers. For instance, many food processing plants only operate 2 to 3 months out of a year with their boilers idle during the remaining months. Thus unit capacity factors in these situations may be significantly lower than previously estimated.

In summary, the most important comments on boiler fuel consumption are as follows:

- Data are not available to relate amount and type of fuel burned to type of boiler and type of application of the various boiler-fuel combinations.
- Determination of the percentage of each type of fuel being consumed in boilers involves the use of secondary sources of information, some of which are dated or of questionable reliability.
- In spite of these data limitations sufficient information is available to relate type and amount of fuel burned to major consuming sectors.
- Utility consumption of all fuels is about 60 percent of the total fuel consumed in boilers. Coal is the major utility fuel. About 60 percent of the coal produced in the United States is burned in utility boilers.
- Industrial and commercial boilers consume over half of the combined production of distillate and residual oil burned in boilers. This represents about one-fourth of the oil burned in the United States.

SECTION 4

ATMOSPHERIC EMISSIONS FROM BOILER OPERATION: SULFUR OXIDES, NITROGEN OXIDES, PARTICULATE MATTER, CARBON MONOXIDE, AND HYDROCARBONS

EMISSION ESTIMATES

Air pollution discharges from boilers were estimated using fuel consumption data for 1975 and emission factors presented in EPA's "Compilation of Air Pollutant Emission Factors," (U.S. EPA, 1977). These factors which are given for emissions per unit of fuel burned, represent a compilation of test data on various boiler types and fuels. The EPA has ranked these factors as "very good" with respect to the data used to derive the factors. PEDCo has compiled more recent test data on boiler emissions and the results were not significantly different from the EPA values. In most cases the EPA values were within 5 to 20 percent of the more recent test data.

Estimated emissions from boilers of particulate matter, sulfur oxides, and nitrogen oxides are shown in Table 8 along with EPA estimates for the total annual emissions for the United States. It should be noted that AP-42 factors yield an estimate for total uncontrolled particulate emissions. A 1973-1974 survey by PEDCo (PEDCo, 1976) determined that the overall particulate collection efficiency at that time was approximately 94 percent for utility boilers; the particulate emission value in Table 8

TABLE 8. ESTIMATED EMISSIONS OF THREE CRITERIA POLLUTANTS FROM BOILERS, 1975

Sector/fuel	Emissions, 10^6 tons/yr: Particulate matter	NO_x	SO_x
Utility			
Coal	1.38[1]	2.29	16.31
Oil	0.08	1.11	1.49
Gas	0.00	1.00	0.00
Industrial/commercial			
Coal	0.42[2]	0.26	1.69
Oil	0.11	0.44	1.55
Gas	0.05	0.43	0.00
Total emissions for U.S.[a]	16.0	24.4	28.5

[a] (U.S. EPA, 1976).

[1] Reflects an assumed control efficiency of 95 percent.

[2] Reflects an assumed control efficiency of 84 percent.

reflects an assumed 95 percent average efficiency for 1975. The value of the EPA estimate for utility particulate emissions in 1975 (3.9×10^6 tons) is significantly different from the value in Table 8. However the EPA value is based upon NEDS data for control levels and fuel consumption that are probably less accurate than the more recent reports used in this study. Industrial and commercial boilers use less sophisticated control equipment and are less likely to use control devices. Examination of NEDS data indicates an average of about 84 percent control efficiency for industrial/commercial boilers. This value was used for the estimates in Table 8. On this basis, the utility and industrial/ commercial sectors represent about 8.8 and 3.6 percent of the total nationwide particulate emissions. However, it is probable that the NEDS data are more complete for larger, well-controlled boilers and use of these data has probably led to an overestimate of the nationwide level of control for industrial/commercial boilers. It is possible therefore that this group would also account for about 5 to 10 percent of the total nationwide particulate emissions.

Boiler firing accounted for 5.5 million tons of nitrogen oxides compared with 24.4 million tons estimated as the total for 1975. Much of this was from coal-fired utility boilers that are not, at present, effectively controlled. The modest contribution from industrial and commercial boilers is surprising considering that they consumed 36 percent of the total boiler fuel burned in 1975. This difference is attributable to lower emission factors for these boilers. For gas-fired boilers which are important contributors to NO_x from all sectors, the NO_x emission factors are 700, 175, and 100 lb/10^6 cu. ft. of gas fired for utility, industrial, and commercial boilers, respectively. These factors from AP-42 compare favorably with the previously mentioned test data on the emissions from industrial boilers. Differences are generally small except in a few instances where differences of ± 20-25 percent were found. Therefore it appears that industrial and commercial boilers are modest contributors to the total emissions of nitrogen oxides compared to utility boilers and other sources.

The total contribution of sulfur oxides from boilers represents the dominant portion of the total emissions estimated for 1975 (19.5 million tons out of a total of 28.5 million tons). Again, the utility contribution is much greater than that of non-utility boilers. However, the industrial and commercial emissions do amount to about 10 percent of the total for 1975; and the impacts associated with low level discharges from small boilers with short stacks in urban areas may be especially significant. Also, the industrial/commercial SO_x emissions are largely attributable to residual oil (about 50 percent). Sulfur oxides from oil burning may have special significance due to association with co-contaminants, (see Section 5).

The estimated amounts of hydrocarbons from the national boiler population are 68,600 tons from the industrial/commercial sector and 86,000 tons from the utility sector. These quantities are insignificant compared with an estimated nationwide total of 28.9 million tons in 1975. Estimated quantities of carbon monoxide emitted by the boiler population are also insignificant amounting to only 213,000 tons from the industrial/commercial sector and 270,000 tons from the utility sector, compared with an estimated nationwide total of 95 million tons in 1975.

PROJECTED DISCHARGES

Development of definitive projections for overall growth of a boiler population made up of different types of equipment which are applied by many industries in different types of services would be difficult even if equipment and usage patterns were not poorly defined. Attempts to translate the impact of growth in boiler population into estimates of future air pollution discharges are further complicated by the need to predict fuel use patterns of the future. This involves trying to estimate the impact of legislation, the effect of shifting economics associated with the price fixing on imported oil, and many other factors which are beyond the scope of this study. It was considered important however, to determine whether modest growth in usage might change the relative importance of the boiler contribution to pollution levels. For purposes of such projections a 3.7 percent growth rate estimate by PEDCo (Devitt et al, 1979) was used for industrial and commercial boilers. This estimate assumed (among other things) that boiler fuel consumption would vary directly with projected increases in total fuel consumption in five industries which consume about 80 percent of the industrial fuel. A 5.2% growth rate for utility boilers (the rate predicted by FPC for all power generation) was used for coal and residual oil fired boilers (FPC, 1976b).

Figure 2 illustrates the projected increase, based on this growth rate, in emissions of SO_x, particulate matter, and NO_x from utility and industrial/commercial boilers. As can be seen from this figure and the values in Table 8, SO_x emissions from utility coal-fired boilers dominate from a criteria pollutant perspective.

Because of this dominance and the high level of interest in controlling SO_x emissions from utility coal-fired sources, projections of SO_x emissions were prepared for utility coal-fired boilers under several different growth and control scenarios. One set of estimates for SO_x is shown in Figure 3. The upper curve shows the amount of sulfur oxides that would be discharged from coal-fired power plants if no emission controls were used beyond those being applied in 1975 (i.e., no control of new plants). The second highest curve shows the emissions estimated to occur if current (December 1971) NSPS are met by all new boilers coming on stream between 1975 and 1990. The next lower curve shows estimated emissions if all new boilers use flue gas desulfurization to achieve 90 percent control of sulfur oxides. The lower curve shows the amount discharged from boilers in operation in 1975 and continuing to operate in future years

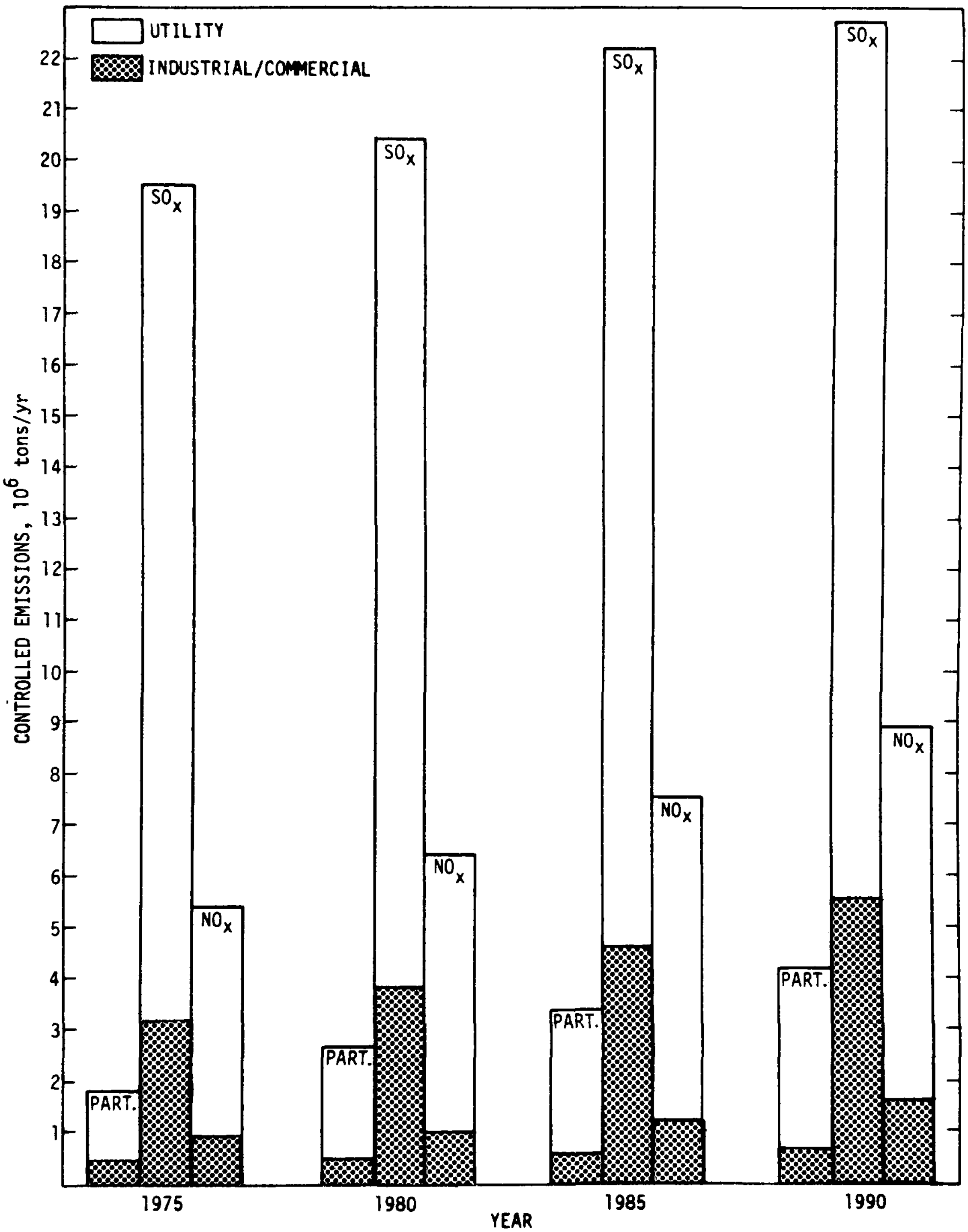

Figure 2. Projected emissions of particulate matter, SO_x and NO_x from utility and industrial/commercial boilers.

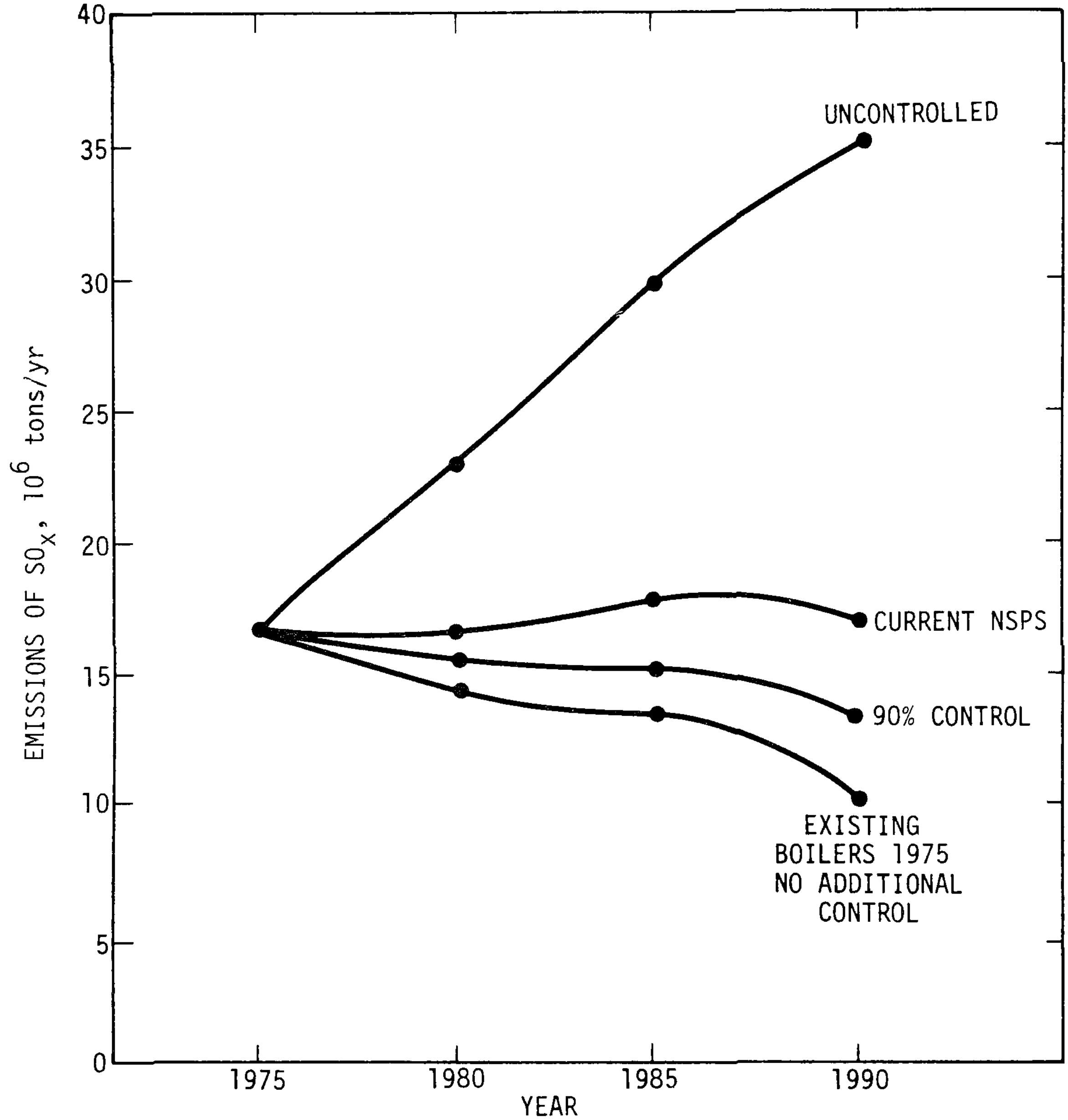

Figure 3. Projected sulfur oxide emissions for coal-fired power plants.

assuming normal retirement rates and no further SO_x controls applied.

Several important conclusions can be drawn from this figure. First, there would be a significant increase in SO_x emissions if controls were not applied to new units. Second, meeting current NSPS will keep emissions from increasing significantly. Third, the benefits possible if more stringent controls are met may be marginal. Finally, boilers in operation in 1975 are likely to be significant sources of pollution in 1990 and beyond. It should be noted that, as indicated earlier, these curves assume a 5.67 percent growth rate for coal fired boilers which is the growth prediction of the Federal Power Commission for all power generation (FPC, 1976b). Any change in the assumed rate of growth, however, will have a significant impact upon the conclusions drawn above. For instance, under a higher growth rate of about 9 percent, a 90 percent control level for new boilers would be required to maintain utility SO_x emissions at the 1975 level.

Another consideration in examining future levels of SO_x emissions from utility sources is the attainment of State Implementation Plan (SIP) control levels on the boilers in existence in 1975. Control to the current SIP requirements for SO_x emission levels is estimated to reduce SO_x emissions by about 4 million tons per year by 1990 (Gibbs et al. 1978). If this occurs, the current NSPS (December 1971) would be sufficient to maintain total SO_x emissions at 1975 levels through the year 1990, even assuming a 9 percent growth rate.

In summary the most important observations from analysis of atmospheric emissions of criteria pollutants are as follows:

- Except for the SO_x emissions from coal- and oil-fired units boilers are not a dominant contributor to national levels of pollution from criteria pollutants. Their contribution to NO_x and particulate matter is quite significant however when compared to other individual sources.

- Projections for future air discharges from boilers (based on a growth estimate which could vary considerably without changing the general conclusions) indicate that NO_x and particulate discharges could assume increasing relative importance as the volume from boilers increases, and that from other important sources such as motor vehicles are more closely controlled.

- The greatest threat of increased pollution from SO_x emissions comes from the expanded use of coal-fired utility boilers. Given modest increases in capacity (5.2%) meeting present standards for new boilers should keep total annual discharges about where they are now. A greater rate of increase would require more stringent standards for either existing or new boilers to prevent significant increase in total SO_x discharged.

SECTION 5

ATMOSPHERIC EMISSIONS FROM BOILER OPERATION: TRACE METALS, POLYCYCLIC ORGANIC MATTER, AND SULFATES

Sulfates, polycyclic organic matter (POM), and trace metal compounds are air pollutants that are also of great concern in boiler operations. In addition, the presence of radioactive elements in coal ash has been reported but there are insufficient data for determining whether there is cause for concern (Santhanam, 1978).

Sulfur-bearing coal and residual oil produce sulfates directly on combustion (primary) or when sulfur oxide emissions are converted to sulfates in the atmosphere (secondary).* While there is much that is not understood about mechanisms of formation and the relative contribution from various sources of sulfates to general pollution, it is believed that they represent a significant environmental problem. Various epidemiological studies have implicated suspended water soluble sulfates as respiratory irritants and available toxicological data tend to

*Techniques used to monitor air emissions and ambient air quality measure sulfates as a composite group of various sulfate species. The concentration of sulfates measures by these techniques is generally considered a reasonable measure of potential for adverse environmental impact from this class of compounds.

support these implications (Gerstle and Richards, 1976). Extensive toxicological studies are currently underway, and the results will help to quantify the potential impact of specific sulfates.

Primary sulfates represent a small percentage of the sulfur oxides discharged from combustion sources. They range from about 1 to 3 percent for coal-fired sources and from 3 to 12 percent for oil-fired sources. Primary sulfates can impact directly when they occur as local pollutants, i.e., as emissions from low level stacks in urban areas where greater numbers of people would be affected. Secondary sulfates are considered to be the dominant factor in "remote pollution" which manifests itself as acid rain or impaired visibility. They are usually produced from the combustion of coal and oil in boilers. The potential for environmental impact of sulfates from boilers can vary significantly with the type of boiler, its mode of operation, fuel composition, and other variables.

Information on the possible role of boiler-related factors in sulfate production was presented recently (Ando, 1978). Data presented in this report show that reductions of SO_x emissions in Japan have resulted in a corresponding drop in ambient concentrations of sulfates. This is contrary to U.S. experience where substantial reductions in SO_x concentrations have been accompanied by very small decreases, if any, in sulfate concentrations. Part of the reason for this difference is attributed to lower direct sulfate emissions from Japanese boilers. The factors cited as causative are as follows:

- In the United States many oil-fired boilers, (which produce more sulfate than coal-fired boilers) were installed in the last 15 years.
- Very few oil-fired boilers in the United States are equipped with electrostatic precipitators. In Japan electrostatic precipitators with ammonia injection for control of corrosion are used. The ammonia reacts with SO_3 and much of the resulting sulfate is collected in the precipitator.
- Oxidation catalysts which are used in the United States, but not in Japan, may promote sulfate formation in the boiler.
- Unspecified work to reduce NO_x emissions from utility boilers in Japan, which is not being applied in the United States, are felt to contribute to reductions in sulfate emissions.

The author goes on to suggest that the success in control of SO_x and sulfates from large boilers may not be a complete solution. Japan (like the United States) has many small oil-fired boilers which have neither electrostatic precipitators nor good combustion control, and can emit sulfates at low levels in urban areas.

Some further conclusions regarding the relationship between boiler variables and sulfate emissions were reported in a recent workshop (EPA, 1978). Studies suggested that sulfate emissions from oil-burning sources are 3 to 10 times greater than from sources burning coal with an equivalent sulfur content. It is believed that the higher flame temperatures, the vanadium and nickel content, and the lack of particulate control devices for oil-firing contribute significantly to the observed sulfate emissions (Homolya, 1978). In addition, a number of studies demonstrated that available boiler oxygen in excess of stoichiometric will enhance sulfate formation (Homolya, 1978).

The estimated amounts of oil (mostly residual) burned in U.S. utilities is equivalent to about 2700 x 10^{12} Btu/yr while oil burned in industrial and commercial boilers is equivalent to about 2900 x 10^{12} Btu/yr, 60 percent of which is residual oil. Much of the combustion in industrial and commercial boilers is likely to be poorly controlled for conditions such as excess air. If we are to continue to burn large amounts of oil it appears that more effective control of both large and small oil-fired boilers would be necessary for effective reduction of the exposure of the U.S. population to sulfates.

Polycyclic organic matter (POM) has been defined most simply as all organic matter with two or more benzene rings. Discharges of this class of compounds have been considered potentially hazardous in that many are toxic and some are known carcinogens. POM concentrations are frequently used as an index of the potential for adverse environmental impact of organic air emissions. Incomplete combustion, natural or man-made is accepted as the primary source of POM in the environment. Very little is known however, about the relative contribution of various sources to the total volume of POM discharged to the environment and the data for estimation of the relative impact of the individual compounds are very sparse. Quantitative information about stationary sources is mainly limited to that developed for discharges of benzo(a)pyrene (BaP) that were reported some years ago (Hangebrauck et al., 1967).

It is believed, however, that both mobile and stationary sources of combustion make significant contributions to high POM levels in urban areas. While some sources such as coke ovens are especially suspect as a significant contributor to high ambient concentrations, other stationary sources such as boilers are also believed to be significant sources. Two interrelated boiler characteristics have a great effect on the amounts of POM generated: type of fuel and combustion efficiency. In general more POM would be expected from burning of coal or oil than from gas. And larger boilers operated continuously under well-controlled conditions would produce less POM. Small boilers which are generally used in applications where loosely controlled operation and poor maintenance are much more common, can emit much larger quantities of POM per unit of fuel burned.

The relationship between fuel type, boiler efficiency and POM discharges is illustrated by data from the Hangebrauck study shown in Table 9. For the units burning coal, those units which would be expected to have lowest combustion efficiency have by far the largest emissions of POM. These data also show average values for gas and oil furnaces which suggest that oil- and gas-firing will produce less BaP than coal firing. It must be considered, however, that these data represent results of a very

TABLE 9. RELATIVE BaP EMISSION RATES FROM STATIONARY FUEL COMBUSTION SOURCES (Hangebrauck et al, 1967)

Fuel	Source	Estimated BaP emission rate ($\mu g/10^6$ Btu)
Coal	Residential - hand stoked	1,400,000
	Residential - underfeed	44,000
	Commercial	5,000
	Industrial	2,700
	Utility	90
Oil		200
Natural gas		100

old screening study which did not provide final answers relative to potential impacts of discharges from the units tested. The test data are insufficient to justify a conclusion that gas- and oil-fired units are not significant contributors to POM pollution.

These general conclusions and the small amount of data available suggest that the fuel burned in utility boilers (about 12,000 x 10^{12} Btu/yr for coal and oil) would produce less POM than similar fuels burned in industrial and commercial boilers (about 4000 x 10^{12} Btu/ yr). Furthermore the small industrial and commercial boilers burning coal and oil are located mostly in urban areas and emit POM at low elevations from a very large number of sources. These sources could impact much more on human health than the larger more remote sources.

Many of the metal ions present in coal and oil (such as arsenic, cadmium, and mercury) have potential for being emitted as toxic compounds but there is very little information available to establish whether they, in fact, are. Some metals (vanadium and nickel) have potential for catalyzing undesirable atmospheric transformations such as the conversion of sulfur dioxide to sulfates. While there is some evidence to suggest that this is occurring, data are not available to establish the seriousness of the resulting environmental impact. It appears, however, that trace metal compounds from fossil fuel combustion could prove to be a problem in the future. If so, boiler fuel consumption could be expected to play a prominent role.

Trace metal compounds associated with fossil fuels vary widely in kind and amount. While trace elements in coal have been studied intensively, it is still difficult to generalize relative to their occurrence (Mezey et al., 1976). This is demonstrated by Table 10 which shows data for 101 coals of the U.S. Data for trace elements from oil are less plentiful but that which are available suggest that crude oils are equally variable as far as composition is concerned. Table 11 shows data for 24 crude oils. It should be noted that these values (except for those shown for copper, nickel, uranium and vanadium) are shown only as percent in ash from crude oil. They are intended mainly to show variability. It is worth noting also that vanadium and nickel can be expected to occur in some amount in all crudes and may be present in amounts which will produce high concentrations when it is concentrated in the residual oil. This can be illustrated by considering that vanadium which can be present in crude oil in amounts up to 100 ppm may be concentrated in residual oil by a factor of 5 to 10 or more by the refining process.

These data and fuel consumption data suggest that trace metal emissions from coal combustion in boilers are primarily from utility boiler consumption (about 9000 x 10^{12} Btu/yr) rather than industrial and commercial boilers (about 1000 x 10^{12} Btu/yr). Whether the environmental impacts from many small, less efficient boilers burning lesser amounts of fuel but discharging emissions at low levels outweigh those from a much smaller number

TABLE 10. MEAN ANALYTICAL VALUES FOR 101 COALS
(Ruch et al, 1974)

Constituent	Mean	Unit	Standard deviation	MIN	MAX
As	14.02	PPM	17.70	0.50	93.00
Be	1.61	PPM	0.82	0.20	4.00
Cd	2.52	PPM	7.60	0.10	65.00
Cr	13.75	PPM	7.26	4.00	54.00
F	60.94	PPM	20.99	25.00	143.00
Hg	0.20	PPM	0.20	0.02	1.60
Ni	21.07	PPM	12.35	3.00	80.00
Pb	34.78	PPM	43.69	4.00	218.00
V	32.71	PPM	12.03	11.00	78.00
Zn	272.29	PPM	694.23	6.00	5350.00

TABLE 11. DISTRIBUTION OF 28 TRACE METALS IN ASHES OF 24 CRUDE OILS (Mezey et al, 1976)

Metal	Occurrence in percent of samples	Concentration range in ash,[a] percent	Concentration range[b] Percent of ash	ppm in crude
Al	100	0.001 - 10		
Fe	100	0.01 - >10		
Ti	50	0.001 - 1.0		
Mn	96	0.001 - 1.0		
Ca	100	0.01 - >10		
Mg	100	0.1 - 10		
Na	88	0.1 - >10		
K	8	1 - 10		
Ag	17	0.1 - 1		
As	21	0.001 - 1		
B	17	0.001 - 1		
Ba	100	0.001 - 1		
Ce	33	0.01 - 1		
Co	100	0.001 - 1		
Cr	100	0.001 - 0.1		
Cu	100	0.001 - >10	13 - 0.007	1.7 - 0.03
Ga	67	0.0001 - 0.01		
La	38	0.001 - 1		
Mo	83	0.001 - 1		
Nd	8	0.1 - 1		
Ni	100	0.01 - >10	16 - 0.1	35 - 0.03
Pb	96	0.001 - 1.0		
Sn	38	0.001 - 1.0		
Sr	92	0.0001 - 1.0		
V	100	0.001 - >10	46 - 0.41	106 - 0.002
Zn	58	0.01 - 10		
Zr	33	0.001 - 1.0		
U	100	0.0001 - 0.01	0.0075-0.001	0.013-0.00012

(a) Semiquantitative values.

(b) Quantitative values.

of large boilers whose emissions will be widely dispersed is open to question. The same factors must be considered in weighing the relative impacts from utility and non-utility boilers burning residual oil. It would appear that the roughly equivalent consumption figures for the different sectors would make the non-utility boiler impact more significant as far as any adverse effects might be concerned.

Important points from the analysis of information on these air pollutants from boilers are as follows:

- Data needed for assessment of potentially hazardous impacts from boiler associated sulfates, POM, and trace metal compounds are very sparse and inconclusive.
- Burning of residual oil in small boilers may be producing potentially hazardous discharges of sulfates, POM, and trace metal compounds.
- Burning of distillate oil may be producing potentially hazardous discharges of sulfates and POM.

SECTION 6

WATER POLLUTION AND SOLID WASTE DISCHARGES FROM BOILER OPERATION

For practical purposes the problems of water pollution associated with boiler operation are limited to wastewater from large watertube boilers. Cast iron and firetube boilers being used mainly for space heating do not require cooling water which is the main source of wastewater from boilers. Solid waste disposal problems involve ash, and in some situations, sludge from SO_2 scrubbing systems. Ash is a significant problem only for coal-fired watertube boilers. Scrubber sludge can result from control of watertube boilers burning either coal or residual oil. Only a few cast iron and firetube boilers burn coal and in small amounts so that dry collection and landfill disposal of ash presents no significant problem. Since SO_2 control is not practiced for boilers in these categories no sludge is produced.

Boilers in the utility and industrial sector are the only ones for which wastewater and solid waste is a serious consideration. The handling of waste disposal and water management practices are not well defined for the industrial sector but it is generally assumed that conventions and procedures used by utilities are being applied (GCA, 1976).

Utility boilers, because of their size and number, have considerable potential for environmental impact from discharges of wastewater, ash or scrubber sludges. As a result they have been the subject of numerous assessment studies. While these problems are generally felt to be managable using presently available control technology, some discussion to illustrate the nature of the problems to be dealt with seems appropriate.

The main sources of wastewater are cooling water systems, ash disposal systems, and boiler feedwater treatment systems. These discharges are continuous during boiler operation. Other discharges of wastewater occur on an intermittent basis from such sources as boiler blowdown, boiler cleaning systems, and runoff from coal storage piles. Another potential source of wastewater effluent is wet scrubber flue gas cleaning systems.

The most significant of these sources is the effluent from cooling water systems. These effluents are potential causes of thermal pollution, stream depletion, and contamination from water treatment additives. Where cooling towers are used, the blowdown discharge contains dissolved and suspended solids and contaminants such as corrosion inhibitors and algicides.

The wastewater from ash handling systems can contain significant quantities of dissolved and suspended solids and potentially hazardous materials (cadmium, arsenic, and lead). Seepage and leaching from ash sedimentation basins are potential sources of ground water pollution unless the basins are controlled with proper lining materials.

The quantities of wastewater from boiler blowdown, boiler cleaning operations, water treatment systems and coal pile runoff are insignificant compared with cooling water discharges and ash handling discharges. However, these sources are potential contributors to hazardous material discharges such as PCB, nickel, zinc, antimony, low or high pH water, and many others. These streams are usually treated to reduce effluents to acceptable levels.

Table 12 presents the estimated quantities of wastewater from utility plants in 1973 (GCA, 1976). These data indicate the relative importance of different sources.

Ash produced by coal-fired power plants is a function of ash content of the coal which can vary from about 8 to 15 percent. The average for utility coal was 13.4 percent in 1975 (FPC, 1976). Coal-fired boilers generated an estimated 64 million tons of ash in 1975. Of this total about 30.4 million tons was emitted as fly ash (47.5%) while the rest was produced as bottom ash. Utility coal-fired boilers account for over 90 percent of the total ash generated. Although a large percentage is emitted as fly ash, utility plants have very efficient fly ash control devices (95% average collection efficiency). Of the total fly ash emitted, an estimated 28.9 million tons are collected by control equipment and must be disposed of.

Disposal methods include land filling and ash settling ponds. In addition, approximately 20 to 25 percent of the bottom

TABLE 12. UTILITY WASTEWATER DISCHARGES[a]

Waste stream	Flow quantity (10^9 gal/yr)
Ash handling	280
Cooling	
Once-through	49,000
Recirculated	5,300
Fuel handling	7.9
Boiler feed water	
Treatment	9.0
Boiler blowdown	6.6
Equipment cleaning	2.2
Total	54,605.7

[a] Data from Table 23 in reference (GCA, 1976).

ash (7 to 8 million tons) is recycled for use as road-base aggregate, for use as aggregate in concrete block production, and for application to icy roadways (National Ash Association, 1978).

The major potential environmental impacts of disposal of ash from boiler operation is contamination of water and soil by leaching and runoff. Significant quantities of potentially hazardous materials including trace metal compounds, can be carried in these discharges.

Sludges are now being produced in relatively small quantities by scrubbing systems which utilize lime or limestone to collect SO_x from flue gases. Table 13 shows estimates from a study assessing the impact of burning more coal as indicated in the National Energy Plan. Projections for fuel consumption and degree of application of flue gas desulfurization (FGD) are based on predictions by the Department of Energy under the National Energy Plan (Santhanam, et al. 1978). Such projections are necessarily very uncertain. The rate at which coal use will expand and FGD will be applied are debatable. These data do indicate, however, what the magnitude of the disposal problem may be for the two materials and show the general relationship between the quantity of the two materials that would be generated.

In summary, the most important considerations relating to wastewater and solid waste generated by boilers are:

- Solid waste and wastewater are produced in significant quantities only by large watertube boilers burning coal or residual oil. Coal burning utility boilers are the dominant contributor.

TABLE 13. PROJECTED ASH AND FGD SLUDGE GENERATION FOR COAL-FIRED BOILERS LARGER THAN 250 x 10^6 Btu/h[a]

	Ash and sludge, 10^3 tons		
	1975	1985	2000
Industrial boilers			
Coal ash	5,600	18,987	43,518
FGD sludge	0	6,500	23,100
Utility boilers			
Coal ash	59,800	72,947	85,842
FGD sludge	6,800	26,100	34,600
Total			
Coal ash	65,400	91,934	129,360
FGD sludge	6,800	32,600	57,700

[a] 1975 estimates are derived from data in (Devitt et al., 1978). Projections for 1985 and 2000 are from (Santhanam et al., 1978).

- Wastewater and solid waste are produced by utility boilers in amounts that are comparable to the amounts produced in other major industries of the United States.

- Presently available control technology is adequate to dispose of both wastewater and solid waste from boilers in environmentally sound ways.

- The cost of pollution control is a function of stringency of control. The scale of the operations involving boilers is such that levels of control, which are set pursuant to the many laws that apply, can have significant impact on the national cost for environmental protection.

SECTION 7

CONCLUSIONS AND RECOMMENDATIONS

The present study has developed data that provide new insights into the contribution of boiler operation to levels of pollution in the United States. The findings suggest that new activities could be undertaken to better protect against present and future pollution. The activities that are suggested fall into the following four categories:

1. Additional information should be collected to fill gaps in the data base describing the boiler population of the United States. This information could be used to confirm and expand on conclusions in this study.

2. Sampling and analysis to better characterize air emissions (especially those of noncriteria pollutants such as sulfates, unburned hydrocarbons, and trace metal compounds) is needed for a number of different types of boilers.

3. Information needed to understand past and future changes in boiler fuel consumption patterns should be collected so that potential adverse environmental impacts associated with fuel switching can be adequately understood.

4. A research and development program should be initiated to address potential environmental problems which have been identified for industrial and commercial boilers.

These four areas of recommended activity are discussed in further detail below.

COLLECT ADDITIONAL DATA ON BOILER POPULATION

Data now available are not adequate for clear definition of all factors that are needed to assess the environmental impacts associated with boiler operation, e.g., the relationship between type of boiler and type of service (space heating, process steam, etc.) is not well established. Also, background on average boiler age and typical use factors is incomplete. The main sources of information on boiler operation are the National Emissions Data System (NEDS) of the U.S. Environmental Protection Agency, the Major Fuel Burning Installation Survey (MFBI) conducted by the Department of Energy in 1975, and the Census of Manufacturers of the Department of Commerce which gives data on energy consumption. All sources of information have known deficiencies that have never been thoroughly evaluated. Since boiler firing consumes more fossil fuel than any other activity (including transportation), efforts to clear up ambiguities in the data base would be worthwhile. Specific activities that could be undertaken to build a more reliable data base include the following:

- Make further detailed cross comparisons between data available from NEDS, MFBI, and the present study to establish the reliability of data from the different sources.
- Contact boiler manufacturers and major users of boilers in industrial and commercial service to collect information on operating and maintenance practices.
- Consult state agencies, insurance companies, and other groups that are concerned with boiler safety to determine whether data are available to cross check information from other sources.

- Work with the American Boiler Manufacturers Association (ABMA) to develop a questionnaire to obtain information needed to fully define the boiler population.

MEASUREMENT OF AIR EMISSIONS

Better data are needed for emissions from all types of boilers. Information on pollutants including direct sulfates, polycyclic organic materials and trace metals is very limited. Several types of boilers appear to need full characterization from the standpoint of air pollutants emissions.

Cast iron and firetube boilers burning distillate oil need to be tested to determine whether poorly maintained commercial and institutional boilers with cyclic and intermittent operation are producing potentially hazardous emissions of unburned hydrocarbons and sulfates.

Cast iron and firetube boilers burning residual oil in commercial service should be characterized giving special attention to unburned hydrocarbons, sulfates, and trace metal emissions.

Stoker-fed coal-fired watertube boilers with capacities in the neighborhood of 25 to 50 x 10^6 Btu/h should be characterized to determine whether a shift to coal from natural gas and oil would increase potential air pollution in small watertube boilers.

FACTORS INFLUENCING FUEL USE PATTERNS

Future fuel use patterns are of obvious importance to potential pollution from boiler operation, e.g., it is important to know whether the use of petroleum based fuels will continue despite efforts to increase coal consumption. Oil burning might continue because production of petroleum fuels is tied to increasing amounts of gasoline consumption or because coal-burning hardware capable of meeting present needs is not available. Also it is important to know more about waste materials being used as boiler fuels. Increasing fuel cost, coupled with increasing difficulty in disposal of materials which are potentially harmful to the environment, is resulting in more burning of materials whose impact on air quality is not understood. At present our understanding of the needs served by boilers and the hardware available is very sketchy except for large watertube boilers. In addition, information on where boilers fit into the overall energy picture is out of date. While the Department of Energy is responsible for generating information on energy use patterns, the U.S. Environmental Protection Agency may need to insure that it has the data base to anticipate future energy related environmental impacts.

FUTURE RESEARCH AND DEVELOPMENT NEEDS

Collection of data of the type described above would permit a more definitive assessment of research and development needs. Some specific projects are, however, apparent from background developed during the present study.

It appears that a low-pollution coal burning boiler is required in the capacity range of 25 to 50 x 10^6 Btu/h. The capability for building such a system with available technology needs to be investigated.

High efficiency burners for combustion of oil in small boilers (less than 10×10^6 Btu/h) would contribute substantially to minimizing potential for environmental impact from boiler operation. The applicability of catalytic combustion for high efficiency and minimum NO_x production appears to be worthy of investigation.

Methods for clean combustion of residual oil appear to be needed. Large amounts are now being burned in a great number of small boilers where the impact of the pollutants produced on the populace is at a maximum. There is a need for more effective means of utilizing petroleum residues which will be with us as long as gasoline is used.

Methods are needed for minimizing the potential pollutants input with the coal fed to small boilers, not amenable to control by other methods. Also, evaluation of the applicability of gasification to produce industrial boiler fuels appears to be needed.

The potential for substitution of electric boilers for those now burning fossil fuels directly, needs to be investigated. Also, the ability to substitute heat pumps for boilers now being used for space heat should be evaluated. Use of electricity from well-controlled central generating stations would minimize pollution from direct combustion in smaller combustion units.

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16. ABSTRACT The report describes the fossil-fuel-fired boiler population of the U.S. It presents data on the number and capacity of boilers for categories most relevant to producing pollution. Information presented includes: type of fuel burned (coal, residual oil, distillate oil, natural gas); usage sector (utility, industrial, commercial); size category (less than 25 million Btu/hr, 25-250 million Btu/hr, greater than 250 million Btu/hr); and heat transfer configuration (water tube, fire tube, cast iron). Fuel consumption data are presented for each type of fuel burned in each usage sector. These data are used to estimate the amount of sulfur oxide, nitrogen oxide, and particulate air emissions produced by boiler operation. Other air pollutants are discussed qualitatively. Solid waste and water pollution from boiler operation is discussed generally.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Dust	Pollution Control	13B	11G
Fossil Fuels	Aerosols	Stationary Sources	21D	07D
Combustion		Particulate	21B	
Boilers			13A	
Fuel Consumption			21K	
Sulfur Oxides			07B	
Nitrogen Oxides				

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