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Control Technology for Fine-Particulate Emissions

Prepared by
Chemical Engineering Department
Manhattan College

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COAL UTILIZATION PROGRAM

ARGONNE NATIONAL LABORATORY

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CONTROL TECHNOLOGY FOR FINE-PARTICULATE EMISSIONS

Prepared by

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The Bronx, New York

for

MASTER

Argonne National Laboratory

October 1978

Work sponsored by
Division of Environmental Control Technology
Assistant Secretary for Environment
United States Department of Energy

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NOTE

Government policy is to use SI (metric units) exclusively or to list both the common British engineering unit and its SI equivalent. However, British units are primarily used in this report for the convenience of the majority of the reading audience. Readers more familiar and at ease with SI units are advised to refer to Appendix A of this report.

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CONTROL TECHNOLOGY FOR FINE-PARTICULATE EMISSIONS

Prepared by

Chemical Engineering Department
Manhattan College

ABSTRACT

This report presents a detailed review and critical evaluation of current control technologies as applied to fine particulate emissions from coal-fired utility boilers. Topics reviewed are: sources and characteristics of coals and fly ash; performance characteristics of various types of coal-fired utility boilers; design, operation, performance and maintenance features of the conventional control devices (electrostatic precipitator, fabric filter baghouse, wet scrubber), and descriptions of (and where available, performance data on) novel control devices.

In addition to the above reviews, the report also includes quantitative assessments of the capabilities of both conventional and novel devices to meet three different performance standards -- the present New Source Performance Standard (NSPS) of 0.1 lb particulate per MBtu heat input, and standards of 0.05 and 0.03 lb particulate per MBtu. Each of the three conventional devices is compared and rated with respect to eight different performance categories. This information is presented in BRAT (Buonicore, Reynolds And Theodore) charts, which can be used to determine the relative effectiveness and attractiveness of these three control devices. The novel devices are compared and rated in the same manner. Because of the lack of experience in commercial application with novel devices, however, the same level of confidence that applies to the BRAT charts for conventional devices does not apply to the novel-device charts.

The major conclusions of the report are: (1) The use of conventional scrubbers for fine particulate control on coal-fired utility boilers will no longer be feasible should a more stringent NSPS be promulgated. (2) At the present NSPS, conventional electrostatic precipitators and baghouses are competitive. For a stricter standard, however, the baghouse will become a more attractive alternative than the precipitator. (3) Novel devices appear to offer almost no hope for this particular application (at a commercial level) between now and 1985 and only little hope before 1990.

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1 THE COAL SCENARIO

In 1976, the total energy consumption in the United States was almost 74,000 trillion Btu (74 Quad).[1] Of this amount, the electrical sector consumed approximately 27%. By the year 2000, this figure is expected to approach 163,500 trillion Btu (163.5 Quad), with the electrical sector consuming almost half.[2] Current installed generating capacity is approximately 550,000 megawatts (MW). This is projected to increase to almost 1,900,000 MW by the year 2000, at an average annual growth rate of 5.4 percent.[2] Net generation is expected to increase at an average annual growth rate of 6.0 percent, to more than 8,650 billion kWh in the year 2000.[2]

The electric utility industry relies on oil, natural gas, coal, hydroelectric and nuclear energy sources for the generation of electric power. Although oil and natural gas currently provide 75% of our energy needs, future availability will reduce this percentage significantly. Hydroelectric power, currently providing about 4% of our energy needs, is not anticipated to expand significantly, primarily because most of the large sites that are readily available have already been developed. Nuclear sources are now providing about three times the amount of energy as electric, but environmental and political considerations make their future somewhat uncertain. At present, coal is providing less than 19% of our energy needs. However, the existence of large quantities of coal reserves places it in a particularly good position for the future. For the utility industry, coal-fired power plants currently generate about 45% of the nation's electricity.[3] Recent projections forecast coal demand by the utilities to increase approximately 5.2% per year through 1990, from the present 485-million-ton consumption rate to more than 860 million tons in 1990.[4]

1.1 COAL RESOURCE BASE

Although coal combustion presently accounts for less than 19% of U.S. energy generation, it makes up more than 90% of our known resources of fossil fuels (coal, petroleum and natural gas). The principal coal fields in the U.S. are shown in Figure 1.1.[3] Total reserves, defined as "that part of the resource for which rank, quality and quantity have been reasonably determined and which is deemed to be minable at a profit under existing market conditions," are estimated to be 437 billion tons.[4] Of this amount, less than half has a sulfur content less than 1% by weight (cf. Figure 1.2).[5-7]

Coal consumption by the electric utilities is presented in Figure 1.3.[8] Approximately 58% of the coal consumed is concentrated in the eight-state region of Michigan, Illinois, Indiana, Ohio, Pennsylvania, Kentucky, West Virginia and Tennessee. Low-sulfur coal is in relatively short supply in the East but is plentiful in the Great Plains. However, burning high-sulfur coal (and using more emission control equipment) is often less expensive than paying the high cost of transporting the low-sulfur coal to the East. The total of identified and hypothetical coal remaining in the ground is estimated at about 3.25 trillion tons. However, many of the deposits are deep and inaccessible, which will substantially reduce the amount practically available. In terms of estimated coal reserves in the United States, the western states account for about 16% of bituminous coal, 81% of sub-bituminous coal, and 98% of lignite. The anthracite deposits are negligible (less than 1%). Eighty percent of estimated sub-bituminous coal reserves and 91% of estimated lignite reserves in the western states contain less than 1% sulfur. The lowest rank coal, lignite, is generally found in western North Dakota and part of eastern Montana. The highest rank surface coal is found in the southwest portions of Arizona and New Mexico. The highest rank underground coal occurs in Utah and Colorado. Wyoming is the leading state in western coal production, followed by Montana and

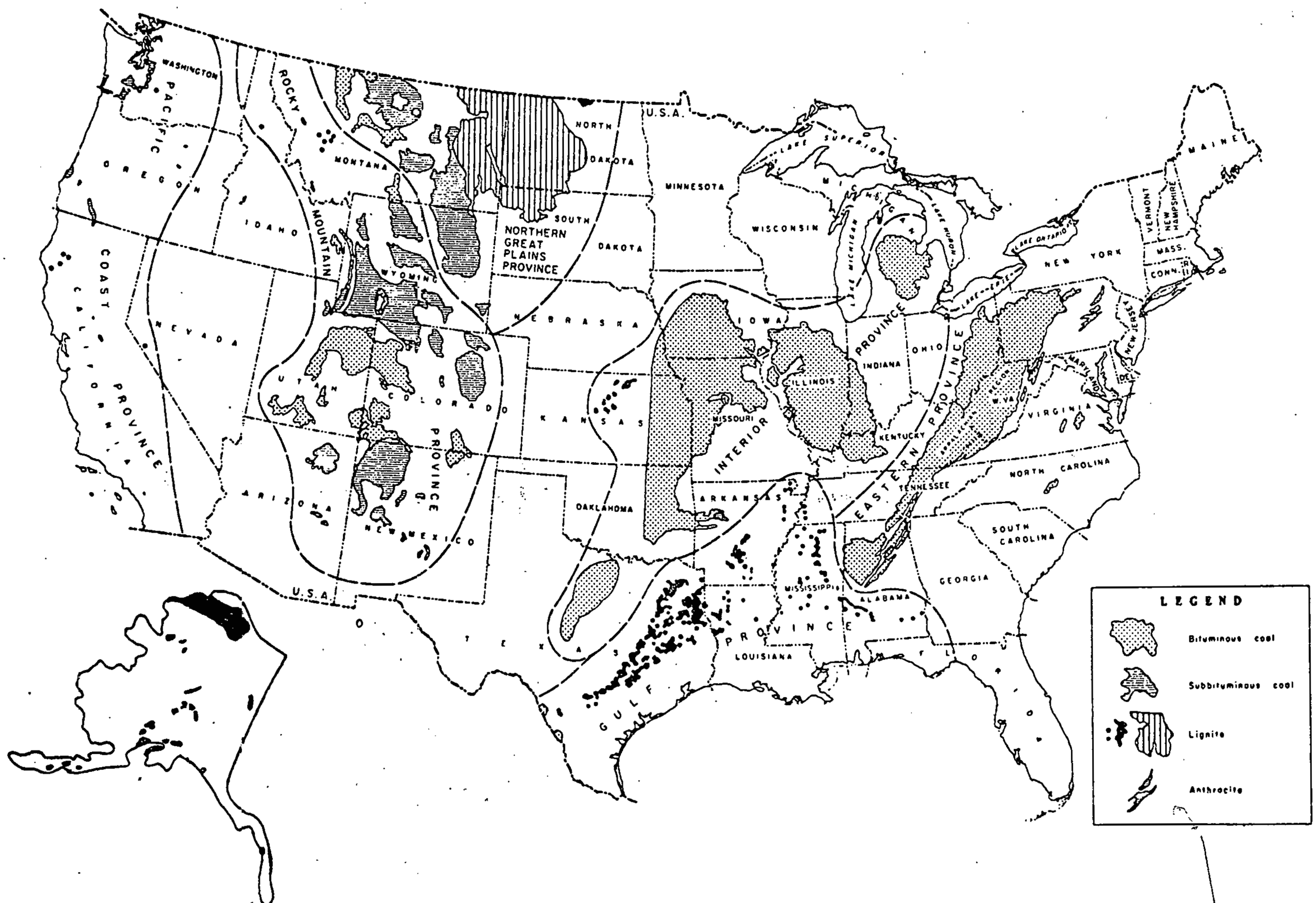


Figure 1.1 Coalfields of the United States (Adapted from U.S. Geological Survey Maps; coal types not distinguished in Alaska).[3]

TOTAL DOMESTIC COAL RESERVES		
SULFUR LEVEL, PERCENT	AMT. COAL AVAILABLE, BILLION TONS	PORTION OF TOTAL COAL RESERVES, PERCENT
<1.0	200.2	46.8
1.1 - 3.0	93.0	21.3
>3.0	92.7	21.2
UNKNOWN	50.8	11.7
TOTAL	436.7	100.0

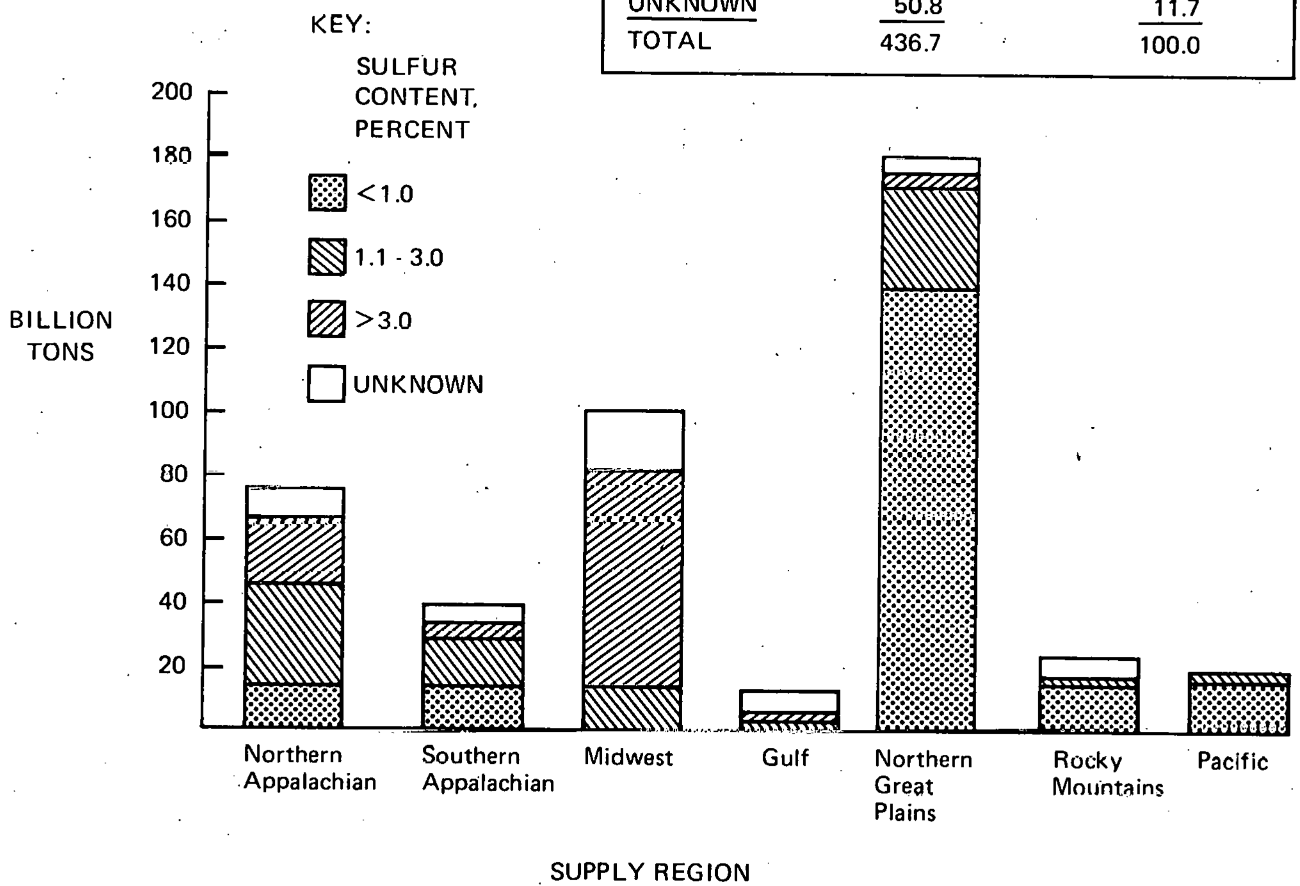


Figure 1.2 U.S. Coal Reserves.[5-7]

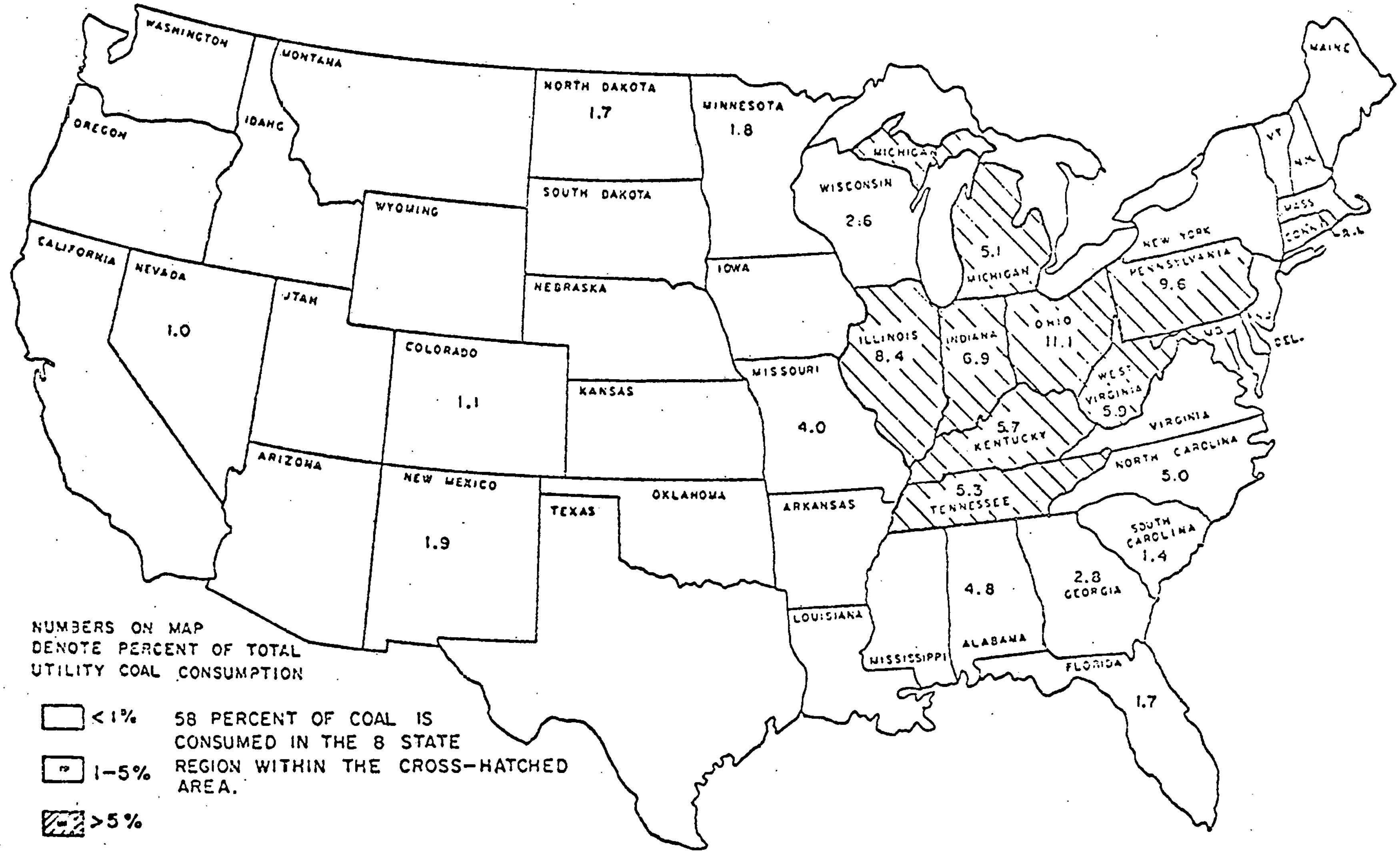


Figure 1.3 Geographical Distribution - Electric Utility Coal Consumption.[8]

New Mexico. Almost 14 million tons were produced in the state of Wyoming in 1973. Montana produced almost 10 million, and New Mexico over 9 million, tons in the same year. The western states' coal production estimates indicate that the production will increase about 8.6 times between 1972 and 1985. Approximately 70% of the western coal produced remained in western producing districts.

Considering overall ranges for coal properties, the western coals are in the medium range of volatile matter, in the lower range for fixed carbon, in the higher range for moisture content, in the lower range for caloric values, and in the lower range of sulfur content. Comparison of ash compositions in western coals and eastern coals reveals that low-sulfur-containing western coals are also low in iron. However, generally higher SO_3 content in the ash is observed with western coals. The western coals are also 2 to 4 times higher in average calcium and magnesium, and 2 to 8 times lower in average potassium content. Sodium content does not seem to follow any particular trend, with the exceptions of North Dakota and Montana coals, which have relatively high sodium contents of 4.4% and 2.8%, respectively. Other U.S. coals range in average sodium content between 0.1 and 1.7% as Na_2O. Total trace element content in western coals is nearly the same as in other coals of the United States, but the distribution of each element differs.

The reserves of the various states, divided by sulfur content, are shown in Table 1.1.[10]

1.2 COAL CLASSIFICATION

Coals are ranked according to their degree of progressive conversion, from low-carbon-content lignite to high-carbon-content anthracite (cf. Table 1.2[11]). Lignite, a brown coal in which the original structure of the wood is still recognizable, contains between 25 and 45% carbon; sub-bituminous and bituminous coals

Table 1.1 Estimated Remaining Coal Reserves of the United States by Rank, Sulfur Content, and State, on January 1, 1965[10]

Coal Rank & State	(Million Short Tons) Sulfur Content Percent 0.7 or Less	0.8-1.0	1.1-1.5	1.6-2.0	2.1-2.5	2.6-3.0	3.1-3.5	3.6-4.0	Over 4.0	Total
Bituminous Coal:										
Alabama	889.2	1,189.3	5,421.7	5,182.8	458.8	417.4	---	---	18.6	13,577.8
Alaska	20,287.4	1,100.0	---	---	---	---	---	---	---	21,387.4
Arkansas	---	---	1,128.4	293.1	154.0	---	40.3	---	---	1,615.8
Colorado	25,178.3	37,237.2	---	---	---	---	---	---	---	62,415.5
Georgia	---	76.0	---	---	---	---	---	---	---	76.0
Illinois	---	573.7	4,942.4	2,615.1	809.6	16,583.8	33,650.4	57,652.2	19,062.0	135,889.2
Indiana	197.5	173.0	3,645.2	4,248.8	3,543.4	4,110.5	10,872.8	5,105.5	2.944.0	34,841.1
Iowa	---	---	---	---	---	---	117.1	---	6,405.4	6,522.5
Kansas	---	---	519.7	519.7	1,038.7	2,070.6	4,148.0	8,287.3	4,153.8	20,738.0
Kentucky										
West	---	---	1,119.6	162.0	336.3	3,793.6	12,759.3	13,643.3	5,081.3	36,895.4
East	13,639.9	8,491.9	2,286.8	1,658.8	1,158.3	2,154.4	24.7	---	---	29,414.8
Maryland	---	---	---	124.6	191.8	208.2	378.6	56.4	220.4	1,180.0
Michigan	---	---	---	---	---	---	---	205.0	---	205.0
Missouri	---	---	---	---	---	---	6,456.7	20,669.2	51,634.1	78,760.0
Montana	51.2	218.2	205.0	397.2	400.0	175.0	40.0	27.0	591.0	2,104.6
New Mexico	5,212.0	5,474.0	---	---	---	---	---	---	---	10.686.0
North Carolina	---	---	---	---	---	110.0	---	---	---	110.0
Ohio	---	611.0	369.0	2,110.2	2,750.4	7,810.5	9,785.3	10,148.2	8,439.4	41,024.0
Oklahoma	250.6	772.2	825.0	368.1	---	---	577.2	19.1	490.6	3,302.8
Oregon	---	14.0	---	---	---	---	---	---	---	14.0
Penn.	44.0	1,154.4	7,624.4	12,424.9	19,689.5	9,995.6	5,287.6	1,150.5	580.6	57,951.5
Tennessee	3.3	160.9	715.9	258.7	178.2	190.5	219.7	43.6	68.5	1,839.5
Texas	---	---	---	---	7,978.0	---	---	---	---	7,978.0
Utah	8,551.4	13,584.0	---	1,524.9	---	---	---	---	3,997.7	27,658.0
Virginia	1,981.5	6,077.5	1,637.1	---	123.9	---	---	---	---	9,820.0
Washington	898.9	672.1	---	---	---	---	---	---	---	1,571.0
West Va.	20,761.0	26,710.6	21,819.7	13,290.6	8,496.1	2,491.8	3,147.4	5,949.2	---	102,666.4
Wyoming	6,222.2	6,596.6	---	---	---	---	---	---	1.1	12,819.9
Other States[a]	---	616.0	---	---	---	---	---	---	---	616.0
Total	104,168.4	111,502.6	52,260.1	45,179.5	47,307.0	50,111.9	87,505.1	122,957.1	103,888.5	724,680.2
Percent Of Total	14.4	15.4	7.2	6.2	6.5	6.9	12.1	17.0	14.3	100.0
Subbituminous Coal:										
Alaska	71,115.6	---	---	---	---	---	---	---	---	71,115.6
Colorado	13,320.8	4,908.7	---	---	---	---	---	---	---	18,229.5
Montana	94,084.4	36,728.0	0.5	1,303.7	---	---	---	---	---	132,116.6
New Mexico	38,735.0	12,000.0	---	---	---	---	---	---	---	50,735.0
Oregon	87.0	87.0	---	---	---	---	---	---	---	174.0
Utah	---	---	150.0	---	---	---	---	---	---	150.0
Washington	3,693.8	500.0	---	---	---	---	---	---	---	4,193.8
Wyoming	35,579.7	72,315.6	---	---	---	---	---	---	8.6	107,503.9
Other States[b]	---	4,047.0	---	---	---	---	---	---	---	4,047.0
Total	256,616.3	130,586.3	150.5	1,303.7	---	---	---	---	8.6	388,665.4
Percent Of Total	65.0	33.6	0.1	0.3	---	---	---	---	(c)	100.0
Lignite:										
Alabama	---	---	20.0	---	---	---	---	---	---	20.0
Arkansas	280.0	70.0	---	---	---	---	---	---	---	350.0
Montana	60,214.5	24,141.6	2,660.9	---	---	464.7	---	---	---	87,481.7
No.Dakota	284,129.1	34,987.3	31,581.6	---	---	---	---	---	---	350,698.0
So.Dakota	---	2,031.0	---	---	---	---	---	---	---	2,031.0
Texas	---	---	6,902.0	---	---	--	---	---	---	6,902.0
Washington	---	116.6	---	---	---	---	---	---	---	116.6
Other States[d]	---	42.0	---	---	---	---	---	---	---	42.0
Total	344,623.6	61,388.5	41,164.5	---	---	464.7	---	---	---	447,641.3
Percent Of Total	77.0	13.7	9.2	---	---	0.1	---	---	---	100.0
Anthracite:										
Alaska	2,101.0	---	---	---	---	---	---	---	---	2,101.0
Arkansas	---	---	---	145.5	286.3	---	---	---	---	431.8
Colorado	---	90.0	---	---	---	---	---	---	---	90.0
New Mexico	---	6.0	---	---	---	---	---	---	---	6.0
Penn.	12,211.0	---	--	---	---	---	---	---	---	12,211.0
Virginia	335.0	---	---	---	---	---	---	---	---	335.0
Washington	5.0	---	---	---	---	---	---	---	---	5.0
Total	14,652.0	96.0	---	145.5	286.3	---	---	---	---	15,179.8
Percent Of Total	96.5	0.6	---	0.9	2.0	---	---	---	---	100.0
Grand Total	720,060.3	303,573.4	93,575.1	46,628.7	47,593.3	50,576.6	87,505.1	122,957.1	103,097.1	$1.58x10^6$
Percent Of Total	45.7	19.3	5.9	3.0	3.0	3.2	5.5	7.8	6.6	100.0

[a] Arizona, California, Idaho, Nebraska, Nevada

[b] Arizona, California, Idaho

[c] Less than 0.1 percent

[d] California, Idaho, Louisiana, Nevada

Table 1.2 Classification of Coals by Rank[a]

Class	Group	Fixed Carbon Limits Per Cent (Dry, Mineral-Matter-Free Basis) Equal or Greater Than	Fixed Carbon Limits Per Cent (Dry, Mineral-Matter-Free Basis) Less Than	Volatile Matter Limits Per Cent (Dry, Mineral-Matter-Free Basis) Greater Than	Volatile Matter Limits Per Cent (Dry, Mineral-Matter-Free Basis) Equal or Less Than	Calorific Value Limits Btu per pound (Moist,[b] Mineral-Matter Free Basis) Equal or Greater Than	Calorific Value Limits Btu per pound (Moist,[b] Mineral-Matter Free Basis) Less Than	Agglomerating Character
1. Anthracitic	1. Meta-anthracite..	98	...	...	2	...	...	...
	2. Anthracite.......	92	98	2	8	...	...	...
	3. Semianthracite...	86	92	8	14	...	...	Nonagglomerating[e]
11. Bituminous	1. Low volatile bituminous coal......	78	86	14	22	...	...	
	2. Medium volatile bituminous coal..	69	78	22	31	...	...	
	3. High volatile A bituminous coal..	...	69	31	...	14 000[c]	...	Commonly agglomerating[e]
	4. High volatile B bituminous coal..	...	...	...	...	13 000[c]	14 000	
	5. High volatile C bituminous coal..	...	...	...	...	11 500	13 000	
						10 500	11 500	Agglomerating
111. Subbituminous	1. Subbituminous A coal............	...	...	...	...	10 500	11 500	Nonagglomerating[e]
	2. Subbituminous B coal...........	...	...	...	...	9 500	10 500	...
	3. Subbituminous C coal..........	...	...	...	...	8 300	9 500	...
1V. Lignitic	1. Lignite A......	...	...	...	...	6 300	8 300	...
	2. Lignite B......	...	...	...	...	...	6 300	...

[a]This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high-volatile bituminous and subbituminous ranks. All these coals either contain less than 48 percent dry, mineral-matter-free fixed carbon or have more than 15,500 moist, mineral-matter-free British thermal units per pound.

[b]Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

[c]If agglomerating, classify in low-volatile group of the bituminous class.

[d]Coals having 69 percent or more fixed carbon on the dry mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

[e]It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are notable exceptions in the high volatile C bituminous group

range from 40 to 80% carbon; anthracite, a bright, lustrous, hard, brittle mineral coal, may contain in excess of 90% carbon. The ASTM ranking classifications given in Table 1.2 show that sub-bituminous coals have a Btu-per-pound range from 8300 to 11,500 on a moisture- and mineral matter-free basis. Lignite ranges from below 6300 to 8300 Btu per pound.

Figure 1.4[9] is a graphical representation of all coals and indicates that sub-bituminous coals have lower fixed carbon and higher inherent moisture contents than higher ranking bituminous and anthracite coals. State-wide values for coal composition, heating value, ash softening temperature, rank index and ash analysis are presented here. Table 1.3[10] shows representative minimum, maximum and average values of coal characteristics for 20 states, including 8 western states. Rank Index is included and is defined as:

$$\text{RI} = \text{Rank Index} = \frac{\text{Btu (dry basis)}}{\text{Volatile matter (dry basis)} \times 10}$$

Moisture and Btu values given are "as received." All other properties are on a dry basis. Averages are arithmetic estimates from available data.

1.3. ENVIRONMENTAL IMPLICATIONS OF COAL USE

The potential environmental problems associated with the extraction, processing, transportation, distribution and ultimate combustion of coal are more significant than those associated with the other fossil fuels. Coal presents significant environmental problems during the mining stage. Its conversion to heat has an even more significant impact on the environment, because it is accompanied by the production of several undesirable by-products.

Coal systems are based on either surface or underground mining. The last complete survey of mining operations in the U.S. indicated that about 3.2 million acres of land had been disturbed by surface mining. Of this total, approximately

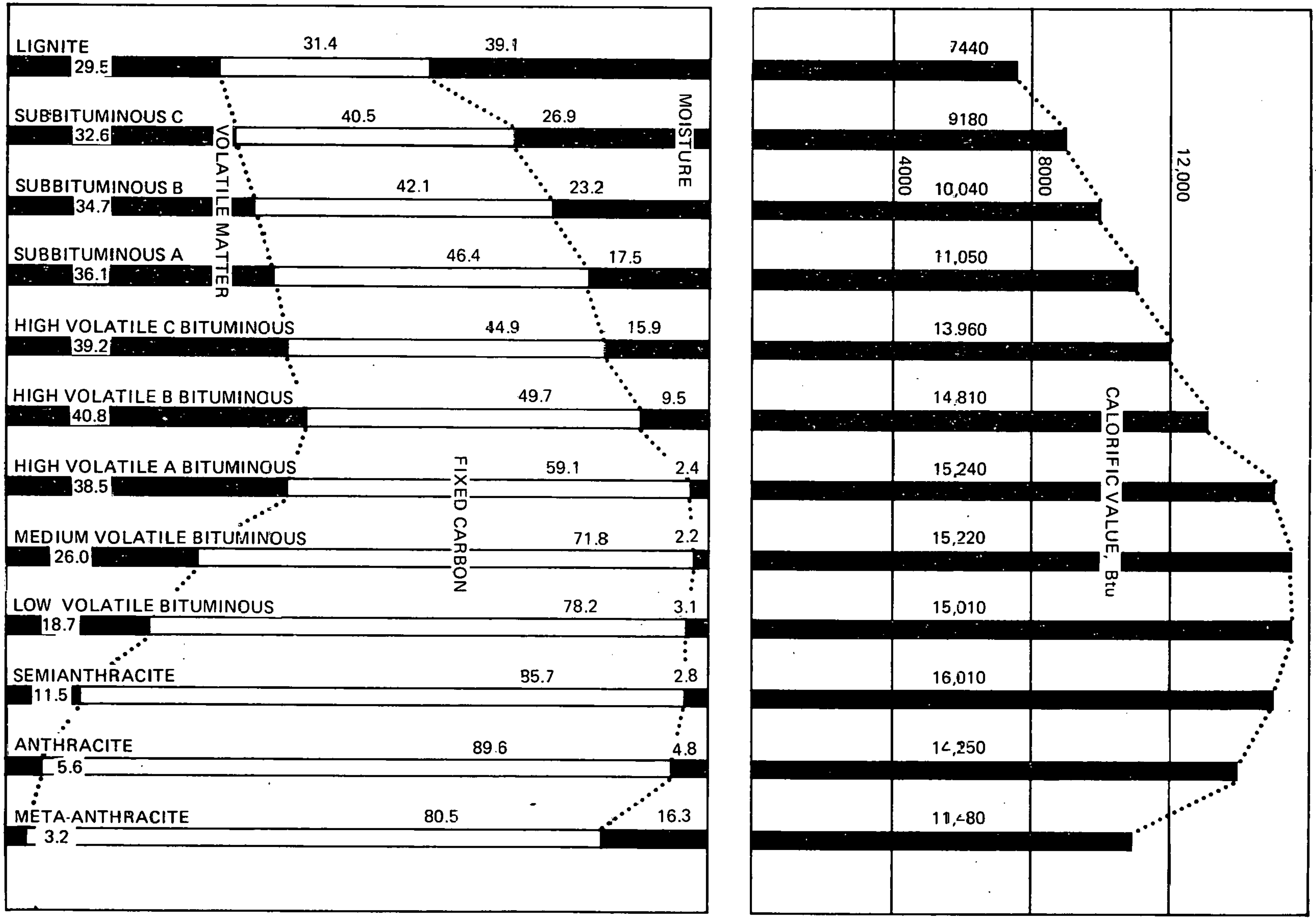


Figure 1.4 Analysis of United States Coals Selected to Represent the Various Ranks.[9]

Table 1.3 Range of Coal Characteristics[10]

State		Mois-ture	Volatile Matter	Fixed Carbon	Ash	S	H	C	N	O	Btu	Ash Softening Temperature	Rank Index
Alabama	Min.	2.9	29.7	51.9	2.5	0.6	---	---	---	---	12160	2130	33.0
	Ave.	4.7	37.7	55.9	6.1	1.2	4.9	76.9	1.8	8.7	13280	2320	36.3
	Max.	12.5	42.0	62.7	14.6	2.0	---	---	---	---	14150	2680	45.7
Arizona	Ave.	11.7	44.4	47.1	8.5	0.4	5.1	70.3	1.1	14.6	10900	----	24.5
Colorado	Min.	4.6	37.2	46.6	5.1	0.3	---	---	---	---	10730	2260	24.7
	Ave.	12.9	39.6	51.8	8.6	0.6	---	---	---	---	11050	----	27.4
	Max.	22.5	43.3	56.1	14.6	1.1	---	---	---	---	11270	2910+	32.2
Illinois	Min.	4.8	35.3	44.5	6.1	1.5	---	---	---	---	10000	2000	24.3
	Ave.	10.5	41.0	49.9	9.1	2.8	---	---	---	---	11780	2090	28.9
	Max.	21.9	47.4	55.7	11.5	4.3	---	---	---	---	12810	2180	35.1
Indiana	Min.	8.0	38.1	44.4	7.7	1.1	---	---	---	---	10670	2000	24.8
	Ave.	11.4	42.7	47.5	9.8	3.2	---	---	---	---	11540	2330	26.9
	Max.	19.0	45.3	52.4	11.6	4.5	---	---	---	---	12370	2700	31.0
Iowa	Min.	9.6	38.1	32.3	13.1	2.5	4.0	52.6	0.9	4.3	8350	1910	22.3
	Ave.	15.6	40.9	41.0	18.1	4.5	4.5	62.0	1.3	6.6	9580	2060	23.7
	Max.	19.2	48.1	46.6	29.6	10.0	4.9	68.7	1.6	8.9	10970	2200	24.9
Kansas	Min.	3.6	36.6	48.3	8.5	2.3	4.9	72.0	---	3.1	8350	1980	30.7
	Ave.	4.6	38.5	50.5	11.0	3.8	5.0	72.6	1.2	3.7	9580	2020	33.2
	Max.	5.8	40.6	53.0	11.3	4.8	5.1	73.3	---	4.3	10970	2070	35.5
Kentucky	Min.	2.0	33.6	48.2	3.6	0.6	5.3	---	---	---	11210	2130	27.7
	Ave.	6.1	39.2	54.3	7.8	2.2	5.4	79.5	1.6	7.2	12800	2410	31.8
	Max.	14.9	45.1	60.7	17.7	3.9	5.5	---	---	---	14150	2800	42.2
Missouri	Min.	11.1	43.7	46.7	6.9	---	---	---	---	---	11390	2020	25.7
	Ave.	12.1	44.0	47.1	8.9	4.1	---	---	---	---	11530	2030	26.2
	Max.	13.2	44.3	47.4	9.0	---	---	---	---	---	11680	2050	26.7
Montana	Min.	8.0	33.0	44.0	7.0	0.4	---	---	---	---	7290	2380	17.4
	Ave.	25.4	38.2	51.1	10.7	1.0	4.5	68.1	1.0	14.7	8680	2430	22.7
	Max.	43.0	42.0	58.0	16.0	2.3	---	---	---	---	11030	2490	33.4
New Mexico	Min.	11.7	44.1	46.6	7.1	---	---	---	---	---	-----	2080	24.5
	Ave.	12.7	44.2	47.6	8.2	0.7	5.2	70.9	1.3	12.6	10790	----	25.4
	Max.	13.7	44.3	48.6	9.3	---	---	---	---	---	-----	2910+	26.2
North Dakota	Min.	33.3	40.1	46.8	7.9	0.4	---	---	---	---	-----	1990	15.2
	Ave.	35.1	41.9	48.3	9.8	0.7	---	---	---	---	6700	2240	16.9
	Max.	38.6	44.2	49.2	13.1	1.0	---	---	---	---	-----	2520	18.2
Ohio	Min.	3.2	39.1	45.3	6.1	2.1	---	---	---	---	11340	----	27.1
	Ave.	5.9	41.8	49.7	9.4	2.7	5.1	74.5	1.5	6.2	12560	----	30.1
	Max.	8.2	45.2	54.1	13.6	3.2	---	---	---	---	13440	----	34.0
Oklahoma	Min.	1.0	39.4	47.9	7.1	---	---	---	---	---	12730	----	29.8
	Ave.	3.5	42.2	48.7	9.0	3.5	1.5	76.8	1.5	5.6	13070	----	31.1
	Max.	5.0	45.0	49.6	11.0	---	---	---	---	---	13420	----	32.3
Pennsylvania	Min.	1.0	16.0	46.3	5.8	0.7	4.9	73.7	1.1	4.8	10750	2020	30.9
	Ave.	3.7	33.4	57.0	9.6	2.3	5.1	76.7	1.4	5.6	13020	2410	45.7
	Max.	12.0	41.4	77.0	21.0	8.1	5.4	79.5	1.5	6.9	14420	2910+	88.9
Tennessee	Min.	1.8	29.0	51.8	10.0	0.6	---	----	---	---	12370	2080	35.1
	Ave.	3.0	31.0	57.3	11.7	1.0	4.9	73.5	1.8	7.2	12870	2460	40.0
	Max.	3.8	36.8	61.0	14.6	1.2	---	----	---	---	13350	2910+	46.0
Utah	Min.	2.8	40.5	44.4	5.7	0.3	---	---	---	---	11370	2110	26.8
	Ave.	5.3	45.2	50.1	7.3	0.5	---	---	---	---	11430	2250	28.7
	Max.	8.7	47.0	53.5	13.6	0.8	---	---	---	---	12850	2420	31.7
Washington	Min.	4.8	38.0	46.0	15.6	0.3	---	---	---	---	11630	2590	30.6
	Ave.	5.0	38.0	46.2	15.8	0.3	---	---	---	---	11670	----	30.7
	Max.	5.2	38.0	46.4	16.0	0.4	---	---	---	---	11720	2910+	30.8
West Virginia	Min.	1.5	29.1	53.0	2.8	0.6	4.3	73.1	1.2	1.9	11930	2070	33.3
	Ave.	3.6	36.4	56.7	7.9	1.0	5.1	80.0	1.5	5.3	13130	2540	38.0
	Max.	8.5	40.4	65.6	16.5	1.6	7.0	86.6	1.8	7.9	14390	2910+	49.9
Wyoming	Min.	15.5	41.7	47.1	3.5	0.5	---	---	---	---	9540	----	22.3
	Ave.	20.1	43.4	50.8	5.7	0.8	5.0	72.1	1.6	14.1	10140	2450	22.9
	Max.	23.0	46.4	54.2	7.9	1.0	---	---	---	---	10700	----	23.7

41 percent resulted from activities associated with coal production.[12] Although the total land area directly disturbed by surface mining amounts to only a few tenths of one percent nationally, the effects are often severe in the immediate and adjacent areas. Surface mining often leads to acid mine drainage and silt runoff in these areas, both of which degrade water quality. It can result in serious erosion if adequate plant cover is not available to hold down the soil, especially when water is permitted to run off the site from roads, terrace outlets, out slopes, or slides. Erosion deposits sediment in channels and reduces a lowland stream bed's capacity to carry flood waters. Silt can smooth the gravel which provides spawning grounds for certain species of fish. Surface mining has contributed to landslides and floods, degraded fish and wildlife habitats, impaired scenic values and counteracted efforts to conserve soil, water, and other natural resources.

Underground mining can also have an adverse impact on the environment. It often results in acid drainage and can cause land subsidence over mined-out areas unless mining systems are designed to prevent the deterioration and failure of abandoned-mine pillars. Approximately 1,850,000 acres of land in the U.S. have been affected by subsidence -- and almost all due to the underground mining of coal.[12] Acid mine drainage from underground mines is more difficult to control than that from surface mines; however, preventing water from entering the mine and the rapid removal of water that seeps into the mine have proven effective methods for reducing water pollution. Acid mine drainage can also be effectively reduced by neutralization of the mine water before it is discharged to the streams; however, this can be expensive. Underground mining is also a dangerous occupation, resulting in a high rate of fatalities, injuries and disease.

Erosion and sedimentation caused by either type of coal mining can be reduced by controlling the surface runoff that follows rainstorms. A significant amount of damage can also be prevented through proper land reclamation, adequate drainage, and planting to achieve soil stabilization.

Approximately 30 percent of all coal is not mechanically cleaned but is transported directly from the mine to the user.[12] The remaining coal is washed to reduce the inorganic and ash content, producing approximately 90 million tons of waste annually.[12] If not returned to the mine, this waste accumulates in piles near the plant and mine and may, at times, become ignited and burn for long periods, thus creating an air pollution problem. Rainwater can also leach salts and acid from the piles to contaminate nearby streams.

Most coal moves to power plants by rail, with a considerable amount of land devoted to railroad rights-of-way. A typical 1000-MW coal-fired power plant requires approximately 120 carloads of coal every 24 hours.

At the power plant the coal is burned to produce electricity, causing several pollution problems. Depending on the characteristics of the coal, a 1000-MW power plant, if uncontrolled, emits large quantities of air pollutants -- primarily sulfur oxides, nitrogen oxides and particulates, as well as toxic trace elements -- and thermal discharges to the water. The solid waste produced from the utilization of coal is in the form of ash and slag.

1.4 PARTICULATES AND TRACE ELEMENTS FROM COAL-FIRED POWER PLANTS

The combustion of coal produces particulate air pollutants, which range in size from less than 1 micron to hundreds of microns. The larger particles are efficiently removed in the emission control system. Unfortunately, the smaller sized particles (less than a few microns) are more difficult to capture. It is these "fine particulates" that have been associated with adverse health effects. These fine particulates can bypass the body's respiratory filters and penetrate deeply into the lungs. When released into the atmosphere, they can remain airborne for extended periods of time, obstruct light and cause limited visibility. They have also been identified as transport vehicles for gaseous pollutants.

Particulates from the combustion process also provide the means by which trace elements in the coal are transferred to the atmosphere. When traces of these heavy metal elements condense on the surfaces of the fine particulates, these particles serve as effective carriers for the elements, some of which are toxic and can give rise to serious health effects.

1.4.1 Fine Particulates and Health

Airborne particulates, when inhaled, are deposited in different regions of the body depending on their aerodynamic size. This behavior is illustrated for three compartments of the respiratory system in Figure 1.5.[13] From a toxicological standpoint, the smallest particles (less than 1 micron), which deposit in the pulmonary region of the respiratory tract, are of the greatest concern. This is because the efficiency of extraction (by the blood stream) of toxic species from particles deposited in the pulmonary region is high (60-80%), whereas the extraction efficiency from the larger particles which deposit in the nasopharyngeal and tracheobronchial regions (and are subsequently removed to the pharynx by cilial action and swallowed) is low (5-15%).[14-17] Consequently, toxic species, which are carried predominantly by particles in the submicron size range, have easier access to the blood stream than material carried by the larger particles.

Clearly, the effective toxicity of respirable particles will depend upon the nature of the toxic species present, on its size distribution in the aerosol, and on the efficiency with which it is extracted in the region of respiratory deposition.

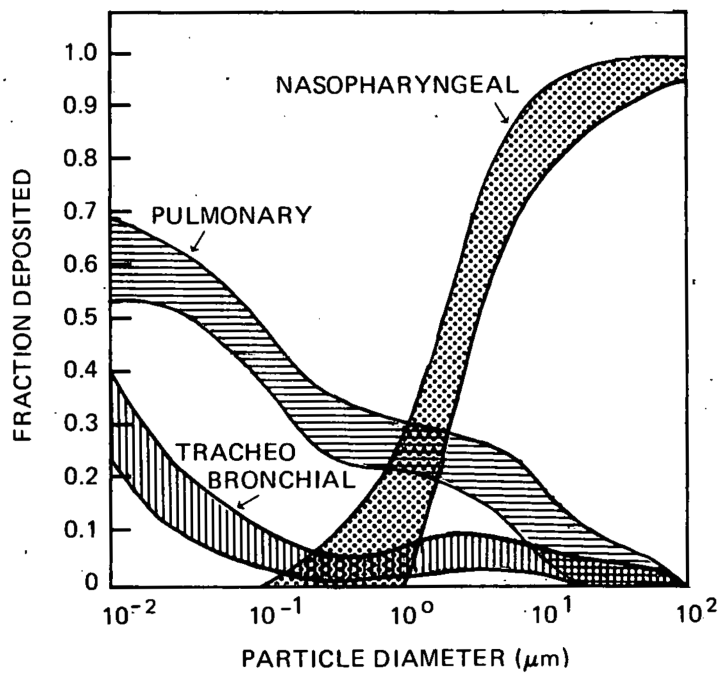


Figure 1.6 Efficiency of Particle Deposition in the Three Respiratory System Compartments.[13]

1.4.2. *Trace Elements in Coal-Fired Boilers*

On combustion, the trace elements in coal are transferred to slag, fly ash, or gases and are discharged to the environment. After these elements enter the boiler in the coal stream, they are first partitioned between a bottom ash (or slag) stream, and a flue gas stream containing suspended fly ash and the vapors of volatile elements or compounds. A further partitioning of the flue gas stream takes place in the particulate emission control devices -- electrostatic precipitators, fabric filters or scrubbers -- that easily remove the large fly ash particles but allow vapors and many of the finer particles to remain in the gas stream.

The concentration (mass of trace element per mass of particulate) levels of such toxic trace elements as Sb, As, Be, Cd, F, Pb, Hg, Se, Tl, and V have been shown to be two to three orders of magnitude greater in urban aerosols (0.1 to 10 μm) than in the earth's crust.[18,19] Because the trace elements are concentrated largely on the surfaces of fly ash particles from which they may be readily desorbed following inhalation, trace element emissions from coal combustion pose a potential health hazard.

Almost every naturally occurring element has been detected in coal. Trace elements typically found in U.S. coal ash from all regions are Ba, Be, B, Cd, Cr, Co, Cu, F, Ga, Ge, La, Pb, Li, Mn, Hg, Mo, Ni, Sc, Se, Sr, Sn, V, Yb, Zn and Zr. Also present on a less widespread basis are As, Bi, Ce, Nd, Nb (Cb), Rb and Tl.

Trace element contents in coal ash for three areas of the U.S. are shown in Table 1.4.[20, 21] Table 1.5[22] shows the average trace element concentrations of the ashes obtained from various U.S. coals. Various trace elements found in American coals and ashes from these coals are shown in Tables 1.6 and 1.7[22] With

Table 1.4 Average Trace Element Content in Ash of Coal from Three Areas, as Weight Percent*[20, 21]

Element	Crustal	Approximate Lower Limit Of Detection	Eastern Province		Interior Province		Western States	
			Frequency Of Detection	Average Trace Element Content Of Ash	Frequency Of Detection	Average Trace Element Content Of Ash	Frequency Of Detection	Average Trace Element Content Of Ash
Barium	0.0425	0.002	100	0.0876	100	0.0399	100	0.1467
Beryllium	.00028	.0001	100	.0012	100	.0014	100	.0006
Boron	.0010	.0002	100	.0265	100	.0731	100	.0529
Chromium	.0100	.0001	100	.0230	100	.0224	100	.0066
Cobolt	.0025	.0020	100	.0184	98	.0193	98	.0097
Copper	.0055	.0001	100	.0128	100	.0089	100	.0047
Gallium	.0015	.0002	100	.0071	100	.0039	100	.0033
Germanium	.00015	.0003	99	.0048	100	.0104	95	.0017
Lanthanum	.0030	.01	92	.0145	86	.0131	81	.0128
Lead	.0013	.0001	100	.0055	100	.0131	100	.0029
Lithium	.0020	.0001	100	.0584	100	.0235	100	.0168
Manganese	.0950	.0001	100	.0260	100	.0325	100	.0212
Molybdenum	.00015	.0001	99	.0082	99	.0073	100	.0020
Nickel	.0075	.0001	100	.0209	100	.0262	100	.0054
Scandium	.0022	.002	100	.0089	100	.0069	97	.0052
Strontium	.0375	.001	100	.1052	100	.0658	100	.1456
Tin	.0002	.0001	100	.0019	99	.0019	100	.0017
Vanadium	.0135	.0001	100	.0336	100	.0325	100	.0152
Ytterbium	.00034	.0001	100	.0007	100	.0005	100	.0003
Yttrium	.0033	.001	100	.0142	100	.0118	100	.0076
Zinc	.0070	.005	98	.0230	100	.0743	93	.0258
Zirconium	.0165	.005	100	.0704	100	.0825	100	.0850
Arsenic	.00018	.005	67	.0159	41	.0119	16	.0073
				(.0107)		(.0049)		(.0012)
Bismuth	.0002	.0001	82	.0002	77	.0001	83	.0001
				(.0002)		(.0001)		(.0001)
Cerium	.0060	.02	31	.0238	11	.0214	13	.0238
				(.0074)		(.0024)		(.0031)
Neodymium	.0028	.01	29	.0213	10	.0183	15	.0295
				(.0062)		(.0018)		(.0044)
Niobium	.0020	.001	73	.0053	88	.0055	85	.0053
(Columbium)				(.0039)		(.0048)		(.0045)
Rubidium	.0090	.001	97	.0239	100	.0276	58	.0064
				(.0232)		(.0276)		(.0037)
Thallium	.0005	.0005	43	.0019	49	.0008	9	.0005
				(.0008)		(.0004)		(.00005)
Average Trace Element, % of Ash				.6651		.6568		.6466
Average Ash, % of Dry Coal				10.5				9.8
Average Trace Element, % of Dry Coal				.0618		.0690		.0634
Number of Samples				600		123		104

* Averages calculated for number of samples in which element was detected, except that averages in parentheses were calculated for all of the samples tested using zero for element contents below limit of detection.

Table 1.5 Average Trace-Element Contents of the Ash from U.S. Coals of Various Rank[a] [22]

Element	Anth[b]	LVB[c]	MVB[d]	HVB[e]	L(SB)[f]
Ag	<1	<1	<1	<1	<1
B	90	123	218	770	1010
Ba	866	740	896	1253	5027
Be	9	16	13	17	6
Co	81	172	105	64	45
Cr	304	221	169	193	54
Cu	405	379	313	293	655
Ga	42	41		40	23
Ge	<20	<20			
La	142	110	83	111	62
Mn	270	280	1432	120	688
Ni	220	141	263	154	129
Pb	81	89	96	183	60
Sc	61	50	56	32	18
Sn	962	92	75	171	156
Sr	177	818	668	1987	4660
V	248	278	390	249	125
Y	106	152	151	102	51
Yb	8	10	9	10	4
Zn		231	195	310	
Zr	688	458	326	411	245

[a]ppm by weight
[b]Anth=Anthracite.
[c]LVB=low-volatile bituminous.
[d]MVB=medium-volatile bituminous.
[e]HVB=high-volatile bituminous.
[f]L(SB)=lignite (subbituminous).

Table 1.6 Range of Trace Elements in U.S.Coals[a] [22]

Major Elements[b]

Element	Range (%)	
Na	0	- 0.20
Mg	0.1	- 0.25
Al	0.43	- 3.04
Si	0.58	- 6.09
Cl	0	- 0.56
K	0.02	- 0.43
Ca	0.05	- 2.67
Ti	0.002	- 0.32
Fe	0.32	- 4.32
Zn[c]	0	- 0.56

Minor Elements

Element	Range (ppm by weight)	
Be	0	- 31
B	1.2	- 356
F	10	- 295
P	5	-1430
Sc	10	- 100
V	0	-1281
Cr	0	- 610
Mn	6	- 181
Co	0	- 43
Ni	0.4	- 104
Cu	1.8	- 185
Ga	0	- 61
Ge	0	- 819
As	0.5	- 106
Se	0.4	- 8
Br	4	- 52
Y	<0.1	- 59
Zr	8	- 133
Mo	0	- 73
Cd	0.1	- 65
Sn	0	- 51
Sb	0.2	- 9
La	0	- 98
Hg	0.01	- 1.6
Pb	4	- 218
U	<10	-1000

[a]References used were Ruch et al. (1974), Abernethy and Gibson (1962), Zubovic et al. (1961-1967), Sun et al. (1971) and Magee et al. (1973). (Data by Deul and Annell in these references have been omitted.)

[b]Elements present in 0.2% in coals.

[c]Zinc is not normally considered a major element in coals.

Table 1.7 Range of Trace-Element Concentrations in Ashes from U.S. Coals[a] [22]

Major Elements[b]		Minor Elements	
Element	Range (%)	Element	Range (ppm by weight)
Na	0.71 - 2.72	Li	<20 - 3100
Mg	0. - 2.4	Be	0 - 1100
Al	5.3 -21.2	B	30 - 6500
Si	9.3 -28	P	<440 - 3360
K	0.66 - 1.32	Sc	2 - 155
Ca	0.58 -14	V	6 - 3800
Ti	0.1 - 2.6	Cr	<1 - 1800
Fe	2.09 -24.4	Mn	30 - 1800
Zn[c]	0. - 1.6	Co	0 - 600
Sr	0.009- 0.96	Ni	0 - 1200
Ba	0.01 - 1.39	Cu	10 - [illegible]
		Ga	0 - 540
		Ge	0 - 1500
		As	21 - 570
		Rb	<91 - 1100
		Y	0 - 620
		Zr	100 - 1450
		Mo	0 - 2900
		Ag	<1 - 84
		Sn	0 - 4250
		Sb	<40 - 230
		La	0 - 820
		Yb	<2 - 23
		W	<10 - 182
		Hg	<70 - 259
		Pb	10 - 1420
		Bi	1 - 900

[a]References used were O'Gorman and Walker (1971 & 1972), Sun et al. (1971), Magee et al. (1973), Abernethy and Gibson (1962), Headlee and Hunter (1953) and Zubovic et al.(1961-1967). (Data by Deul and Annell in these references have been omitted.)

[b]Elements present in 0.7%.

[c]Zinc is not normally considered a major element in coals.

few exceptions, trace elements are more abundant in coal than they are in the earth's crust or soil.

Generally, a higher total sulfur content in coal is accompanied by higher iron content. This is primarily due to iron and sulfur occurring in the form of pyrite, FeS_2. The amount of sulfur in coal is moderate in the Appalachian region, higher in the interior region (east and west), and lower in all the western states.

Trace element concentration as a whole correlates only moderately with geographical location and not at all with coal rank. Boron, which is in relatively high concentration in lignites and lower concentration in high rank coals, is an exception. The amount of some trace elements is commonly highest in the top and bottom few inches of a bed, and at the edges of a coal basin (Ge, Be, Ga and B at the bottom only). These variations are frequently greater than the differences between the averages for different beds. Other elements (Cu, Ni, Co) show no such correlation.

Attempts to characterize the trace element content of coal and to determine the fate of trace elements following combustion have had limited success. The chemical composition of coal varies greatly from one deposit to another, even in the same seam, and it is therefore difficult to extract a representative sample for analysis. The ash content is dependent upon the care taken in mining, especially when there are ore beds nearby, and upon whether cleaning and coal preparation processes are used.

The trace elements discussed above are transferred during combustion to particles that range in size from less than 0.1 µm to greater than 100 µm. Particulate control devices remove most of the large particles and substantial amounts of the small particles from the combustion gases leaving the furnace, but, because of variations in equipment design, emissions to the atmosphere from a given unit must be determined by stack gas sampling. The trace elements are concentrated on the surfaces of particles, with the highest concentrations found on the smallest particles.

The process by which trace elements are enriched on the smallest particles seems to begin in the combustion zone with the volatilization of some chemical species containing the element. Beyond the combustion zone, condensation and adsorption on particulate surfaces take place. Because the rate of adsorption is dependent linearly on surface area, the highest concentrations occur on those particles with the greatest ratio of surface area to volume (i.e., the smallest particles).

Trace elements can be classified by their degree of enrichment in fly ash. The disposition of minor and trace elements during combustion and a qualitative estimate of the degree of their enrichment in fly ash are presented in Table 1.8.[23] Specific enrichment data on the various types of boilers are provided at the end of this section. Elements listed in Table 1.8, which are enriched in fly ash or volatilized, are generally found in coal in the form of sulfides. Elements that are not enriched in fly ash are usually found in the form of the less volatile silicates.

Concentrations of the trace elements in the various combustion products of southern Illinois/western Kentucky coal (11-13% moisture, 35-36% volatile matter; 40-43% fixed carbon, 10-12% ash, 3-3.5% sulfur; 10,700-11,400 Btu/lb) have been categorized into three classes of partitioning as shown in Table 1.9.[24] Cr, Cs, Na, Ni, V, and U were not assigned to classes but appear intermediate between Classes I and II. The ability of the electrostatic precipitator (ESP) to remove trace elements from the flue gas stream depends on the specific element and its

Table 1.8 Disposition of Minor and Trace Elements During Combustion[23]

Minor and trace elements not enriched in fly ash		Minor and trace elements enriched in fly ash	
Element	Symbol	Element	Symbol
Aluminum	Al	Antimony	Sb
Barium	Ba	Arsenic	As
Beryllium	Be	Cadmium	Cd
Bismuth	Bi	Chromium	Cr
Calcium	Ca	Copper	Cu
Cerium	Ce	Gallium	Ga
Cobalt	Co	Lead	Pb
Europium	Eu	Mercury	Hg
Hafnium	Hf	Nickel	Ni
Iron	Fe	Polonium	Po
Lanthanum	La	Selenium	Se
Magnesium	Mg	Thallium	Tl
Niobium	Nb	Zinc	Zn
Potassium	K	Minor and trace elements partially volatilized during combustion	
Rubidium	Rb	Element	Symbol
Samarium	Sm	Arsenic	As
Scandium	Sc	Bromine	Br
Silicon	Si	Cadmium	Cd
Strontium	Sr	Chlorine	Cl
Tantalum	Ta	Fluorine	F
Thorium	Th	Iodine	I
Tin	Sn	Lead	Pb
Titanium	Ti	Mercury	Hg
Yttrium	Y	Selenium	Se

Table 1.9 Trace Element Partitioning[24]

Class	Elements	Concentration	Proposed Mechanism
I	Al, Ba, Ca, Ce, Co, Eu, Fe, Hf, K, La, Mg, Mn, Rb, Sc, Si, Sn, Sr, Ta, Th, Ti	Readily incorporated into the slag; partitioned about equally between ESP inlet fly ash and slag; no apparent tendency to concentrate in the ESP outlet fly ash.	These elements are not volatilized in the combustion zone, but instead form a melt of rather uniform composition that becomes both fly ash and slag. The slag is removed directly and quickly from the combustion zone, while the fly ash remains in contact with the cooling flue gas. Class I elements remain in the condensed state and hence show minimal partition between slag, ESP inlet fly ash, and ESP outlet fly ash.
II	As, Cd, Cu, Ga, Pb, Sb, Se, Zn	Poorly incorporated into slag; concentrated in the ESP inlet fly ash compared to the slag and in the outlet fly ash compared to the inlet fly ash.	These elements are volatilized on combustion. Since slag is removed from the combustion zone, they have no opportunity to condense on the slag. They do, however, condense or become adsorbed in the fly ash as the flue gas cools. These elements are thus preferentially depleted from the slag (volatility effect) and preferentially concentrated on the outlet fly ash compared with the inlet fly ash (particle size effect).
III	Hg, Cl, Br	Essentially completely in the gas phase.	

distribution, as well as on precipitator design and operating conditions, with Class I elements removed more efficiently than Class II elements (Class III elements remain essentially unaffected by the ESP). ESPs can be made efficient for the removal of most elements, but they will be less efficient for removal of those elements that concentrate on the very fine particulates and have essentially no effect on the removal of such volatiles as Hg.

1.4.2.1 Cyclone-Fired Boilers

Ash produced in cyclone-fired boilers is distributed about equally between slag and fly ash, in contrast to the more common pulverized-coal-fired boilers, where as much as 90% of the total ash may be fly ash.

1.4.2.2 Pulverized-Coal-Fired Boilers

Testing was recently completed on a pulverized-coal (PC) boiler, firing 0.6%-sulfur coal with about 6% ash; a mechanical dust collector followed by an ESP and scrubber in parallel were used for particulate removal.[25] For each sample, the mean concentrations of a number of elements along with the analytical methods used to determine these concentrations are listed in Table 1.10.[25]

1.4.2.3 Stoker-Fired Boilers

Trace element analyses in stoker-fired boilers are not yet available. Any speculation on this subject is unwarranted at the present time.

Table 1.10 Trace Elements in Power Plant Samples[25]

(Pulverized-Coal-Fired Boilers)

Sample	Al, % by wt	Fe, % by wt	Concentration, µg/g Cu	Zn	As	Rb	Sr	Y	Nb	Zr	Mo	Sb	Pb	Se	Hg
Coal	0.49	0.37	9.6	7.3		2.9	120	3.0	0.76	13	0.99			1.9	0.070
BA	8.8	6.6	82	58	15	48	1800	44	12	220	3.5	2.8	5	7.7	0.140
MA	9.6	7.0	150	100	44	50	2400	61	16	260	12	4.7	13	4.1	0.026
PA	10.2	6.9	230	250	120	73	2500	68	19	210	41	14	66	27	0.310
SI	9.0	7.4	280	360	130	51	2200	52	17	150	54	14	110	73	
PO	9.2	7.4	320	370	150	56	2500	60	19	130	60	18	130	62	
SO	7.4	4.9	290	600	280	28	2500	31	13	80	110	22	340	440	
SS	0.10	0.063	2.4	2.2	1.1	0.50	21	0.49	0.49	1.8	0.53	0.10	0.91	0.33	0.014
Analytical method	AA	AA	XRF	XRF	XRF	XRF	XRF	XRF	XRF	XRF	XRF-WC	XRF	XRF	XRF	FAA

Samples analyzed: whole coal, bottom ash (BA), mechanical-collector-hopper ash (MA), electrostatic-precipitator-hopper ash (PA), scrubber-inlet fly ash (SI), electrostatic-precipitator-outlet fly ash (PO), scrubber-outlet fly ash (SO), scrubber slurry (SS). Measurement methods: conventional atomic absorption spectrophotometry (AA), X-ray fluorescence (XRF), wet chemistry (WC), flameless atomic absorption (FAA), radiochemical analysis (RA), Brunauer-Emmett-Teller method (BET), aerodynamic particle size (APS).

2 CHARACTERISTICS OF COAL-FIRED POWER PLANTS

Chapter 1 presented information related to coal resources, properties, characteristics, etc. The environmental effects of the combustion of coal were also discussed, particularly with respect to air pollution control problems. However, coal type is not the only variable affecting air pollution control equipment performance. The type of boiler and operating conditions also have a profound influence, and it is to this subject that this chapter is addressed.

The major types of boilers used by utilities can be divided into three categories:

1. Cyclone-fired
2. Pulverized-coal-fired
   - Wet Bottom
   - Dry Bottom
3. Stoker-fired

The relationship of each type of boiler to the coal scenario is summarized in Table 2.1.[26] Pulverized-coal-fired boilers burn approximately 85% of the coal consumed by utilities. Emission factors for the various types of boilers firing different types of coal are presented in Tables 2.2 through 2.4.[27]

Table 2.1 Coal-Fired Utility Boilers [26]

Boiler Type	No. of Boilers (% of Total)	Btu/Capacity (% of Total)	Coal Burned (% of Total)
Cyclone	6.6	12.6	13.5
Pulverized			
Dry bottom	57.8	69.5	71.8
Wet bottom	17.2	15.8	13.5
Stoker	18.4	2.2	1.2

Table 2.2 Emission Factors for Bituminous Coal Combustion without Control Equipment [27]

Furnace size, 10^6 Btu/hr heat input	Particulates[a] lb/ton coal burned	Particulates[a] kg/MT coal burned
Greater than 100		
(Utility and large industrial boilers)		
Pulverized		
General	16A	8A
Wet Bottom	13A[b]	6.5A
Dry Bottom	17A	8.5A
Cyclone	2A	1A
10 to 100		
(large commercial and general industrial boilers)		
Spreader stoker[c]	13A[d]	6.5A
Less than 10		
(commercial and domestic furnaces)		
Spreader stoker	2A	1A
Hand-fired units	20	10

[a]The letter A on all units other than hand-fired equipment indicates that the weight percentage of ash in the coal should be multiplied by the value given. Example: If the factor is 16 and the ash content is 10 percent, the particulate emissions before the control equipment would be 10 times 16 or 160 pounds of particulate per ton of coal (10 times 8 or 80 kg of particulates per MT of coal).

[b]Without fly-ash reinjection.

[c]For all other stokers use 5A for particulate emission factor.

[d]Without fly-ash reinjection. With fly-ash reinjection use 20A. This value is not an emission factor but represents loading reaching the control equipment.

Table 2.3 Emissions from Anthracite Coal Combustion without Control Equipment[27]

Type of furnace	Particulate[a]	
	lb/ton	kg/MT
Pulverized (dry bottom), no fly-ash reinjection	17A	8.5A
Overfeed stokers, no fly-ash reinjection[b]	2A	1A
Hand-fired units	10	5

[a]A is the ash content expressed as weight percent.

[b]Based on data obtained from traveling-grate stokers in the 12 to 180 Btu/hr (3 to 45 kcal/hr) heat input range. Anthracite is not burned in spreader stokers.

Table 2.4 Emissions from Lignite Combustion without Control Equipment[a] [27]

Type of boiler	Particulate[b]	
	lb/ton	kg/MT
Pulverized-coal	7.0A[c]	3.5A[c]
Cyclone	6A	3A
Spreaker stoker	7.0A[d]	3.5A[d]
Other stokers	3.0A	1.5A

[a]All emission factors are expressed in terms of pounds of pollutant per ton (kilograms of pollutant per metric ton) of lignite burned, wet basis (35 to 40 percent moisture, by weight).

[b]A is the ash content of the lignite by weight, wet basis.

[c]This factor is based on data for dry-bottom, pulverized-coal-fired units only. It is expected that this factor would be lower for wet-bottom units.

[d]Limited data preclude any determination of the effect of flyash reinjection. It is expected that particulate emissions would be greater when reinjection is employed.

Table 2.5 Summary of Utility Boiler Design Features[28]

Firing Mechanism	Fuel Preparation Size	Fuel Preparation Drying	Ash Removal
Cyclone	¼ in.	Partial	Wet
Pulverized Coal	200 mesh	Partial	Dry (typically)
Stoker	2 in.	No	Dry

2.1 DESCRIPTION OF EQUIPMENT

A sketch of a typical steam boiler is shown in Figure 2.1.[28] The radiant section of the boiler is lined with boiler tubes on the walls, floor and roof of the furnace enclosure. The boiler feed water is converted to saturated steam within these tubes through the radiant transfer of heat from the hot combustion gases within the furnace. Additional heat transfer tubes required to superheat the saturated steam (i.e., the primary, secondary and reheat superheaters) are usually included directly following the radiant section of the boiler. Finally, most boilers have an air preheater to transfer heat from the boiler exhaust to incoming combustion air. The three areas where steam-generating equipment differ in design are in fuel preparation, firing mechanism, and ash removal. These variables are summarized in Table 2.5.[28]

2.1.1 *Cyclone-Fired Boilers*

The cyclone furnace fires crushed coal, ground to through 1/4-in. size coal, into a water-cooled, refractory-lined cylindrical chamber, which discharges gases nearly horizontally into a water-tube boiler. The burner itself is shown schematically in Figure 2.2.[28] The temperature within the burner is hot enough to melt the ash to form a slag. Centrifugal force from the vortex flow forces the melted slag to the outside of the burner where it coats the burner walls. As the solid coal particles are fed into the burner, they are forced to the outside and are imbedded

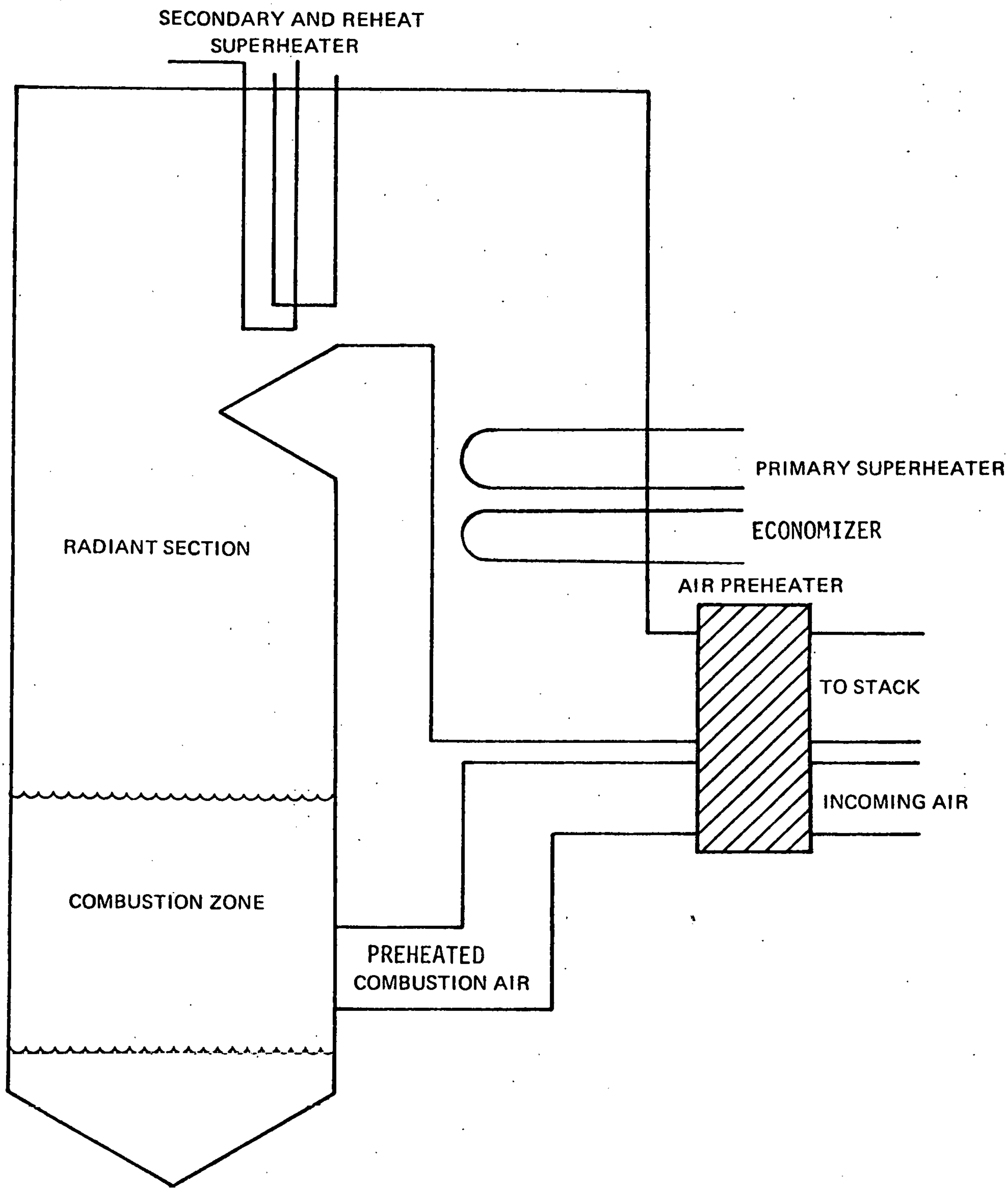


Figure 2.1 Schematic Diagram of Utility Steam Generator.[28]

in the slag layer. The solid coal particles are trapped there until complete burnout is attained. Approximately 85% of the ash fired is retained as molten slag; hence, the fly ash load is much lower than with pulverized coal. The ash that does escape the cyclone boiler, however, is extremely fine.

The ash from the burner is continuously removed through a slag tap flush with the furnace floor (see Figure 2.2). Such a system insures that the burner has a sufficient thickness of slag coating on the walls at all times.

2.1.2 Pulverized-Coal-Fired Boilers

In a pulverized-fuel steam generator, the fuel is fed from the stockpile into bunkers adjacent to the steam boiler. From the bunkers, the fuel is metered into several pulverizers, which grind it to approximately 200-mesh particle size. A stream of hot air from the air preheater partially dries the fuel and conveys it pneumatically to the burner nozzle where it is injected into the burner zone of the boiler. Common burner arrangements (cf. Figure 2.3[28]) for firing pulverized coal in steam generators include;

- Tangential firing
- Horizontally-opposed burners
- Front wall burners

Because of the capital costs required for small pulverized-coal installations in comparison with similar size stoker installations, pulverized coal units smaller than 100,000 pounds of steam per hour are uneconomical. In larger units, where the furnace size and configuration are less disproportionate, lower operating costs result from greater efficiency. The furnace must be proportioned so that combustion is completed within the furnace volume for the type of firing used. For pulverized-coal-fired furnaces the heat release range is usually between 15,000 and 22,000 Btu per hr per cu ft of furnace volume.

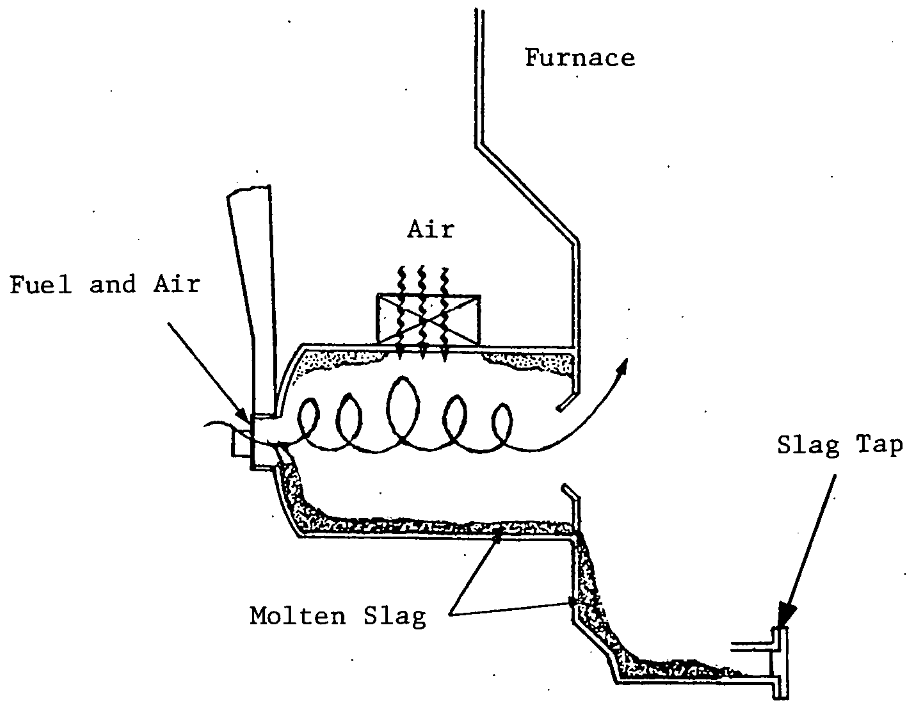


Figure 2.2 Schematic of Cyclone Firing of Coal in a Utility Boiler.[28]

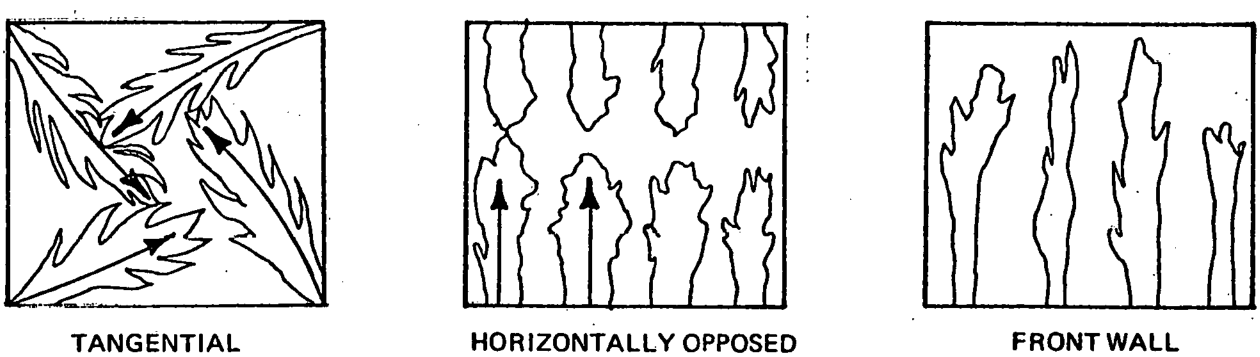


Figure 2.3 Burner Arrangements for Pulverized-Fuel Firing in a Utility Boiler.[28]

The primary coal characteristics that influence the design of pulverized-coal-firing equipment are grindability, coal rank, coal moisture content, coal volatile matter content and coal ash content. The usual limits in these coal characteristics for pulverized-coal firing are: (1) maximum total moisture (as fired), 15% (although higher inherent-moisture-content coal such as bituminous or lignite may be used); (2) minimum volatile matter (dry basis), 15%; and (3) maximum total ash (dry basis), 20%.

2.1.3. Stoker-Fired Boilers

In a stoker-fired furnace, shown schematically in Figure 2.4[28], the coal is spread across a grate to form a bed, which burns until the coal is completely used up. Stoker-fired furnaces are dry-bottom furnaces and, as such, generally have lower heat release rates and lower temperature profiles than the corresponding pulverized-coal or cyclone-fired units. For stoker furnaces, the coal is broken up into approximately 2-in. particles and fed into the furnace by one of several feed mechanisms -- underfeed, overfeed or spreading.

Underfed beds are inherently smoke-free. The air and fresh fuel flow concurrently, usually upward. Hence, the zone of ignition, which is near the point of maximum evolution of combustible gases, is amply supplied and well mixed with air; this promotes complete combustion. The usual underfed stoker is better suited for caking coals than for noncaking or free-burning coals, because the volatiles are released more slowly from caked masses than from a porous bed of coals.

The traveling grate is usually applied to the burning of anthracite, sub-bituminous and weakly caking bituminous coal, lignite and, occasionally, coke. As indicated above, it works best with noncaking fuels, because air distribution is most uniform through an even bed of noncaked masses. For many years, mixing of the burning gases above the traveling grate was achieved by the use of elaborate suspended arches, which forced the upward

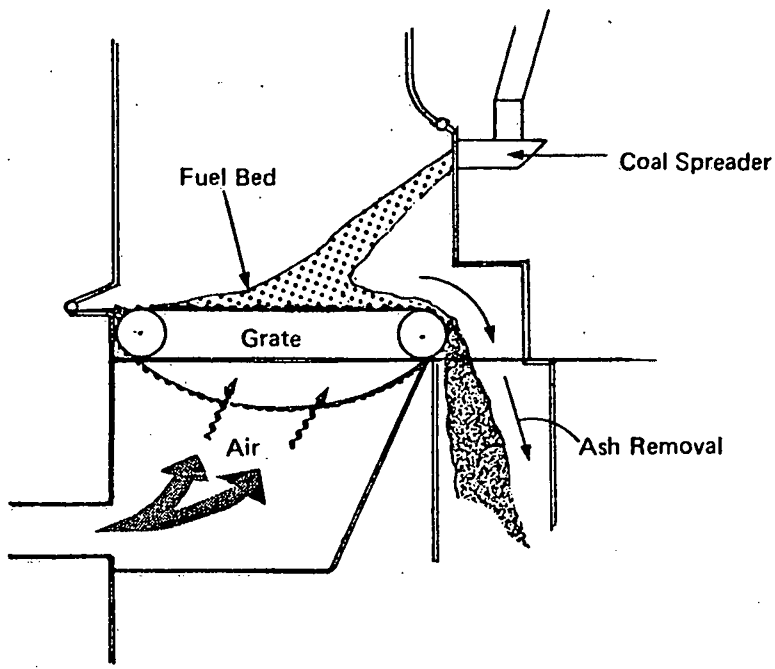


Figure 2.4 Schematic of Spreader-Stoker Firing in a Boiler, with Traveling Grate.[28]

flow of flame into a narrow throat walled by incandescent refractory. However, the recent trend has been to use only rear arches or simple open furnaces and to attain mixing by means of high-velocity jets of secondary air directed from a number of nozzles located in one or more of the furnace walls. Zoned control of the air admitted to various portions of the fuel bed is an effective means of reducing smoke and fly ash emissions.

Vibrating-grate stokers move the coal slowly across the furnace by means of small, rapid oscillations of the grate. Fly ash may be slightly higher than on traveling-grate stokers because of increased agitation of the fuel bed. The water-cooled vibrating grate stoker is an adaptation of a design used successfully with many low ranking lignite and brown coals found in central Europe. It is also capable of burning better grades of coal. Because of simplicity, inherent low fly ash carryover characteristics and very low maintenance, this stoker has been steadily gaining acceptance and now has replaced larger size multiple retort underfed stokers in the intermediate range.

The spreader stoker employs either a mechanical spreader or jets of steam or air to throw the solid fuel into the furnace, where it falls on a grate that is traveling or stationary. The coal is spread on the grate in such a fashion that at the end of the grate only ash remains. When the ash reaches the end of the grate, it falls off into an ash collection hopper and is removed from the furnace. Essentially, the spreader stoker employs overfed burning, an inherently smoky method, plus suspension burning, an inherently smoke-free fly-ash-producing method. Overfire jets have been found essential to smoke-free operation.

Smoke is characteristic of most spreader stokers if they are operated at less than approximately 25% of full load, because low furnace temperatures cause incomplete suspension burning. Accordingly, a spreader stoker-fired system should be supported by suitable auxiliary heat-generating means so that at low plant loads the stoker can either be operated to carry all of the load or be shut down completely.

The spreader stoker is mostly used in the capacity range from 75,000 to 400,000 lb of steam per hour, because it responds rapidly to load swings and can burn a wide range of fuels. The spreader coal-feed mechanism provides a continuous, well distributed supply of fuel at a variable rate as required by the load demand.

Since a part of the combustion in spreader stokers takes place in suspension, a greater carry-over of carbon-containing particulate matter occurs in the flue gas than with other types of stokers. An increase in boiler efficiency of 2 to 3% results from reintroducing carbonaceous fly ash into the furnace. The carbonaceous fly ash from the spreader stokers is easily collected in a cyclone-type collector. This collector is provided with a selective feature that permits the skimming-off of the coarse carbon-containing particles. The fines are deposited in a hopper for discharge to the ash disposal system.

As the amount of fines in the coal increases and the size of the fines decreases, the carbon loss out of the stack will increase. Units that have inherent fly ash traps and are equipped with dust collectors and fly ash returns will show less loss from this cause than units not so equipped. Coals having a high ash content will show an additional overall efficiency loss. Coals having a low ash fusion temperature will cause clinker formation. These clinkers carry away carbon, resulting in lower boiler efficiency and increased maintenance.

In conclusion, of the stoker burners, the spreader stoker can burn the widest range of coals. Coal ranks from lignite through semianthracite (even anthracite, with certain qualifications) can be burned on a spreader stoker. Since most of the volatile matter and tarry hydrocarbons are distilled from the coal particles before they reach the grates, the coal caking properties have little effect upon spreader stoker performance. Coals with high ash content and low ash fusion temperature are more easily burned with spreader stokers than with other stoker types. The physical size of stoker-fired boilers is limited because of structural requirements and extreme difficulties in obtaining uniform fuel and air distribution to the grate. Most manufacturers of stoker-fired equipment limit their design to 30 MW.

2.2 *FLY ASH CHARACTERISTICS*

The operating characteristics of the various furnace types are shown in Table 2.6.[29] Of the three types of boilers (cyclone-fired, pulverized-coal-fired and stoker-fired), stoker-fired boilers tend to produce the coarsest fly ash and cyclone-fired boilers the finest fly ash.

2.2.1 *Cyclone-Fired Boilers*

The concentration of particulate emissions from cyclone firing and its relationship to the ash content of the coal are shown in Figure 2.5.[29] (In Figs. 2.5-2.8, dotted lines indicate the range of values, solid lines the most probable curves.) Average emission rates range between 0.4 to 1.5 grains/SCFD (standard cubic foot dry) over an ash content range of 5.0 to 12.5%. These values correspond to approximately 25-30% of the coal ash appearing in the flue gases as particulates.

Particle size distribution data (Bahco) for cyclone firing are presented in Figure 2.6.[29] The most probable particle size distribution is 65% less than 10 microns, with a particle specific gravity of 2.79.

2.2.2 *Pulverized-Coal-Fired Boilers*

Concentration of particulate emissions from pulverized coal firing and its relationship to the ash content of the coal are shown in Figure 2.7.[29] The most prevalent range of coal ash content is about 7 to 12%, and average particulate emissions for coals with ash contents in this range vary from 2.4 to 3.4

Table 2.6 Coal-Burning Equipment Operating Characteristics

PULVERIZED

1. Load range is wide and varies with the number and type of pulverizers.
2. Flyash carry-over in the flue gases is high, and it is finer than the flyash from the spreader stokers. Therefore, although the boiler must be designed to prevent erosion, the allowable flue gas velocity is somewhat higher.
3. Initial cost for pulverized coal equipment is about the same as for spreader stokers at 250,000 lb/hr. It becomes less expensive above these capacities.
4. Pulverized coal equipment can burn a very wide range of coal.
5. Maintenance costs for pulverizers vary considerably with types of coal.
6. Response to load changes is very fast.
7. Coal sizing to a pulverizer is 3/4 in. x 0. Coal segregation is no problem.
8. Repairs and maintenance on pulverizers may be conducted while the boiler is in operation by taking one of several pulverizers out of service at a time.

VIBRATING GRATE STOKER

1. A wide load range, from banked fire to maximum capacity.
2. Low flyash carry-over unless the unit is overloaded.
3. A dust collector may be required, depending upon local conditions.
4. Sizing and distribution of coal is important.
5. Caking coals have been burned on this stoker.
6. Water-cooled grates tend to reduce grate maintenance when properly designed.
7. Burning rate is usually about 400,000 Btu/sq ft-hr with a furnace heat release of 30,000 Btu/cu ft.

CHAIN AND TRAVELING GRATE STOKER

1. Wide load range from banked fire to maximum capacity.
2. Low flyash carryover in the flue gases; a dust collector is not usually required.
3. Initial cost is more than for an underfed stoker.
4. Ash softening temperature should be reasonably high, about 2200°F or higher.
5. Maintenance costs are generally low.
6. Response to load changes is about medium; faster than the underfed but slower than the spreader.
7. Coal sizing should be 1 in.x0 with approximately 20 to 50% through a 1/4 in. screen.
8. Coal should have a minimum ash content of 6% on a dry basis to protect the grates from overheating.
9. Sensitive to changes in coal sizing and distribution.
10. Offered for a maximum continuous burning rate of 425,000 Btu/sq ft-hr with high moisture (20%), high ash (20%) bituminous coals, such as that from some districts in Illinois, and 500,000 Btu/sq ft-hr with lower moisture (10%), lower ash (8-12%) bituminous coal, such as that from Kentucky. Furnace heat release should be maximum of 30,000 Btu/cu ft for water-cooled furnaces.
11. Large (above 70,000 lb./hr) front arch, chain grate stokers should have a maximum heat release of about 7MKB/ft (MKB= million Btu) of stoker width for Kentucky coal, depending upon the volatile matter and heating value.
12. Strongly coking coals are not suitable for conventional chain or traveling grate stokers.

UNDERFED STOKER

1. A wide load range, banked fire to maximum capacity.
2. Low flyash carryover with the flue gases, provided the stoker is not overloaded.
3. Initial cost is low compared to other stokers.
4. Ash softening temperature should be 2500°F or above for best operation. Coals with ash softening temperature of 2200°F to 2500°F may be utilized; however, the heat release rate per square foot of grate area must be reduced about 20%.
5. In general, maintenance costs are higher than for other stokers.
6. Response to load changes is rather slow, because of the relatively large fuel bed.
7. Coal sizing should be 1¼ in. x 0, nut and slack, with not more than 50% through ¼in. screen to obtain proper distribution on the grate.
8. The free swelling index should be below about seven to maintain proper fuel distribution in the furnace and to keep maintenance to a minimum.
9. Grate heat-release rate should be no more than 425,000 Btu/sq ft and a maximum furnace heat release rate of 35,000 Btu/cu ft for water-cooled furnaces.

SPREADER STOKER

1. Turn-down or load range is generally from 1/5 load to maximum capacity. With additional equipment, minimum load can be decreased to about 1/8 of maximum load.
2. Since about 25% of the coal burns in suspension, the flyash carryover is high. A dust collector is always required. A precipitator may be required depending upon the air emission regulations.
3. To obtain the best reasonable efficiency, the flyash collected in the boiler hoppers must be reinjected onto the stoker grate.
4. Initial cost of dumping grate spreader stoker is the lowest, with the pulsating or oscillating grate next, and the traveling grate the highest.
5. The spreader will burn with little difficulty a wide variety of coals of different fusion temperatures and different coking indices.
6. In general, maintenance costs are approximately the same as for a chain grate.
7. The spreader stoker has a very fast response to load swings.
8. Coal sizing should be 3/4 in. x 0 with no more than 50% through a 1/4 in. mesh. The pulsating or oscillating grates should be fired with coal having an ash softening temperature of above 2200°F to ensure proper coal and ash flow over the grates.
9. Spreaders are designed for burning rates from 450,000 Btu/sq ft-hr for dumping grates, to 600,000 Btu/sq ft-hr for pulsating or oscillating grates, to 750,000 Btu/sq ft-hr for traveling grates. Furnace heat release should be a maximum of 30,000 Btu/cu ft.
10. On large spreaders (above 70,000 lb/hr steam capacity) the heat release per foot of stoker width must also be considered, and will vary from about 8 MKB ft-hr to 13 MKB/ft-hr depending upon the amount and method of flyash reinjection.
11. Some mention should be made of the two types of reinjection generally used: pneumatic and gravity types. The gravity type is much preferred for the higher steam capacities (above 70,000 lb/hr), if equipment arrangement and building space is sufficient. As the name implies, the flyash flows by gravity from the boiler hopper and is deposited on the stoker grates. The stoker should be lengthened to accommodate this gravity return.

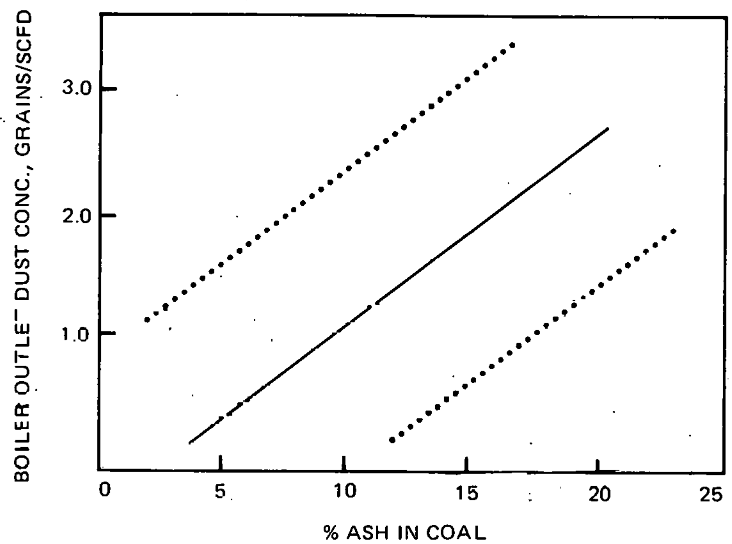


Figure 2.5 Dust Concentration, Cyclone Furnace [29]

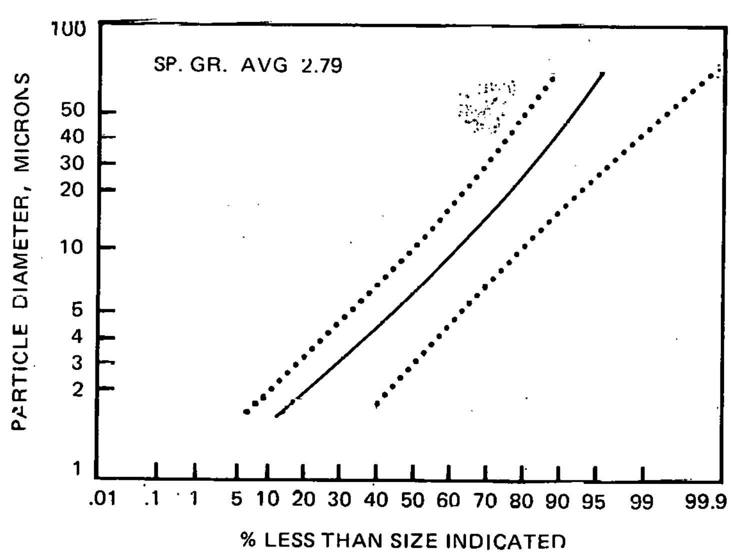


Figure 2.6 Particle Size Distribution, Cyclone Furnace [29]

grains/SCFD with maximum values in the range of 3.9 to 4.9 grains/SCFD. For typical conditions (13,000 Btu/lb coal; 40% excess air), these values indicate that about 80% of the ash in the coal appears in the boiler effluent as suspended particulate.[29]

Particle size distribution data, as determined by the ASME PTC 28 Method (Bahco) of particle size analysis, are given in Figure 2.8.[29] The most probable particle size distribution is 44% less than 10 microns; the specific gravity is 2.34.

2.2.3 Stoker-Fired Boilers

For stoker-fired boilers, particulate emission rate does not correlate with ash content as well as for pulverized coal and cyclone boilers. This is due to the influence of other, more critical variables, such as the flow of combustion air through the grate (underfire arc), the type of feed mechanism and whether fly ash reinjection is practiced or not. With fly ash reinjection, particulate emission rates typically range from 2.5 to 4.0 grains/SCFD. Without reinjection, particulate emission rates are typically less than 1.0 grain/SCFD.

Particle size distribution data (Bahco) for stoker-fired boiler emissions are presented in Figure 2.9.[29]

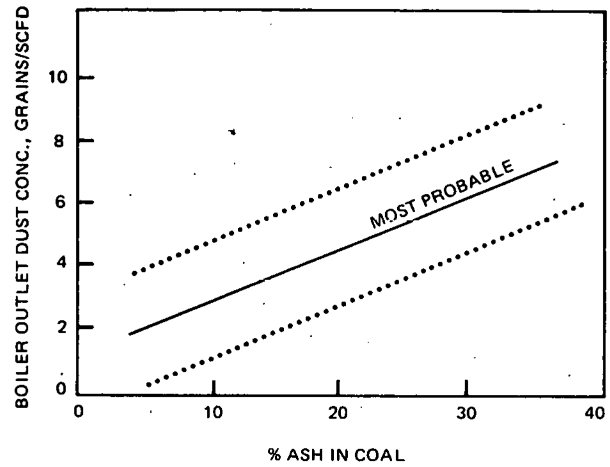


Figure 2.7 Dust Concentration of Pulverized Coal[29]

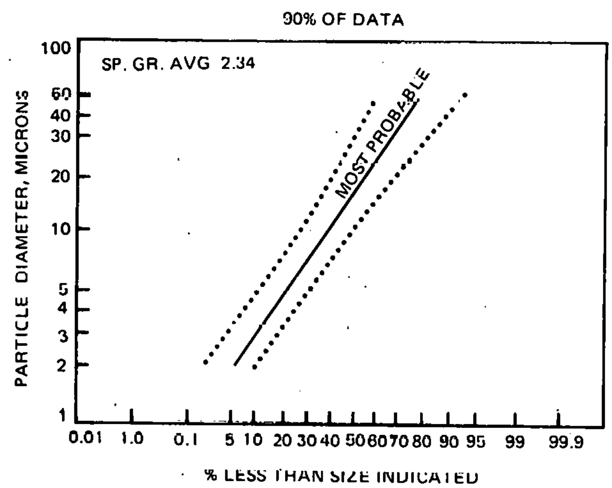


Figure 2.8 Particle Size Distribution of Pulverized Coal.[29]

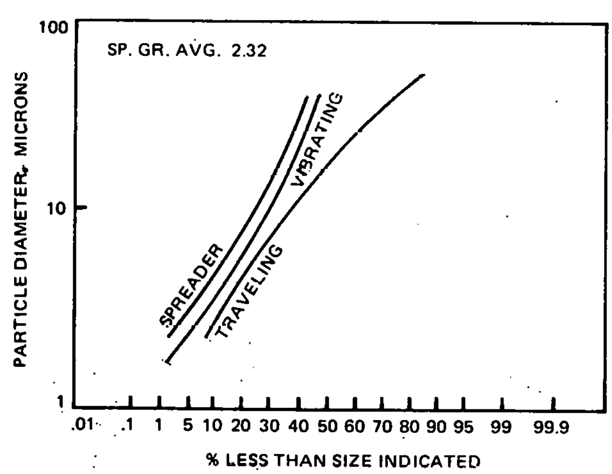


Figure 2.9 Particle Size Distribution, Stokers.[29]

3 PROCESS CONTROL TECHNOLOGY FOR FINE PARTICULATE EMISSIONS: CONVENTIONAL

Three types of conventional control devices are used to control particulates from coal-fired boilers: electrostatic precipitators, wet scrubbers and fabric filters.

Historically, electrostatic precipitators have been the control device of choice. In the past few years, however, wet scrubbers and fabric filters have also been used, especially with the increased use of low-sulfur western coal.

In designing a control device for the collection of particulates from coal-fired boilers, each installation is characterized in terms of fixed input parameters such as coal and boiler type and the various design parameters for the control device. More recently, the effect of coal feed variability is also taken into account. Figure 3.1 illustrates this relationship for electrostatic precipitators, wet scrubbers and fabric filters as applied to coal-fired utilities.[30]

3.1 ELECTROSTATIC PRECIPITATORS

With the advent of pulverized coal use in power plant boiler systems around 1924, electrostatic precipitators entered into an intimate association with the power industry. Their usefulness rested on the fact that pulverized coal-fired boilers generated large volumes of flue gas containing a significant proportion of very small dust particles (fly ash) which could not be removed by other, more conventional collection devices of the day, such as settling chambers and inertial separators. About 70% of the fly ash particles from a typical pulverized-coal-fired boiler are smaller than 30 µm. The problem of cleaning large flue gas volumes containing small particles became even more pronounced in the 1950s with the introduction of the cyclone furnace, where typically 65% of the particulate matter released is smaller than 10 µm.

Fixed Input Parameters

Type of coal (sulfur, ash, minerals, etc.)
Particle size distribution
Gas stream characteristics (temperature, pressure, velocity, acfm)
Type of boiler
Desired collection efficiency

Variable Design Parameters

Precipitators

- SCA (collection area ft^2/1000 cfm)
- Power density (watts/ft^2)
- Precipitation rate (ft/sec)
- Duct spacing (in.)
- Gas velocity (ft/sec)
- Aspect ratio
- Plate area per electrical set (ft^2/el. set)
- Degree of high tension sectionalization $\frac{\text{bus sections}}{\text{100,000 cfm}}$

Scrubbers

- Gas-handling capacity per module and number of modules (cfm/module)
- Pressure drop (in. of water)
- Liquid-to-gas (L/G) ratio (gal/1000 cfm)
- Ratio of water requirement/water recirculation
- Availability of equipment/downtime (duplication of equipment)
- Total power consumption as a fraction of generated power (%)

Fabric filters

- Air-to-cloth ratio
- Pressure drop (in. of water)
- Cleaning mode and frequency
- Composition and weave of fabric
- Number of compartments
- Type of housing

Figure 3.1 Fixed and Variable Design Parameters for Particulate Control Devices on Coal Fired Utility Boilers.[30]

Alone among methods of particle collection, the electrostatic precipitator acts solely on the particles to be collected rather than on the entire gas stream. The gas flow through a precipitator takes place with little more pressure drop than would be experienced in an equivalent length of straight flue.

3.1.1 Description of Equipment

Electrostatic precipitators installed on utility boilers are of the high-voltage, single-stage type. Particles are collected on flat, parallel collecting surfaces (plates) spaced 8 to 12 in. apart, with a series of discharge electrodes spaced along the center line of adjacent plates, as shown schematically in Figure 3.2[31]. A typical arrangement of a commercial plate-type electrostatic precipitator is shown in Figure 3.3[32]. The gas to be cleaned passes horizontally between the plates. Collected particles are removed by rapping and are deposited in hoppers at the base of the precipitator.

For increased performance and reliability, precipitators on utility boilers are divided into a number of independently energized bus sections. Each bus section has its own transformer rectifier, voltage stabilization controls and high-voltage conductors, which energize the discharge electrodes within that section. The main advantage of sectionalization is that it insures the maximum operating voltage in as much of the precipitator as is practical. Thus, an effect present in one part of the precipitator that reduces the sparkover voltage (i.e., the maximum operating voltage) will not necessarily reduce the voltage to the same level elsewhere in the precipitator, if the precipitator is sectionalized. The sectionalization can offset the dampening effects on corona power input of heavy flue gas dust loadings. These heavy flue gas dust loadings occur mainly in the inlet sections of a precipitator. By sectionalization, corona power input and particle charging can be increased in the inlet sections, thereby raising overall precipitator collection efficiency.

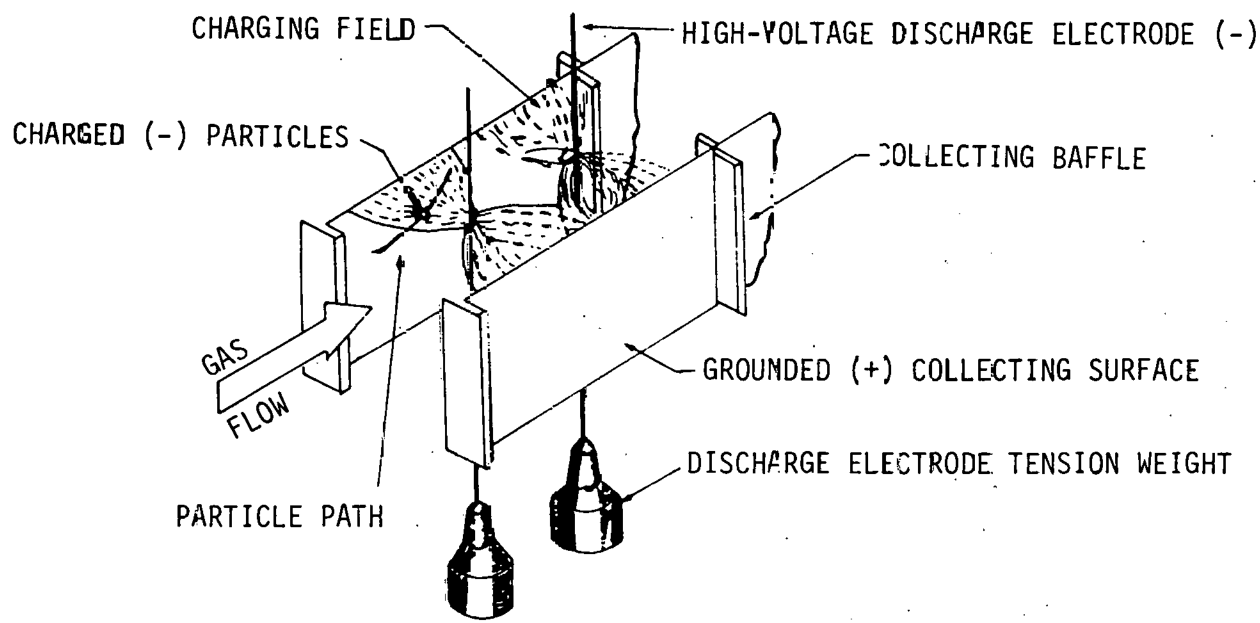


Figure 3.2 Collecting Surface Schematic for Plate-Type Precipitator [31]

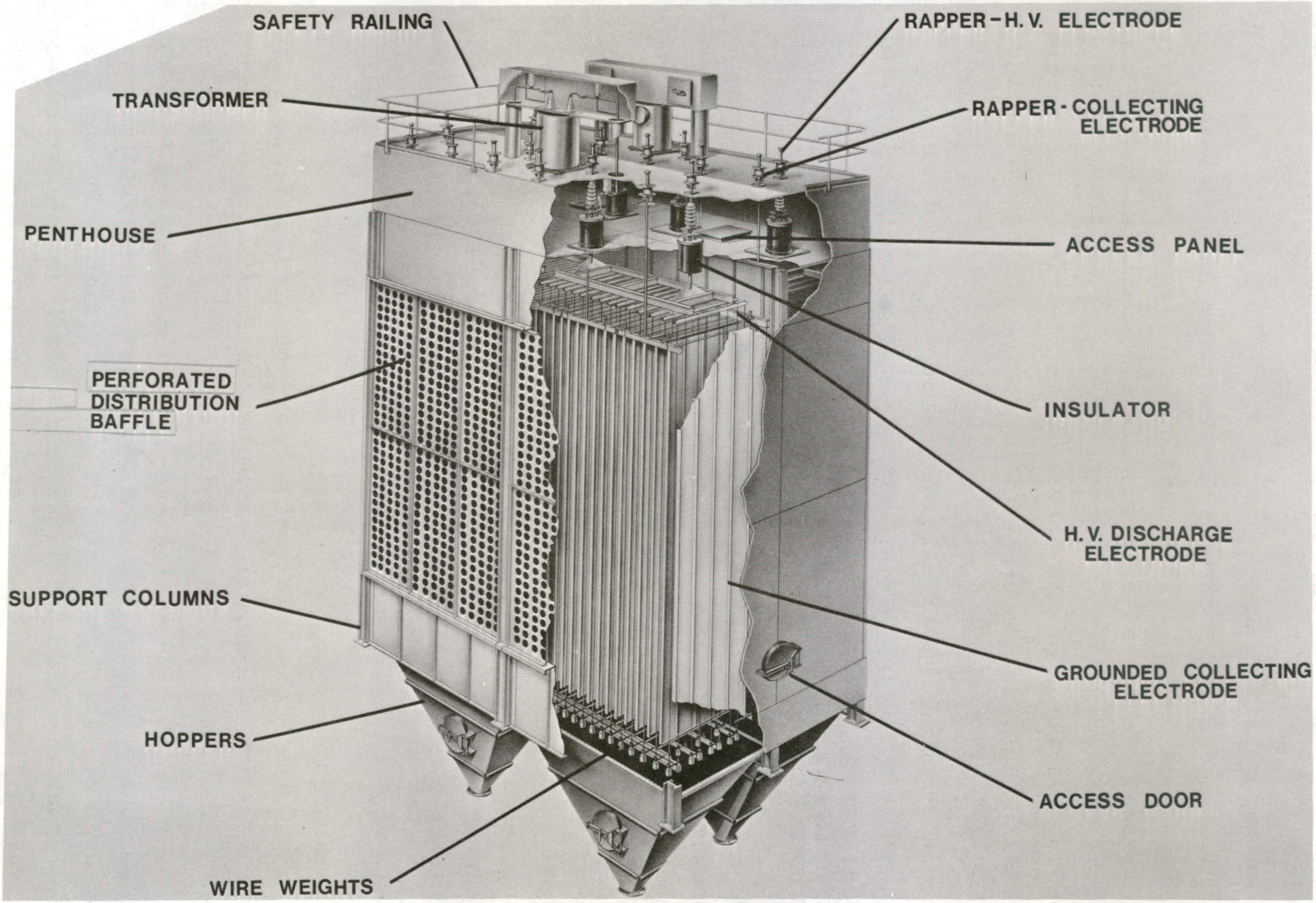


Figure 3.3 Cutaway View of a Plate-Type Electrostatic Precipitator.[32]
(Courtesy of UOP, Air Correction Division)

3.1.2 *The Precipitation Process*[33]

The process of electrostatic precipitation consists of corona formation around a high-tension wire, with particle charging by ionized gas molecules formed in the localized region of electrical breakdown surrounding the high-tension wire. This is followed by migration of the charged particles to the collecting electrodes. Finally, the particles captured on the collecting electrode are removed.

The corona is a gas discharge phenomenon associated with the ionization of gas molecules by electron collision in regions of high electric field strength. As the potential difference between the electrodes is raised, the gas near the more sharply curved electrode breaks down at a voltage less than the spark-breakdown value for the gap length in question. This incomplete breakdown, called corona, appears in air as a highly active region of glow (bluish white or possibly reddish in color) extending into the gas a short distance beyond the discharge electrode surface. The process of corona generation requires a nonuniform electric field, which is obtained by the use of a small-diameter wire as one electrode (discharge electrode) and a plate as the other electrode (collecting electrode). The application of a high voltage to this electrode configuration results in a high electric field near the wire.

The corona process is initiated by the presence of electrons in the high-field region near the wire. Electrons for corona initiation are supplied from natural radiation or other sources. Since they are in a region of high electric field, they are accelerated to high velocities. They may possess sufficient energy so that, on impact with gas molecules in the region, they release orbital electrons from the gas molecules. The additional free electrons are also accelerated and join the ionization process. This avalanche process continues until the electric field decreases to the point where the electrons released do not acquire enough energy for ionization.

In the region where ionization is taking place, defined by the corona glow discharge, there are free electrons and positive ions resulting from electron impact ionization. The behavior of these charged particles depends on the polarity of the electrodes. The corona can be negative (if the discharge electrode is negative) or positive (if the discharge electrode is positive). In the case of a negative discharge wire, free electrons in the high-field zone near the wire gain enough energy from the field to produce positive ions and other electrons by collision. These new electrons are, in turn, accelerated and produce further ionization, thus giving rise to the cumulative process termed an electron avalanche. The positive ions formed in this process are accelerated toward the wire. By bombarding the negative wire and giving up relatively high energies in the process, the positive ions cause the ejection of secondary electrons, necessary for maintaining the discharge, from the wire surface. In addition, high-frequency radiation originating in the excited gas molecules within the corona envelope may photo-ionize surrounding gas molecules, likewise contributing to the supply of secondary electrons. Electrons are attracted toward the anode; as they move into the weaker electric field away from the wire, they tend to form negative ions by attachment to neutral oxygen and nitrogen molecules. These ions form a dense unipolar cloud filling, making up most of the inter-electrode volume. They constitute the only current in the entire space outside the region of corona glow. The effect of this space charge is to retard the further emission of negative charge from the corona, limiting the ionizing field near the wire and stabilizing the discharge. However, as the voltage is progressively raised, complete breakdown of the gas dielectric (i.e., sparkover) eventually occurs.

In a positive corona, the electrons generated by the avalanche process flow toward the collection electrode. Since the positive ions are the charge carriers, they serve to provide an effective space charge, and the presence of an electronegative gas is not required.

Electrode geometry, gas composition, and gas conditions have important influences on corona generation. In general, the smaller diameter wire requires a higher electric field strength for corona initiation. For a given spacing, however, the onset of corona occurs at a lower voltage for a smaller diameter wire. Also, for a given voltage, higher currents are obtained with smaller diameter discharge electrodes. Temperature and pressure also influence corona generation by changing the gas density, viscosity, and, hence, the mean molecular velocity and free-path length. With increased molecular spacing, higher velocities can be achieved between collisions. Thus, ionizing energy can be achieved with low electrical fields for low gas densities.

When gases laden with suspended particulate matter are passed through an electrostatic precipitator, the great bulk of the particles acquire an electric charge of the same polarity as that of the discharge electrodes. This preferential charging occurs because the region of corona (i.e., the region of intensive ion-pair generation) is limited to the immediate vicinity of a discharge wire, thus occupying only a small fraction of the total cross section of the precipitator.

Two distinct particle-charging mechanisms are generally considered to be active in electrostatic precipitation: (1) bombardment of the particles by ions moving under the influence of the applied electric field (field-dependent charging) and (2) attachment of ionic charges to the particles by ion diffusion in accordance with the laws of kinetic theory (diffusion charging).

Particles in an electric field cause localized distortion of the field so that electric field lines intersect the particles. Ions present in the field tend to travel along the electric field lines. Thus, ions will be intercepted by the dust particles, resulting in a net charge flow to the particle. The ion will be held to the dust particle by an induced image-charge force between the ion and dust particle. As additional ions collide with and are held to the particle, it becomes sufficiently charged to repel the electric field lines so that they do not intercept it. Under this condition, no ions contact the dust particle, and it receives no further charge. The electrostatic theory of the process shows that the saturation value of the charge on the particle is related to the magnitude of the electric field in the region where charging takes place, particle size and particle dielectric constant. The saturation charge is proportional to the square of the particle diameter. Thus, larger particles are more easily collected than smaller ones. This mechanism of charging is called field-dependent charging.

For fine particles (diameter less than 0.2 μm), the field-dependent charging mechanism is less important, and collision between the particles and gas ions is governed primarily by thermal motion of the ion. As the charge on a particle increases, the probability of impact decreases, so that there is a decreasing charging rate associated with an increasing particle charge. This second charging process is called diffusion charging. Since the range of thermal velocities has no upper boundary, there is no saturation value associated with diffusion charging.

Field charging is the dominant mechanism for large particles with a diameter greater than about 0.5 μm, while diffusion charging predominates for small particles with diameters less than approximately 0.2 μm. In the intermediate range, both mechanisms contribute significant charge.

3.1.3 Design Methodology[31]

Electrostatic precipitator design and specification involves many parameters that must be taken into consideration. The more important parameters are summarized in Table 3.1.[31]

Table 3.1 Design Factors Requiring Consideration for Electrostatic Precipitator Specification[31]

1. Collection electrodes: type, size (area) mounting, and mechanical and aerodynamic properties
2. Discharge electrodes: type, size, spacing, and method of support
3. Shell: dimensions, insulation requirements, and access
4. Rectifier sets: ratings, automatic control system, number, instrumentation, and monitoring provisions
5. Rappers for corona and collecting electrodes: type, size, range of frequency and intensity settings, number, and arrangement
6. Hoppers: geometry, size, insulation requirements, number, and location
7. Hopper dust removal system: type, capacity, protection against air inleakage, and dust blowback
8. Inlet and outlet gas duct arrangements, gas handling, and distribution system
9. Degree of sectionalization
10. Support insulators for high-tension frames: type, number, and reliability

The goal in precipitator design and operation should be an economic balance between collecting plate area and power input, with consideration given to other performance determinants, such as resistivity and other particle characteristics.

The usual approach taken to size electrostatic precipitators for fly ash collection makes use of a form of the Deutsch-Anderson equation modified to account for such factors as sneakage and re-entrainment. The unmodified form is:

$$\eta = 1 - \exp(-wA/Q) \qquad (1)$$

The term w represents the effective migration velocity or precipitation rate parameter which is selected on the basis of experience with a particular dust. Precipitation rate parameters for fly ash collection from coal-fired boilers typically range from 0.13-0.67 ft/sec, with values of 0.33-0.44 frequently found on precipitators collecting pulverized coal fly ash. Since the desired collection efficiency (η) and gas flow rate (Q) are usually specified, the required collection area (A) can be determined once an appropriate precipitation rate parameter (w) has been chosen.

Many parameters can affect the precipitation rate parameter. The general effects of fly ash resistivity and sulfur content of the fuel are shown in Figures 3.4[34] and 3.5[35], respectively.

Although not all low-sulfur fuels produce high-resistivity fly ash (above 2×10^{10} ohm-cm) at the usual operating temperature range (250 to 350°F), a great many do. A typical relationship between temperature, resistivity and fuel sulfur content for eastern bituminous coals is shown in Figure 3.6.[36] In order to achieve required removal for low-sulfur coal, there are four alternatives that are commonly practiced:

1. The precipitator is run "hot," before the air preheater, so that the temperature is in the 600 to 800°F range where the resistivity is reduced to acceptable levels. As evidenced from Figure 3.6, the resistivity curves drop sharply as the temperature increases. However, due to larger gas volumes and structural considerations at the higher temperatures, "hot" precipitators are both large and costly.

2. Conditioning agents such as sulfur trioxide are used. These also increase capital and operating costs.

3. The precipitator is over-designed (i.e., the collection surface area of the precipitator is increased). This will also increase costs.

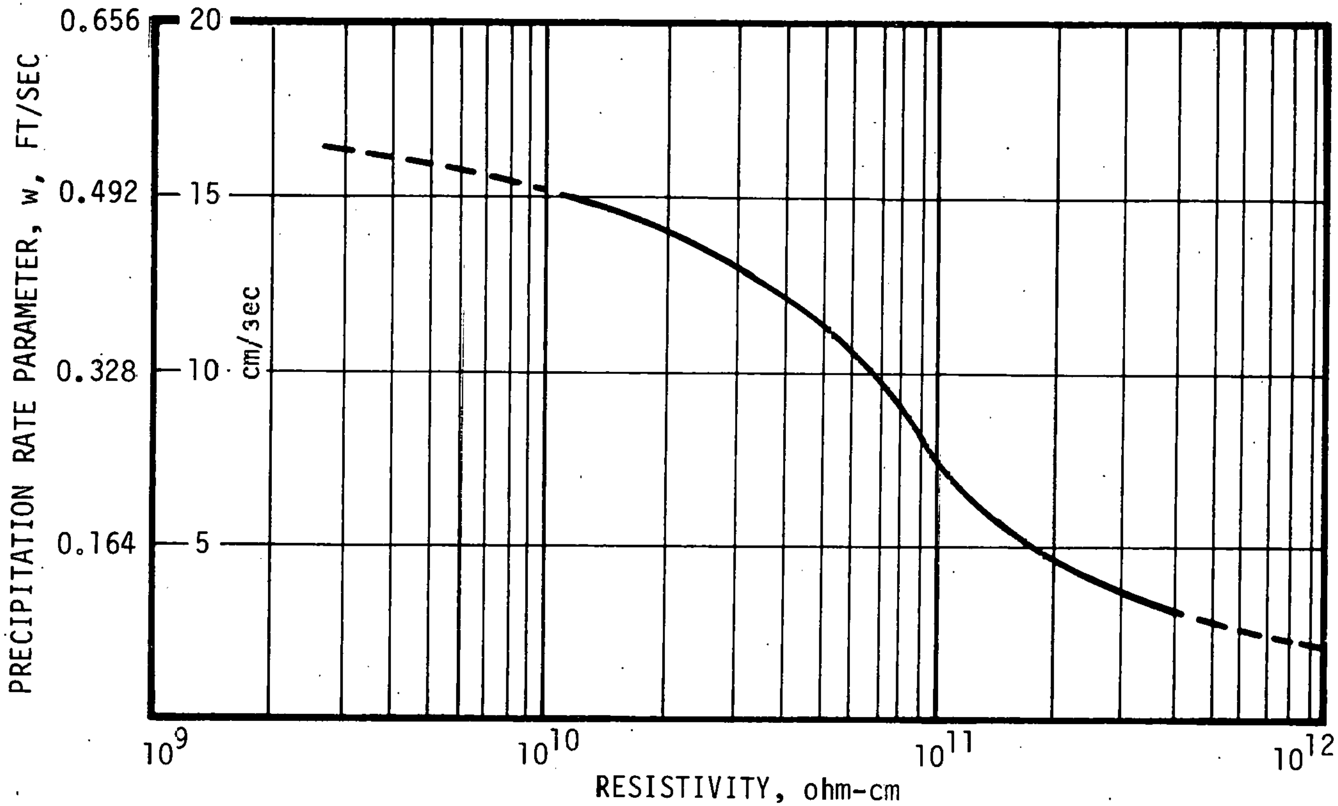


Figure 3.4 Relationship between Precipitation Rate Parameter and Resistivity.[34]

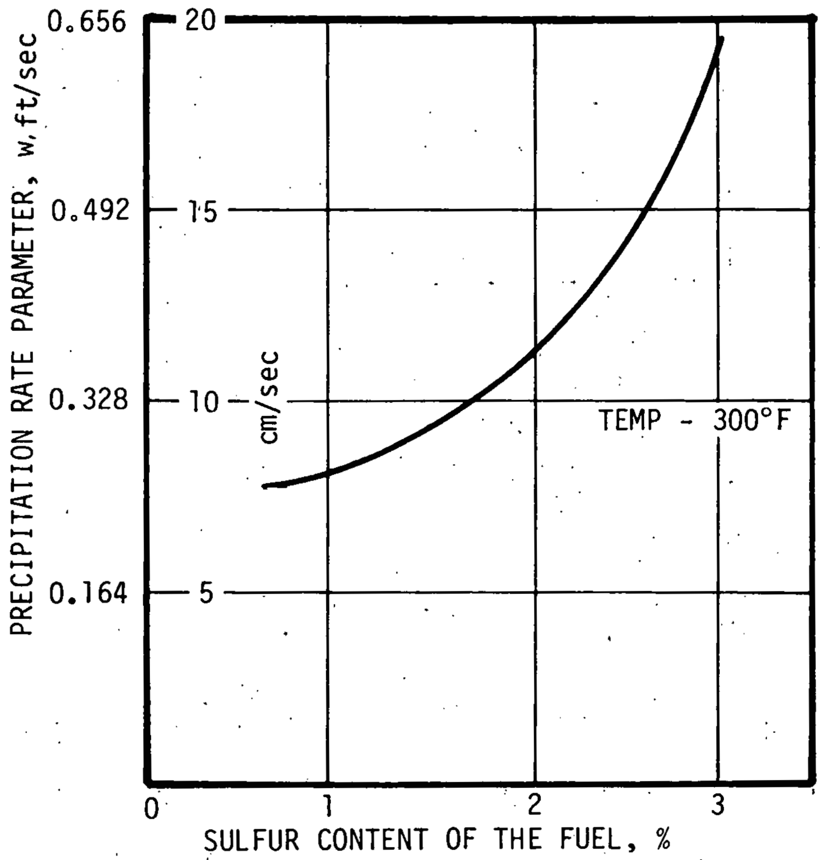


Figure 3.5 Relationship between precipitation rate parameter and sulfur content for electric utility installations at a temperature of 300 F. (From Ramsdell, R.G., Proc. Am. Power Conf., 30, 129, 1968. With permission.)[35]

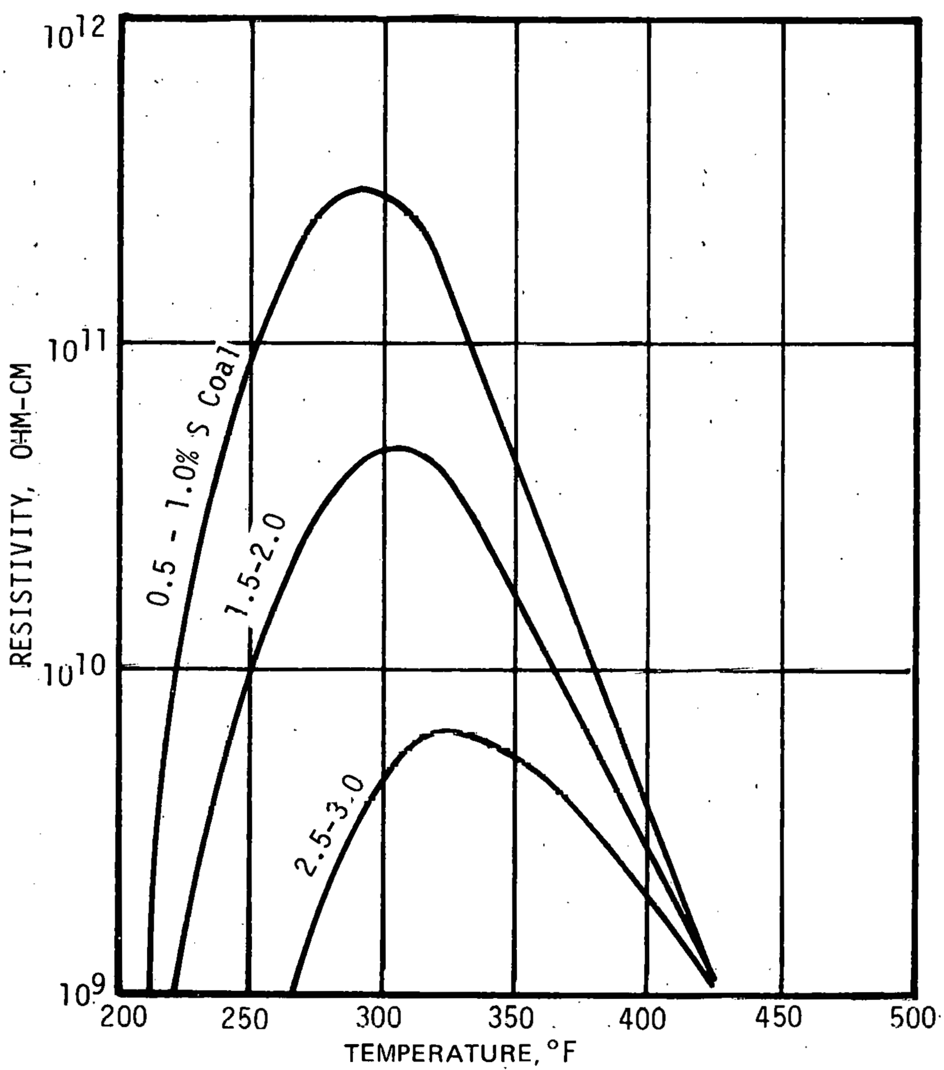


Figure 3.6 Resistivity, Temperature, Fuel, Sulfur Relationships - Eastern Bituminous Coals.[36]

4. The precipitator is run in the lower temperature range of Figure 3.6, where the resistivity also drops sharply. This, however, increases the likelihood of acid condensation and consequent corrosion problems. This type of operation is favorable if suitable, economical materials of construction are available.

Although none of these alternatives is especially attractive, the current trend is toward "hot" precipitators when the fly ash is highly resistive. Typically, to achieve 99% collection efficiency on a "hot" precipitator, a specific collecting area (defined as the ratio of plate area to gas volumetric flow rate, and abbreviated SCA) of around 250 ft^2/1000 ACFM is required. The corresponding SCA for a cold precipitator is about 150 ft^2/1000 ACFM -- if resistivity is not a problem. If the resistivity is high, however, the required SCA of a cold precipitator can be as high as 500 ft^2/1000 ACFM.

Input power can range from about 50 to 150 watts/1000 ACFM. A relationship between the precipitation rate parameter and the power density for pulverized-coal boilers is shown in Figure 3.7,[36] and a relationship between collection efficiency and input power is given in Figure 3.8.[36] A relationship between collection efficiency and SCA for various coal sulfur contents is given in Figure 3.9[36]. Figure 3.10 specifically demonstrates this relationship for Wyoming low-sulfur coal.[37]

3.1.4 Performance Data for Typical Operational Systems

The performance of an electrostatic precipitator is affected by the concentration and size distribution of the fly ash being collected, the electrical resistivity of the layer of collected particles, the uniformity of gas flow and the gas sneakage and re-entrainment level of the system.

Typical operational data on a variety of coals and boiler types are reviewed with particular emphasis on the efficiency

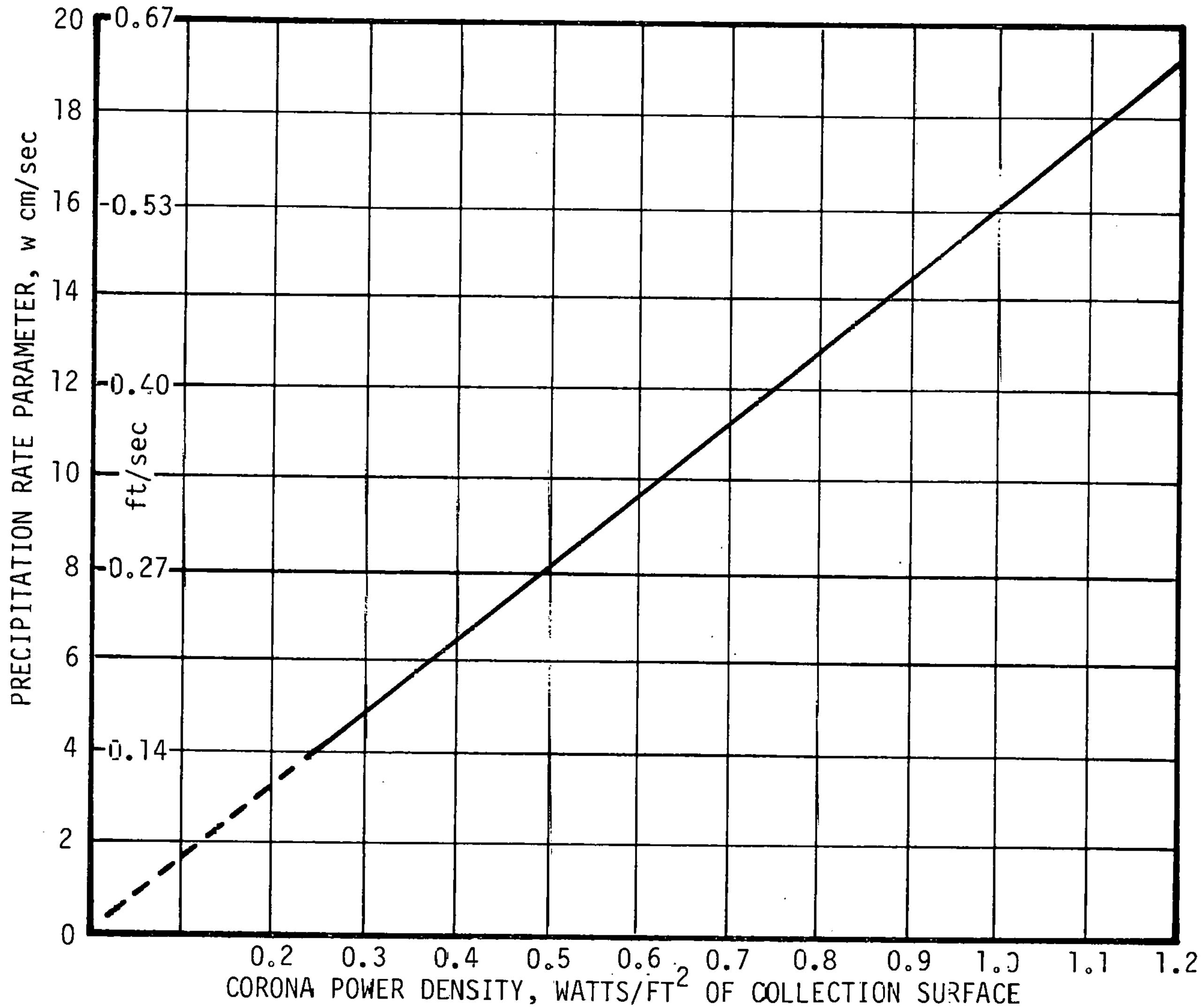


Figure 3.7 Linear Relationship between Precipitation Rate Parameter and Power Density for Fly Ash Collectors.[36]

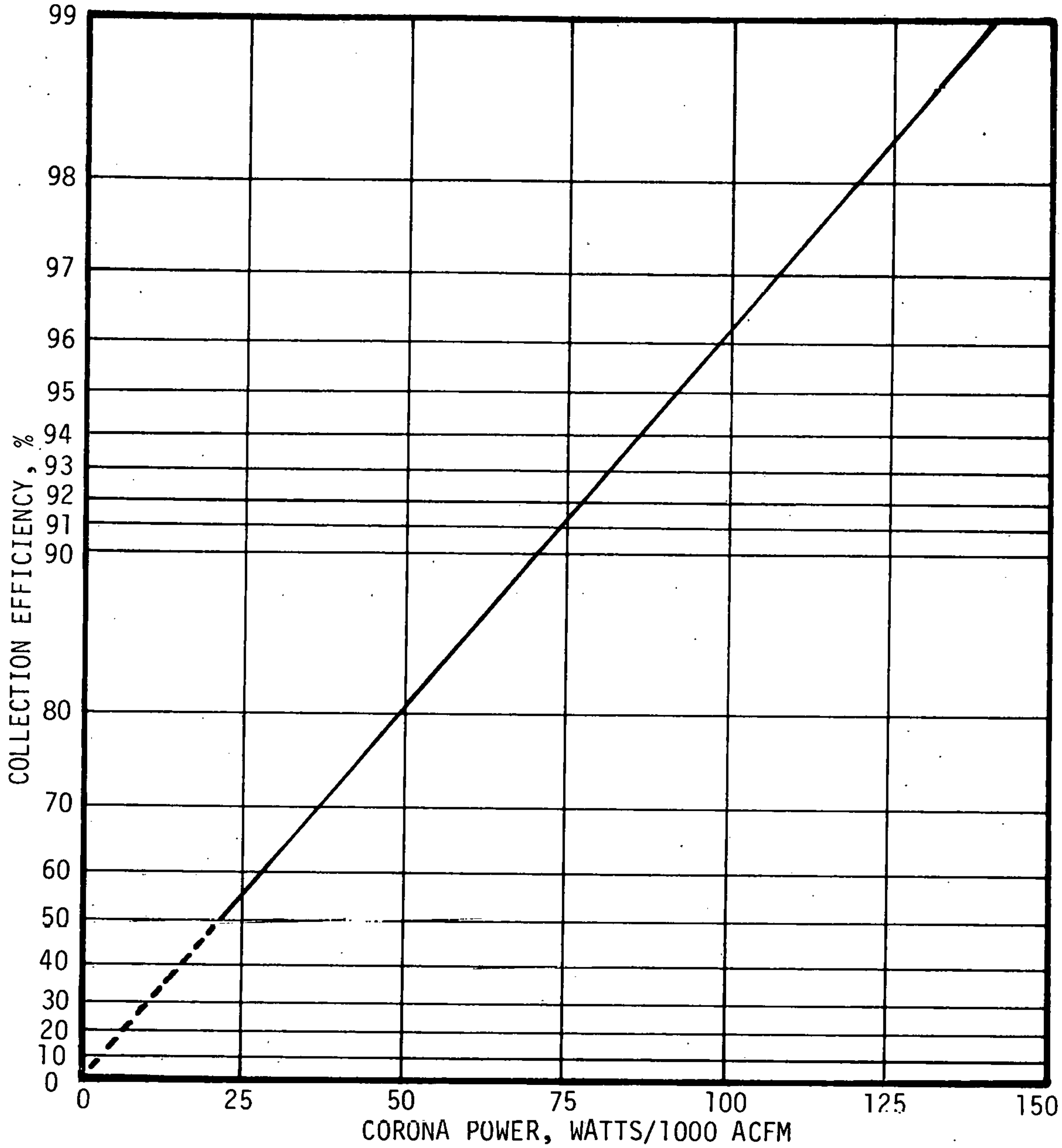


Figure 3.8 Relationship between Collection Efficiency and Corona Power for Fly Ash Precipitators.[36]

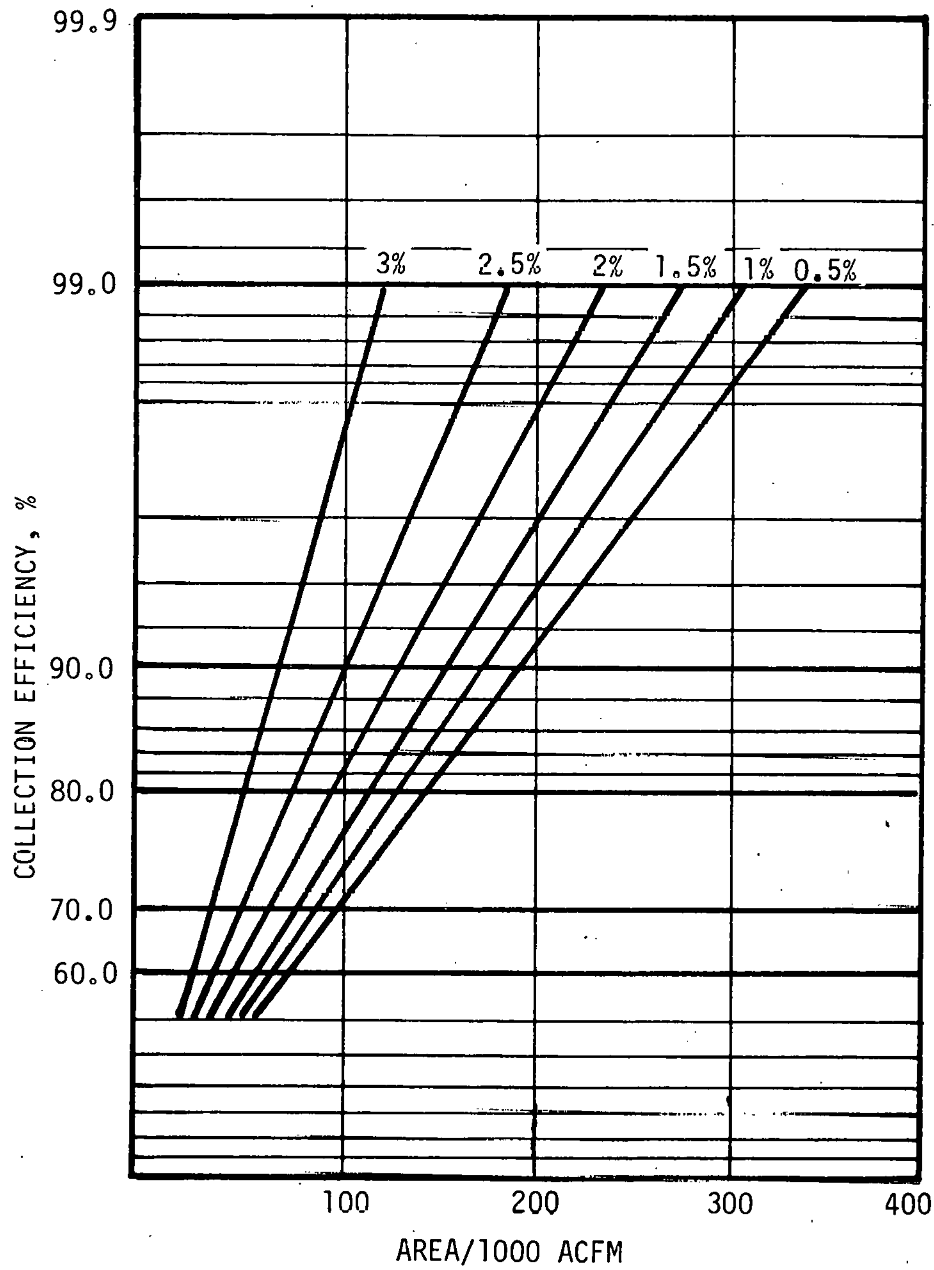


Figure 3.9 Relationship between Collection Efficiency and Collecting Surface Area to Gas Flow Ratio for Various Coal Sulfur Contents. [38]

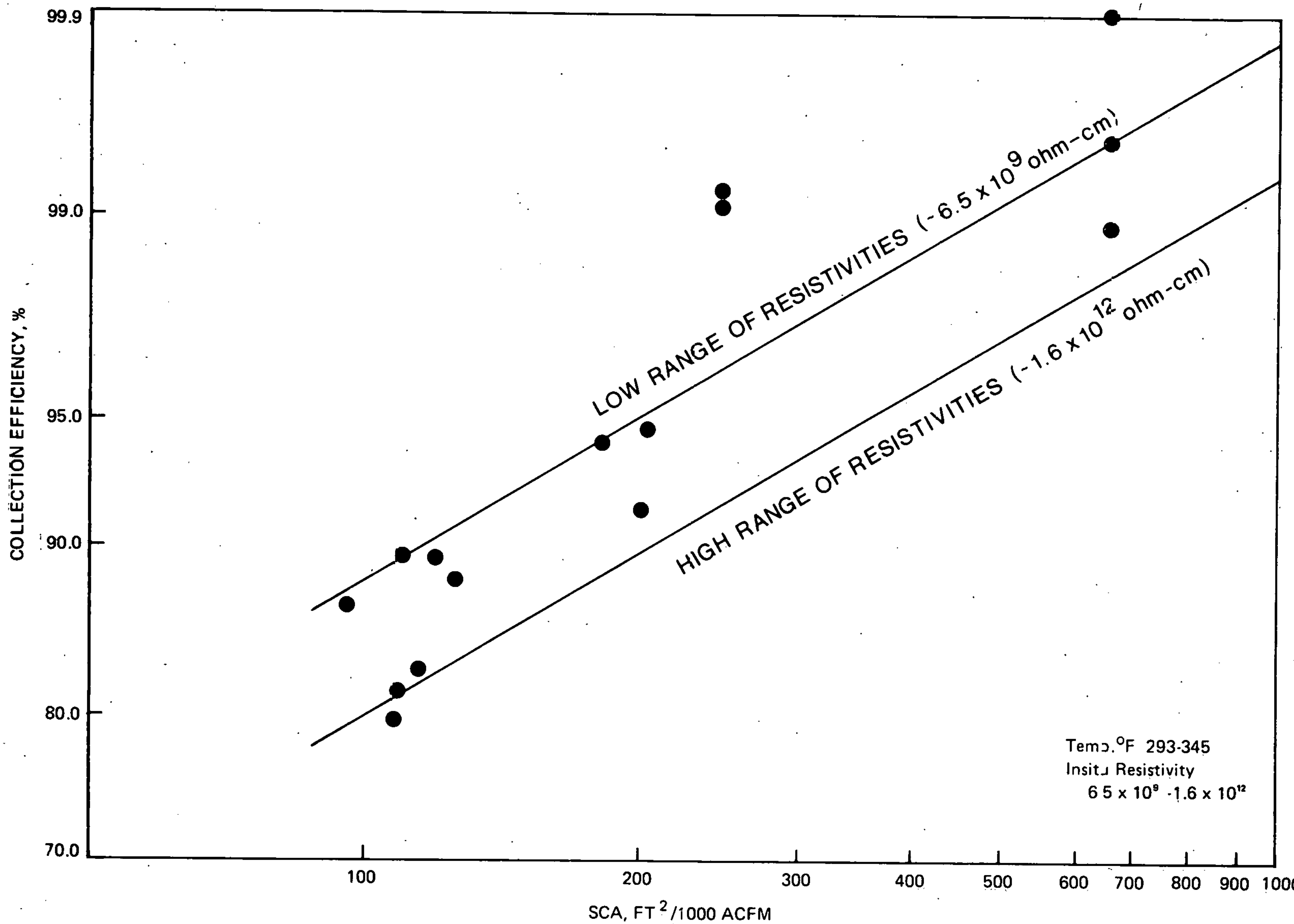


Figure 3.10 Relationship between Collection Efficiency and Collecting Surface Area to Gas Flow Ratio for Various Coal Sulfur Contents. For Wyoming Low Sulfur Coal.[37]

relationship in the fine particulate size range. Other pertinent data and information, where available, are also included.

The performance of a cold-side ESP operating at the J.E. Corette Power Plant of the Montana Power Company is shown in Figure 3.11[38]. The pulverized-coal boilers are fired with Montana sub-bituminous coal with 0.69% sulfur, 8.21% ash, 25.37% moisture and 8,632 Btu/lb. The ESP tested was designed to treat 600,000 ACFM at 300°F and achieve 96% particulate removal efficiency. The particle size data were obtained using a University of Washington Cascade Impactor. Testing at the inlet (Test E) showed a loading of 3.151 grains/SCFD. Under normal operating conditions, the outlet loading ranged from 0.052 (Test B, 98.35% efficiency) to 0.064 (Test A, 97.97% efficiency) grains/SCFD.

The performance of a cold-side ESP on an eastern bituminous coal is presented in Figure 3.12[39]. These data were obtained on the pulverized-coal boilers at the Gorgas Power Station (757 MW) of the Alabama Power Company. The coal contained 1.43% sulfur, 14.71% ash, 7.05% moisture and 11,515 Btu/lb. At full load, the precipitator tested was designed to treat 1,100,000 ACFM at 300°F with a resulting specific collection area (SCA) of 283 ft^2/1000 ACFM. Fractional efficiency data were arrived at using a Brinks cascade impactor at the inlet, an Andersen impactor at the outlet to measure particles greater than 0.5 micron and a diffusion battery with a condensation nuclei counter to measure particles in the sub-micron range. The precipitator efficiencies determined from the testing were 99.59% and 99.69%.

Figure 3.13[39] presents the fractional efficiency data obtained on a hot ESP installed before the air preheater on a pulverized-coal boiler firing southwestern low-sulfur coal. The coal averaged 1.0% sulfur, 23.6% ash, 4.4% moisture and 9850 Btu/lb. The plant, rated at 357 MW, utilized four ESPs, each designed to treat 470,000 ACFM at 700°F under full-load conditions and having a design SCA of 310 ft^2/1000 ACFM. Particle sizing was accomplished

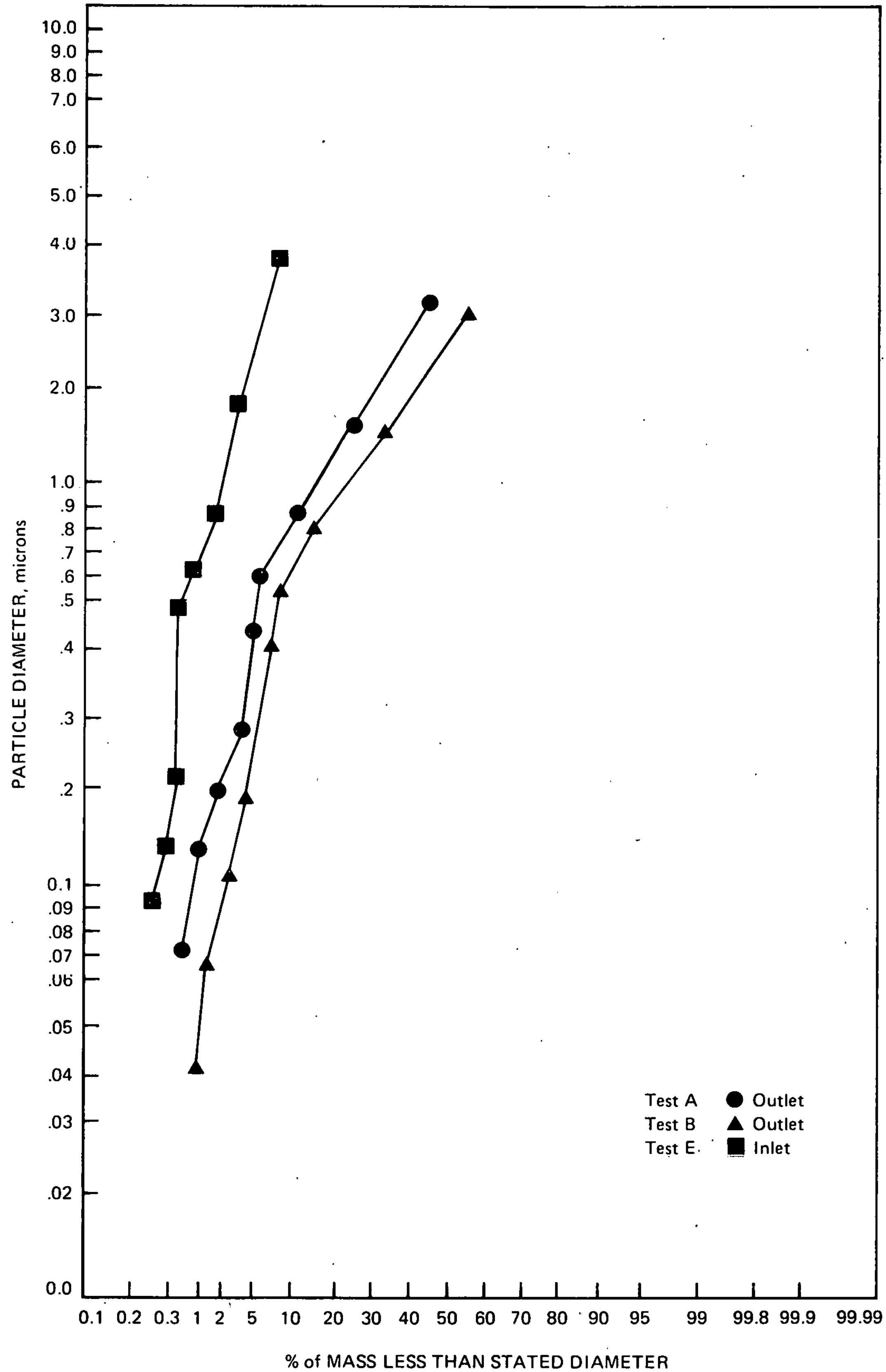


Figure 3.11 Particle Size Distribution for Tests at the J.E. Corette Power Plant (172.8MW) [38]

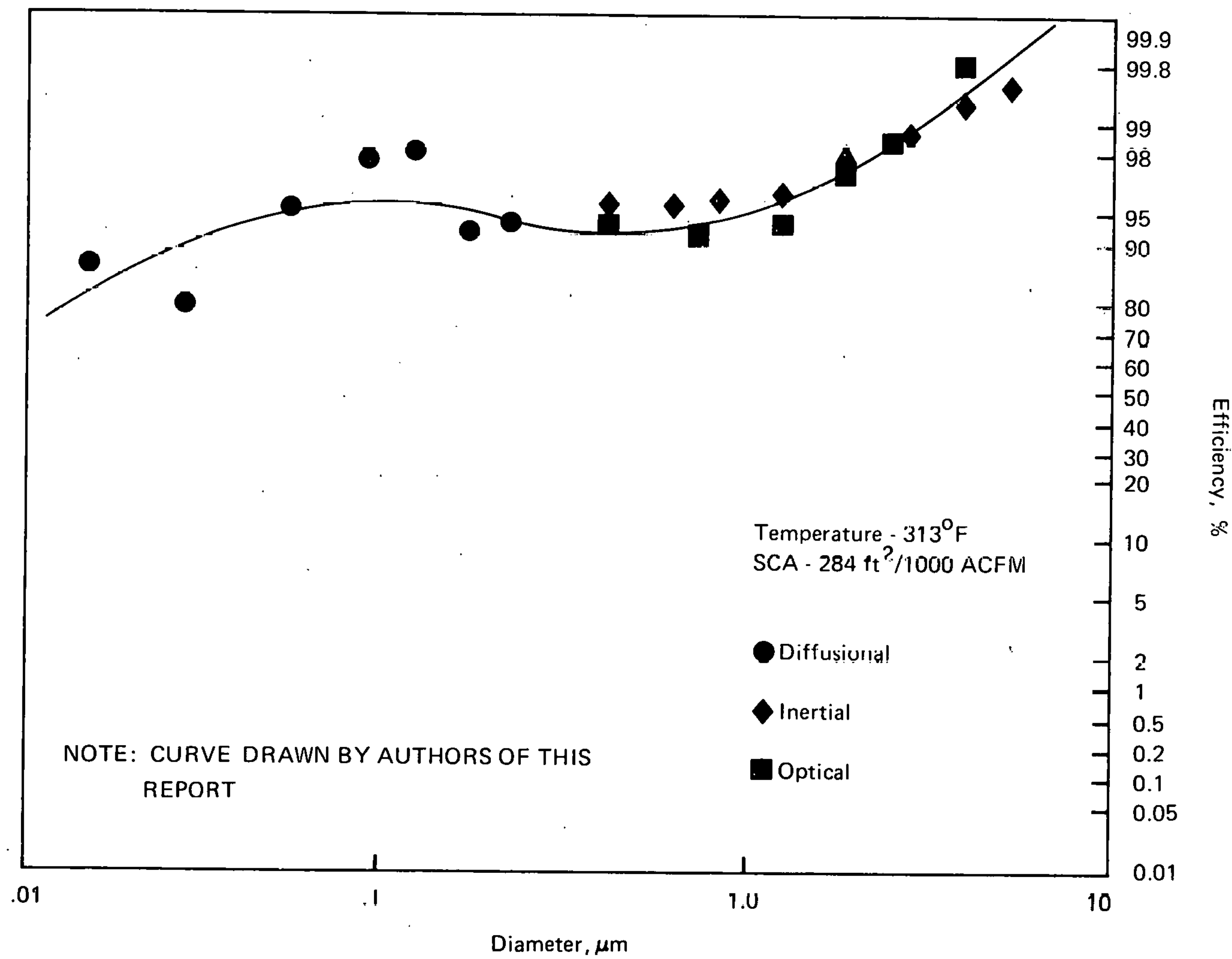


Figure 3.12 Measured Fractional Efficiency for a Cold Precipitator Installation at the Gorgas Plant of Alabama Power Company.[39]

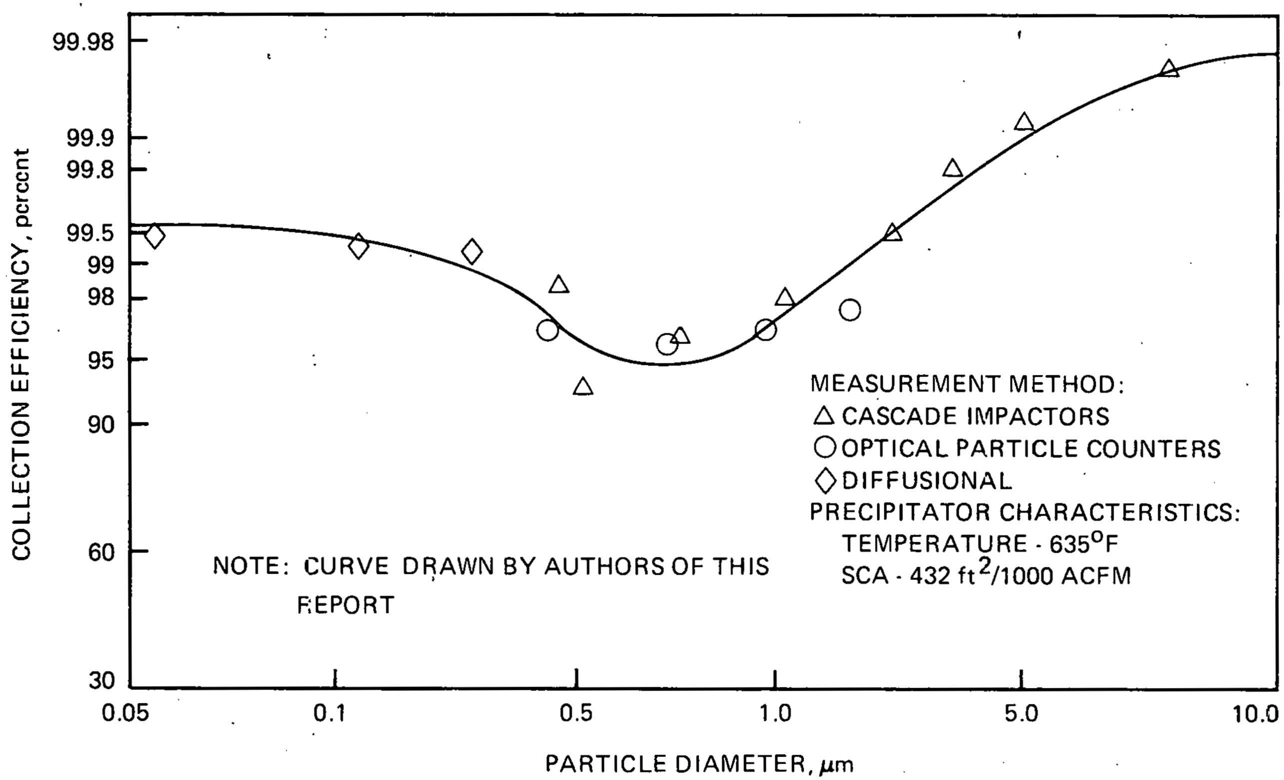


Figure 3.13 Measured Fractional Efficiencies for a Hot-Side Electrostatic Precipitator with the Operating Parameters as Indicated, Installed on a Pulverized Coal Boiler.[39]

in the same manner as in the previous case. Measured precipitator efficiencies ranged from 99.70% to 99.84%.

The performance of a cold-side precipitator handling fly ash from the combustion of low-sulfur coal in a pulverized-coal boiler is shown in Figure 3.14[40]. The precipitator achieved 98.3% efficiency with an SCA of 340 ft^2/1000 ACFM.

The use of sulfur trioxide conditioning was investigated at the George Neal Plant of the Iowa Public Service Company.[41] The coal contained 0.60% sulfur, 10.45% ash, 6.86% moisture and 10,949 Btu/lb. The precipitator, designed for 1,086,000 ACFM at 263°F with an SCA of 197 ft^2/1000 ACFM, achieved 91.3% efficiency without sulfur trioxide injection. The resistivity of the fly ash in this case was about 6 x 10^{10} ohm-cm. Sulfur trioxide conditioning brought the resistivity down to about 4 x 10^{10} ohm-cm and increased the precipitator efficiency to 99.0%.

The performance of a cold-side ESP installed on a cyclone-type coal boiler is shown in Figure 3.15[40]. The boiler was firing a moderate-sulfur coal and the precipitator was achieving 98.1% efficiency at an SCA of 279 ft^2/1000 ACFM.

A generalized comparison of precipitator SCA as a function of sulfur content of bituminous coal for pulverized and cyclone firing at an efficiency level of 99% is presented in Figure 3.16.[30] The cyclone-fired boiler requires an SCA 30 to 40 percent greater than the pulverized coal boiler. This is because of increased carbon carry-over and, to a lesser extent, a smaller particle size distribution, both of which alter the precipitability of the fly ash. A similar situation between pulverized and cyclone boilers is evident in hot-side precipitators, as shown in Figure 3.17[30]. In this case, however, the iron, sodium and other alkali contents of the fly ash, rather than the sulfur content of the coal, govern the SCA requirements.

Certain generalizations about the performance of ESPs with respect to fine particulate control may be drawn from the

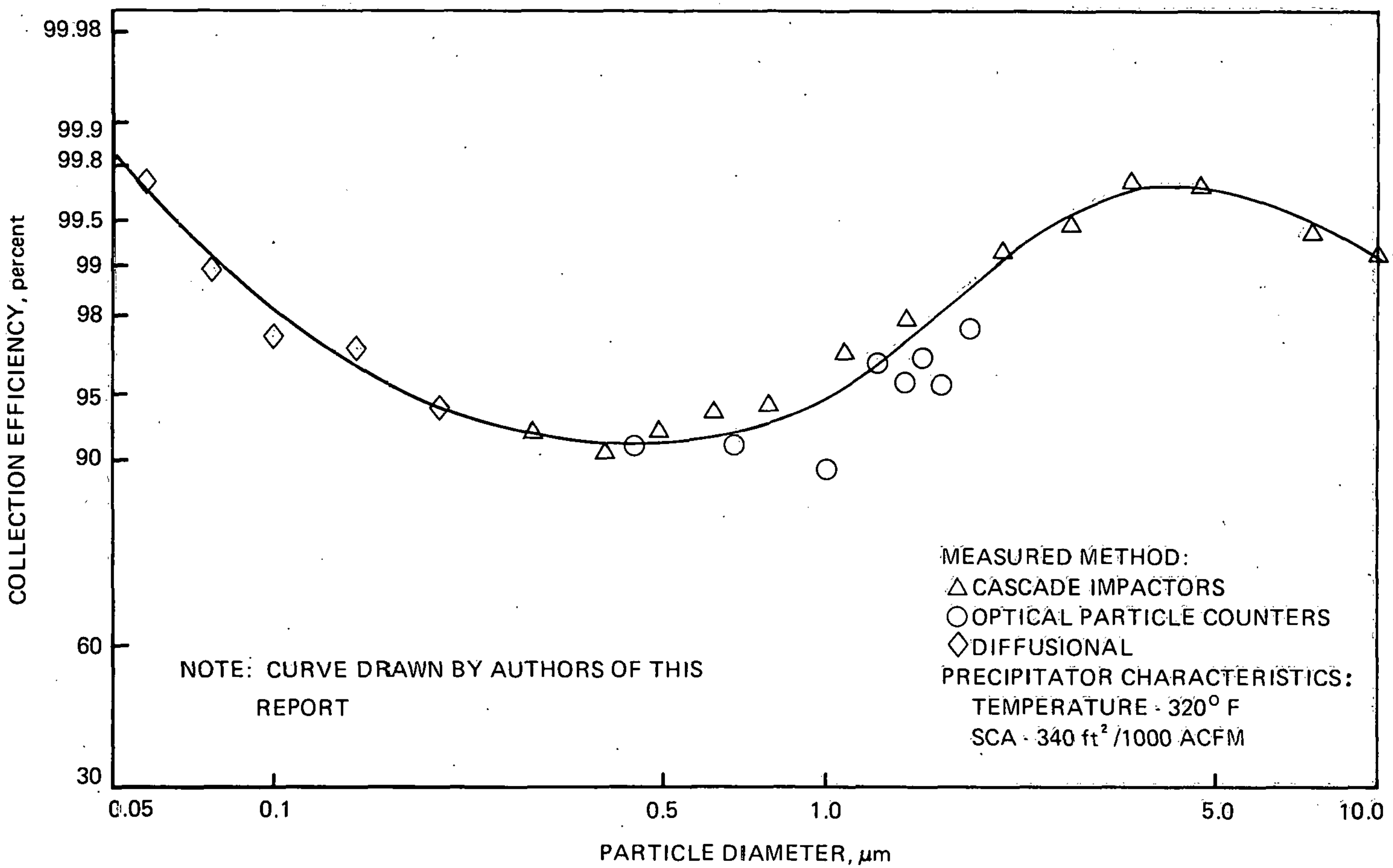


Figure 3.14 Fractional Efficiencies for a Cold-Side Electrostatic Precipitator with the Operating Parameters as Indicated, Installed on a Pulverized Coal Boiler.[40]

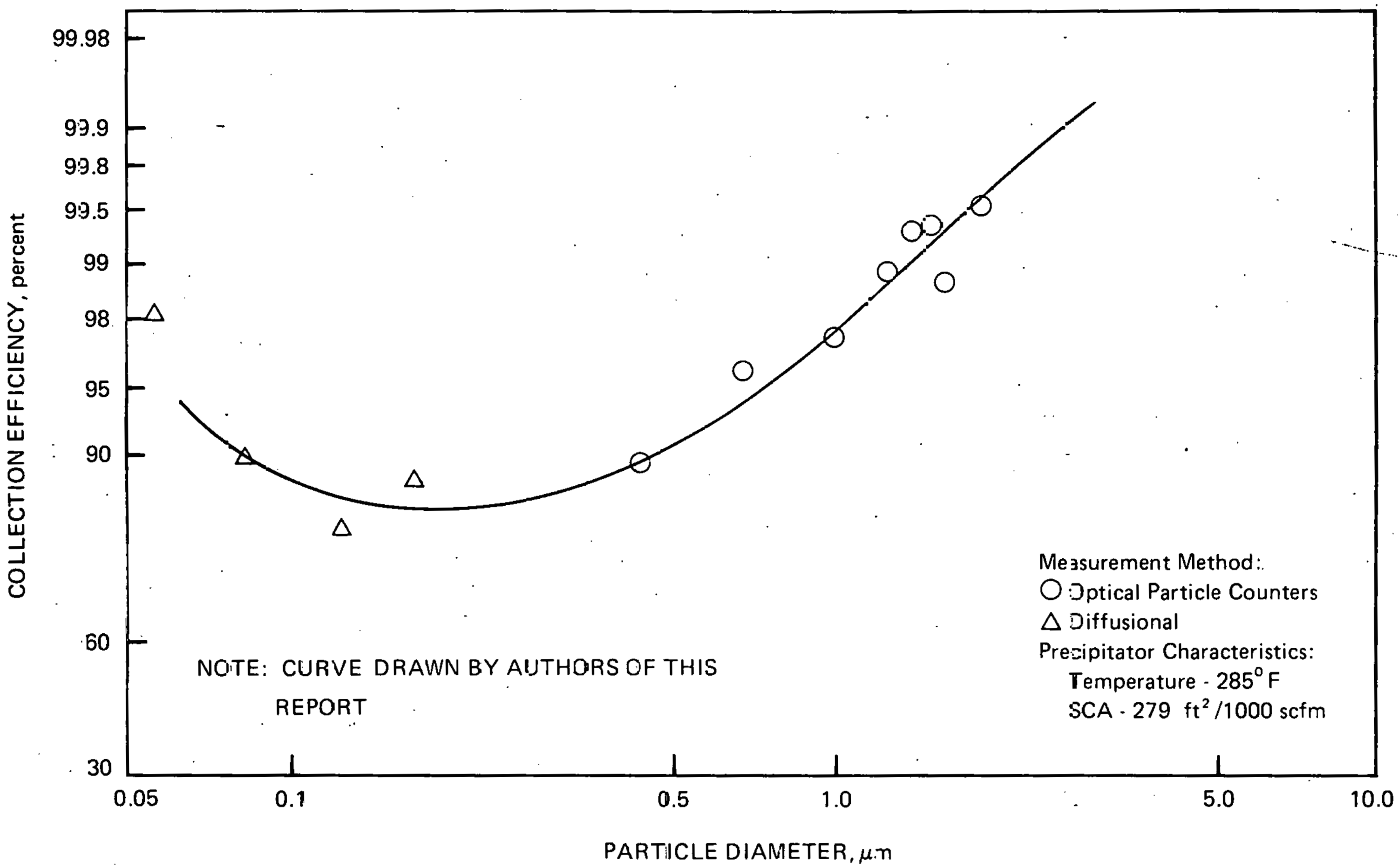


Figure 3.15 Measured Fractional Efficiencies for a Cold-Side Electrostatic Precipitator with the Operating Parameters as Indicated, Installed on a Cyclone Type Coal Boiler.[40]

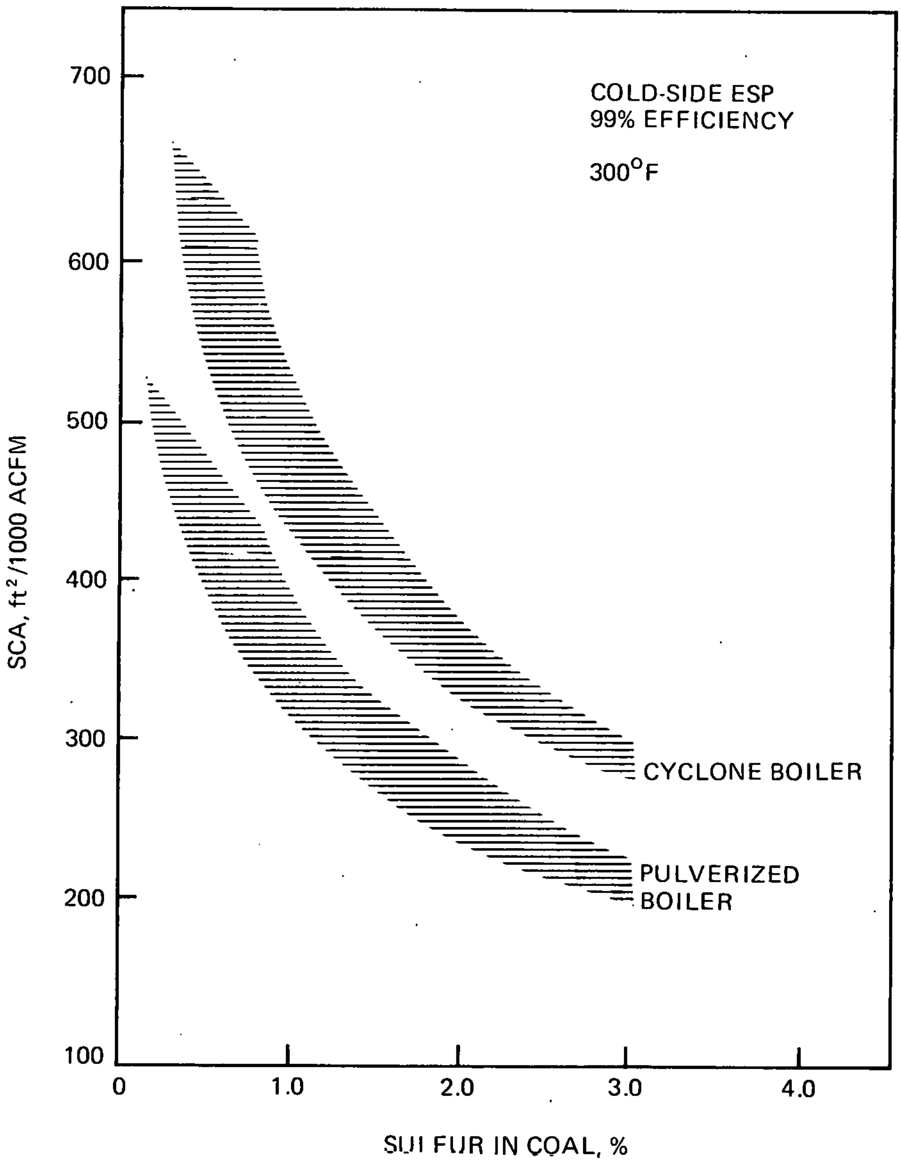


Figure 3.16 SCA vs. Sulfur Content of Bituminous Coal.[30]

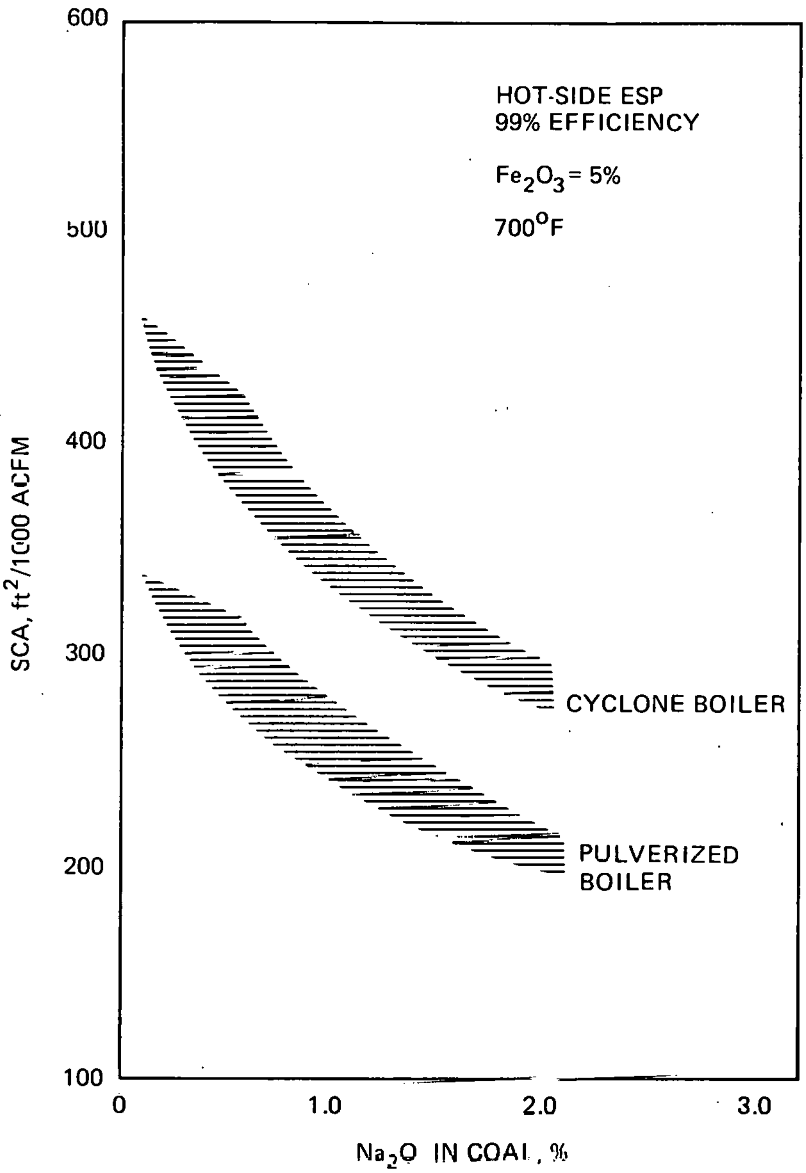


Figure 3.17 SCA vs. Na_2O Content of Western Coal.[30]

above data and analysis of the mechanisms of particle charging and collection. First, ESPs can control fine particulate emissions where the particulate electrical properties are properly treated in the design phase. Second, ESPs can be as effective in controlling the very fine particulates (less than 2μm) as they are in controlling the coarse particulates (greater than 2μm) due to the combined effects of diffusion charging and ion bombardment. Finally, the fine particulates most difficult to control in typical "cold" ESP operation are those approximately 0.3 micron in diameter. This is due to the fact that the diffusion charging mechanism works best on small particles, whereas ion bombardment has its effect on large particles. The combined charging mechanism has a minimum at the aforementioned particle diameter (0.3 μm).

3.1.5 Operation and Maintenance

Problems with ESPs can arise both when the unit is brought on-line and after extended operation. Many precipitator components are subject to failure or malfunction, which can lead to increased emissions. Faulty design, installation, or operation of the precipitator can cause these malfunctions. The reduction in efficiency is variable and depends on the severity of the malfunction. Many malfunctions are interrelated.

The most common malfunctions associated with precipitators stem from broken discharge wires and plugged ash hoppers.[42] Other problems result from failure of rappers or vibrators and suspension insulators, changes in coal specifications, poor distribution of gas flow and boiler-related malfunctions or variations.[42] Some of these malfunctions are briefly discussed below.

3.1.5.1 Broken Discharge Wires

When a discharge electrode breaks, it usually causes an electrical short circuit between the high-tension discharge-wire system and the grounded collection plate. This electrical short trips the circuit breaker, disabling a section of the precipitator. Electrical erosion, mechanical fatigue, and ash hopper build-up are three common causes of electrode wire failure.

The impact of wire failures on precipitator availability and efficiency is a function not only of the frequency of failure but also of the degree of sectionalization, the availability of spare sections and the difficulty involved in removing failed wires during operation. Most precipitators do not have suitable isolation dampers to allow safe access to the interior while the boiler is in operation; thus, the unit must be shut down for removal of these broken wires. Inadequate sectionalization causes a greater drop in efficiency, and a number of wire breaks in different sections may seriously impair the operation of the precipitator.

3.1.5.2 Collection Hoppers and Ash Removal

Inadequate ash removal is a major cause of precipitator malfunction. Most problems associated with hoppers are related to the proper flow of the dust. Improper adjustment of the hopper vibrators or failure of the conveyor system is usually the cause of the hoppers failing to empty. Low flue gas temperature, which permits moisture condensation, can also cause plugging of the hopper. This results from carrying the boiler exit gas temperature too low or from excessive leakage of ambient air into the hopper.

Buildup of ash can cause short-circuiting of the precipitator. It can also cause excessive sparking, which erodes electrodes and sometimes pushes internal components out of position, causing misalignment that can drastically affect performance.

3.1.5.3 Rappers or Vibrators

Poor performance can result from rapping forces that are either too mild or too severe. Although some re-entrainment always occurs, effective rapping minimizes the amount of material re-entrained in the gas stream. Rapping that is too intense and too frequent results in a clean plate, which causes the collected dust to become re-entrained rather than falling into the hopper. Inadequate rapping of the discharge electrode results in a heavy dust build-up with localization of the corona, low corona current, excessive sparking, impaired performance and possible grounding of the high-voltage system.

3.1.5.4 *Insulator/Bushing Failure*

Suspension insulators are used to support and isolate the high-voltage parts of the precipitator. Inadequate pressurization of the top housing of the insulators can cause ash deposits, as well as moisture condensation on the bushing, which may result in electrical breakdown. Fouling and cracking of insulators reduce the effective voltage levels and collector performance but rarely decommission a bus section.

Table 3.2[42] lists common precipitator malfunctions, their causes, the effects on emissions, and the corrective action required.

3.1.6 *Operational Procedures and Firing Practices That Affect Emissions*

In addition to precipitator malfunctions, a number of operating and coal boiler firing practices can affect precipitator emissions. Changes in these practices can also cause precipitator malfunctions, which may in turn degrade performance.

3.1.6.1 *Gas Volume*

Any increase in boiler load that results in excessive flow through the precipitator will cause a loss in efficiency. For example, if a precipitator is designed for a velocity of 3 ft/sec and an efficiency of 99%, an increase in velocity to 4 ft/sec (a 33% load increase in the volumetric flow rate) can decrease the efficiency to about 97%.

3.1.6.2 *Temperature*

A change in operating temperature may also affect precipitator efficiency, as is shown in the following example, in which

Table 3.2 Summary of Problems Associated with ESP's[42]

Malfunction	Cause	Effect on ESP Efficiency[a]	Corrective action	Preventive measures
1. Poor electrode alignment	1) Poor design 2) Ash buildup on frame hoppers 3) Poor gas flow	Can drastically affect performance and lower efficiency	Realign electrodes Correct gas flow	Check hoppers frequently
2. Broken electrodes	1) Wire not rapped clean, causes an arc which embrittles and burns through the wire 2) Clinkered wire. Causes: a) poor flow area, distribution through unit is uneven; b) excess free carbon because of excess air above combustion requirements or fan capacity insufficient for demand required; c) wires not properly centered; d) ash buildup resulting in bent frame, same as c); e) clinker bridges the plates & wire shorts out; f) ash buildup, pushes bottle weight up causing sag in the wire; g) "J" hooks have improper clearances to the hanging wire; h) bottle weight hangs up during cooling causing a buckled wire; i) ash buildup on bottle weight to the frame forms a clinker and burns off the wire	Reduction in efficiency because of reduced power input, bus section unavailability	Replace electrode	Boiler problems; check space between recording steam & air flow pens, pressure gauges; fouled screen tubes. Inspect hoppers Check electrodes frequently for wear Inspect rappers frequently
3. Distorted or skewed electrode plates	1) Ash buildup in hoppers 2) Gas flow irregularities 3) High temperatures	Reduced efficiency	Repair or replace plates Correct gas flow	Check hoppers frequently for proper operation; check electrode plates during outages
4. Vibrating or swinging electrodes	1) Uneven gas flow 2) Broken electrodes	Decrease in efficiency caused by reduced power input	Repair electrode	Check electrodes frequently for wear
5. Inadequate level of power input (voltage too low)	1) High dust resistivity 2) Excessive ash on electrodes 3) Unusually fine particle size 4) Inadequate power supply 5) Inadequate sectionalization 6) Improper rectifier and control operation 7) Misalignment of electrodes	Reduction in efficiency	- Clean electrodes; gas conditioning or alterations in temp. to reduce resistivity; Increase sectionalization	Check range of voltages frequently to make sure they are correct In situ resistivity measurements
6. Back corona	1) Ash accumulated on electrodes - causes excessive sparking requiring reduction in voltage charge	Reduction in efficiency	Same as above	Same as above
7. Broken or cracked insulator or flower pot bushing leakage	1) Ash buildup during operation causes leakage to ground 2) Moisture gathered during shutdown or low load operation	Reduction in efficiency	Clean or replace insulators &	Check frequently Clean and dry as needed; check for adequate pressurization of top housing
8. Air inleakage through hoppers	1) From dust conveyor	Lower efficiency - dust reentrained through ESP	Seal leaks	Identify early by increase in ash concentration at bottom of exit to ESP
9. Air inleakage through ESP shell	1) Flange expansion	Same as above, also causes intense sparking		

[a] The effects of precipitation problems can only be discussed on a qualitative basis. There are no known emission tests of precipitators to determine performance degradation as a function of operational problems.

Table 3.2 (Cont'd.) Summary of Problems Associated with ESP's[42]

Malfunction	Cause	Effect on ESP Efficiency[a]	Corrective Action	Preventive measures
10. Gas bypass around ESP: - dead passage above plates - around high-tension frame	1) Poor design - improper isolation of active portion of ESP	Only few percent drop in efficiency unless severe	Baffling to direct gas into active ESP section	Identify early by measurement of gas flow in suspected areas
11. Corrosion	1) Temperature goes below dew point	Negligible until precipitator interior plugs or plates are eaten away; air leaks may develop causing significant drops in performance	Maintain flue gas temperature above dew point.	Energize precipitator after boiler system has been on line for ample period to raise flue gas temperature above acid dew point
12. Hopper pluggage	1) Wires, plates, insulators fouled because of low temperature 2) Inadequate hopper insulation 3) Improper maintenance 4) Boiler leaks causing excess moisture 5) Ash conveying system) gasket leakage malfunction) blower malfunction) solenoid valves 6) Misadjustment of hopper vibrators 7) Material dropped into hopper - from bottle weights 8) Solenoid, timer malfunction 9) Suction blower filter not changed	Reduction in efficiency	Provide proper flow of ash	Frequent checks for adequate operation of hoppers. Provide heater thermal insulation to avoid moisture condensation
13. Inadequate rapping, vibrators fail	1) Ash buildup 2) Poor design 3) Rappers misadjusted	Resulting buildup on electrodes may reduce efficiency	Adjust rappers with optical dust measuring instrument in ESP exit stream	Frequent checks for adequate operation of rappers
14. Too intense rapping	1) Poor design 2) Rappers misadjusted 3) Improper rapping force	Reentrains ash, reduces efficiency	Same as No. 13	Same as No. 13 Reduce vibrating or impact force
15. Control failures	1) Power failure in primary system 2) Transformer or rectifier failure a. insulation breakdown in transformer b. arcing in transformer between high voltage switch contacts c. leaks or shorts in high voltage structure d. insulating field contamination	Reduced efficiency	Find source of failure and repair or replace	Pay close attention to daily readings of control room instrumentation to spot deviations from normal readings
16. Sparking	1) Inspection door ajar 2) Boiler leaks 3) Plugging of hoppers 4) Dirty insulators 5) Too-high voltage	Reduced efficiency	Close inspection doors; repair leaks in boiler; unplug hoppers; clean insulators; reduce voltage	Regular preventive maintenance will alleviate these problems

[a]The effects of precipitation problems can only be discussed on a qualitative basis. There are no known emission tests of precipitators to determine performance degradation as a function of operational problems.

a 1.5% sulfur coal and a 99% efficiency guarantee at 325°F is assumed:

Temperature, °F	Efficiency, %
200	99.6
325	99.0
400	99.4

This effect is due to: (1) gas volume being a strong function of temperature, and (2) particle resistivity varying greatly in the temperature range of 200 to 400°F. This impact of temperature on efficiency depends on the coal composition.

3.1.6.3. Fuel

Any significant change in the type of fuel being fired will affect precipitator performance. For example, changing from a bituminous coal with 2% sulfur to a subbituminous western coal with 0.5% sulfur can result in a design efficiency of 99.5% dropping to 90% or less. Other chemical constituents in the ash, such as sodium oxide, can also affect performance by reducing bulk resistivity. In addition, changes in fuel will change the particle size distribution, affecting performance.

3.1.6.4 Inlet Loading

Since a precipitator is designed to remove a certain percentage (by weight) of the entering material, a 50% increase of the inlet concentration may cause the outlet concentration to increase by the same amount if no other factors change. This increase can be expected to result in greater opacity of the emission.

3.1.6.5 Carbon

Variations in firing practice or coal pulverization that affect the quantity of combustibles in the fly ash also have an impact on precipitator performance. Carbonaceous materials readily take on an electrical charge in a precipitator but lose their charge quickly and are readily re-entrained. The carbon particle is very conductive and is also large and light in comparison with the other fly ash constituents.

3.2 WET SCRUBBERS

Wet scrubbers are used on coal-fired boilers because of their inherent ability to effectively remove both particulate and gaseous (i.e., sulfur dioxide and nitrogen oxides) pollutants.

3.2.1 Collection Mechanisms[31]

The primary particulate collection mechanism involved in the conventional wet scrubbing operation may include some or all of the following:

1. Inertial impaction
2. Direct interception
3. Diffusion (Brownian movement)
4. Condensation

Inertial impaction occurs when an object (the droplet), placed in the path of a particulate-laden gas stream, causes the gas to diverge and flow around it. Larger particles, however, tend to continue in a straight path because of their inertia. They may impinge on the obstacle and be collected (cf. Figure 3.18A[31]). Since the trajectories of particle centers can be calculated, it is possible to determine theoretically the probability of collision.

Deposition by direct interception occurs when the particles, moving along streamlines of the fluid, approach the droplet within a distance equal to the radius of the particle. As previously stated, the trajectory of particle centers can be calculated; however, even though the center may by-pass the target object, a collision might occur, since the particle has finite size (cf. Figure 3.18B). A collision occurs due to direct interception if the dust particle's center misses the target object by some dimension less than the particle's radius.

The diffusion mechanism results from very small (submicron) particles suspended in a gas stream having an individual oscillatory motion, known as Brownian movement (cf. Figure 3.18C). In this case, particle and target collide as a result of relative motion within

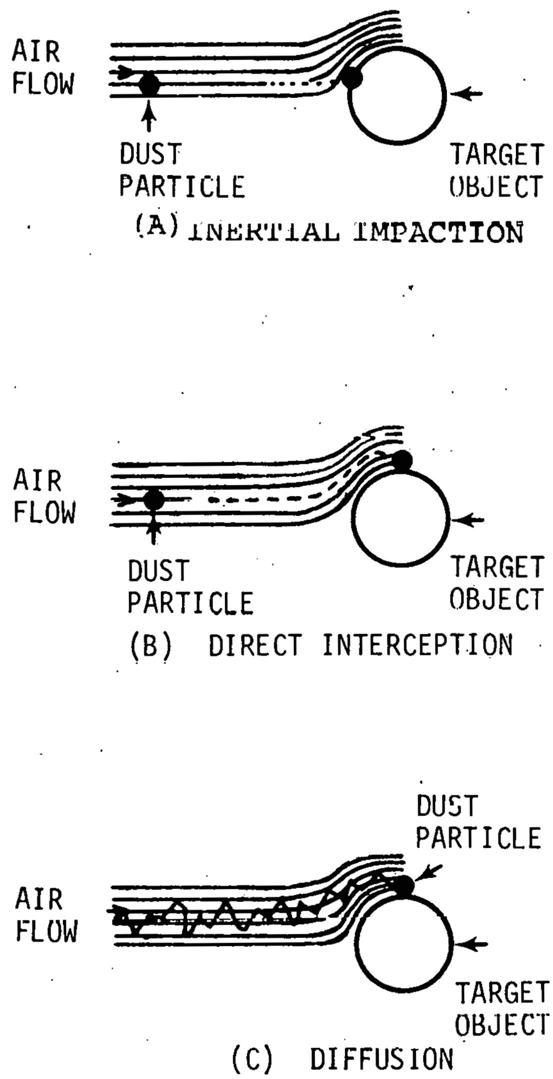


Figure 3.18 Principal Collection Mechanisms In Wet Scrubbers.[31]

limited space. In all diffusion processes, the rate of transfer is proportional to the surface area available for diffusion. Thus small liquid droplets with high surface-to-volume ratios lead to high collection efficiencies.

Condensation effects may also come into play. Condensation occurs if the gas or air is rapidly cooled below its dew point. When moisture is condensed out of the gas stream, fogging occurs, and the dust particles can serve as condensation nuclei. The dust particles can become larger as a result of the condensed liquid, and the probability of removal by impaction and diffusiophoresis is increased.

3.2.2 Description of Equipment

Four types of wet scrubbers are presently used for particulate control in the electric utility industry:

- moving-bed scrubbers
- Venturi scrubbers
- preformed spray scrubbers
- flooded fixed-bed scrubbers

Brief descriptions are provided below.

3.2.2.1 Moving-Bed Scrubbers

Moving-bed (fluid-bed) scrubbers incorporate a zone of movable packing where gas and liquid can mix intimately. The system shown in Figure 3.19[31] uses packing consisting of low-density polyethylene or polypropylene spheres about 1½ inches in diameter; these are kept in continuous motion between the upper and lower retaining grids. Such action keeps the spheres continually cleaned and considerably reduces any tendency for the bed to plug. Pressure drops typically range from 3 to 5 inches of water (per stage), and collection efficiencies are in excess of 99% for particles down to 2 µm. Particle collection may be enhanced by using several moving-bed stages in series. Liquid-to-gas ratios typically range from 15 to 60 gal/1000 ACFM.

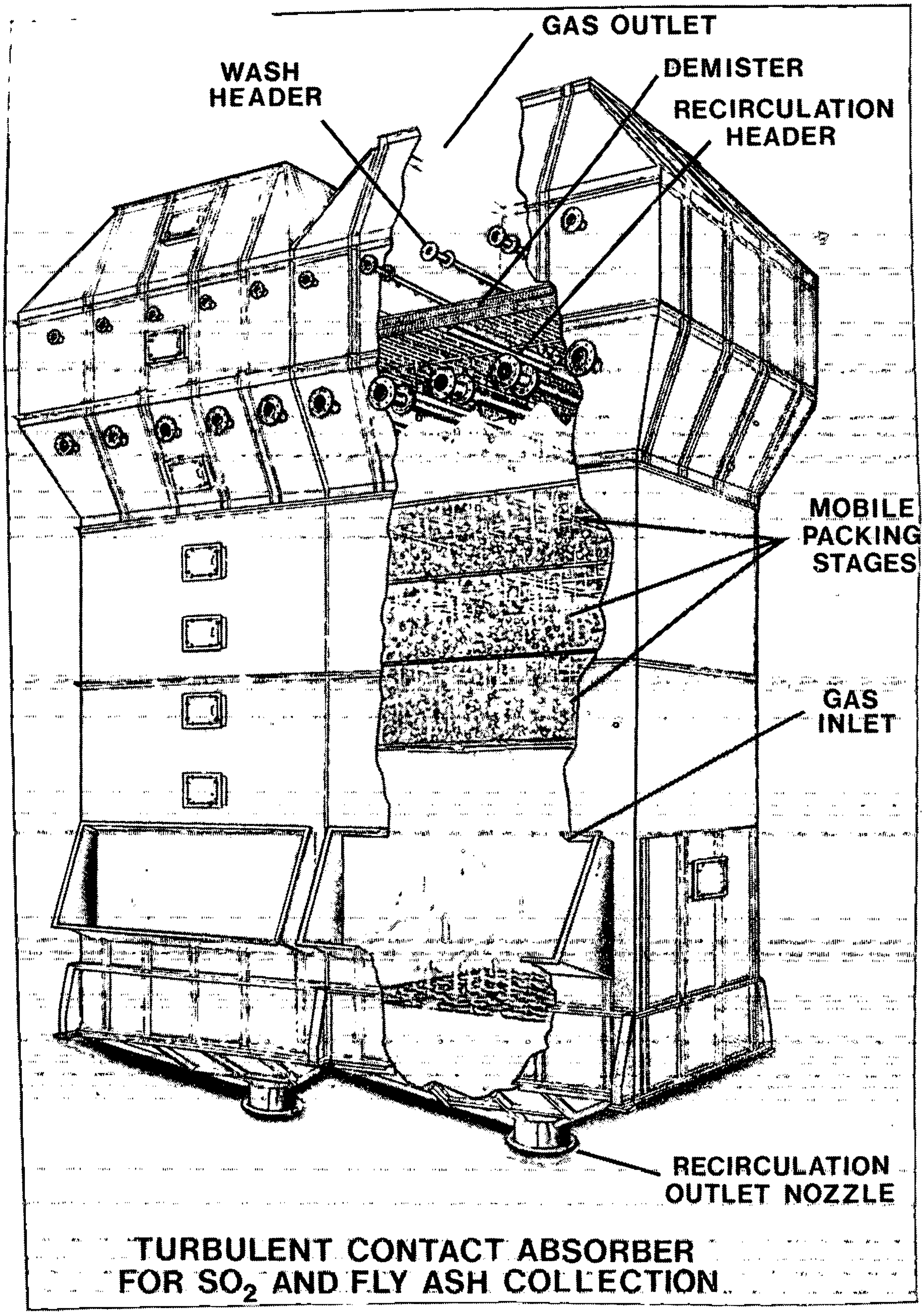


Figure 3.19 Moving-Bed Scrubber.[31]

3.2.2.2 Venturi Scrubbers

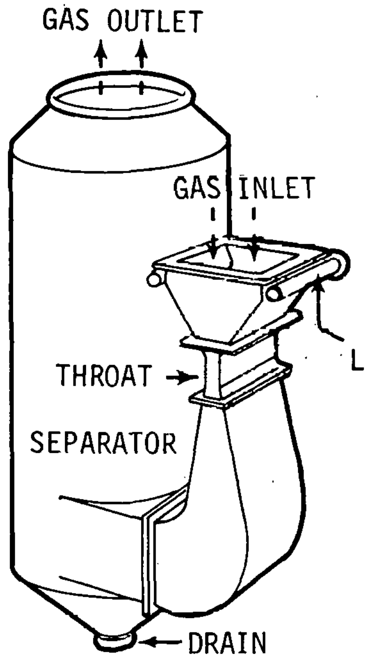
The Venturi scrubber, the type of gas-atomizing scrubber most often used in air pollution control, is discussed in this sub-section. To achieve a high efficiency of collection of particulates by impaction, a small droplet diameter and a high relative velocity between the particle and droplet are required. In a Venturi scrubber this is accomplished by introducing the scrubbing liquid at right angles to a high-velocity gas flow in the Venturi throat (vena contracta). Very small water droplets are formed and high relative velocities are maintained until the droplets are accelerated to their terminal velocities. Gas velocities through the Venturi throat typically range from 12,000 to 24,000 ft/min, although values as high as 40,000 ft/min have been reported. The velocity of the gases alone causes the atomization of the liquid. The energy expended in the scrubber (except for the small amount used in the sprays and mist eliminator) is accounted for by the transfer of momentum to the accelerating drops, which is nearly equal to the gas stream pressure drop through the scrubber. Another factor important to the effectiveness of the Venturi scrubber is the conditioning of the particulates by condensation. If the gas in the reduced pressure region of the throat is fully saturated (or supersaturated, preferably) some condensation will occur on the particulates in the throat due to the Joule-Thompson effect. Condensation will be more pronounced if the gas is hot, due to the cooling effect of the scrubbing liquid and the combined effects of thermophoresis and diffusiophoresis.

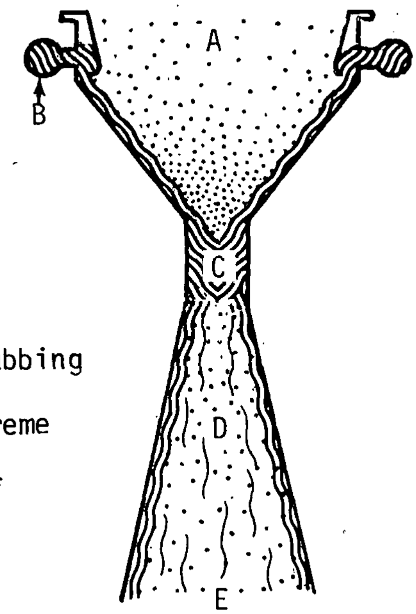
The Venturi itself is only a gas conditioner and must be followed by a separating section for the elimination of entrained droplets (cf. Figure 3.20[31]). Water is injected into the Venturi in quantities typically ranging from 6 to 15 gal/1000 ft^3 of gas. Very high collection efficiencies are achievable depending on the operating pressure drops selected. For example, a 10-in. pressure drop Venturi can typically remove particles as small as 2-4 microns with virtually 100% efficiency, while a 60-

P R I N C I P L E S OF O P E R A T I O N

A - The contaminated gas enters the Venturi and is accelerated in the converging section.

B - The scrubbing liquid is introduced, uniformly, at the top of the converging section and cascades by gravity and velocity pressures towards the throat. (This feature keeps the walls of the converging section wetted and continuously flushed, thereby eliminating material build-up).





C - The contaminated gas and the scrubbing liquid enter the Venturi Throat, where they are mixed at high energy and extreme turbulence. (This throat, with its length, provides an extended period of thorough mixing).

D - The scrubbed gas and entrained droplets (with contaminants entrapped) enter the diverging section where further collisions and agglomeration take place, creating larger drops.

E - The gases then proceed to the separator, where liquid drops are easily removed from the gas stream and collected.

Figure 3.20 Venturi Scrubber with Cyclone Separator.[31]

in. pressure drop Venturi is often required to completely remove particles as small as 0.3 to 0.4 μm. Since collection efficiency is directly related to pressure drop, variable-throat Venturi scrubbers have been introduced (cf. Figure 3.21[31]) to maintain pressure drop with varying gas flows, such as are encountered in boiler plants. In these systems the scrubbing efficiency and pressure drop may be adjusted (manually or automatically) by changing the position of a disk located in the Venturi throat.

3.2.2.3 Preformed Spray Scrubbers

In preformed spray scrubbers, high-pressure spray nozzles (100 to 200 psig) are used to generate liquid droplets (300 to 600 microns in diameter), which are projected at high velocity against a "membrane" through which the gas is flowing (cf. Figure 3.22[31]). The "membrane" is made up of vertical bars closely spaced to act as Venturis. The spray nozzles are arranged so that a rebound zone of fast-moving droplets is established at the "membrane" surface. When the dirty gas enters the scrubber, the large solid particles are captured by the high-speed water droplets, mainly by virtue of the impaction mechanism. At the "membrane," the gas is suddenly accelerated through linear Venturis, where more scrubbing is accomplished. As expected, particle size distribution has a significant effect on the overall performance.

Gas retention time is very short -- on the order of 2 to 3 seconds -- and gas throughput velocities are very high -- up to 600 fpm. Due to the short retention time, diffusion forces are not very effective in capturing submicron particles. In general, the device is not efficient enough to compete with a high-pressure drop Venturi scrubber. Gas pressure drop in preformed spray scrubbers is on the order of 3 to 4 inches of water, while liquid-to-gas ratios typically range from 4 to 8 gal/1000 ACFM.

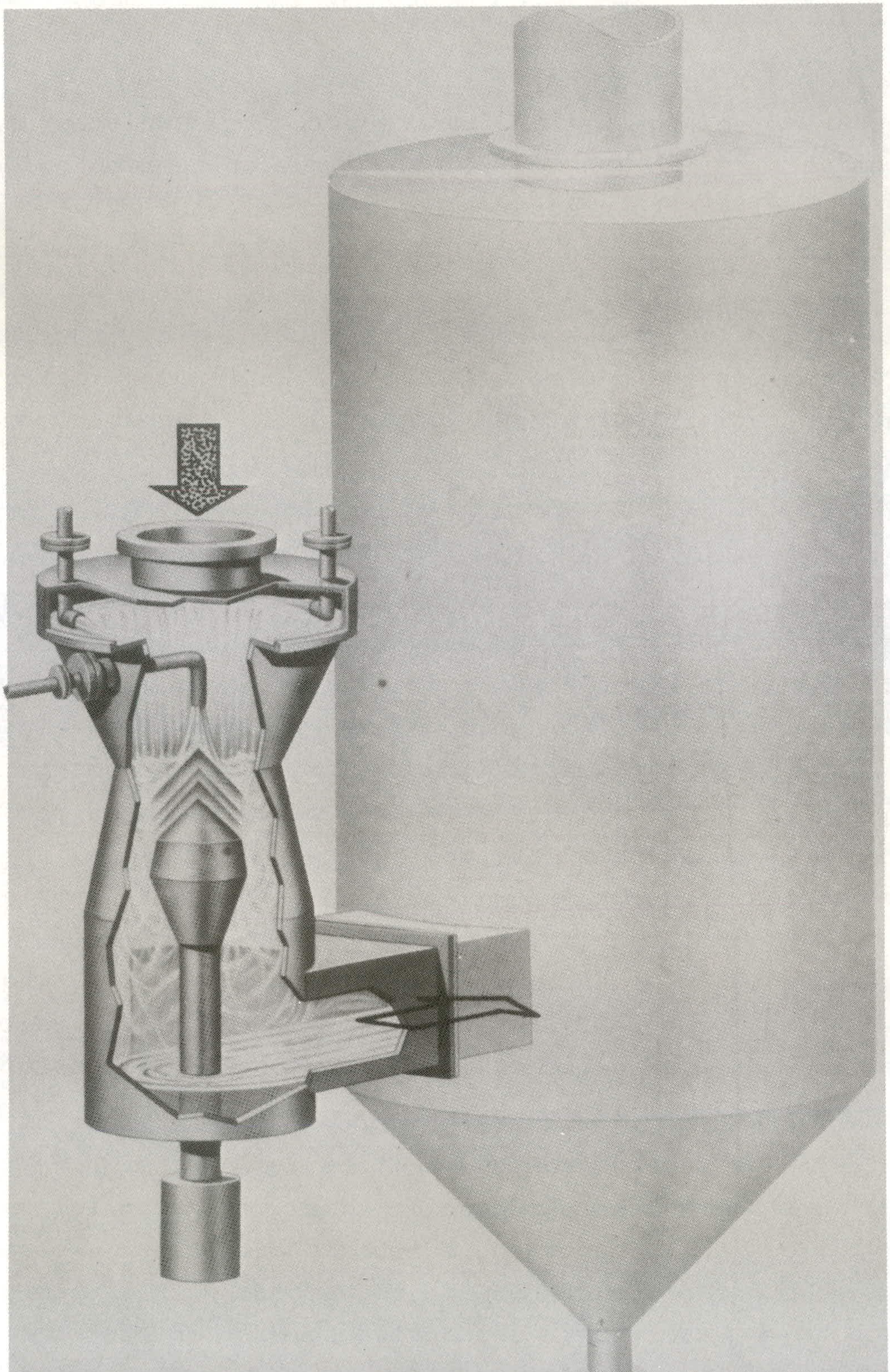


Figure 3.21 Variable-Throat Venturi Scrubber.[31]

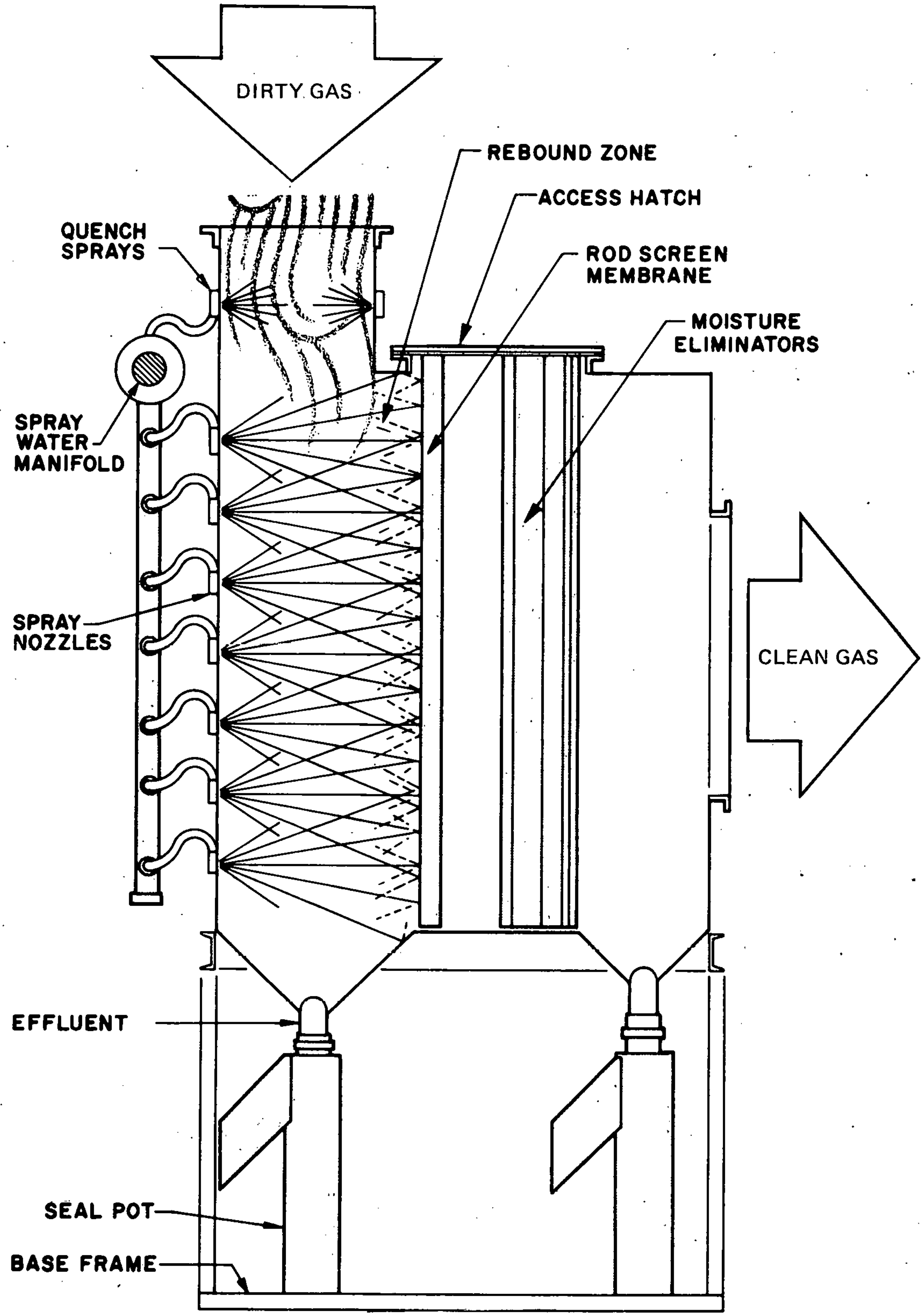


Figure 3.22 Preformed Spray Scrubber.[31]

3.2.2.4 *Flooded Fixed-Bed Scrubbers*

Flooded fixed-bed scrubbers are composed essentially of fixed packed beds, which operate in a flooded mode (cf. Figure 3.23[31]). A highly efficient turbulent layer is formed above the bed. The gas flows up through the packing (usually marbles) and interacts with the liquid in both the bed and the turbulent layer. Scrubbing liquid is usually fed co-currently at a rate ranging from 10 to 15 gal/1000 ACFM with a single bed pressure drop of approximately 4 to 6 in. W.C. Efficiencies can be increased by using multiple beds.

3.2.3 *Design Methodology*[31]

The principal factors that affect the performance of wet scrubbers on coal-fired boilers are the scrubber pressure drop and the particle size distribution of the fly ash. The relationship between pressure drop and efficiency forms the basis of a scrubber design technique that has developed from the contact power theory. This theory assumes that particulate collection efficiency in a scrubber is solely a function of the total pressure loss for the unit. The total pressure loss, P_T (expressed in units of hp/1000 ACFM), is composed of two main constituents: the pressure drop of the gas passing through the scrubber, P_G, and the pressure drop of the spray liquid during atomization, P_L. These two terms can be estimated by:

$$P_G = 0.1573\ (\Delta p) \tag{2}$$

$$P_L = 0.583\ p_L\ (L/G) \tag{3}$$

$$P_T = P_G + P_L \tag{4}$$

where

P_G = contacting power based on gas stream energy input, hp/1000 ACFM

Δp = gas pressure drop across scrubber, in. W.C.

P_L = contacting power based on liquid stream energy input, hp/1000 ACFM

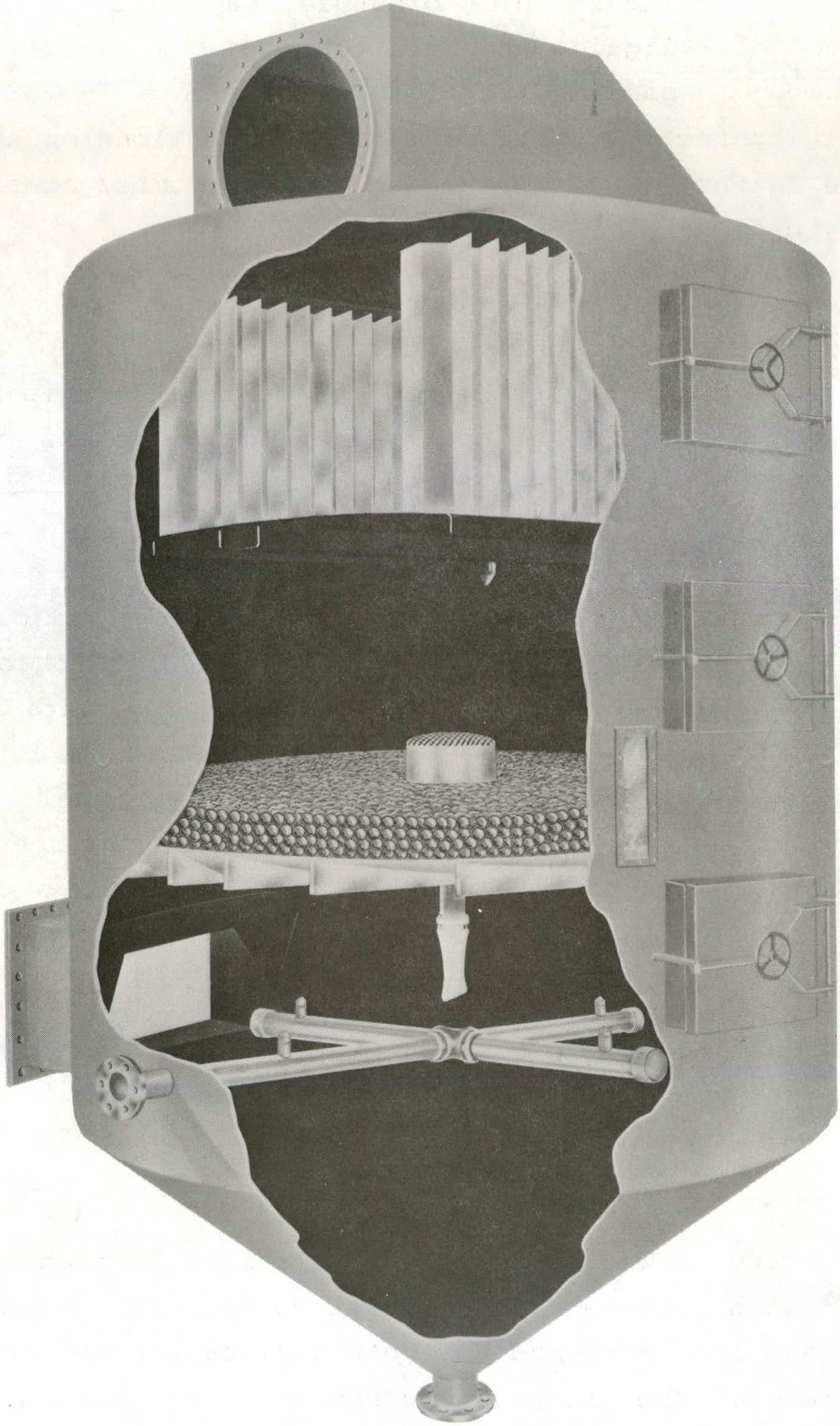


Figure 3.23 Flooded-Bed Wet Scrubber.[31]

P_L = liquid inlet pressure, psi

L = liquid feed rate, gpm

G = gas flow rate, ACFM

To correlate contacting power with scrubber collection efficiency (η), the latter is often expressed as the number of transfer units, N_t, defined as:

$$N_t = \ln [1/(1 - \eta)] \tag{5}$$

For a given type of scrubber collecting a specific type of particulate, there will usually be a distinct relationship between the number of transfer units and the contacting power. This relationship has been expressed as:

$$N_t = \alpha P_T^{\beta} \tag{6}$$

where α and β are characteristic parameters for the type of particulates being collected. The relationship is illustrated in Figure 3.24 for a Venturi scrubber operating on fly ash from a power boiler fired with pulverized coal[43]. The scatter in the data results from actual variations in the particle-size distribution of the fly ash. For this particular case, $\alpha = 2.76$ and $\beta = 0.189$. Hence, for example, to achieve 99.5% collection efficiency ($N_t = 5.3$) on fly ash from a pulverized coal boiler, the pressure drop required would be approximately 30 in. W.C. Both α and β can be expected to vary with boiler type and with particle size distribution.

Other theories and design approaches are also available in the literature.[31]

3.2.4 Performance Data for Typical Operational Systems

A summary of wet scrubber installations is presented in Table 3.3[28] with pertinent operational parameters. Most of the scrubbers have been designed for both particulate and sulfur dioxide removal. The greatest concentration of these units is in the western U.S., where the available low-sulfur coal is so highly resistive that electrostatic precipitation is not economically feasible.

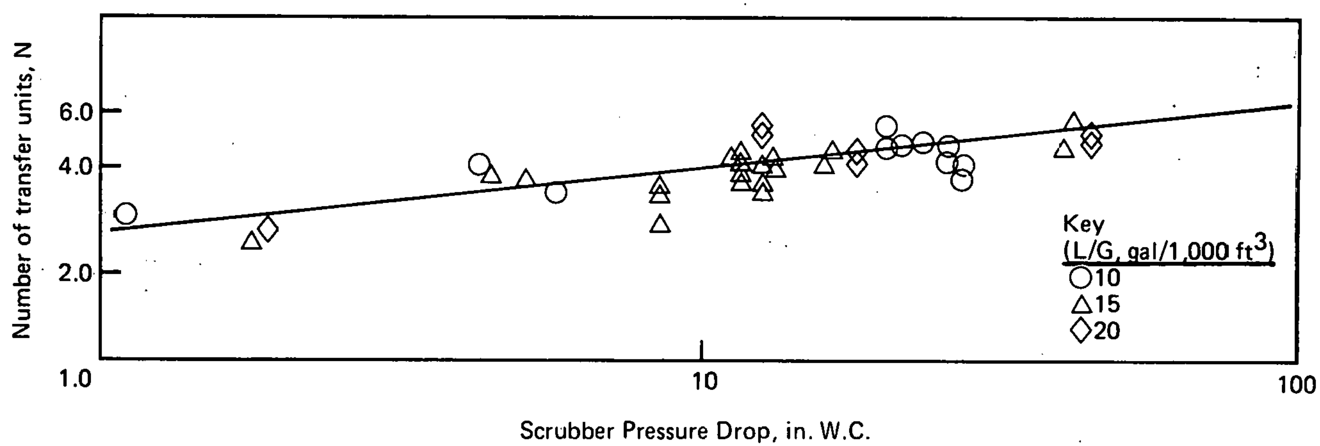


Figure 3.24 Performance Curve for a Venturi Scrubber Collecting Fly Ash.[43]

Table 3.3 Wet-Scrubber Installations on Coal-Fired Utility Boilers[28]

Plant	Boiler Capacity, MW	Scrubber Type	Particulate Removal Efficiency, %	L/G gal/ 1000 ACFM	ΔP in, W.C. Scrubber	Remarks
Arizona Public Service						
Four Corners	575	Venturi	99.2	8.5	22	Pulverized Coal
Cholla	115	Venturi	99.2	10	10	Pulverized Coal-Fired 0.01 gr/SCFD
Commonwealth Edison Will County No. 1	167	Venturi	98	18	9	Cyclone Boiler; 0.04 gr/SCFD
Detroit Edison Co. St.Clair No.6	180	Venturi	99.7	20	14	Two Stage Super Heater; Peaking; 0.01 gr/SCFD
Duquesne Light Co.						
Phillips Sta.	410	Venturi	99	29	30	Pulverized Coal-Fired Boiler
Elrama Sta.	510	Venturi	99	29	30	Pulverized Coal-Fired Boiler
Kansas City Power & Light La Cygne Sta.	820	Venturi	98.2	12	7	Dry Bottom Pulverized Coal, Cyclone-Fired; 0.13 lb/MBtu
Kansas Power & Light Lawrence Sta.						
Unit 4	125	Marble Bed	99	22	8	
Unit 5	400	Marble Bed	99	22	8	
Minnesota Power & Light						
Clay Boswell Station	350	High Pressure Spray	97	8.3	2.4	Pulverized Coal-0.08 gr/SCFD
Aurora Sta.	116	High Pressure Spray	98	8.3	2.5	Pulverized Coal 0.04-04.046 gr/SCFD
Montana-Dakota Utilities Lewis & Clark Station	55	Venturi	98	13	13	Pulverized Coal
Montana Power Co. Colstrip Units 1 & 2	720	Venturi	99.5	15	17	Pulverized Coal 0.06 lb/10^6Btu (design) Opacity at 10-15%
Nevada Power Co. Reid Cardner Sta.						
Units No. 1 & 2	250	Venturi	97	9.5	15	0.02 gr/SCFD
Unit No. 3	125	Venturi	97	9.5	15	0.02 gr/SCFD
Northern States Power Co. Shelburne County No. 1 & 2	1420	Marble Bed	98	10	6	0.035-0.044 gr/SCFD; 0.075-0.085 lb/10^6Btu
Pacific Power & Light Dave Johnson Sta. Unit 4	330	Venturi	99	13	11	Pulverized Coal
Penn.Power & Light						
Holtwood Sta.	80	Venturi	99	12.5	6	
Bruce Mansfield	1650	Venturi	99.8	25	21	Pulverized Coal; 0.0175 gr/SCFD (design)
Phila.Elec.Co. Eddystone Sta.	120	Venturi	99+	5.4	17	
Potomac Elec. & Power Dickersen	95	Venturi	99.3	20	11	Pulverized Coal Dry Bottom
Public Serv.Co. Colorado						
Cherokee Sta. No. 1	110	Moving-bed Scrubber				
No. 3	150	"	97	56	8-12/ 10-15	Pulverized Coal; 0.02 gr/SCFD
No. 4	350	"				
Valmont Sta.	180	"	96	58	8-12/ 10-15	Pulverized Coal; 0.02 gr/SCFD
Arapahoe Sta.	180	"	96	54	8-12/ 10-15	Pulverized Coal; 0.02 gr/SCFD

Recent tests on the Montana Power Company's Colstrip scrubbers have shown the average outlet particulate loadings to be 0.031 lb/MBtu and 0.030 lb/MBtu for Unit No. 1 and Unit No. 2, respectively.[44] This compares favorably with the NSPS of 0.1 lb/MBtu. Scrubber outlet opacity averaged 10-15%.

Venturi scrubbers and moving-bed scrubbers have been the most popular choices for coal-fired utility boilers. As such, their performance has been studied extensively. Performance data on the moving-bed scrubber (also referred to as the turbulent contact absorber) installed at the Cherokee Station of the Public Service Company of Colorado are given in Figures 3.25 and 3.26.[45] The scrubber was a three-stage unit operating at 12 in. W.C. pressure drop plus 2 in. W.C. across the demister. The liquid-to-gas ratio ranged from 40 to 50 gal/1000 ACFM. Particle size distribution data were obtained using a University of Washington cascade impactor. Performance in the fine particulate size range as determined by a diffusion battery with condensation nuclei counter is presented in Figure 3.27.[46] Maximum penetration is at approximately 0.5 micron, when the collection efficiency is only 15 to 30%.

Performance data on a Venturi scrubber were obtained at Pacific Power and Light's Dave Johnson Station with the scrubber operating at 10 in. W.C. pressure drop and a liquid-to-gas ratio of 10-15 gal/1000 ACFM. This is presented in Figures 3.28 and 3.29.[46] Particle size distributions were measured using a University of Washington cascade impactor. As was the case with the turbulent contact absorber, the data indicate that fine particulates, which present the most serious health hazard, are not collected efficiently at these low pressure drops.

3.2.5 Operation and Maintenance

Many of the problems with wet scrubbers on utility boilers arise from lack of experience on this type of application (i.e.,

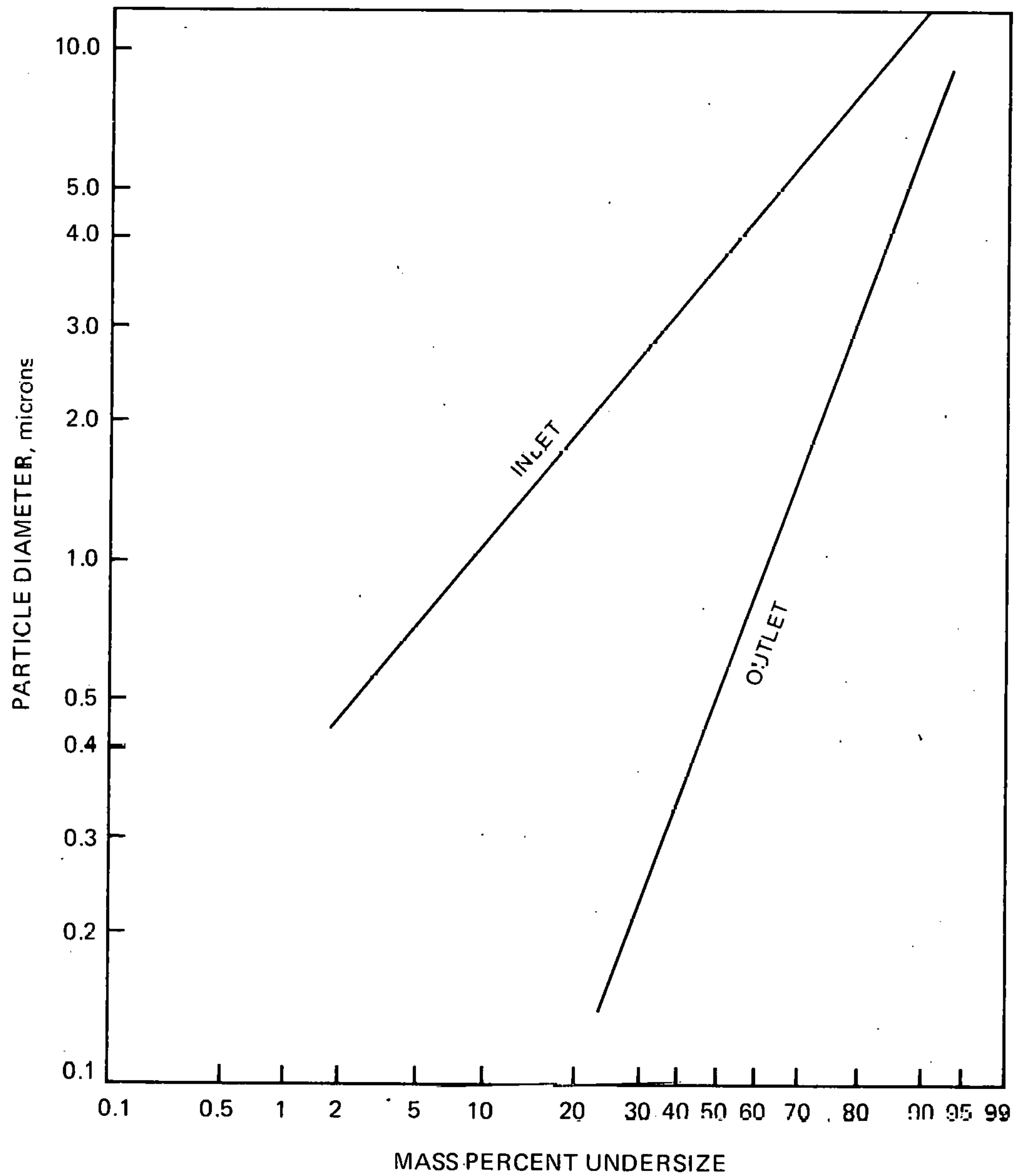


Figure 3.25 Particle Size Distribution (Cherokee Station Scrubber).[45]

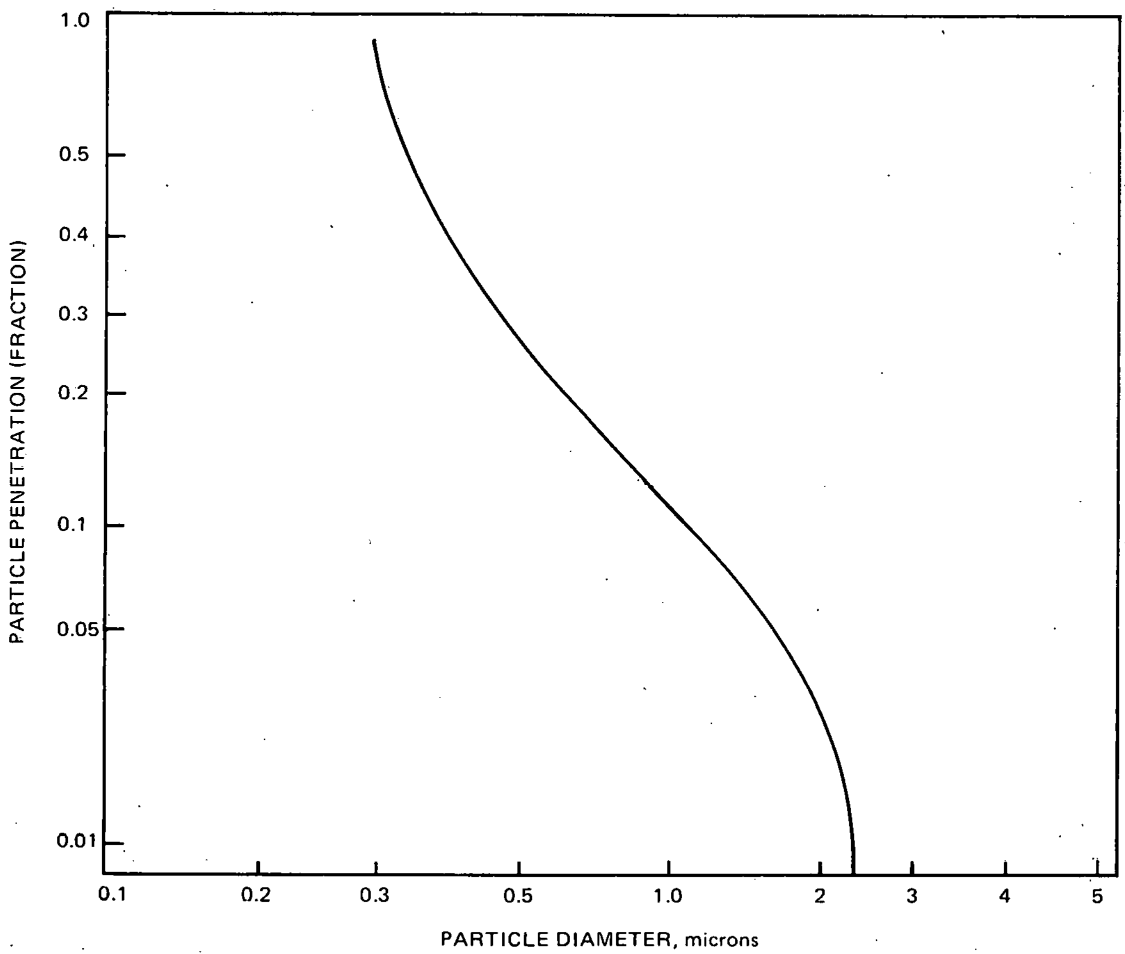


Figure 3.26 Particle Penetration versus Aerodynamic Particle Diameter for Turbulent Contact Absorber Scrubber.[45]

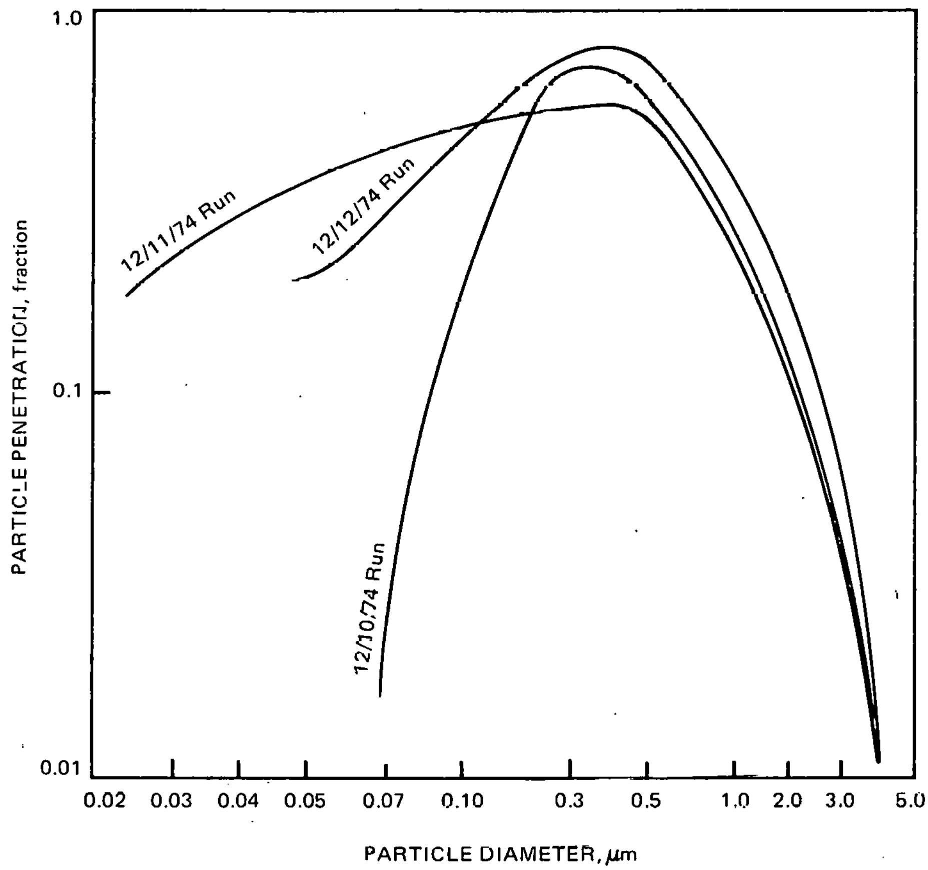


Figure 3.27 Fractional Efficiency Data in the Fine Particle Size Range Using the Turbulent Contact Absorber Scrubber.[46]

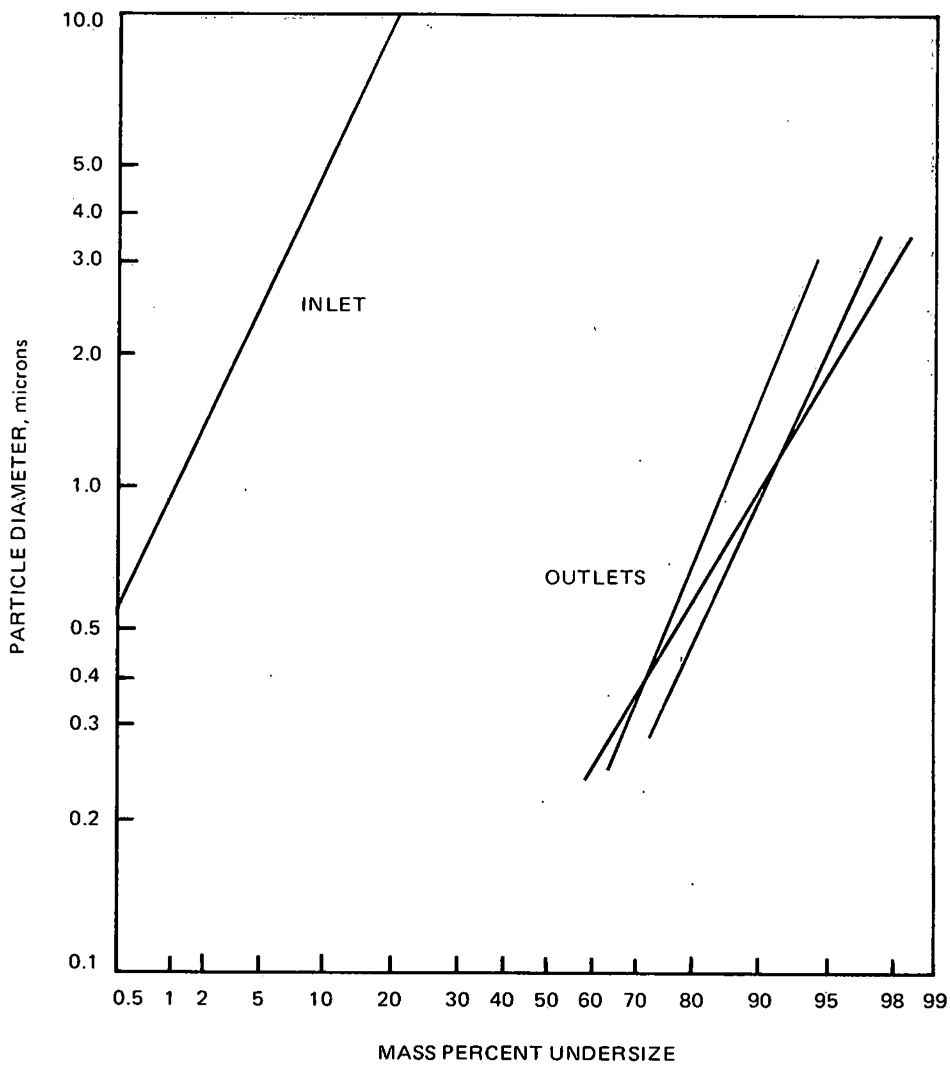


Figure 3.28 Inlet and Outlet Particle Size Distributions.[46]

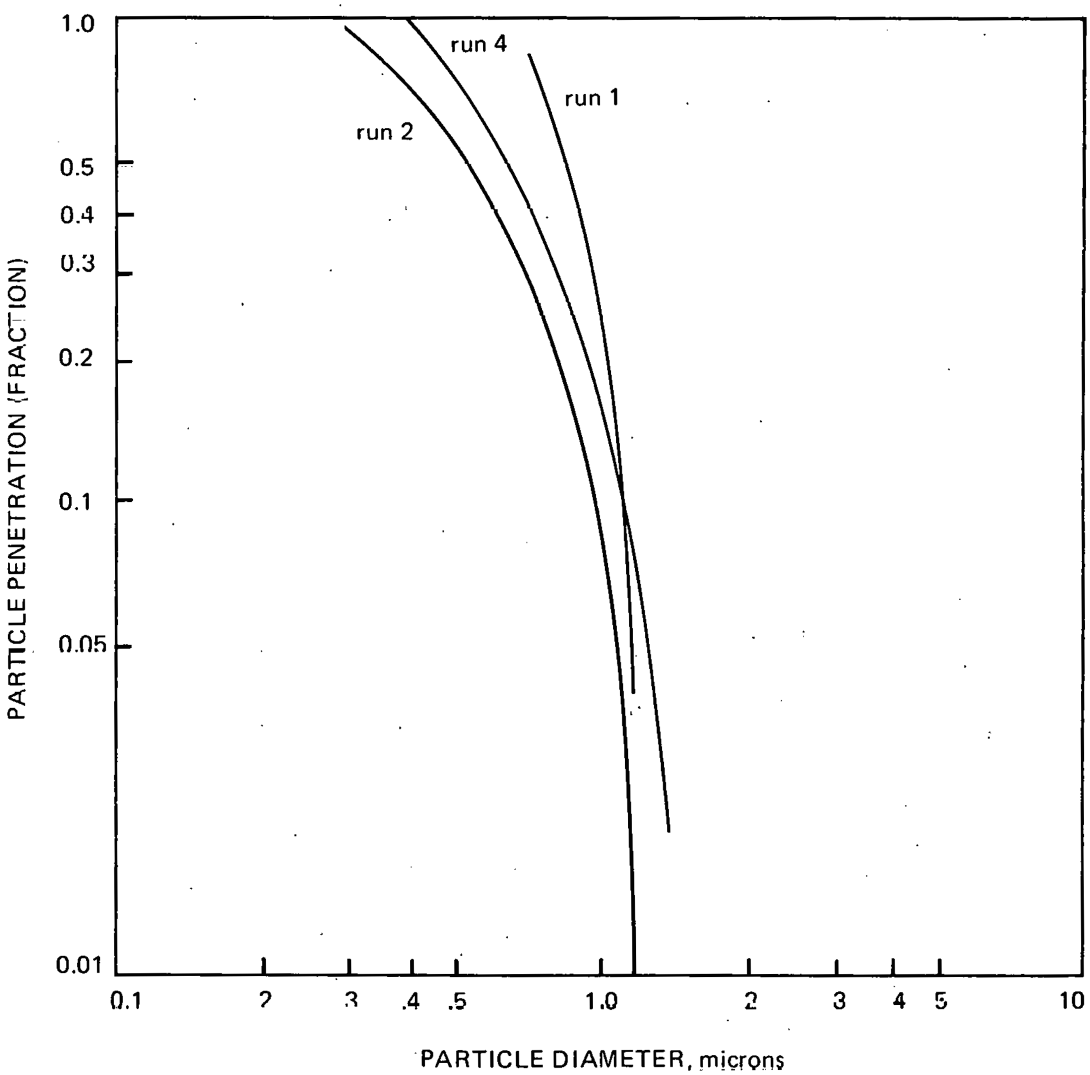


Figure 3.29 Particle Penetration Versus Aerodynamic Diameter.[46]

the lack of commercialization of the units). The occurrence of erosion, corrosion, scaling, and plugging underscores the need for development of scrubber technology. Both corrosion and building-up decrease the efficiency of particulate removal, the finer particles being the ones most likely to escape collection. No clear trend emerges as to the preferred scrubber system for use in collection of fly ash from utility boilers.

There are a number of general operation and maintenance problems shared by various scrubbers, and each type of scrubber has displayed its own characteristic problems. The problem areas most evident are summarized for each scrubber category in Table 3.4[48]. In general, the most common problems associated with wet scrubbers are corrosion, scaling and plugging. Although these problems usually decrease after the scrubber has operated for some time, routine maintenance requirements are still greater than for precipitators or fabric filters.

3.3 FABRIC FILTERS

One of the oldest, simplest, and most efficient methods for removing solid particulate contaminants from gas streams is by filtration through fabric media. The fabric filter is capable of providing high collection efficiencies for particles as small as 0.5 μm and will remove a substantial quantity of those particles as small as 0.01 μm.[47] In its simplest form the fabric filter consists of a woven or felted fabric through which dust-laden gases are forced. A combination of factors results in the collection of particles on the fabric fibers. When woven fabrics are used, a dust cake eventually forms; this, in turn, acts predominantly as a sieving mechanism. When felted fabrics are used, this dust cake is minimal or nonexistent. Instead, the primary filtering mechanisms are a combination of inertial forces, impingement, etc., as related to individual particle collection on

Table 3.4 Characteristic Maintenance Problems of Particulate Scrubbers on Coal-Fired Utility Boilers[48]

Scrubber type	Characteristic maintenance problems
Venturi scrubber	1) Line nozzle, and pump plugging
	2) Worn pump parts
	3) Worn erosion/corrosion prevention liners
	4) Instrument failure (level indicators, pH indicators, etc.)
Preformed spray impingment scrubber	1) Erosion and plugging of nozzles
	2) Ash buildup on wet induced draft fan
	3) Scaling in scrubber liquid circuit
	4) Stack gas mist carryover in the scrubber and liquid circuit
Moving-bed scrubber	1) Mobile bed contactors (premature wear of spheres)
	2) Structural integrity of vertical partitions
	3) Isolation and flow-control damper leaks and sticking
	4) Reheater section (corrosion)
	5) Worn erosion/corrosion-prevention liners
	6) Presaturator plugging
	7) Mist eliminator (corrosion, plugging)

single fibers. These are essentially the same mechanisms that are applied to particle collection in wet scrubbers, where the collection medium is in the form of liquid droplets rather than solid fibers.

At present, fabric filters are being given serious consideration for fly ash emission control. This situation has been brought about principally for two reasons: (1) the efficiency requirements for handling emissions from coal-fired utility boilers are continuously being upgraded, and (2) a combination of the energy crisis and more stringent sulfur dioxide emission control requirements has resulted in a large degree of fuel source variability.

3.3.1 Description of Equipment

The basic filtration process may be conducted in many different types of fabric filters, in which the physical arrangement of hardware and the method of removing collected material from the filter media will vary. The essential differences may be related, in general, to:

1. Type of fabric
2. Cleaning mechanism
3. Equipment geometry
4. Mode of operation

As applied to coal-fired boilers, the type of fabric usually used is woven glass fiber. The equipment geometry is such that the boiler flue gas is drawn through the bag from inside, with the collected dust forming a loosely deposited cake on the inside surface of the bag. The baghouse is usually compartmentalized to facilitate continuous operation and on-stream maintenance. The bag cleaning mechanisms are typically reverse-air and/or shaking. A typical reverse-flow cleaning baghouse is shown in Figure 3.30[31].

A comparison of the bag cleaning methods is presented in Table 3.5.[31] The highest air-to-cloth ratios (ratio of gas volumetric flow rate to bag surface area, also referred to as

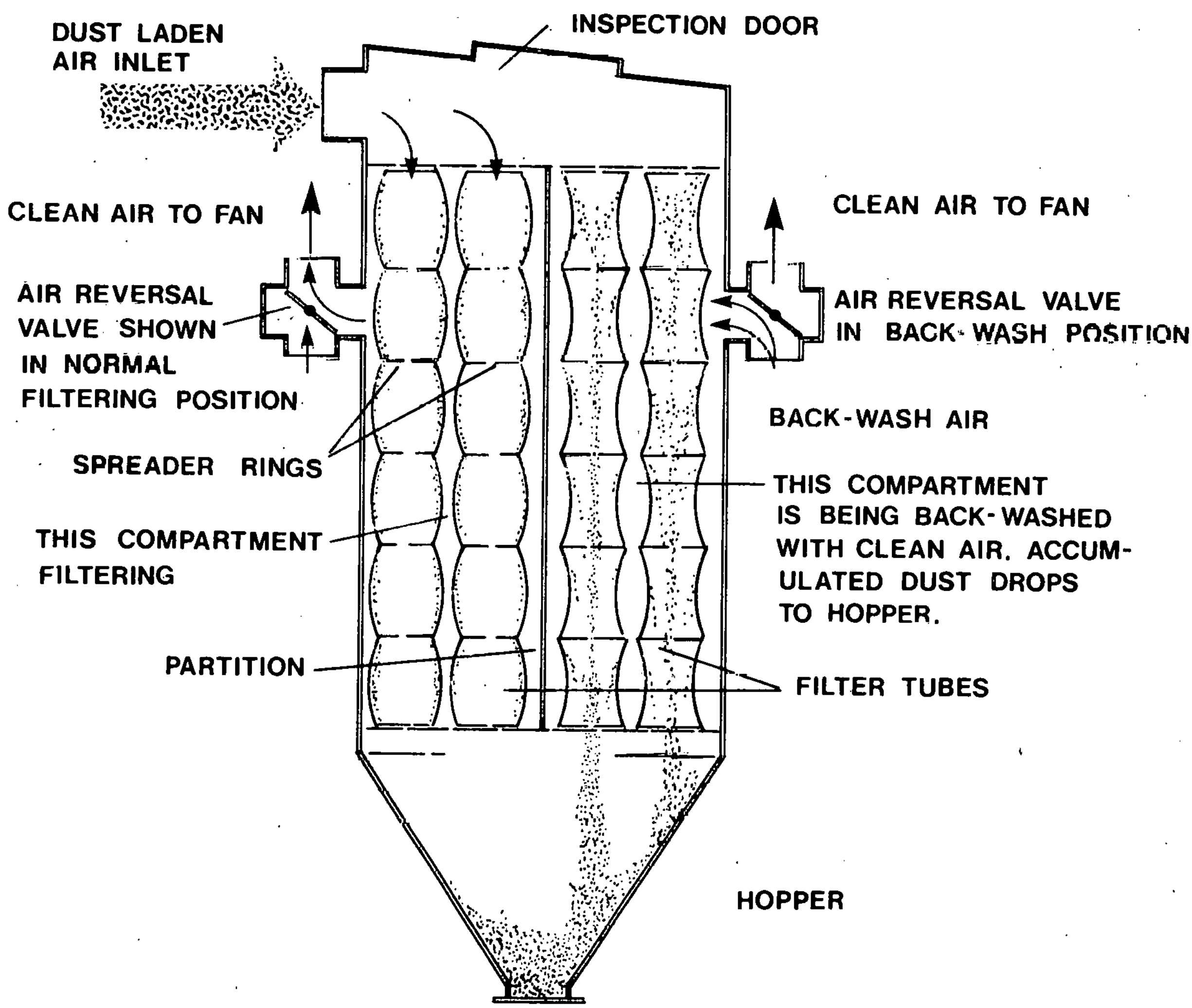


Figure 3.30 Typical Reverse-Flow Cleaning Baghouse.[31]

Table 3.5 Comparison of Bag Cleaning Methods[31]

Cleaning method	Uniformity of cleaning	Bag attriton	Equipment ruggedness	Type fabric	Filter velocity	Apparatus cost	Power cost	Dust loading	Submicron efficiency
Shaking	A	A	A	Woven	A	A	L	A	G
Reverse flow, no flexing	G	L	G	Woven	A	A	M-L	A	G
Reverse flow, with collapse	A	H	G	Woven	A	A	M-L	A	G
Pulse-compartment	G	L	G	Felt,woven	H	H	M	H	H
Pulse-bags	A	A	G	Felt,woven	H	H	H	VH	H
Reverse-jet	VG	A-H	L	Felt,woven	VH	H	H	H	VH
Vibration, rapping	G	A	L	Woven	A	A	M-L	A	G
Sonic assist	A	L	L	Woven	A	A	M	-	G
Manual flexing	G	H	-	Felt,woven	A	L	-	L	G

Note: A=average; G=good; H=high; L= low; M=medium; VG=very good; VH=very high.

filtration velocity) are used with reverse-jet cleaning (10-30 ACFM/ft^2). Pulse-jet cleaning allows air-to-cloth (A/C) ratios ranging from 4 to 20 ACFM/ft^2, with the remaining cleaning mechanisms using A/C ratios of 1 to 5 ACFM/ft^2. Typical properties of common filter media are shown in Table 3.6.[31] Normal operating temperatures in the boiler system preclude, for all practical purposes, the use of most fabrics, with the exceptions of teflon and fiberglass.

3.3.2 Design Methodology

The most important parameters that control filtration system performance are air-to-cloth ratio, pressure drop, cleaning frequency and degree of sectionalization. Design A/C ratios for fabric filters presently installed on utility boilers range from 1.9 to 2.8 ACFM/ft^2. Maximum pressure drop on these systems is 6 in. W.C. The frequency of cleaning is adjusted so that no sizable portion of the total fabric will be out of service for cleaning at any given time. Typically, no more than 10% of the compartments in the baghouse will be out of service for cleaning. The degree of sectionalization or compartmentalization is selected on the basis of expected variations in gas flow and the anticipated frequency of maintenance.

The design of dust-collection equipment requires consideration of many factors. Figure 3.31[31] illustrates the complex nature of the final selection of a fabric collector. The most important design considerations include the operational pressure drop, cloth area, cleaning mechanism, fabric and fabric life, baghouse configuration, and costs.

The size of a filter plant (baghouse) is primarily determined by the area of cloth required to filter the gases. The choice of an A/C ratio must take certain factors into consideration. Although the higher velocities are usually associated with the greater pressure drops, they also reduce the filter area required. Practical experience has led to the use of a series of A/C ratios for various materials collected and types of equip-

Table 3.6 Typical Properties of Common Filter Media [31]

Fabric	Generic Name	Type yarn	Maximum temperature range, °F: Long periods of time (months)	Maximum temperature range, °F: Short periods of time (min)	Melting temperature °F	Acid resistance	Fluoride Resistance	Alkali Resistance	Flex and abrasion resistance	Relative cost (approximate)	Supports combustion
Cotton[a]	Natural fiber cellulose	Staple	180°	225°	302° decomposes	Poor	Poor	Fair-good	Fair-good	1.0	Yes
Wool[b]	Natural fiber protein	Staple	200°	250°	572° chars	Very good	Poor-fair	Poor-fair	Fair	2.75	No
Nylon[c]	Nylon polyamide	Filament spun	200°	250°	480°	Fair	Poor	Very good-excellent	Very good-excellent	2.5	Yes
Dynel[d]	Modacrylic	Filament spun	160°	240°	325° softens	Good-very good	Poor	Good-very good	Fair-good	3.2	No
Polypropylene[e]	Polyolefin	Filament spun	200°	250°	333°	Excellent	Poor	Excellent	Very good-excellent	1.75	Yes
Orlon[f]	Acrylic	Spun	240°	275°	482° softens	Good-excellent	Poor-fair	Fair	Fair	2.75	Yes
Dacron[g]	Polyester	Filament spun	275°	325°	482°	Good	Poor-fair	Fair-good	Very good	2.8	Yes
Nomex[h]	Nylon aromatic	Filament spun	425°	500°	700° decomposes	Fair	Good	Excellent	Very good-excellent	8.0	No
Teflon[i]	Fluorocarbon	Filament spun	450°	500°	750° decomposes	Excellent	Poor-fair	Excellent	Fair	30.0	No
Fiberglass[j]	Glass	Filament spun bulked	500°	600°	1,470°	Fair-good	Poor	Fair	Poor	5.5	No
Polyethylene	Polyolefin	Filament spun	200°	-	-	Very good-excellent	Poor-fair	Very good-Excellent	Good	2.0	Yes
Stainless Steel[k] (type 304)	-	-	1,400 - 1,500°	-	2,550-2,650°	Excellent	-	Excellent	-	100.0	No

[a] Poor resistance to mildew and fungi; excellent selection in ventilation-type collector.

[b] Similar to those of cotton; good filterability.

[c] High tensile strength, good elasticity; unaffected by mildew and fungi; rugged fiber with excellent resistance to abrasion and alkalies; fair to poor resistance for most sodium salts.

[d] Good chemical and abrasion resistance and excellent dimensional stability; attacked by concentrated nitric acid, sodium hydroxide, and affected by most halogens; adversely affected by ketones, amines, cyclohexanone and acetone.

[e] Chemically resistant to acids and alkalies; strong fiber, low moisture absorption; attacked at elevated temperatures by nitric acid and chlorosulfuric acid; has poor resistance to sodium and potassium hydroxide at high temperatures; not to be used with aromatics and chlorinated hydocarbons.

[f] Resistance to moisture; not harmed by common solvents; not recommended for sulfuric acid (generally fair in environments above acid dewpoint); attacked by zinc chloride; good at elevated temperatures in acid conditions.

[g] High tensile strength, good dimensional stability, and excellent temperature resistance.

[h] Outstanding temperature resistance, high tensile strength, good resistance to abrasion.

[i] Can be used at elevated temperatures and possesses excellent chemical resistance.

[j] Low mechanical strength, hence vulnerable to abrasion; can be used at high temperatures and has high tensile strength.

[k] For extremely high temperatures.

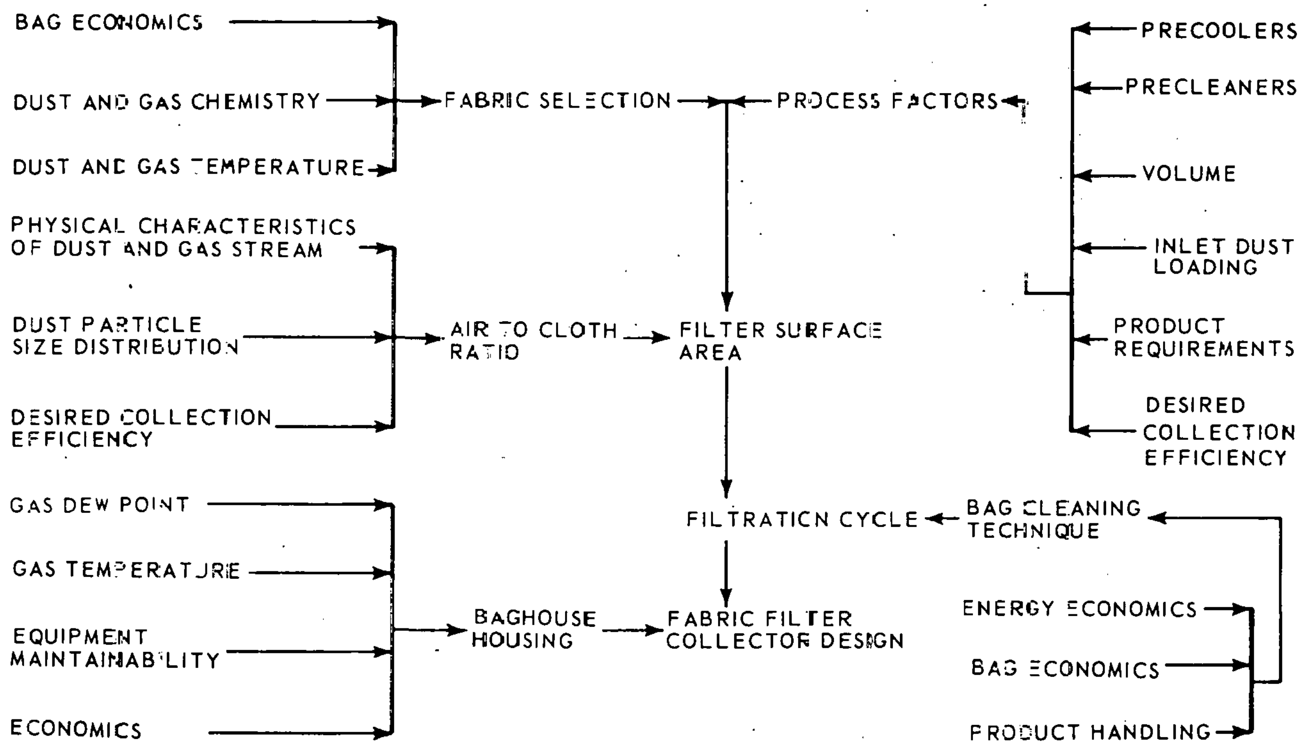


Figure 3.31 System Analysis for Fabric Filter Collector Design.[31]

ment. A ratio of 2.0-2.3 is recommended for coal-fired boiler baghouses using glass bags, with reverse-air and/or shake cleaning.[31]

3.3.3 Performance Data for Typical Operational Systems

A summary of fabric filter installations on coal-fired boilers is presented in Table 3.7[49]. Performance data are available on the three major types of boilers: cyclone, pulverized-coal and stoker. The tested fabric filter systems range in size from a pilot unit adjacent to a large power plant to a full-scale system installed on an 87.5-MW generator. It should be noted that the acceptance of fabric filters for fly ash emission control has been, in part, a result of the demonstrated long-term success at Sunbury Station of Pennsylvania Power and Light.

3.3.3.1 Cyclone-Fired Boiler

Fabric filter performance data on a cyclone-fired boiler were obtained using a pilot system at a 500-MW power plant.[50] The coal consisted of 7% ash, 3.5% sulfur and 13,400 Btu/lb. The filtering systems contained glass fiber bags with a teflon-silicone-graphite coating and used mechanical-shake cleaning for fly ash dislodgement. The filtration velocity was 2.7 fpm and the unit operated at 270-290°F. The inlet fly ash loading was 0.7 gr/SCFD with a mass median diameter of 5 μm and a standard deviation of 3.3. The filter operated at 4.8 to 5.4 in. W.C. pressure drop and averaged 99.62% efficiency. Andersen cascade impactor data are presented in Table 3.8[50] and inlet/outlet particle size distribution data in Figure 3.32.[50]

3.3.3.2 Pulverized-Coal-Fired Boiler

Performance data for a pulverized coal-fired boiler were obtained on full-scale fabric filters installed at the Sunbury Station of the Pennsylvania Power and Light Company. The station capacity of approximately 400 MW is generated by four steam turbines. The boilers burn a mixture of 15% to 35% petroleum coke,

Table 1.7 Electric Utility Baghouse Installations[49]

Utility	Station	Location	Boiler Capacity, MW	Installation Date	Boiler	Fuel	S, %	Ash, %	Flue Gas Temperature. °F	Flue gas Vol, acfm	Air/ Cloth, acfm/ft^2	Pressure Drop in. WG	Fabric	Regeneration
Pennsylvania Power and Light	Sunbury	Shamokin Dam, Pa.	2x87.5	1971-3	Pulverized coal fired	Anthracite silt Bituminous coal Petroleum coke	1.8	22.1	325	900,000 (4x270,000)	2	2.5	Woven glass fiber, 10 oz	Reverse flow
Pennsylvania Power and Light	Holtwood	Holtwood, Pa.	73	1975	Pulverized coal fired	Anthracite silt Bituminous ccal etroleum coke			360	200,000	2.4	4.5	Woven glass fiber, 10 oz	Reverse flow and shake
Colorado-Ute Electric Association	Nucla	Nucla, Co.	3x13	1973	Stoker fired		0.7	12	360	258,000 (3x86,000)	2.8	4.5	Woven glass fiber, 10 oz	Reverse flow and shake
Crisp County Power Comm.		Cordele, Ga		1975		Bituminoms coal	1	10	325	60,000	4	2.8	Woven glass fiber	Reverse flow
Nebraska Public Power System	Kramer	Bellevue, Ne.	113 (4 units)	1976	Pulverized coal fired	Bituminoms coal	1	11		550,000	2	-	Woven glass fiber	
Southwestern Public Service	Harrington No. 2	Amarillo, Tx.	318	1978	Pulverized coal fired	Subbitum - inous coal				1,500,000	3	-	Woven glass fiber	Reverse flow and shake
Texas Power & Light Co.	Monticello	Mt. Pleasant, Tx.	1150 (2x575)	1977	Pulverized coal fired	Lignite	0.6	6.1-23		3,800,000	2.4	-	Woven glass fiber	Reverse flow
Colorado REA		Montrose, Co.	12 (2x6)		Stoker									
Public Service Co. of Colorado	Cameo	Grand Junction, Co.	22	1977										
Department of Public Utilities	Ray D. Dixon	Colorado Springs, Co.	175	1977										

Table 3.8 Anderson Impactor Data on Pilot Fabric Filter (Particle S.G. Assumed to be 2)[50]

Size Interval, (μm)	Inlet Concentration, 10^{-3} gr/SCFD	Outlet Concentration, 10^{-3} gr/SCFD	Penetration $(1-\eta)$, %
> 11	94.4	0.370	0.39
6.9 - 11	57.0	0.132	0.23
4.6 - 6.9	75.0	0.558	0.74
3,3 - 4.6	71.1	0.413	0.58
2.1 - 3.3	89.4	0.495	0.55
1.1 - 2.1	71.1	0.269	0.38
0.64 - 1.1	37.9	0.180	0.48
0.43 - 0.64	13.7	0.012	0.09
< 0.43	22.7	0.346	1.52

with the remainder made up of anthracite silt and No. 5 buckwheat anthracite. The normal fuel consumption is 41 tons/hr/unit, with an exhaust gas volume of approximately 125,000 SCFM per boiler. Originally, particulate was removed from the flue gas by a combination mechanical collector and electrostatic precipitator. However, due to the high resistivity of the low-sulfur anthracite fly ash, the precipitators were unable to remove the desired amount of particulate. Turbine Units 1 and 2, rated at 87.5 MW each, are supplied by four anthracite-fired boilers,each equipped with a fabric filter baghouse rated at 222,000 ACFM at 325°F.[51] The design filter velocity is 1 fpm and cleaning is by reverse air flow. The bags are woven of teflon-coated fiberglass. The average pressure drop during operation is 2.5-3.5 in. W.C. with an allowed maximum of 5 in. W.C. During testing, the average inlet loading was 2.5 gr/SCFD and the average outlet loading 0.002 gr/SCFD; the fly ash removal efficiency was 99.92%. On a Btu heat input basis, the outlet loadings ranged from 0.004-0.005 lb/MBtu. Fractional efficiency data are presented in Figure 3.33.[52]

Performance test results at Nucla and Sunbury indicate that baghouses are capable of very high collection efficiencies in the

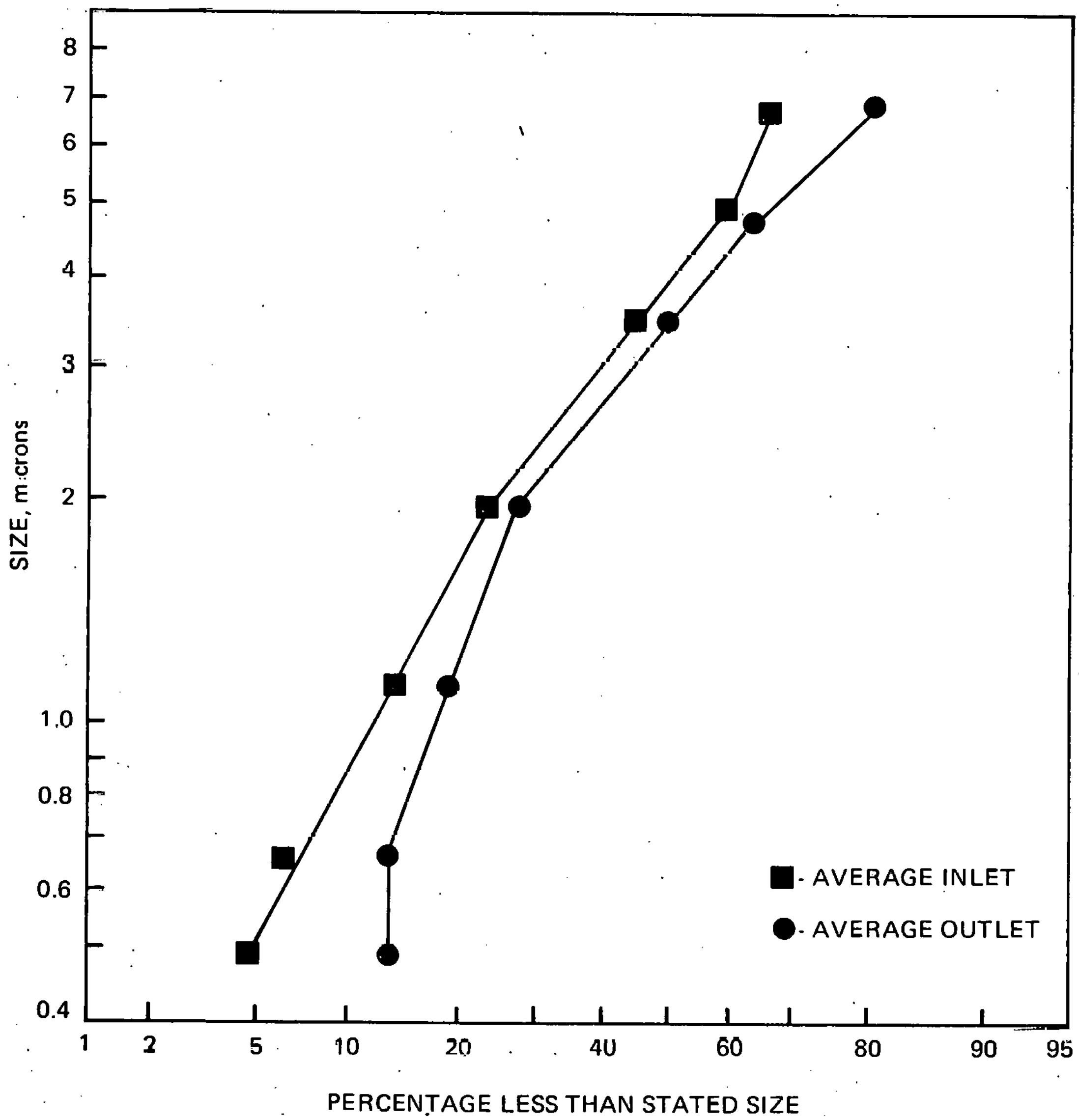


Figure 3.32 Fly Ash Average Cumulative Particle Size Distribution, Assumed Particle Density of 2 gm/cm^3 .[50]

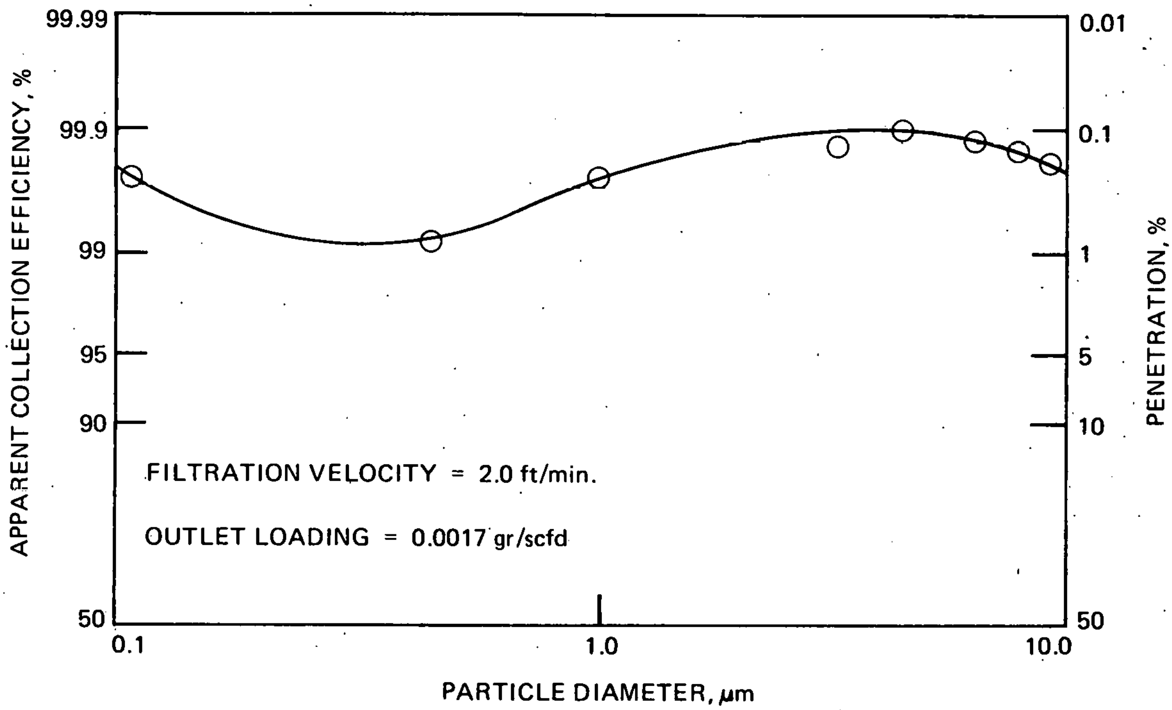


Figure 3.33 Baghouse Performance at Sunbury Steam Electric Station.[52]

fine particle size range, with the apparent ability to maintain high collection efficiencies during changes in boiler load and inlet concentrations.

3.3.3.3 Stoker-Fired Boiler

Performance data for a spreader stoker-fired boiler were obtained on full-scale fabric filters installed at the Colorado-UTE Electric Association Nucla Generating Plant.[48,49] At the Nucla Station, there are three 13-MW generators. Each stoker-fired traveling-grate boiler utilized fly ash reinjection. The fuel is a western coal containing, on the average, 14% ash, 0.7% sulfur and 12,000 Btu/lb. A separate baghouse is used for each boiler. The design gas flow is 86,240 ACFM at 360^{O}F. The bags are made of fiberglass fabric with a silicone-graphite finish and are cleaned by a combination of reverse air flow and gentle mechanical shaking. The pressure drop under normal operating conditions is 4.5 in. W.C. with a maximum of 6.0 in. W.C. (during cleaning). The filtration velocity under normal operating conditions is 2.8 fpm,and the design inlet loading is 1.53 grains/ACF. During the testing, overall outlet mass emissions were 0.0035 lb/MBtu,with collection efficiencies greater than 99.8%. Stack opacity was essentially zero (clear stack). Fractional efficiency data obtained using a MRI cascade impactor are presented in Figure 3.34[53,54]; fractional efficiency data in the fine particle size range, obtained using an electrical aerosol size analyzer (EASA), are presented in Figure 3.35[53,54].

3.3.4 Operation and Maintenance

A properly attended fabric filter system is usually capable of operating satisfactorily for up to 15 years and possibly longer. Certain practices are essential for successful operation, including:

1. Selection of the most suitable equipment in the planning stages (e.g., if a process is charac-

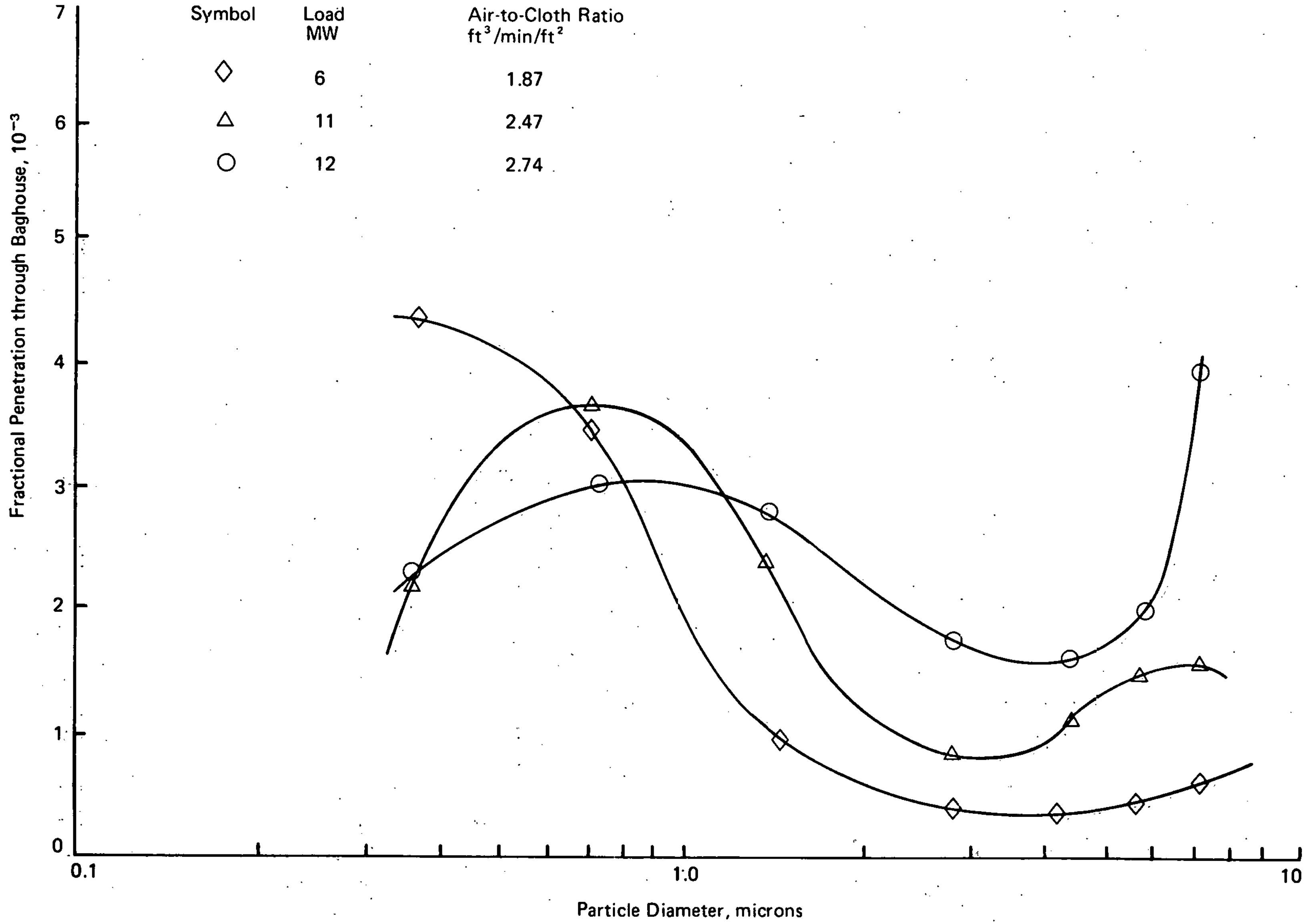


Figure 3.34 Penetration as Functions of Particle Diameter (S.G. = 2) and Load.[53, 54]

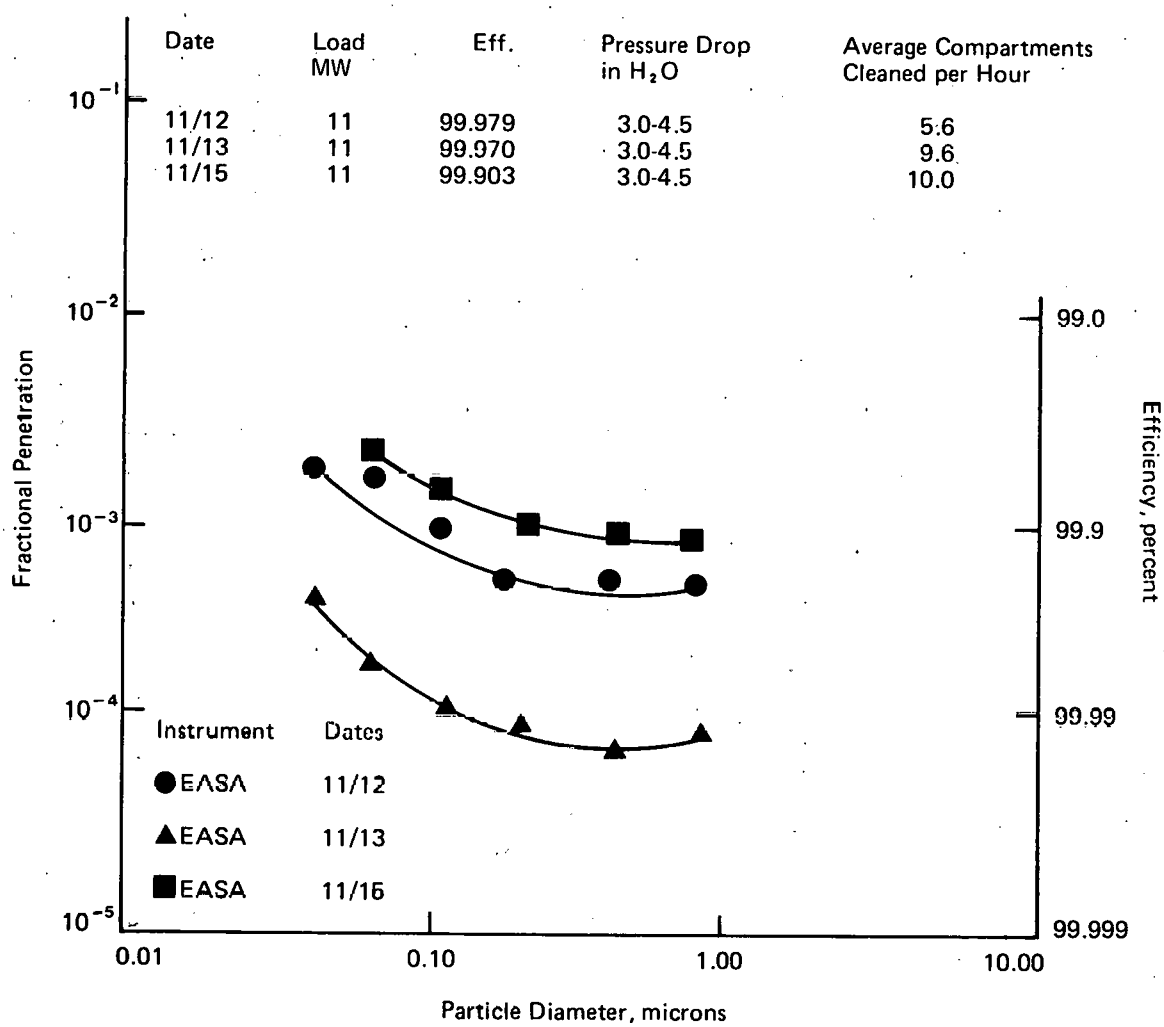


Figure 3.35 Fractional-Penetration and Efficiency of 11-MW Tests, November 12, 13 and 15, 1975, Nucla, Colorado. [53, 54]

terized by variations in gas flow and/or dust loading, the equipment must operate at peak loads without media plugging, as well as at reduced flows where condensation may occur).

2. Familiarity with the operating, instrumentation, equipment and maintenance manuals.

3. Knowledge of the contaminated gas stream to be treated.

4. Proper care of the fabric media.

5. Minimizing the temperature into the filter through precooling, limited only as it approaches the dew point. This can reduce operating and maintenance costs (fan power and bag replacements).

6. Establishing and following a preventive maintenance program.

The primary operating problems associated with fabric filters have been bag caking and pluggage, leakage and short bag life. To avoid plugging because of condensation, the gas temperature should be 50 to 75°F above the dew point. An unusually heavy grain loading may also cause excessive wear or blinding. Leakage through the filter is perhaps the most important service problem. Each bag must be regularly inspected for holes or tears. Chemical deterioration is also one of the factors that can add to the maintenance costs. The rate at which a fabric medium will deteriorate is generally related to the weight of the fabric and the gas stream composition. The heavier the fabric weight, the greater the initial and replacement cost of the filters. Bag spacing is also important. Sufficient clearance must be provided so that one bag does not contact another. A minimum of 2 in., for example, is needed between bags 10 to 12 ft. long, while longer bags require greater clearance distances.

Based on available data from the Sunbury fabric filter installation, most of the maintenance hours have been spent on bag replacement, collapse fan repairs and air-operated damper repairs. Operating and maintenance experience on the fabric at the Nucla plant indicates that the principal problems are associated with fabric failures and bag replacements during the first year of operation. These are apparently caused by condensation at hopper tube sheet outer walls, caking, crusty deposits and cracks in bags. At Nucla, 18% of the bags were replaced in a two-year period.

The following are maintenance problems that could be anticipated for future fly ash fabric filter installations:[31]

1. Erosion of bags at the inlet because of abrasion, which occurs when the fly ash strikes the bag tangentially; bag failure because of blinding, caking, chemical attack and aging.

2. Hopper pluggage because of conveying-system failure. (This is an area where proper inspection can minimize plugging by detecting the problem before it becomes serious.)

3. Fans and blowers, if placed on the dirty side of the baghouse where material can accumulate on the vanes and throw the fans off balance. Corrosion and abrasion can also cause trouble.

4. Improper bag tensioning. (This includes both initial tensioning and subsequent retentioning after the unit has been operated.)

4 PROCESS CONTROL TECHNOLOGY FOR FINE PARTICULATE EMISSIONS: NOVEL DEVICES

Improvement in existing control device technology for coal-fired boilers and the development of potentially advanced techniques are needed:

1. To improve the capabilities for the control of fine particle emissions.
2. To overcome limitations due to the properties of the effluent gases and particulate matter.
3. To extend the capabilities to higher temperatures and pressures.
4. To reduce the cost of the control devices.

Research in the area of advanced control devices includes modifications or additions to existing systems as well as the development of new approaches.

Each of the three conventional control devices discussed in the previous chapter has certain limitations. Precipitators, for example, are limited by the magnitude of the charge on the dust particle, the electric field and the re-entrainment of the dust. Improvements that are possible in precipitator technology are those that improve one or more of these functions. Since the resistivity of fly ash adversely affects both particle charge and electric field, advances are needed to overcome these detrimental effects, in addition to extending the performance of precipitators not limited by resistivity.

Fabric filters achieve substantial collection efficiencies, but physical size is a problem in large power boiler applications. Also, pressure drop and bag life are areas that need attention. Some sacrifices in efficiency might be tolerated if higher air/cloth ratios could be achieved without reducing bag life (e.g., by the use of pulse-jet systems). Improvements in fabric filtration may also be possible by enhancing the electrostatic effects that contribute to the rapid formation of a filter cake after cleaning.

Scrubber technology needs considerable study to control scaling and fouling, improve overall reliability and reduce energy consumption. The collection of fine particles through the use of supplementary forces (e.g., electrically charged drops), acting on particles to cause them to grow or otherwise be more easily collected at lower pressure drops, is an area that has received considerable study.

Use of alternative systems to the three conventional control devices has also been investigated in an effort to achieve better efficiencies at lower costs. The difficulty has been that the removal of particulate matter from a gas stream requires that a force be applied to the particles, and methods for application of this force are limited.

This section describes some of the novel devices that have potential for fine-particle removal. The practical applicability of these devices on coal-fired boilers is evaluated in the next section. Many of these have not been used or tested on coal-fired boiler particulate emissions; the data presented are for other types of particulates. These devices are listed below:

1. Aronetics two-phase jet scrubber
2. Centripetal vortex contactor
3. Wet filter
4. Steam-hydro scrubber
5. Wet electrostatic precipitator
6. Electrostatic scrubber
7. Hybrid wet precipitator
8. Flux force/condensation
9. Electrostatic filter

A brief description of each of the above novel control devices follows. Note that extensive data are not available for most of these devices.

4.1 ARONETICS TWO-PHASE JET SCRUBBER

A pressurized, heated liquid, when passed through a properly designed nozzle, will produce a two-phase mixture of vapor and liquid droplets that is an excellent cleaning medium. The droplets can be accelerated to extremely high velocities as a result of the expansion force created by the conversion of a portion of the liquid to vapor. The general configuration of this type of scrubber is shown in Figures 4.1 and 4.2[31]. The proper arrangement of components allows a draft to be induced, which eliminates or drastically reduces fan power requirements. The two-phase jet scrubber produces water droplet velocities that vary with the temperature of the scrubbing fluid.

The most direct application of the two-phase scrubbing system is in the control of emissions from processes that generate high-temperature gas laden with sub-micron-size particulate. It is substantially more economical if waste heat at a sufficiently high temperature is available. Typical examples are the various metallurgical furnaces and processes.

In this system, an economizer type of heat exchanger is used to transfer thermal energy from the high-temperature process exhaust gas to pressurized hot water, which is delivered to the heat exchanger by a pump. Water leaving the heat exchanger is delivered directly to the nozzle in its liquid state. For most applications, the water temperature is approximately 400°F and the water pressure is approximately 350 psi, or high enough to insure that the fluid remains in the liquid state until it has passed the nozzle throat. A properly dimensioned mixing section must be provided for intimate contact between the accelerated water droplets and the particle-laden gas. The final component in the scrubbing system train is a separator, which will remove the dirty water droplets and allow the clean gas to be discharged. Water drained from the separator is passed to water treatment equipment, which may be used to remove substances scrubbed from the gas and to prepare the scrubbing liquid for recycling.

Collection efficiency was found to be greater than 50 percent for particles larger than 0.15 µm, greater than 90 percent for particles larger than 0.3 µm, and greater than 99 percent for particles larger than 1 µm. Typical fractional efficiency data for a ferro-alloy furnace are presented in Figure 4.3.[55]

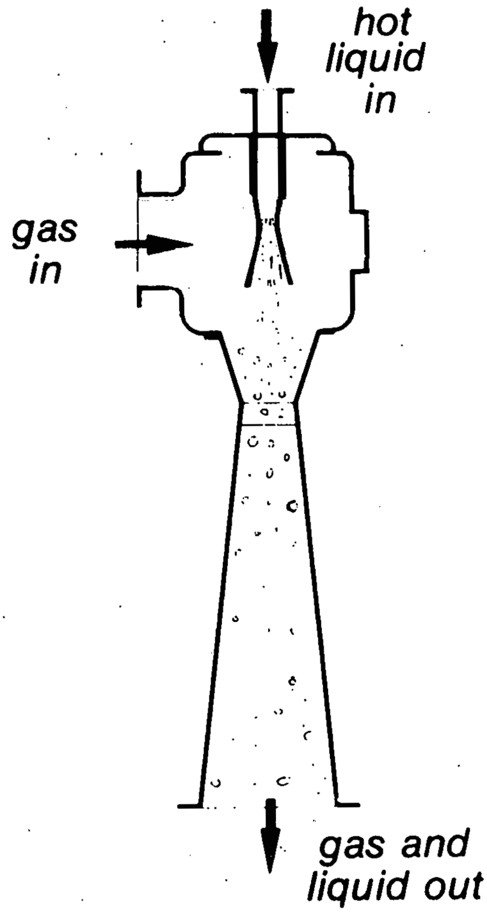


Figure 4.1 Generalized Two-Phase Jet Scrubber Nozzle.[31]

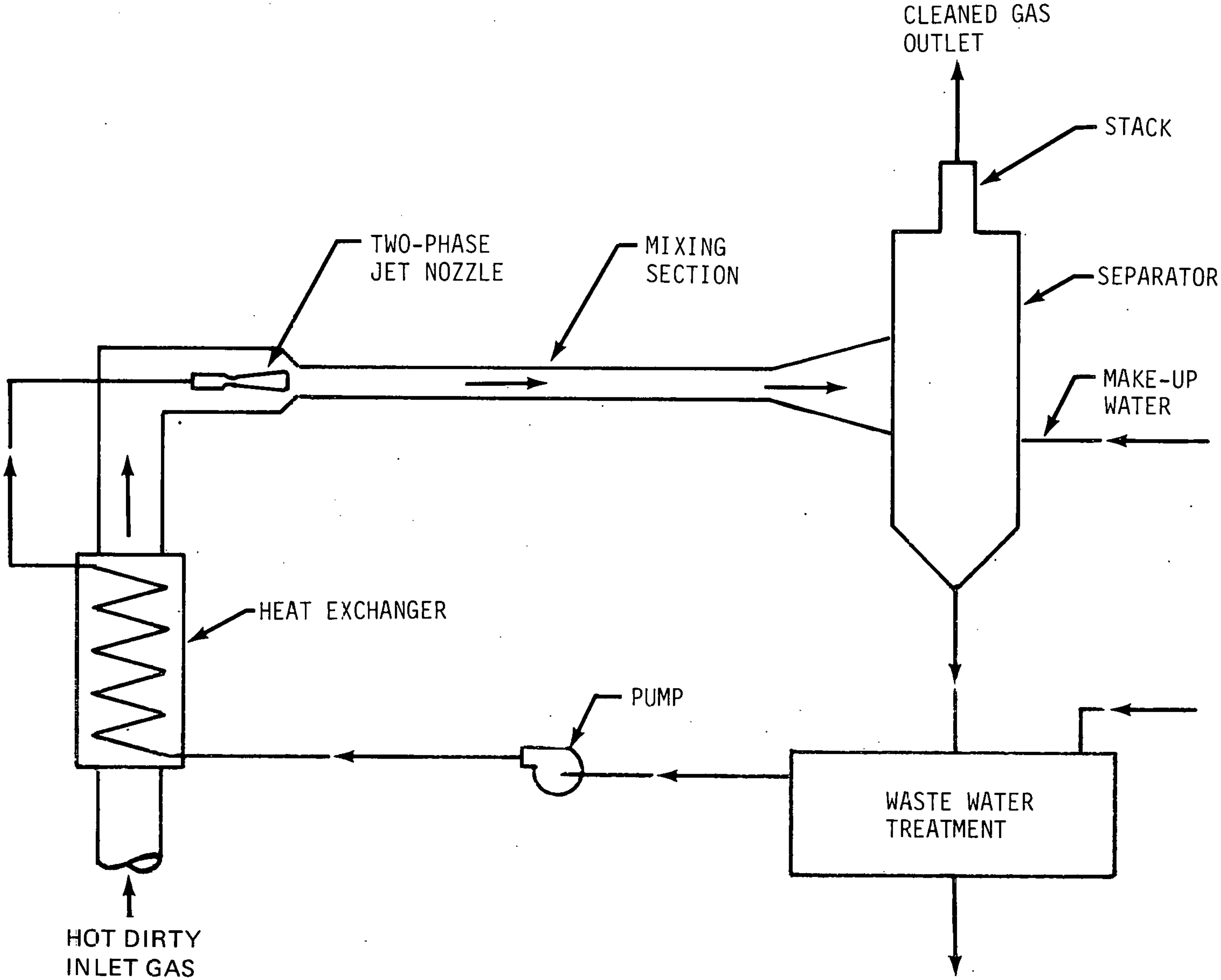


Figure 4.2 Generalized Two-Phase Jet Scrubber System. [31]

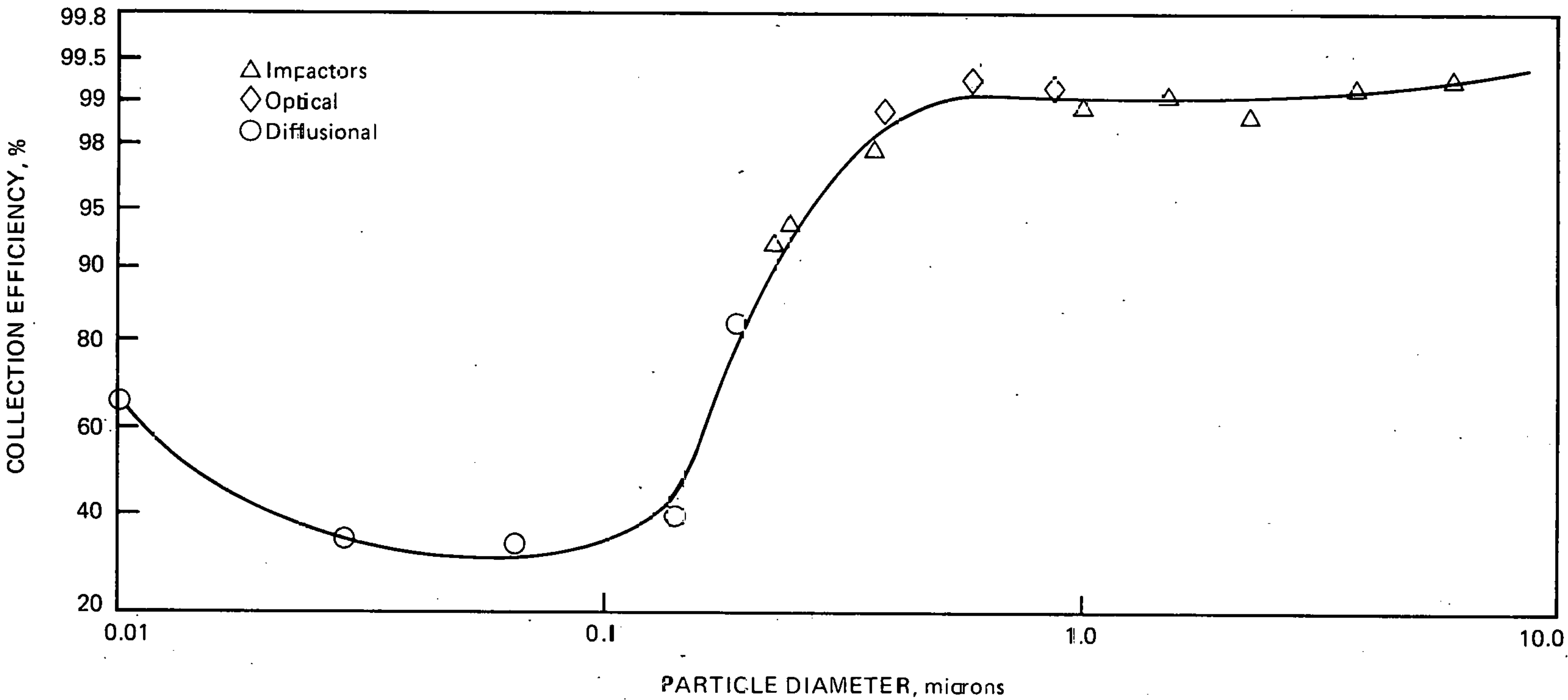


Figure 4.3 Fractional Efficiency of the Aronetics Scrubber Based on Optical, Diffusional and Inertial Sizing.[55]

The scrubber uses power from two sources: electrical energy to drive the pump that supplies water to the heater and thermal energy from the gas to provide the temperature increase in the water heater. If the latter is obtained from heat normally wasted, then (in a sense) it does not count as power consumption. The pump energy is typically 2-2.5 hp/1000 ACFM, while the waste heat power is usually around 17,000 Btu/1000 ACFM. It is desirable that all of the energy be available in the waste gas stream. If not, this is equivalent to an additional 400 hp/1000 ACFM consumed.

4.2 CENTRIPETAL VORTEX CONTACTOR

In the centripetal vortex contactor, the contaminant-laden gases are forced to pass through a high-velocity, high-intensity droplet cloud formed by the aerodynamic motion of the gas stream passing through a stationary circular vane cage (cf. Figure 4.4[31]). The scrubbing liquor, which is fed through an open pipe with no nozzles or restrictions, assumes a fog-mist-droplet phase and forms the tornado-like cloud within the vane cage. Rotation is initiated and sustained by using only the energy in the moving gas stream. There are no moving parts in the unit. The rotating cloud is maintained by the ability of the vane cage to stabilize it axially within the contact area. The cloud is relieved of scrubbing liquor at a rate equal to that at which it is fed. As the gases enter the centripetal vortex contactor, they are bombarded by the larger-sized droplets flushed from the rotating droplet cloud. The centrifugal-centripetal force balance on a droplet in the cloud insures a relatively small equilibrium droplet diameter; i.e., should a droplet be enlarged in any way (size or mass) by agglomeration with other droplets or by particle impaction, the centrifugal force on it will overcome the centripetal force and cause the droplet to be flushed. The droplet-particle interaction resulting from this continual flushing of the gas stream as it enters the contactor and makes its way toward the vane cage serves two purposes: (1) removal of a substantial portion of the

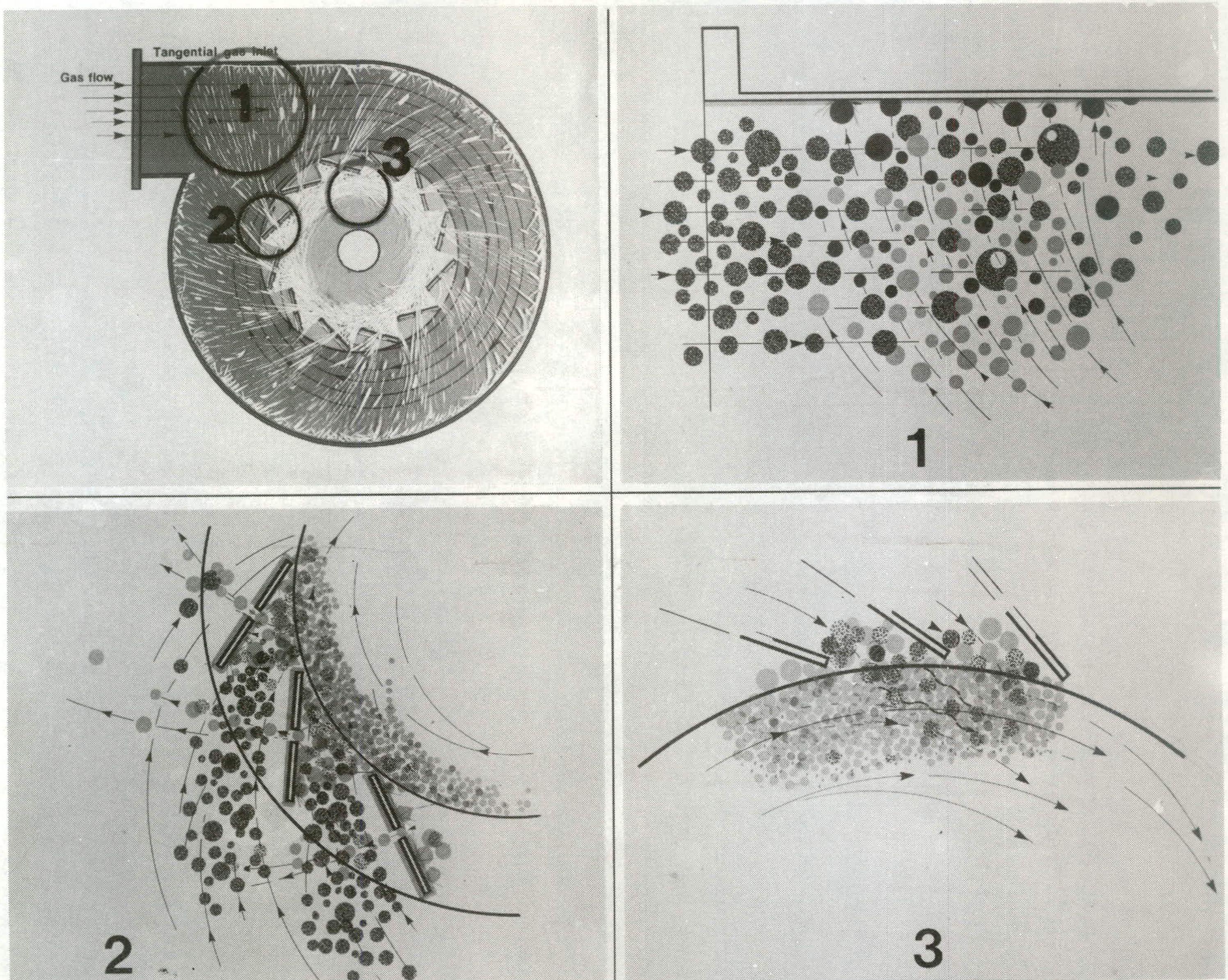


Figure 4.4 Particle Collection Mechanisms Experienced in the Single-Vane Cage Centripetal Vortex Scrubber (1) at Scrubber Inlet, (2) at Entrance into Cloud, and (3) in Cloud.[31]

larger-sized particles, and (2) pre-quenching/pre-conditioning of the gas stream. The next stage of contact occurs just as the gas-particle stream interacts (almost co-currently) with the high-velocity, rotating droplet cloud. Just as in the Venturi scrubber, the high relative velocity difference between the droplets and the particles at this point over an extended surface area (vane) accounts for the high particle collection efficiencies achievable. The final stage of droplet-particle contact occurs once the gas stream, with any uncollected particles, enters the rotating droplet cloud. When the gas stream penetrates the cloud, any particles still entrained assume the velocity of the droplets in the cloud (i.e., the relative velocity difference goes to zero). Yet, as a result of both a pressure and concentration driving force, the particle tends to migrate through the droplet cloud. Its erratic path through the cloud will usually insure contact with and subsequent capture by a droplet.

Fractional efficiency data from an aggregate dryer at an asphalt plant are presented in Figure 4.5[55]. As the scrubber pressure drop is increased above this level, the characteristic dip of the efficiency curve in the 0.1-micron size range decreases; i.e., collection increases in the fine-particle size range. Typical liquid water requirements are 3-5 gal/1000 ACFM.

4.3 WET FILTER

The wet filter is primarily a wetted fibrous bed system. It consists of water sprays to wet and clean the filter medium, a rotary drum containing a fibrous "sponge" filter medium and a water bath reservoir for cleaning the rotary filter. Particle collection is accomplished by filtration mechanisms in the rotary filter.

Figure 4.6[56] is a schematic of a typical system. The cyclonic pre-cleaner with water sprays is used for removing the larger-sized particles. Water is also sprayed on the rotating filter drum. Total liquid requirements are approximately 1.0 gal/

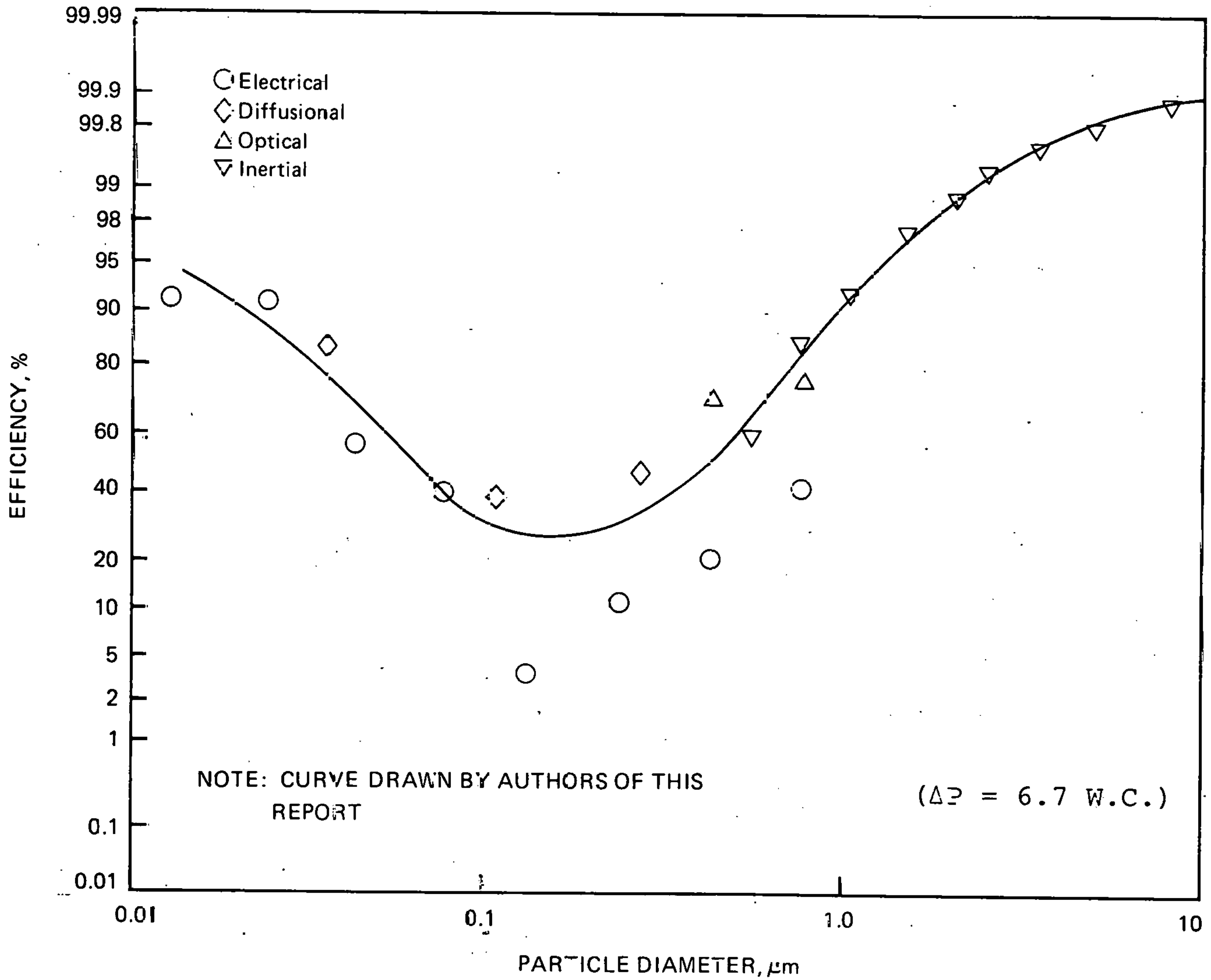


Figure 4.5 Fractional Efficiencies as Determined by the Four Methods used in the Test Program. The particle sizes shown for the impactor data are Stokes Diameters based on a particle density of 2.5 grams·cm^{3} - Asphalt Plant Aggregate Dryer.[55]

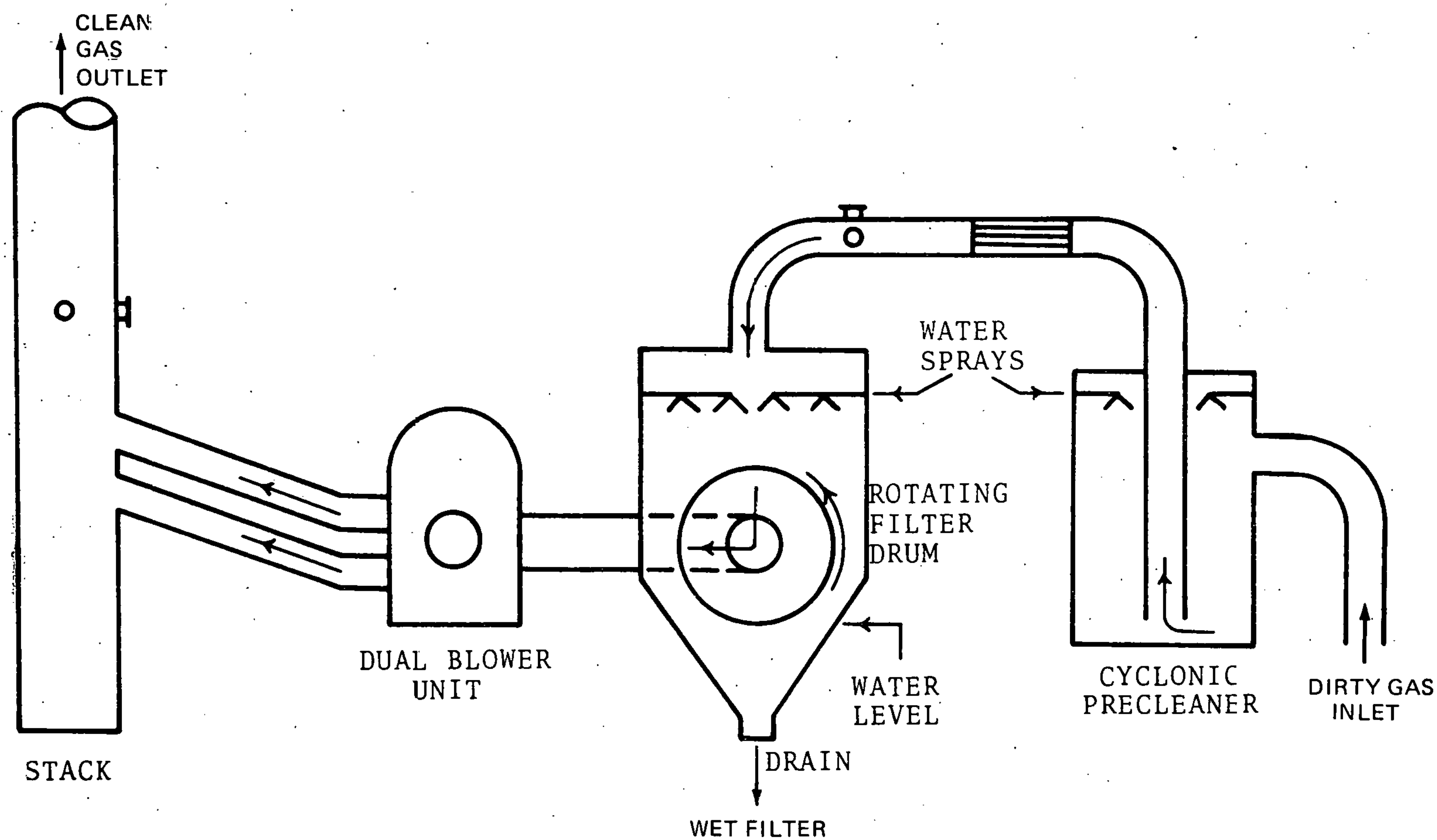


Figure 4.6 Schematic of Wet Filter System [56]

1000 CFM. Fractional efficiency data from a diatomaceous earth dryer are presented in Figure 4.7.[57]

4.4 STEAM-HYDRO SCRUBBER

The steam-hydro scrubber utilizes a high-speed steam drive with injected water to develop an extremely efficient scrubbing action. The heart of the system, which contains no moving parts, consists of a steam nozzle, water injector, mixing tube and twin cyclones (cf. Figure 4.8).[55] Normally, the system operates on energy produced by waste heat captured from the process being controlled. The heat is used to generate steam in a waste heat boiler. In installations where heat energy is low, supplemental heat must be provided. In many cases, a package steam boiler may supply all the energy.

The first stage of cleaning in this device is done in an optional atomizing chamber with water sprays that may be employed to cool the gas stream and remove heavy particulate matter. Most processes do not require this chamber, but it can be installed as a first-phase cleaner for certain difficult effluents. A negative pressure is maintained in this chamber, and a process occurs where steam joins small contaminant particles for second-phase removal in the mixing tube. Collision between injected water droplets and the particles (including acidic gases, if present), encapsulation, nucleation and droplet growth take place in the mixing tube. Collisions occur between particulate and the high-speed water droplets. The particles are encapsulated, and a growth process begins to bring sub-micron particulate to manageable size for disposal through low-pressure-drop cyclones. To insure positive capture of all contaminant, a shock wave pattern is created in the mixing tube. Massive turbulence created by the shock wave pattern subjects the encapsulated particles to a sudden and violent scrubbing action. The separation of the particulate from the gas, when it has grown to a size matched to the system, is achieved in low-pressure-drop cyclones. Centrifugal energy

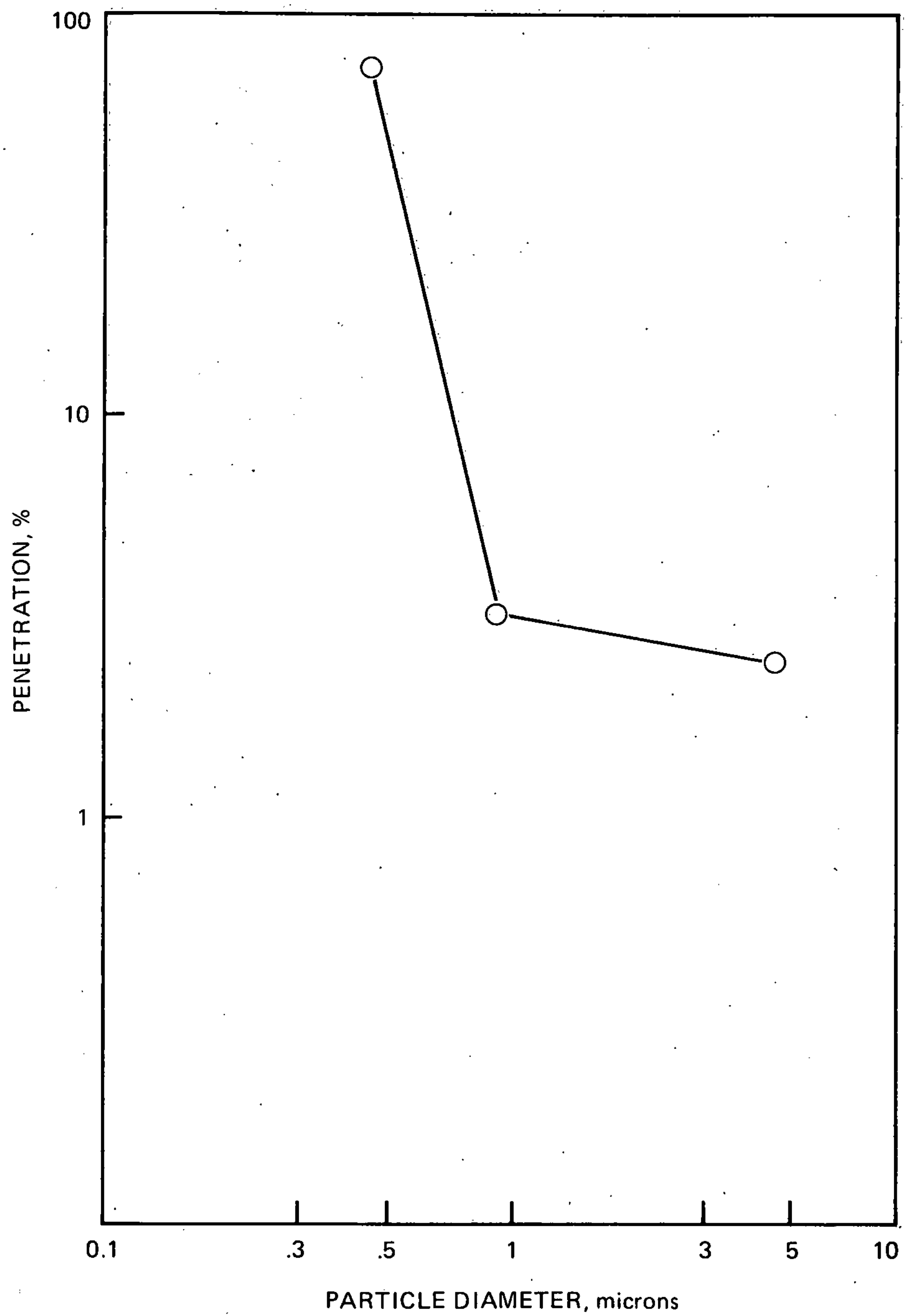


Figure 4.7 Fractional Efficiency Data for a Wet Filter using a Cascade Impactor for Size Classification.[57]

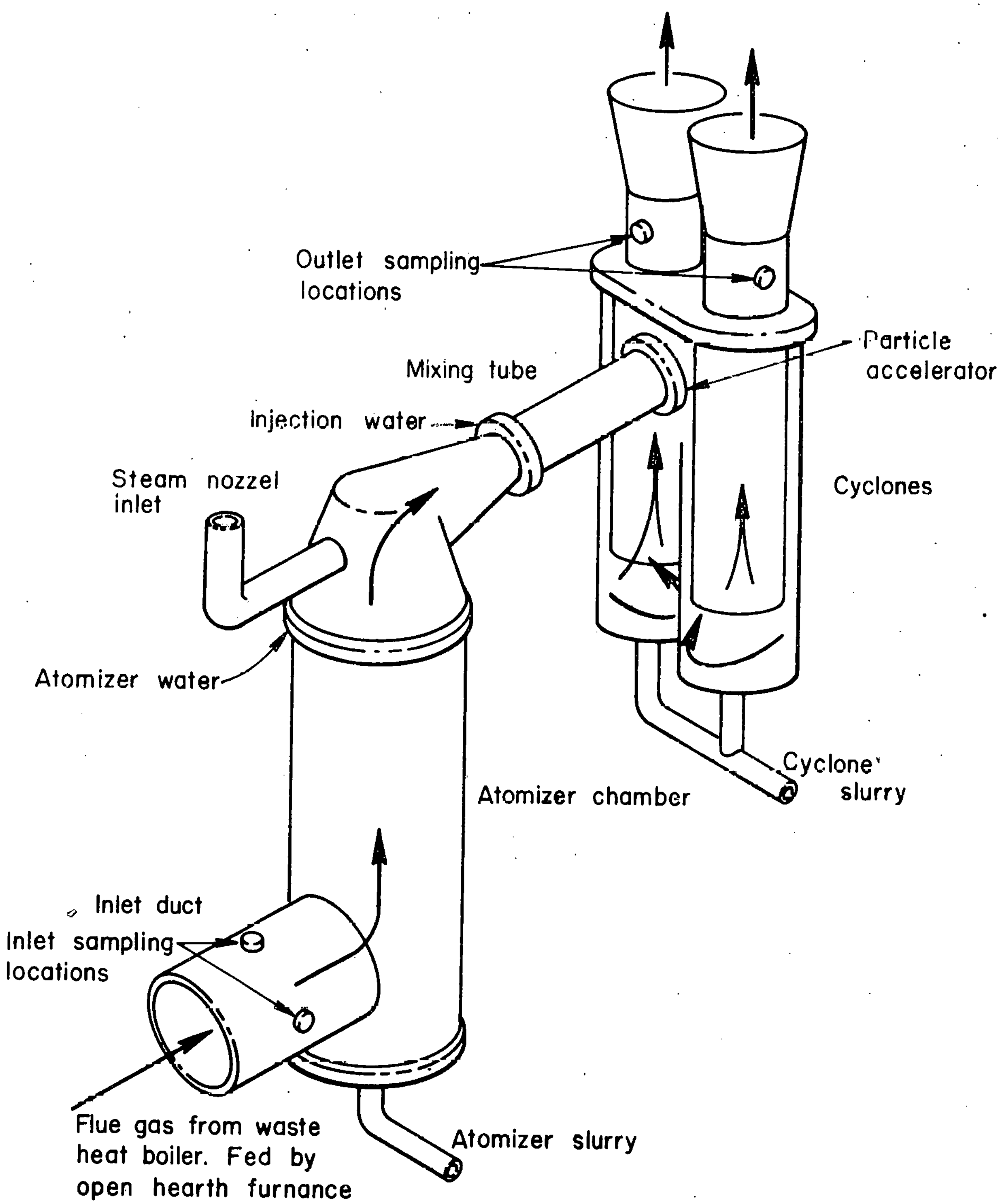


Figure 4.8 The Lone Star Steel Steam-Hydro Air Cleaning System.[55]

in the cyclones is maintained by a force imparted from the mixing tube.

This scrubber uses high pressure steam to move the gas through the system by eduction. The rapidly moving steam entrains gas, particles and droplets. The particles collect on the droplets by various mechanisms. The principal mechanism, used for particles larger than a few tenths of a micron, is thought to be impaction. Diffusion and the condensation of the steam onto the droplets (entraining particles) are also thought to be significant. Once the particles have collected on the droplets, the drop/particle mixture is caught in the centrifugal collectors (cyclones) immediately downstream from the scrubber mixing section. The energy required to move the gas, particulate material and droplets through the system is supplied not by fans or pumps but by steam produced in boilers or economizers operating on the waste heat of the process. As with all scrubbing operations, the wastewater sludge effluent from the cyclones must be disposed of.

Fractional efficiency data from an open-hearth furnace are presented in Figure 4.9[55,57]. Waste heat would have to produce the energy equivalent of 200-300 hp/1000 AFCM for the scrubber to operate without a power penalty.

4.5 WET ELECTROSTATIC PRECIPITATOR

A wet electrostatic precipitator is a hybrid precipitator that utilizes a water spray system to clean the collecting electrodes. Because the dust layer is continuously washed from the electrodes and the gas is saturated with water vapor, dust resistivity is not a factor in the performance. Electrode irrigation is provided by sprays at the precipitator inlet and above the collection plates (cf. Figure 4.10[58]). The sprays provide a mist, which is collected along with the particulates in the flue gas, and the electrode cleaning is accomplished by the coalescence and subsequent downward flow of the collected spray droplets. The sprays are operated continuously, except for those installed

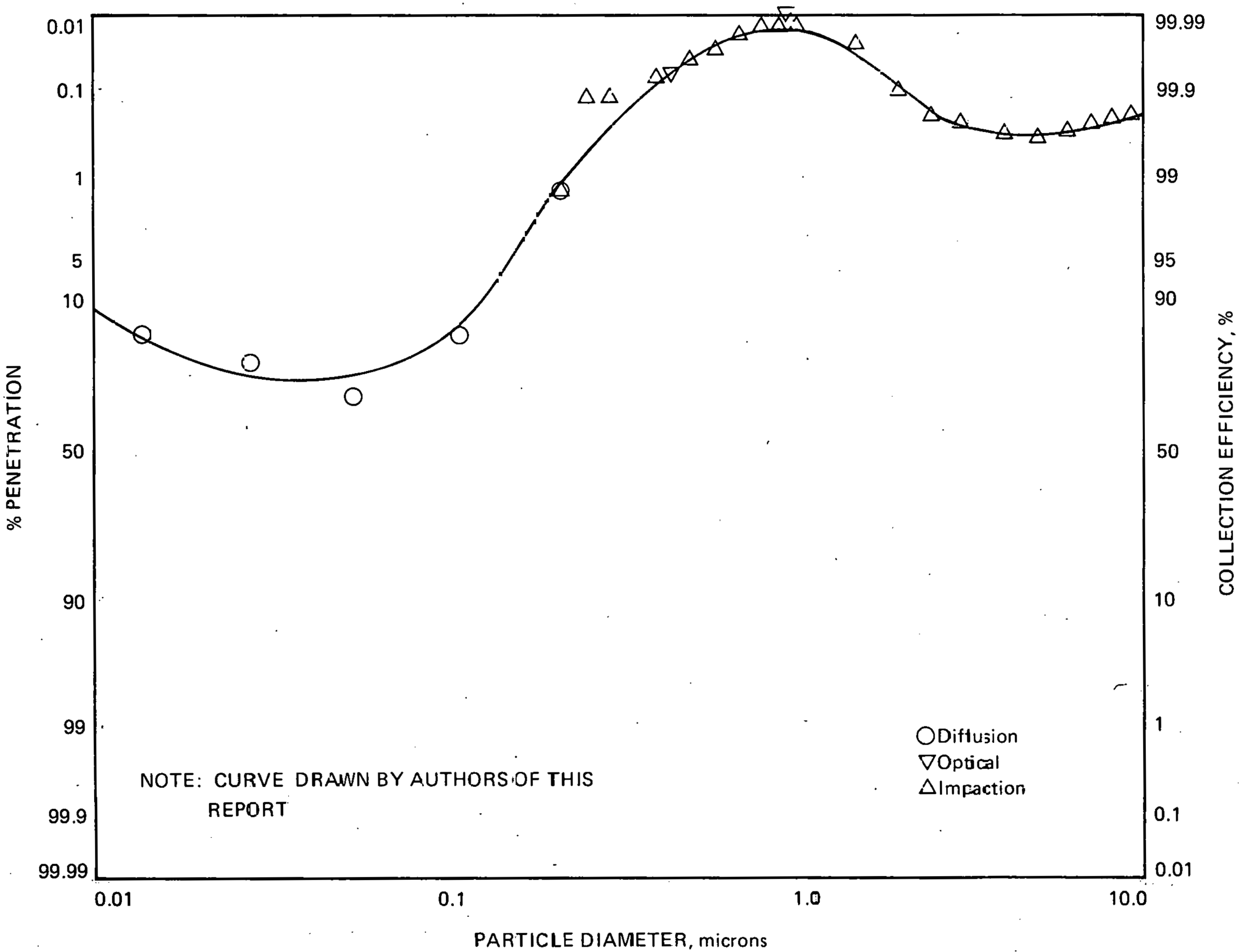


Figure 4.9 Fractional Efficiency of the Steam Hydro Scrubber.[55,57]

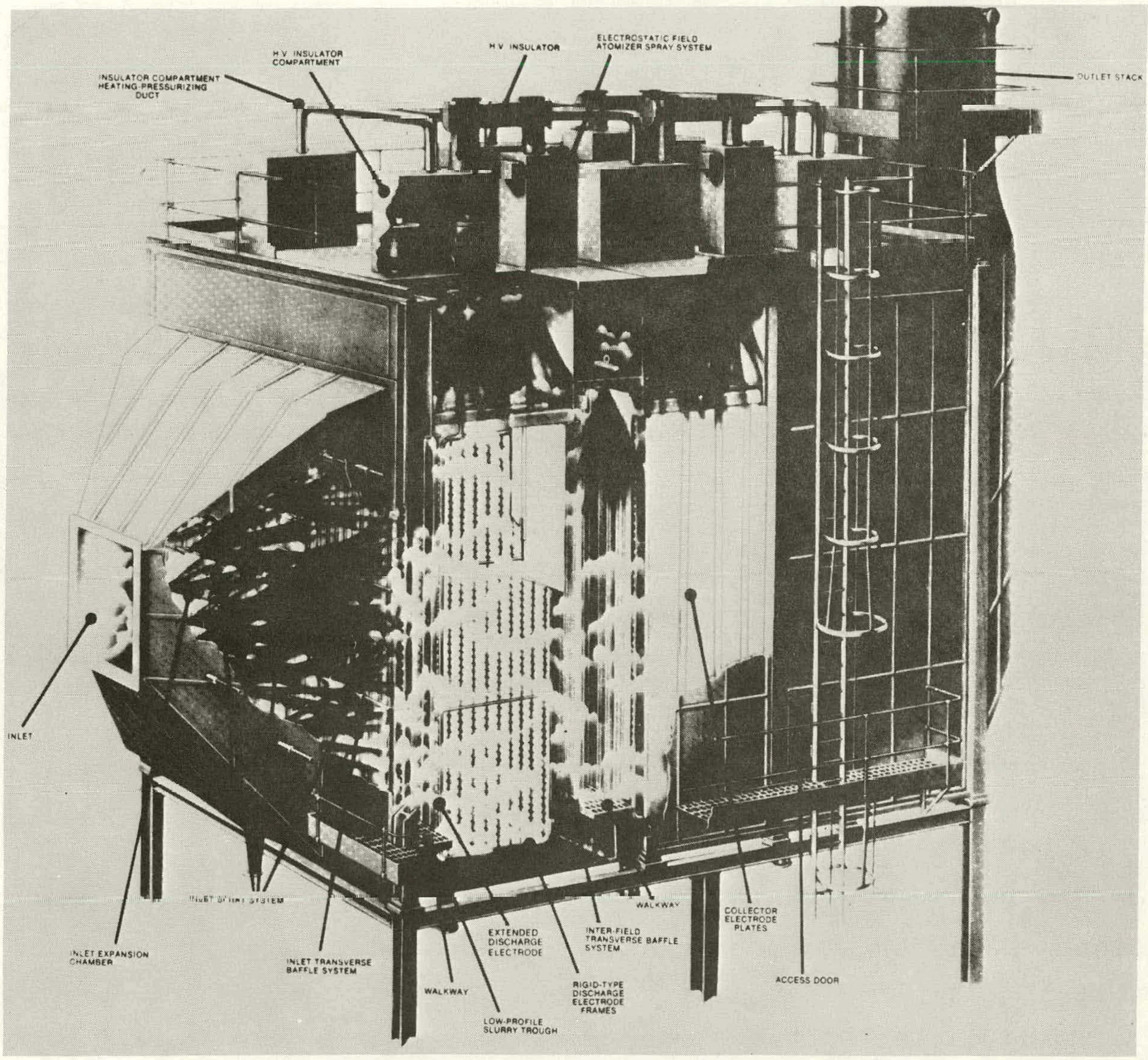


Figure 4.10 Wet Electrostatic Precipitator.[58]

near the precipitator outlet, which are operated only periodically.

Fractional efficiency data from an aluminum reduction pot line are presented in Figure 4.11.[58]

4.6 ELECTROSTATIC SCRUBBERS

4.6.1 University of Washington Electrostatic Scrubber

The electrostatic scrubber uses electrostatically charged water droplets to collect air pollutant particles electrostatically charged to a polarity opposite that of the droplets. As is shown in Figure 4.12,[59] the particles are electrostatically charged (negative polarity) in a corona section. The gases and charged particles flow into a chamber into which charged water droplets (positive polarity) are sprayed. The gases and some entrained water droplets flow out of the spray chamber into a mist eliminator, consisting of a positively charged corona section, in which the positively charged water droplets are collected. Particle collection occurs in each sub-unit, with some particles collected in the corona charging section and some in the mist eliminator section.

Performance data were obtained using a pilot unit on a pulverized coal-fired boiler (rated at 120,000 pounds steam/hr at 650° F and 400 psig), firing a low-sulfur western coal (Utah) with 0.65% sulfur, 5.12% ash and 12,819 Btu/lb. Fractional efficiency data for two test runs are presented in Figures 4.13 and 4.14.[60] The liquid-to-gas ratio was approximately 6 gal/1000 ACFM, and outlet particle concentrations ranged from 0.0013 to 0.0020 grains/SCFD. Energy requirements (gas pressure drop, water pressure drop, electrostatic charging of the water spray droplets and electrostatic charging of the aerosol particles) were about 0.5-0.8 hp/1000 ACFM.

4.6.2 Ionizing Wet Scrubber

The ionizing wet scrubber is basically an electrostatic charger (or ionizer) followed by a Venturi scrubber. A schematic

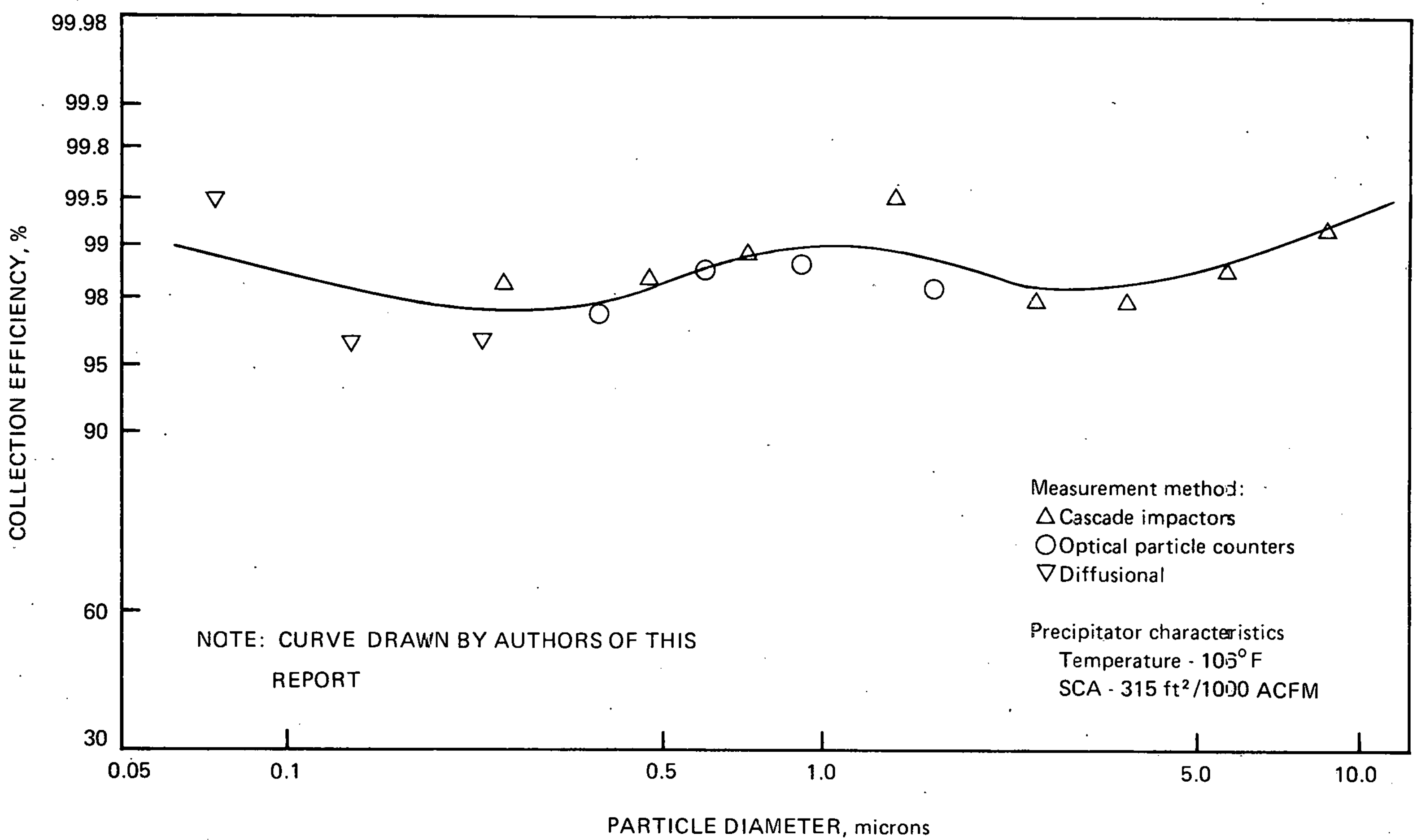


Figure 4.11 Typical Fractional Efficiencies for a Wet Electrostatic Precipitator with the Operating Parameters as Indicated.[58]

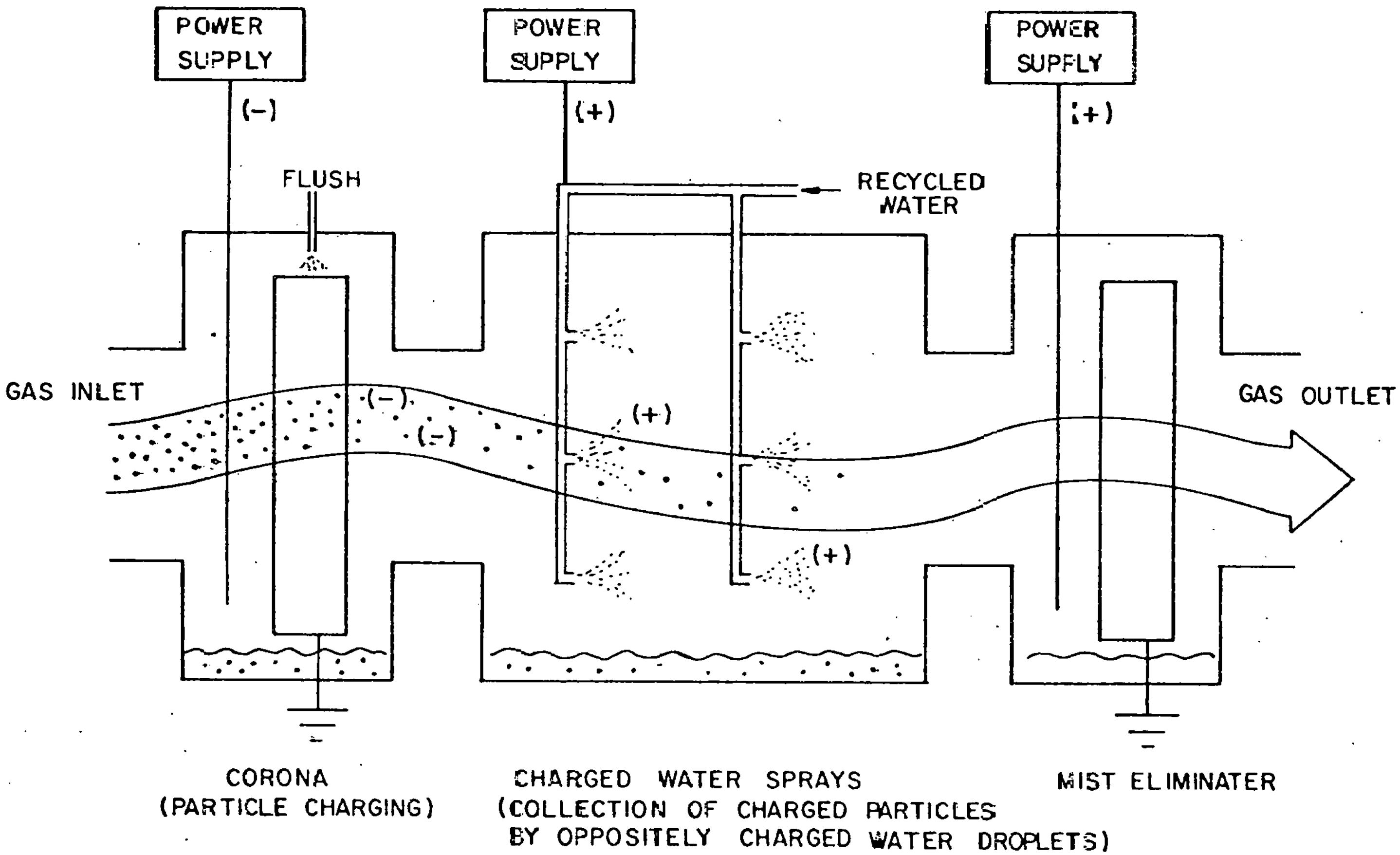


Figure 4.12 Electrostatic Scrubber.[59]

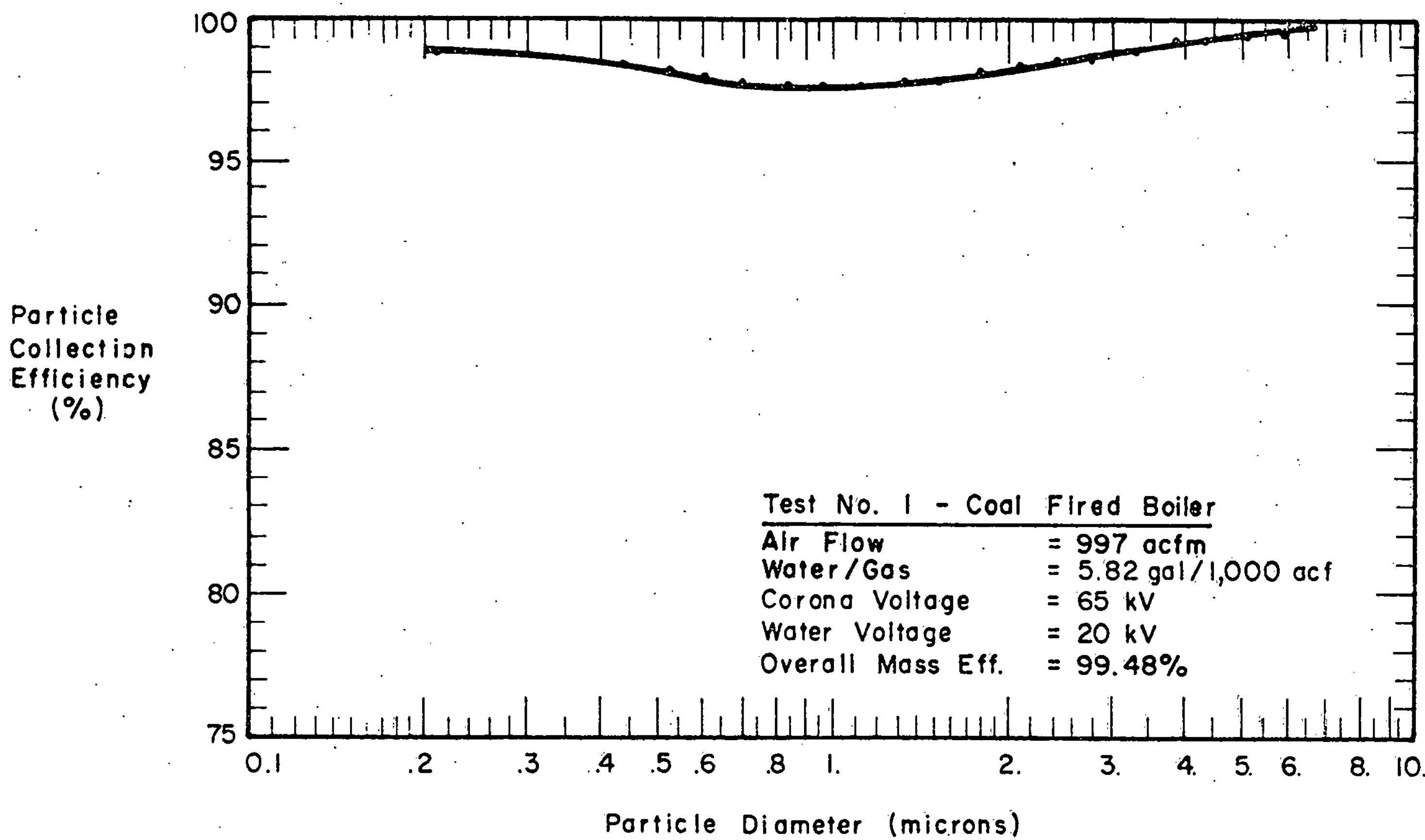


Figure 4.13 Fractional Efficiencies for the University of Washington Electrostatic Scrubber Installed on a Coal-Fired Boiler, Test No. 1.[60]

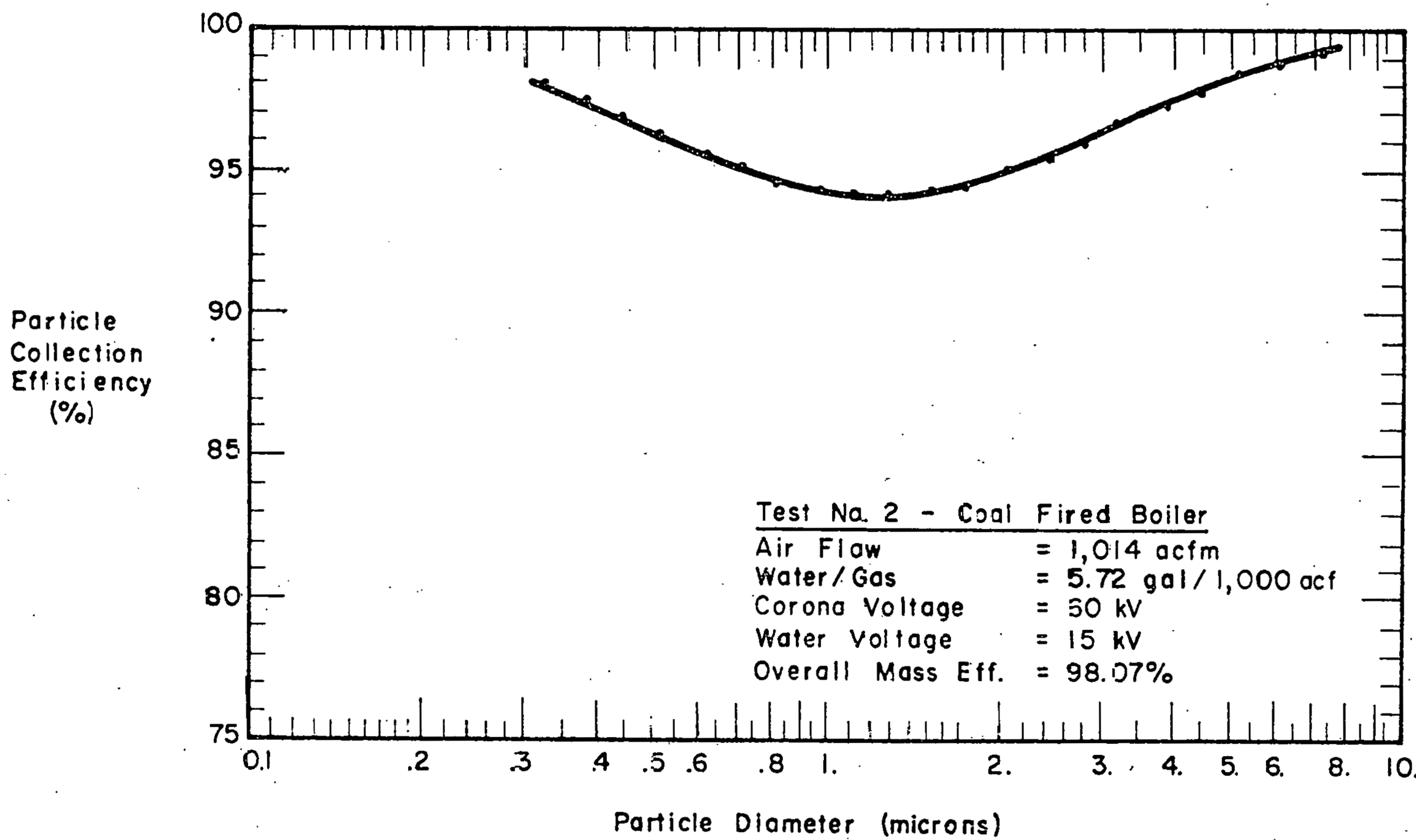


Figure 4.14 Fractional Efficiencies for the University of Washington Electrostatic Scrubber Installed on a Coal-Fired Boiler, Test No. 2.[60]

of the system is shown in Figure 4.15[56]. An electrode is placed upstream of the Venturi to charge the inlet particles, which then enter the Venturi throat. The gas stream atomizes the central water spray in the Venturi throat, and the charged particles are then attached and collected by the highly polarized water molecules.

The charged particles are also collected on the walls of the ionizer section prior to entering the throat of the Venturi. A thin film of water is allowed to trickle down the inclined surfaces to keep the walls clear and prevent high voltage arcing. The particle-laden water droplets are then collected by a cyclonic separator and sent into a settling tank (clarifier).

The ionizer consists of a wire electrode in the inlet of the Venturi section. A stable electrical discharge of high intensity is maintained across the Venturi throat between the center electrode and the wall. The average field that can be maintained across the electrode gap (space between the electrode probe and the wall) is higher (14-16 kV/cm) than that of a standard electrostatic precipitator (around 4 kV/cm).

Fractional efficiency data on a titanium dioxide aerosol (median particle diameter of 1 micron, with a standard deviation of 2.2) are presented in Figure 4.16.[56] The pressure drop across the Venturi was 15.7 in W.C., the water flow rate for the ionizer wall wash was 2.7 gal/1000 ACF of gas and the flow rate to the Venturi throat was 8.1 gal/1000 ACF of gas.

4.7 HYBRID WET PRECIPITATOR

A two-stage electrostatic device called an "Electro-Tube," which combines the features of a wetted-wall electrostatic precipitator with high-intensity particle precharging, has been developed. The system is basically a tubular ESP with a central rod electrode and wetted-wall collector (cf. Figure 4.17).[61] The saturation charge on the particle is increased substantially

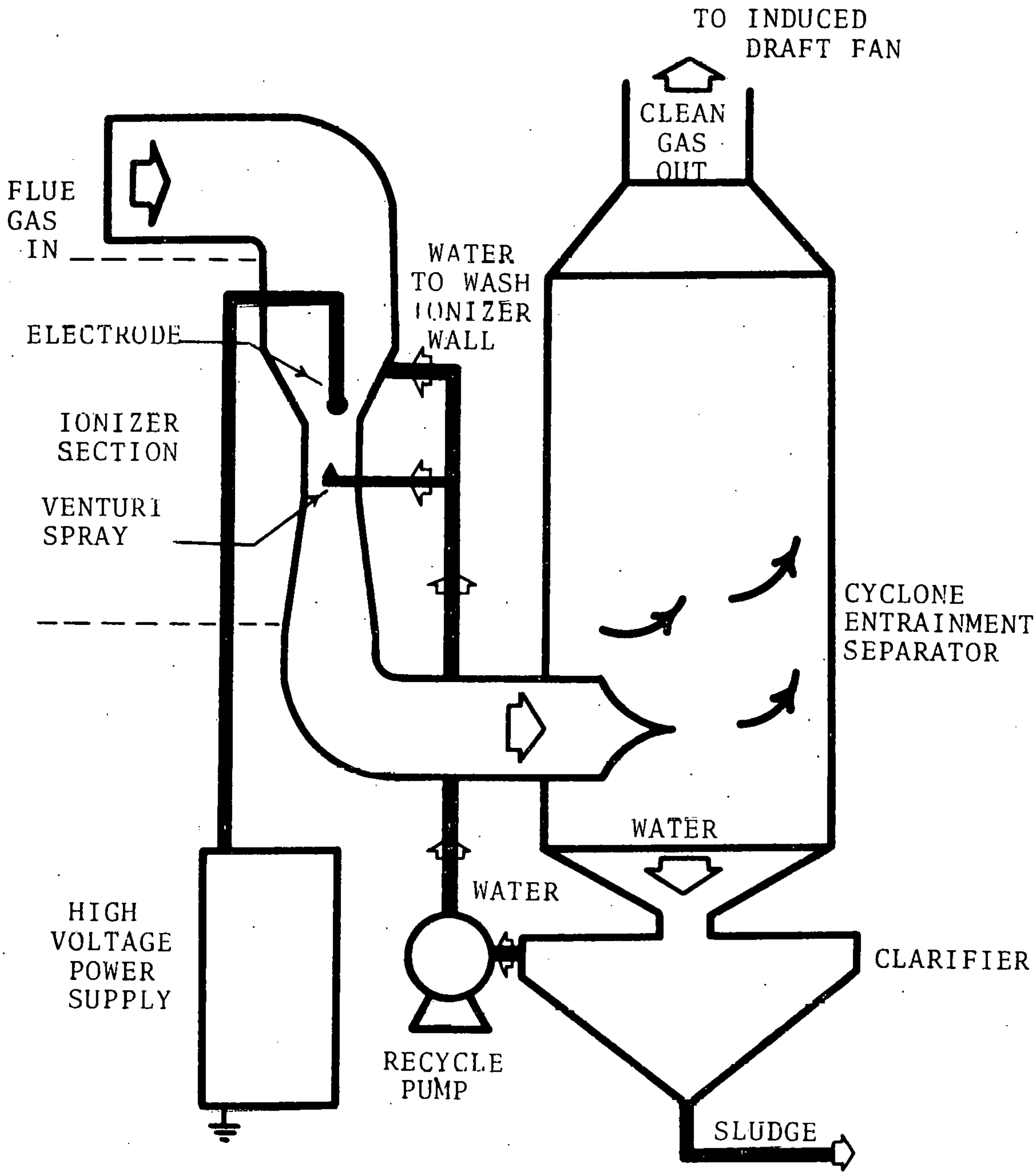


Figure 4.15 Ionizing Wet Scrubber [56]

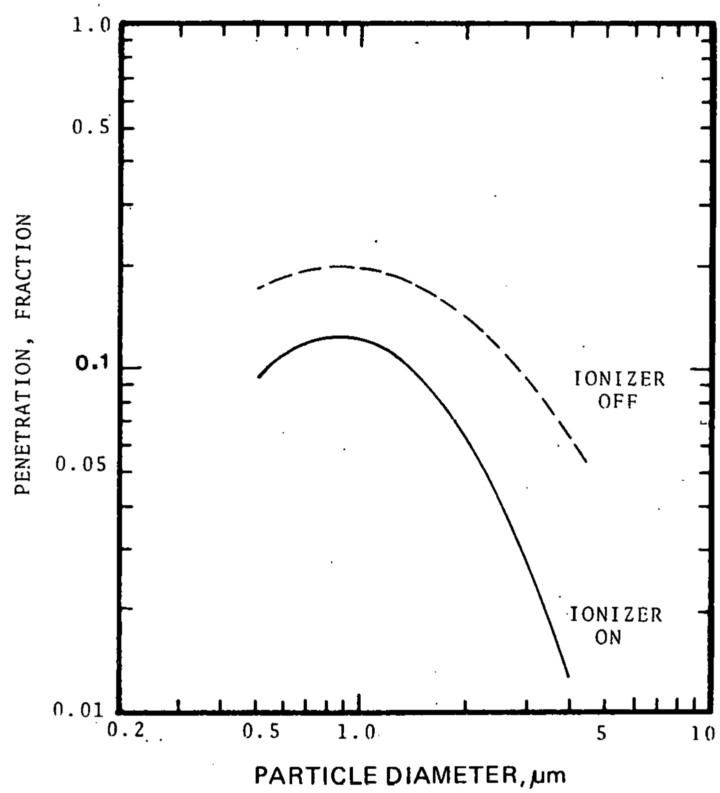


Figure 4.16 Penetration vs. Particle Diameter for Ionizing Venturi Scrubber [56]

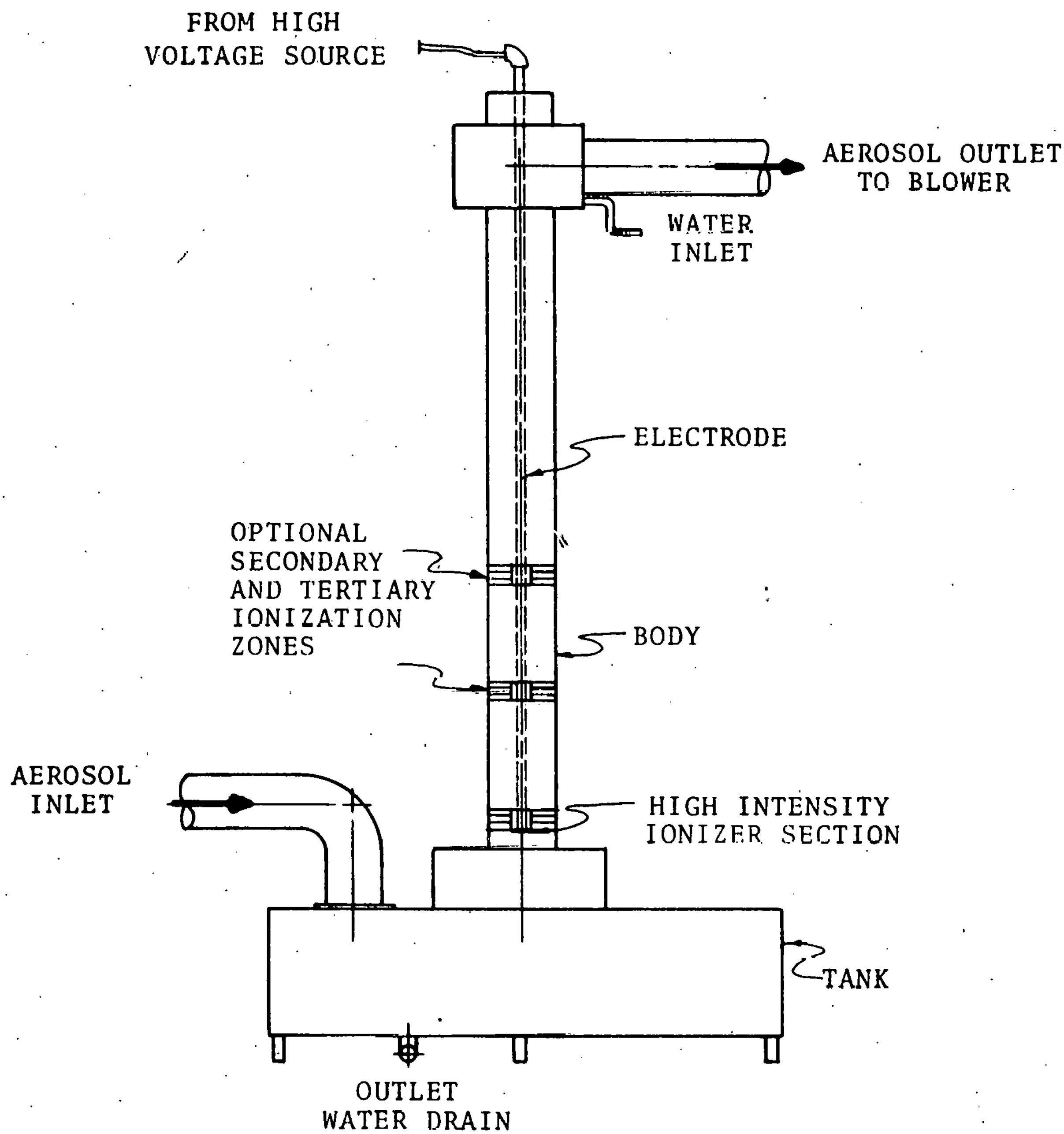


Figure 4.17 Diagram of Electro-Tube.[61]

from the normal 4-5 kV/cm field in a conventional precipitator to 12 kV/cm by first passing the gases through the high-intensity ionizer.

The increased electrostatic charge allows a more effective migration of the fine particles in the collecting electric field of the precipitator. The collecting precipitator, a wetted-wall pipe type, has a passive high-voltage electrode that emits no corona current and operates at an average applied field of 5 to 10 kV/cm. Tests have shown a high degree of stability in the electric fields up to a gas flow velocity of 20 fps. Despite the shorter residence time in the charging field, there is no apparent deterioration of particle charging efficiency.

A single power supply provides high voltage to both ionizer-charger and collector sections, with a total power consumption less than 0.24 W/(ft^3/min). Pressure drop through the Electro-Tube is less than 0.3 in. W.C. Since only a small amount of stack heat is transferred to the wetted walls, the Electro-Tube wet collection process does not quench the gas stream. Water utilization rate ranges between 1 and 2 gal/1000 ft^3, depending on inlet dust loading and degree of prequenching desired. The Electro-Tube is designed so that entrained water does not affect electric field stability. The unit is self-demisting, and any entrained water droplets are collected as fine particulate. Fractional efficiency data utilizing a cascade impactor and a diffusion battery with condensation nuclei counter on a titanium dioxide test aerosol are presented in Figure 4.18.[61]

As a result of very positive laboratory-scale test results, the Electric Power Research Institute is sponsoring an on-going development program for the pre-ionizer.[62] Economic evaluations indicate potential cost savings on new systems and retrofit upgrades.

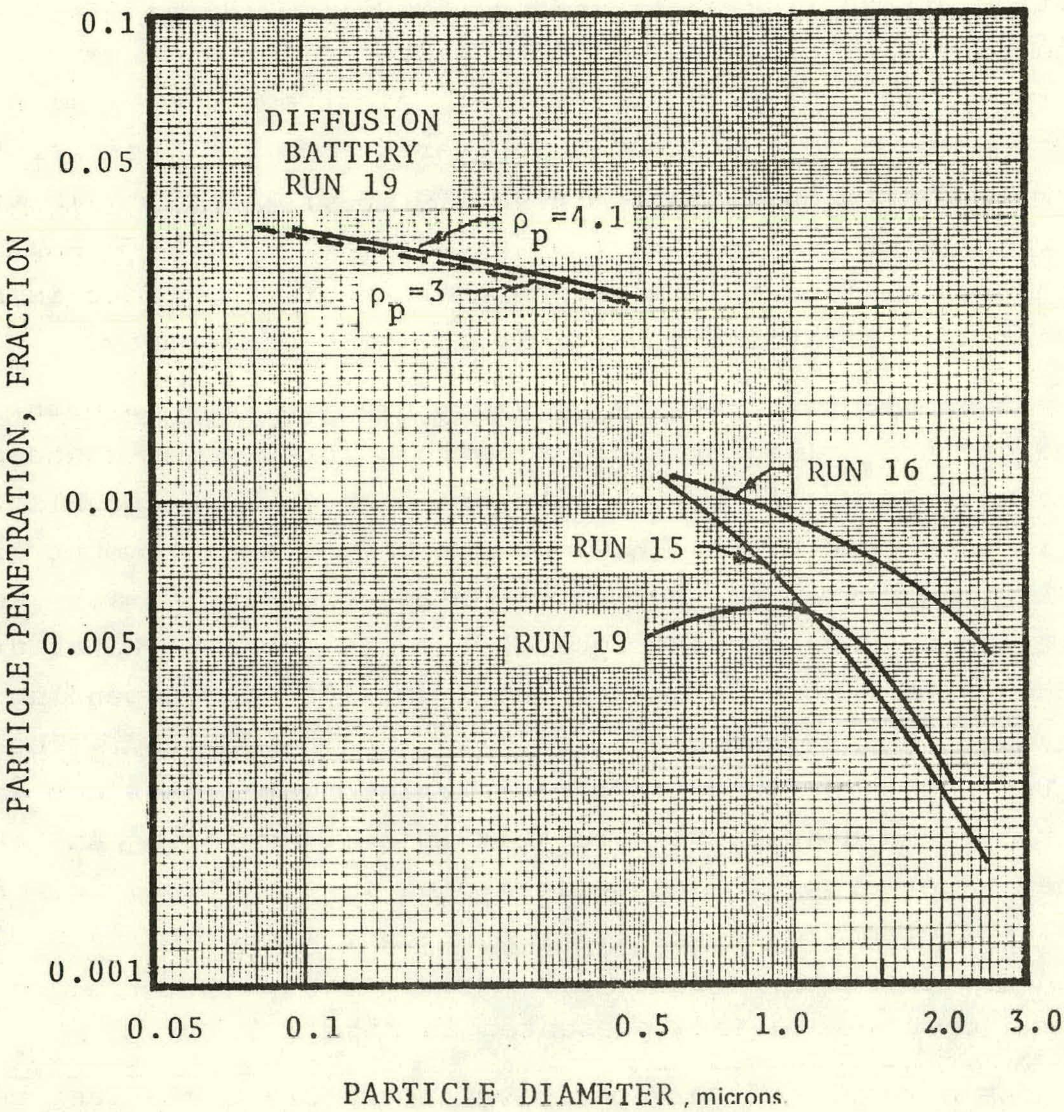


Figure 4.18 Penetration Versus Aerodynamic Particle Diameter for Low Gas Flow.[61]

4.8 MISCELLANEOUS

Flux force/condensation scrubbers and electrostatic filters are two devices currently under development that have a high degree of potential for removing fine particulate matter efficiently.

Flux force and vapor condensation effects have been shown to cause high removal efficiencies for fine particles in low energy scrubbers.[63] These effects can be induced by the cooling of a hot humid gas in contact with cold liquid, the condensation of injected steam, or other means. Particle removal is aided by a temperature gradient, a vapor concentration gradient, vapor condensation, particle growth due to vapor condensation or combinations of the four. Pilot test results using a five-plate scrubber have indicated efficiencies in excess of 90% for 0.5-micron size particles at pressure drops in the area of 13 in. W.C.[61] By contrast, collection efficiencies for particles in this size range in a conventional five-plate scrubber with no induced condensation effect are almost negligible.

Electrostatic filters are also being investigated, as a result of their potential to enhance fine particle capture.[64] Recent work has shown that charged particles can be effectively collected by a bed of knitted fibers having a high bed volume/fiber volume ratio and very low pressure drop.[65] Collection efficiencies for particles in the 0.06-0.7-micron size range have approached 99% at superficial gas velocities ranging from 1.5-3.0 fps.

Although foam scrubbing has been shown (on a pilot scale) to be a viable method for removing fine particulates,[66] there are a number of limitations that make it inappropriate for use with coal-fired utility boilers. Foam scrubbing involves rather basic operations, such as pumping the liquid and gas and using a spinning disk to destroy the foam. The foam is generated by forcing an aerosol through a screen sprayed with a surfactant liquid. Particle collection is believed to take place mainly by diffusion and sedimentation. To achieve high removal efficiencies for fine particulates, very low flow rates and high residence times would be required; this would necessitate extremely large units. Although projected capital costs would be comparable to conventional electrostatic precipitators, operating costs under even the most ideal conditions would be an order of magnitude greater than those for the most expensive conventional control method -- the high energy wet scrubber. High operating costs are principally associated with the cost of the surfactant.

High-gradient magnetic separation was eliminated from consideration with coal-fired boilers, because it is only effective in removing particles with sufficiently high magnetic susceptibility. Such particles are found only in certain process streams--e.g., those of the iron, steel and ferroalloy industries.[67]

Granular bed filters for fine-particle control are still in the developmental stage, primarily as clean-up devices on high temperature and high pressure gas streams such as those experienced in coal gasification systems. In general, the higher efficiencies can be achieved only with the finer-sized granules. Since the grid support structure must have openings smaller than the granules, there is a tendency to accumulate dust deposits on the grid, eventually causing plugging. Another potential problem is re-entrainment. Dust loosened during the cleaning cycle may subsequently be carried directly to the stack. These potential handling and cleaning problems necessitate further research before the usefulness of granular bed filters on conventional coal-fired boilers can be determined conclusively.

5 CONTROL TECHNOLOGY COMPARISONS

In this chapter, the various conventional control devices are compared on both an energy-usage and an economic basis. An evaluation methodology is also established for the comparison of existing control technologies for both conventional and novel control devices with respect to three levels of new source performance standards: 0.1 lb particulate/MBtu (current), 0.05 lb/MBtu and 0.03 lb/MBtu. This analysis can provide: (1) a comparison of the effectiveness of the different conventional devices for fine-particulate control from coal-fired utility boilers, and (2) a rough guide for the selection of those novel devices that offer the best commercialization potential for the control of fine particulates from coal-fired utility boilers.

5.1 ENERGY

The energy penalty must be considered when calculating the costs of emission control systems. Electrical power consumption by the emission control process reduces the net amount of power generated and additional Btus are required to produce a net kilowatt-hour of electricity. Particulate emission control methods cause losses in net generation by a power plant that may require additional generating capacity. Factors that affect the cost of diverting a portion of a utility's electric generating capacity, either to supply the energy requirements of environmental control equipment or to replace lost capacity, are listed below:[68]

A. Percentage of boiler unit capacity needed to supply the electrical energy requirements of environmental control equipment

B. Percentage of the total boiler system capacity to be equipped with environmental control equipment

C. Boiler system capacity in MW

D. Annual load growth of the boiler system

E. Size of reserve capacity in the year that the environmental control equipment is added

F. Reserve boiler capacity requirement

- Unit reliability by type of unit
- Unit reliability by size of unit
- Shape of load curve
- Mix of boiler generating capacity
- Maintenance and overhaul

G. Capability of boiler system interconnections

H. Potential for interchange purchases and sales of electrical energy

- Short-term firm
- Economic transactions

I. Availability of boiler unit participation

J. Cost per KW of added generating capacity

- For each type of capacity (i.e., nuclear, fossil, steam, gas turbine)
- Economics of scale
- Price escalation

K. Cost and availability of fuels

L. Load characteristics

- Load factor
- Relative magnitude of monthly peak loads

M. Mix of generating plant capacity, present and future

N. Financing cost parameters, including cost of capital, depreciation, tax rates and insurance

Values of the capacity losses due to the control options evaluated are presented in Table 5.1, expressed as a percentage of the plant's gross generating capacity.[68]

The energy penalties associated with particulate emission control devices vary depending upon the control method used. Energy is consumed by fans, motors, pumps, ash-handling equipment and, in the case of an ESP, the electrical energization of the collecting surfaces. Table 5.1 presents these penalties as a percentage of the plant's gross generating capacity.[68] (Refer to reference 68 for additional information on control equipment performance specifications required to achieve the various outlet loadings.) Table 5.2 presents the energy penalty as an annualized charge in mills/kWh (with electrical costs calculated at 25 mills/kWh).[68]

Table 5.1 Capacity and Energy Penalties Associated with Particulate Control Alternatives Expressed as a Percentage of Gross Output[68]

NSPS Regulation level	Sulfur, %	Ash, %	Boiler capacity, megawatts	Fabric filters[a] Capacity penalty, %	Fabric filters[a] Energy penalty, %	Electrostatic precipitators Capacity penalty, %	Electrostatic precipitators Energy penalty, %	Venturi scrubbers[b] Capacity penalty, %	Venturi scrubbers[b] Energy penalty, %
0.03 lb /MBTU	0.8	8.0	25			1.25	1.25		
			100			1.14	1.14		
			200	0.33	0.33	1.10	1.10		
			500	0.32	0.32	1.04	1.04		
			1000	0.31	0.31	1.01	1.01		
	3.5	14.0	25			0.35	0.35		
			100			0.35	0.35		
			200	0.27	0.27	0.34	0.34		
			500	0.26	0.26	0.33	0.33		
			1000	0.26	0.26	0.32	0.32		
0.05 lb /MBTU	0.8	8.0	25			1.10	1.10	2.39	2.39
			100			1.00	1.00	2.28	2.28
			500			0.93	0.93	2.10	2.10
			1000			0.90	0.90	2.04	2.04
	3.5	14.0	25			0.32	0.32	1.99	1.99
			100			0.28	0.28	1.90	1.90
			500			0.26	0.26	1.75	1.75
			1000			0.25	0.25	1.70	1.70
0.10 lb /MBTU (existing)	0.8	8.0	25			0.72	0.72	0.58	0.58
			100			0.72	0.72	0.55	0.55
			500			0.67	0.67	0.50	0.50
			1000			0.65	0.65	0.49	0.49
	3.5	14.0	25			0.24	0.24	0.48	0.48
			100			0.24	0.24	0.46	0.46
			500			0.23	0.23	0.42	0.42
			1000			0.22	0.22	0.41	0.41

[a] Level examined was 0.0309 lb /MBTU. Fabric filters are inherently extremely high efficiency devices.

[b] Costs are for Venturis as an integral part of a flue gas desulfurization system. Energy penalties would be unreasonable to achieve a 0.03 lb/MBTU standard. (Note: Venturi scrubber costs do not include stack gas reheat penalty.)

Table 5.2 Energy Penalties Associated with Particulate Control Alternatives Expressed in Mills per Kilowatt Hour[68]

				Particulate control alternative		
				Fabric filters[a]	Electrostatic precipitators	Venturi scrubbers[b]
Regulation level	Sulfur, %	Ash, %	Boiler capacity, megawatts	Energy penalty, m/kWh	Energy penalty, m/kWh	Energy penalty, m/kWh
0.03 lb /MBTU	0.8	8.0	25		0.32	
			100		0.28	
			200	0.08	0.27	
			500	0.08	0.26	
			1000	0.08	0.25	
	3.5	14.0	25		0.09	
			100		0.09	
			200	0.07	0.08	
			500	0.07	0.08	
			1000	0.06	0.08	
0.05 lb /MBTU	0.8	8.0	25		0.27	0.60
			100		0.25	0.57
			500		0.23	0.53
			1000		0.23	0.51
	3.5	14.0	25		0.08	0.50
			100		0.07	0.48
			500		0.06	0.44
			1000		0.06	0.43
0.10 lb /MBTU (existing)	0.8	8.0	25		0.18	0.15
			100		0.18	0.14
			500		0.17	0.12
			1000		0.16	0.12
	3.5	14.0	25		0.06	0.12
			100		0.06	0.12
			500		0.06	0.11
			1000		0.06	0.10

[a]Level examined was 0.0309 lb /MBTU. Fabric filters are inherently extremely high efficiency devices.

[b]Costs are for Venturis as an integral part of a flue gas desulfurization system. Energy penalties would be unreasonable to achieve a 0.03 lb/MBTU standard. (Note: Venturi scrubber costs do not include stack gas reheat penalty.)

5.2 ECONOMICS

The capital and annualized costs of particulate control systems can vary depending on several factors. Factors of major cost impact are boiler size and capacity factor, type of particulate control system, ash content and heating value of the coal, maximum allowable particulate emission rate, boiler status (new or retrofit installation) and replacement power requirements.

The capital cost of a particulate control system is composed of direct costs incurred up to the successful commissioning date of the facility. Direct costs include the costs of various items, including land and site preparation and the labor and material required for installing the equipment and interconnecting the system. Indirect costs are costs that are necessary for the overall facility but cannot be attributed to a specific equipment item. Numbered among these are such items as freight, spares, interest, taxes, etc. Operating costs of a facility include labor, raw materials and utilities required to operate the system on a day-to-day basis. Among these costs are such items as electricity, water, operating labor, etc. A brief description of the capital and annual operating cost components and the procedure used to obtain their values is presented below.[68]

5.2.1 Capital Costs

A discussion of capital costs for particulate control systems follows, under the headings "Direct Costs" and "Indirect Costs."

5.2.1.1 Direct Costs

The "buy-out" cost of the equipment and the cost of installing it are considered direct costs. Installation costs also include the interconnection of the system, which involves piping, electrical and other work for commissioning the system. Installation of the equipment includes foundations, supporting structures, enclosures, piping, ducting, control panels, instrumentation, insulation, painting and other similar items. Costs for interconnection of the various particulate control equipment involve site development, construction of access roads and walkways and the establishment of rail, barge or truck facilities. The cost of administrative facilities is also considered as a part of the direct costs.

Various procedures for estimating the direct costs are available, each using a different route to obtain an installed cost of a facility. In this study, the installation-factor technique is used to estimate total direct costs.

The buy-out cost of each equipment item is multiplied by an individual installation factor to obtain the installed cost. This installed cost also includes the proportional cost of interconnecting the equipment into the system. The installation factors are based on the complexity of the equipment and the cost of the material and labor required. The installed costs of all the equipment are added together to obtain the total direct cost of the facility.

Direct capital costs for an electrostatic precipitator entail the purchase and installation of the ESP, the ducting connecting the ESP to the unit, and the ash-handling and disposal system. The ESP includes the housing, discharge electrodes, collecting plates, distribution plates, rappers, transformer-rectifiers, insulators, bracing, supports, hoppers and foundations.

The direct capital costs of a Venturi scrubber require the purchase and installation of equipment, including the scrubber pumps, circulation tanks, tie-in ducting, foundations and support and a sludge disposal system.

The direct capital costs for a fabric filter include the purchase and installation of the fabric filter, ducting connecting the fabric filter to the unit, and the ash-handling and disposal system. The fabric filter includes the housing, bag supports, bags, shakers or reverse air system, insulation, bracing, supports, hoppers and foundations.

5.2.1.2 *Indirect Costs*

The indirect costs of particulate control systems include the following:

Interest: accrued before and during construction on borrowed capital.

Engineering costs: include administrative, process, projects and general; design and related functions for specifications; bid analysis; special studies; cost analysis; accounting; reports; purchasing; procurement; travel expenses; living expenses; expediting; inspections safety; communications; modeling; pilot plant studies; royalty payments during construction; training of plant personnel; field engineering; safety engineering and consultant services.

Field overhead: includes the cost of securing construction and emission permits and right-of-way sections and the cost of insurance for the equipment and personnel on site.

Freight: includes delivery costs on process and related equipment shipped f.o.b. point of origin.

Off-site expenditures: include those for powerhouse modifications, interruption of power generation and service facilities added to the existing plant facilities.

Taxes: include sales, franchise, property and excise taxes.

Spare parts (stocked to permit maximum process availability): include pumps, valves, controls, special piping and fittings, instruments and similar items.

Shakedown: includes the costs associated with the system start-up.

Contractor's fee and expenses: include costs for field labor payroll; supervision field office; administrative personnel;

construction offices, temporary roadways, railroad trackage, maintenance and welding shops, parking lots, communications, temporary piping and electrical and sanitary facilities, rental equipment, unloading and storage of materials, travel expenses, permits, licenses, taxes, insurance, overhead, legal liabilities, field testing of equipment, start-up and labor relations.

Contingency costs: include those resulting from malfunctions, equipment design alterations and similar unforeseen sources.

Land cost: includes only the cost of the land required for ash disposal. The cost of land for installing equipment items is accounted for in the installation factors.

All the indirect cost components, except the land cost, are estimated by multiplying the direct costs by an indirect cost factor; the land cost is based on land rate and the disposal area required.

5.2.2 Annual Operating Costs

Generally calculated on an annual basis, the operating costs of a particulate control system are composed of:

Utilities: include water for slurries, and electricity for pumps, fans, valves, charging electrodes, rappers, compressed air systems, lighting and controls.

Operating labor: includes supervision and the skilled and unskilled labor required to operate, monitor and control the system.

Maintenance and repairs: consist of both manpower and materials, such as replacement bags, to keep the units operating efficiently. The function of maintenance is both preventive and corrective, to keep outages to a minimum.

Overhead: represents a business expense that is not charged directly to a particular part of a process but is allocated to it. Overhead costs include taxes, administrative, safety, engineering, legal and medical services; payroll; employee benefits; recreation and public relations.

5.2.3 Annual Revenue Requirements

The capital investment of a pollution control system is generally translated into annual fixed charges. These charges, along with the annual operating costs, represent the total revenue requirement of a particulate control system. The annual fixed charges are classified under four cost components:

Depreciation: The value of the depreciation component is obtained by using a straight-line depreciation over the life of the pollution control system. A 20-year life is usually assumed for depreciation purposes. The annual cost is calculated by dividing the total capital investment by the assumed years of life.

Taxes: The value of the tax component is calculated by multiplying the total capital cost by the input tax rate. The tax rate can vary for different plants.

Insurance: The value of the insurance component is obtained by multiplying the total capital cost by the insurance rate for the pollution control system. A constant insurance rate of 0.3 percent is assumed.

Capital charges: The value of capital charges represents the interest paid per year for the usage of capital. The value of this component depends on the applicable rate of interest for the borrowed capital. The value is obtained by multiplying the total capital cost by the input interest rate.

The total annual fixed charges are obtained by adding the values of the above four components. The total annual revenue required can then be obtained by adding the annual operating costs to the total annual fixed charges.

A model plant approach is used in estimating the costs of particulate control on new coal-fired boilers. Typical plants are defined, with characteristics intended to be representative of the electric utility industry. Characteristics of the model plants are presented in Table 5.3.[68] Analyses of the coals used in the calculation of costs are given in Table 5.4.[68] The model plants were selected to incorporate four varying cost factors: plant size (capacity), particulate control system type, coal analysis and degree of particulate control required. Boiler sizes of 25, 100, 200, 500 and 1000 MW were selected to cover the range of new coal-fired utility boilers.

Three regulation levels were chosen for the analysis in order to determine the economic impact of tightening the NSPS for particulate emissions from utility coal-fired boilers. The levels examined were 0.1 lb/MBtu, 0.05 lb/MBtu and 0.03 lb/MBtu, but all three levels were not investigated for all three types of control systems.

Electrostatic-precipitator costs to meet all three regulation levels were analyzed. Design parameters used for the ESPs are presented in Table 5.5[68]

Due to their inherent high efficiency, the cost of fabric filters was analyzed only for meeting the 0.03 lb/MBtu regulation level. Design parameters for the fabric filters are also presented in Table 5.5. Venturi-scrubber costs to meet the 0.1 and 0.05 lb/MBtu levels were determined, with the costs reflective of Venturis used with flue gas desulfurization systems. Design parameters for the Venturi scrubbers are presented in Table 5.5. The two coal types presented in Table 5.4 were used in each case.

A summary of the results of the cost analysis for particulate control is presented in Table 5.6.[68] The costs are in August 1980 dollars and include escalation through project completion. The escalation rate used was 7.5 percent per year.

The results clearly indicate that for the ESPs and scrubbers, costs increase as the emission limit is lowered. At the 0.1 lb/MBtu limit, ESPs are more economical on high-sulfur coal than Venturi scrubbers, while Venturis are more economical on

Table 5.3 Model Plant Parameters and Assumptions
Used in the Particulate Control Analysis[68]

Model plant parameters	Characteristics and assumptions			
Plant capacities, MW	25, 100, 200, 500, and 1000 (single boilers)			
Plant status	New			
Coal characteristics	(See Table 5.4)			
Particulate control requirements	(1) The existing NSPS of 0.1 lb/10^6 Btu heat input. (2) 0.05 lb/10^6 Btu heat input (3) 0.03 lb/10^6 Btu heat input			
Location	Midwest location - East North Central Region.			
Boiler data				
Capacity factor	Assumed 0.65 for all plants			
	Capacity, MW	Heat rate,[69] Btu/kWh	Flue gas[59] flow rate, ACFM/MW	Remaining life, yr
Heat rates, flue gas flow rates and remaining life	25	10,000	3,500	35
	100	9,500	3,350	35
	200	9,200	3,175	35
	500	9,000	3,080	35
	1,000	8,700	3,000	35
Flue gas temperature	Assumed 310°F for all plants			

Table 5.4 Coal Analyses Used in Calculating Particulate Control Costs[68]

Coal type	Sulfur, % by wt.	Ash, % by wt.	Heating value, Btu/lb
Eastern bituminous	3.5	14	12,000
Western sub-bituminous	0.8	8	10,000

low-sulfur coal applications.

If the emission limitation were lowered to 0.05 lb/MBtu, the capital costs of a cold-side ESP when burning high-sulfur coal would increase about 5% for a 500-MW unit, while the capital costs of a hot-side ESP with western low-sulfur coal would increase about 30 percent. Annual costs would be similarly affected, with increases of 5% and 30% for the cold-side and hot-side applications, respectively.

If the regulation level were reduced from 0.1 lb/MBtu to 0.03 lb/MBtu, the capital cost of a hot-side ESP with low-sulfur coal would increase by 19%. Annual costs would be increased by 53% for the low-sulfur case and by 19% for the high-sulfur case. For this level, the most economical option on low-sulfur coal is a fabric filter. Compared with a hot-side ESP, a fabric filter on a 500-MW boiler burning western low-sulfur coal costs 28% less with respect to capital costs and 48% less with respect to annual costs.

The advantages and disadvantages of using electrostatic precipitators, fabric filters and wet scrubbers on coal-fired utility boilers are summarized in Tables 5.7 through 5.9.[44]

5.3 LOW-SULFUR COAL ALTERNATIVES

Conventional technology to handle low-sulfur coal emissions can take one of the following approaches (excluding wet scrubbers):

Table 5.5 Particulate Emission Control Device Design Parameters[68]

Control sytem	Design parameter	Regulation level, $lb/10^6$ Btu *			Regulation level, $lb/10^6$ Btu **		
		0.1	0.05	0.03	0.1	0.05	0.03
ESP	Type, hot or cold	Cold	Cold	Cold	Hot	Hot	Hot
	SCA, ft^2/1000 ACFM	240	300	360	400	550	650
	Temperature, ^oF	310	310	310	700	700	700
Fabric filter	Air-to-cloth ratio ACFM/ft^2			2:1			2:1
Venturi scrubber	L/G ratio, ACFM (gal/1000 ACF)	15	15		15	15	
	Gas velocity, ft/sec	125	125		125	125	
	Pressure drop, in. H_2O	8	30		8	30	

* Eastern bituminous coal, 3.5% sulfur.

** Western subbituminous coal, 0.8% sulfur.

Table 5.6 Costs of Particulate Control Alternatives[68]

Regulation level	Coal Sulfur, %	Coal Ash, %	Boiler capacity, megawatts	Fabric filters[a] Capital cost, $/kW	Fabric filters Annual cost, mills/kWh O&M	Fabric filters Annual cost, mills/kWh Fixed	Electrostatic precipitators Capital cost, $/kW	Electrostatic precipitators Annual cost, mills/kWh O&M	Electrostatic precipitators Annual cost, mills/kWh Fixed	Venturi scrubbers[b] Capital cost, $/kW	Venturi scrubbers Annual cost, mills/kWh O&M	Venturi scrubbers Annual cost, mills/kWh Fixed
0.03 lb /MBtu	0.8	8.0	25				182.20	3.27	5.44			
			100				98.22	1.72	2.93			
			200	69.47	0.37	1.93						
			500	58.45	0.34	1.62	80.71	1.36	2.41			
			1000	53.56	0.33	1.48	73.37	1.24	2.19			
	3.5	14.0	25				91.00	1.04	2.72			
			100				57.32	0.98	1.71			
			200	69.09	0.32	1.65						
			500	51.83	0.29	1.43	31.82	0.54	0.95			
			1000	46.73	0.28	1.30	28.96	0.48	0.87			
0.05 lb /MBtu	0.8	8.0	25				171.40	3.07	5.12	177.08	1.41	6.98
			100				90.67	1.58	2.71	129.47	1.29	5.10
			500				68.45	1.17	2.04	72.84	0.79	2.98
			1000				65.13	1.10	1.94	58.72	0.59	2.27
	3.5	14.0	25				89.80	1.81	2.68	178.48	1.45	7.15
			100				53.16	0.91	1.59	128.10	1.30	5.15
			500				28.21	0.47	0.84	72.63	0.80	3.03
			1000				24.76	0.41	0.74	68.65	0.78	2.87
0.10 lb /MBtu	0.8	8.0	25				134.60	2.49	4.02	111.64	1.38	4.40
			100				76.06	1.32	2.27	101.04	1.25	3.98
			500				52.53	0.89	1.57	58.93	0.76	2.41
			1000				50.15	0.84	1.50	46.07	0.56	1.78
	3.5	14.0	25				91.80	1.82	2.74	112.52	1.42	4.51
			100				51.11	0.87	1.53	99.97	1.26	4.02
			500				26.85	0.45	0.80	58.67	0.77	2.45
			1000				23.61	0.39	0.71	57.21	0.75	2.39

[a]Level examined in a 0.0309 lb /MBtu.

[b]Costs are for Venturis as an integral part of a flue gas desulfurization system.

Table 5.7 Advantages and Disadvantages of Using Precipitators on Coal-Fired Utility Boilers[28]

Control device	Advantages	Disadvantages
Electrostatic Precipitator	1) Can be designed to provide high collection efficiency for all sizes of particles from submicron to the largest present; new designs can meet stringent particulate regulations.	1) High resistivity of low-sulfur coal fly ash degraded performance of cold precipitator not designed for this type of fuel.
	2) Economical in operation because of low internal power requirements and inherently low draft loss; high reliability.	2) Discharge wire breakage and ash hopper plugging are potential maintenance problems.
	3) Can treat very large gas flows.	3) Efficiency is sensitive to change in coal characteristics.
	4) Flexible in gas temperature used, ranging from as low as 200°F to as high as 800°F.	4) Potential explosion and fire problems during start-up because of high voltage sparking.
	5) Long useful life, if properly maintained.	5) High-voltage hazards to personnel if not properly designed.
	6) No water pollution potential	
	7) Extensive history of application.	

Table 5.8 Advantages and Disadvantages of Using Wet Scrubbers on Coal-Fired Utility Boilers[28]

Control device	Advantages	Disadvantages
Wet scrubber	1) Smaller space requirements than precipitator or fabric filter. 2) Not affected by changes in electrical characteristics of fly ash. 3) No high-voltage hazard. 4) High overall mass collection efficiency. 5) Combined collection of particulates and sulfur oxides.	1) Collection efficiency decreases rapidly with decreasing particle size. 2) Maintenance costs are higher than for precipitators and fabric filters. 3) Water pollution control required for scrubber effluent. 4) Greater pressure drop and resulting higher power demand needed for high efficiency.

Table 5.9 Advantages and Disadvantages of Using Fabric Filters on Coal-Fired Utility Boilers[28]

Control device	Advantages	Disadvantages
Fabric filter	1) Collection efficiency essentially independent of sulfur content in coal. 2) High overall mass and fractional collection efficiency. 3) Collection efficiency and pressure drop are relatively unaffected by changes in inlet grain loadings for continuously cleaned filters. 4) No water pollution potential. 5) Corrosion is usually not a problem. 6) No high-voltage hazard, thus simplifying repairs.	1) Higher pressure drop than ESP resulting in higher energy consumption. 2) High gas temperatures (300-500°F) require special fabrics or gas precoolers. 3) Fabric life is difficult to estimate; may be shortened in the presence of acid or alkaline particles. 4) Low air-to-cloth ratios require large amounts of space (1700 ft^2/MW). 5) Condensation of moisture may cause crusty deposits or plugging of the fabric or require special additives.

- cold-side electrostatic precipitator with greater SCA
- hot-side electrostatic precipitator
- cold-side electrostatic precipitator with gas conditioning
- fabric filter baghouse

These approaches were recently compared economically for a 500-600 MW boiler with the design parameters in Table 5.10.[69] The conclusion of this study was that the baghouse system required the least total investment, followed in order by gas conditioning, hot ESP and cold ESP (cf. Figures 5.1 and 5.2).[69] In terms of annual cost, the baghouse and gas-conditioned ESP are rated about the same, followed by the hot ESP and the expanded cold ESP.

Based on the above cost data alone, it may be concluded that when the sulfur content is above 2%, the cold precipitator is more economical than the baghouse; below 1%, the baghouse is more economical. Between 1 and 2% sulfur content, the economics are very heavily influenced by the particulars of the individual case, some of which are discussed in more detail in Section 5.5.

Table 5.10 500-600 MW Boiler Design Parameters[69]

Parameter	Hot ESP	Cold ESP	Cold ESP W/Conditioning	Baghouse
Flow rate, kACFM	3640	2500	2500	2500
Temperature, °F	750	300	300	300
Efficiency, %	99.5	99.5	99.5	99.5
SCA, ft^2/1000 ACFM	321	564	339	---
A/C, ACFM/ft^2	---	---	---	2.08
Area requirements (excluding flues), ft^2	28,000	35,000	19,000	32,000

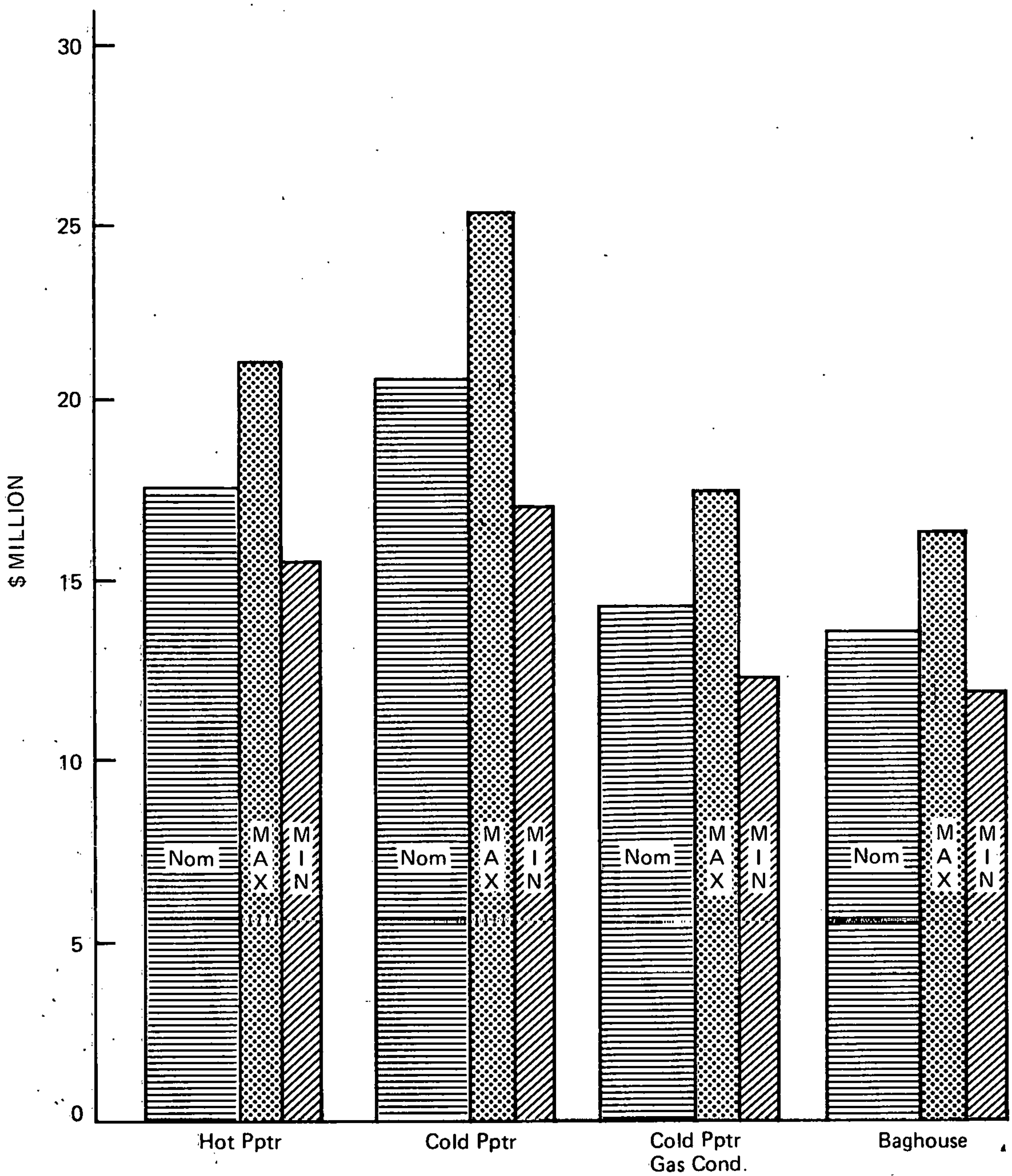


Figure 5.1 Total Investment - Summary [69]

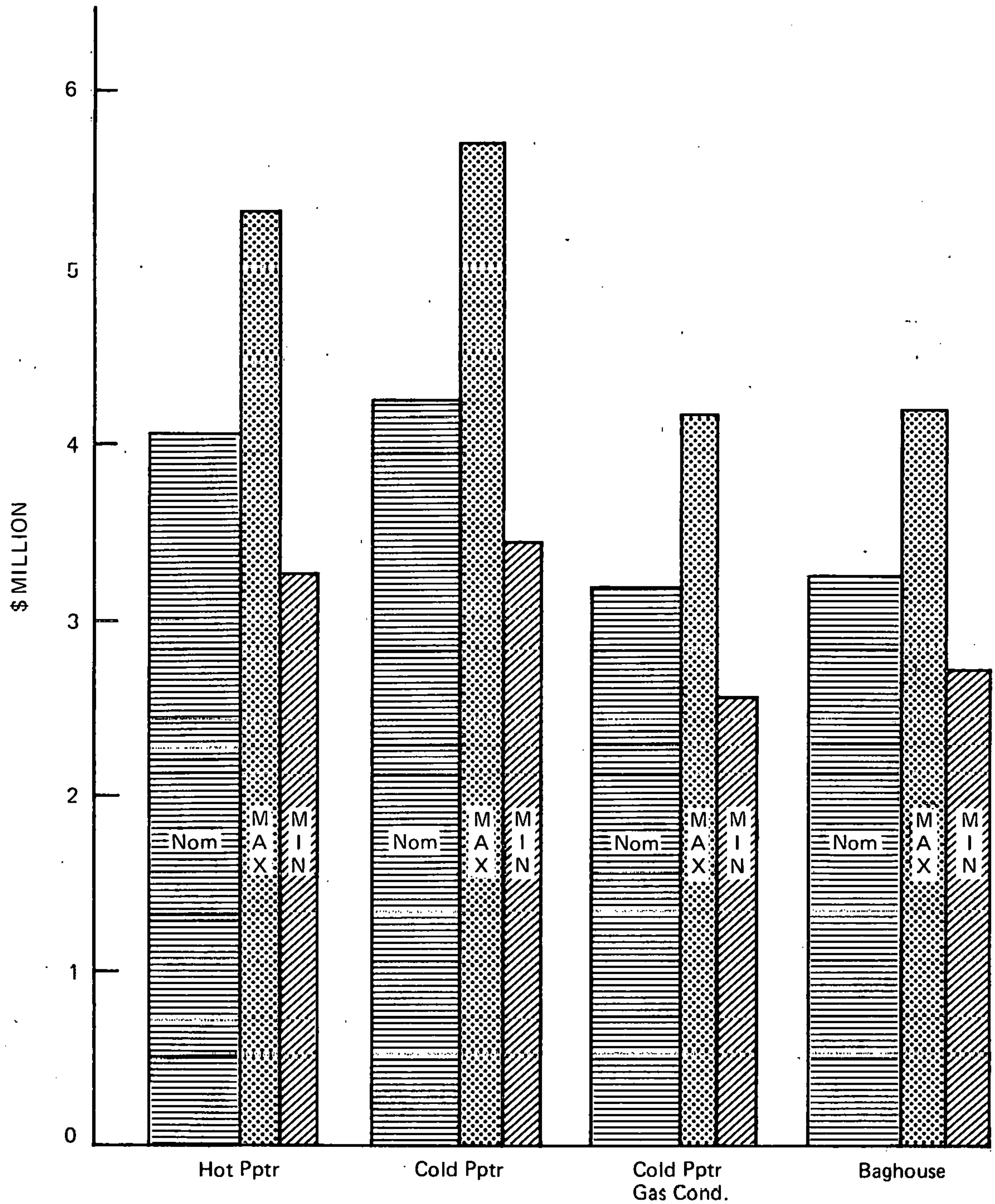


Figure 5.2 Annual Cost – Summary[69]

5.4 EFFECT OF TURNDOWN

Boiler exhaust volumes fluctuate with load, and any air pollution control system must be able to compensate for such variations. Air pollution control equipment is normally designed for maximum load. When the load is reduced, the efficiency of both ESP and fabric filter will increase. When this occurs during scrubber operation, although the scrubber can react by compensation mechanism, the turndown capability is usually limited, depending on scrubber type and system arrangement. In certain cases, where the turndown is excessive, the scrubber efficiency will decrease.

5.5 CONTROL TECHNOLOGY COMPARISON ASSESSMENT

The present New Source Performance Standard (NSPS) for coal-fired power plants is 0.1 lb particulate/MBtu heat input. At this time, the revised standard has not been officially promulgated. However, for the purposes of analysis and evaluation, it is assumed that it will be either 0.05 lb/MBtu (more stringent case) or 0.03 lb/MBtu (most stringent case).

In an attempt to provide an answer to the question "Can a control device realistically and practically achieve the proposed New Source Performance Standard of 0.03 lb/MBtu?", a list of parameters that affect the answer to this question has been prepared. These parameters are shown as headings in Tables 5.11 through 5.13,[70] hereafter referred to as the BRAT (Buonicore, Reynolds And Theodore) charts, for the three different NSPSs as applied to conventional control equipment. An attempt to perform this analysis on novel control equipment has also been made; this development is presented later in this section.

One method of obtaining a quantitative answer to the above question is for a group of experts to assign simple index numbers to each category (parameter) based on their knowledge[70], a higher number reflecting a more attractive answer to the NSPS question. (For

Table 5.11 Conventional Control Equipment

NSPS: 0.1 lb Particulate/10^6 Btu [70]

Category →	Technology	Degree of Commercialization	Cost	Reliability	Energy Requirements	Secondary Environmental	Turndown Capability	Standards Flexibility	Composite Score	Weighted Arithmetic Mean Index
Index Number Range →	100	60	80	60	60	30	20	40	450	1.00
Cold ESP	100	60	70	60	60	25	15	20	410	0.91
Hot ESP	100	40	60	50	60	25	15	15	365	0.81
Baghouse	100	40	65	55	50	25	20	40	395	0.88
Scrubber	100	50	50	40	20	5	15	15	295	0.66

Table 5.12 Conventional Control Equipment

NSPS: 0.05 lb Particulate/10^6 Btu [70]

Category →	Technology	Degree of Commercialization	Cost	Reliability	Energy Requirements	Secondary Environmental	Turndown Capability	Standards Flexibility	Composite Score	Weighted Arithmetic Mean Index
Index Number Range →	100	60	80	60	60	30	20	40	450	1.00
Cold ESP	95	40	60	50	55	25	15	20	360	0.80
Hot ESP	90	30	50	40	55	25	15	15	320	0.71
Baghouse	100	40	65	55	50	25	20	40	395	0.88
Scrubber	95	20	35	20	20	5	15	5	215	0.48

Table 5.13 Conventional Control Equipment

NSPS: 0.03 lb Particulate/10^6 Btu[70]

Category →	Technology	Degree of Commercialization	Cost	Reliability	Energy Requirements	Secondary Environmental	Turndown Capability	Standards Flexibility	Composite Score	Weighted Arithmetic Mean Index
Index Number → Range	100	60	80	60	60	30	20	40	450	1.00
Cold ESP	90	30	40	40	50	25	15	15	305	0.68
Hot ESP	80	25	30	30	50	25	15	10	265	0.59
Baghouse	100	35	65	55	45	25	20	40	385	0.86
Scrubber	75	10	15	5	5	5	15	5	135	0.30

example, a higher number in the *Reliability* category indicates greater reliability; a higher number in the *Cost* category indicates lower relative cost.) However, the assignment of simple index numbers, based on the same index number range for each category, does not take into account the relative importance (or the "weight") of the various parameters involved. This type of indexing is referred to as unweighted, and an unweighted index number analysis can often be rather meaningless. (For example, if the consumer price index were based on the unit price of each of the consumer items used by a typical family, and if no consideration were given to the relative importance of these items, the price index would not give a true picture of the amount spent for such items by the typical family.) To overcome this disadvantage, one can use a weighted index number and obtain a weighted aggregate index (or composite score) and a weighted arithmetic mean index.

Weighting factors have been assigned to each category below by varying the index number range. The magnitude of the range depends on the significance or importance attached to each category. Because the relative importance of the categories under study can change from month to month or from year to year, and because parameters must often be added or deleted, the weighting factors should be periodically updated for continuous use of this type of analysis.

Although this type of approach is subjective, particularly in the assignment of both the weighting factors and magnitudes of the number indices, the analysis can provide numerical answers to the NSPS question for each control device. Perhaps more importantly, the analysis provides a comparison of the effectiveness of the different devices for fine-particulate control.

The categories and corresponding weighting factors (index number ranges) are given below for conventional devices:

technology	0 - 100
degree of commercialization	0 - 60
prorated costs	0 - 80
reliability	0 - 60
energy requirements	0 - 60
secondary environmental effects	0 - 30
turndown capability	0 - 20
performance standard flexibility	0 - 40

These weighting factors and assigned index numbers were arrived at after a critical evaluation of all available data,[70] some of which have been presented earlier in this report. Relative comparisons should be limited to specific new source performance levels.

A brief definition of each category is also in order. *Technology* is primarily concerned with the state of the art; i.e., does the control device have the capability of meeting the NSPS? The performance capability of the device is also considered in this category. (Higher number values are indicative of greater capability.) The *degree of commercialization* is concerned with industry's application of the control device. The *prorated capital and operating cost* category is based on estimated annualized capital (direct and indirect) and operating (including maintenance) costs. *Reliability* is included to estimate both downtime problems and the device's ability to meet and maintain design specifications. *Energy requirements* (other than cost) is concerned with the additional power-generating capacity required to compensate for the power used by the control device. *Secondary environmental effects* can include such factors as water pollution, corrosion, condensation, solid waste pollution, etc. *Turndown capability* provides a measure of the device's ability to handle variable (flow rate) loads -- usually below design values. *Standards flexibility* provides a measure of the device's ability to handle more stringent regulations. The assigned weighting factors, as indicated earlier, are based on the relative importance of each category relative to the NSPS question.

Tables 5.11, 5.12 and 5.13 provide results for conventional devices if the NSPSs are 0.1, 0.05 and 0.03 lb particulates/MBtu, respectively. The next to the last column in these charts provides a weighted aggregate index or composite score. The weighted arithmetic mean, given in the last column, is obtained by dividing the previous column value by the sum of the index ranges for all categories.

Some general trends appear, based on this analysis:

1. As the NSPS gets more stringent, the use of a fabric filter baghouse becomes more promising.
2. For a more stringent NSPS, there is less likelihood of utilizing wet scrubbers.
3. At the lowest NSPS level, the choice of baghouse or electrostatic precipitator will probably be governed by site specific considerations, although the BRAT charts clearly indicate that the baghouse is superior.

These trends are also evident in the IGCI booking statistics as presented in Table 5.14[71]. Wet scrubber bookings are at their lowest level for the period studied (not including flue gas desulfurization systems). Fabric filters are experiencing only moderate growth after a general decline in business from 1974 to 1975. It might be noted that, in general, the immediate future for control equipment looks promising. Initial forecasts indicate that 14,000 MW of coal-fired utility boilers will be ordered in 1978, up from 8,000 MW booked in 1977.

The same basic analysis has also been applied to novel devices, based on available data and information at the time of the preparation of this report. The assigned index number for each category was deduced assuming novel device plant-size availability. Note, however, that many of these devices have not been used or tested on coal-fired boiler particulate emissions; data have, in many cases, been obtained for other types of particulates.

Some of the data and information required to complete these BRAT charts were simply not available at this time, necessitating projections, extrapolations, interpolations, educated assessments, etc. Because of this, part of the analysis consists of projected "equivalent" results for coal-fired utility boilers based on data and information from other processes; also, the *degree of commercialization* category ranking was limited to coal-fired boilers. In light of past experiences with new and/or evolving technologies, most of the economic data must be considered suspect. It is not uncommon, for example, for actual costs of control processes to be two or even three times above initial projections. Thus, the same level of confidence should not be attached to the BRAT charts on novel devices as to those for conventional devices. These charts should also not be compared directly with those for conventional devices. Notwithstanding the above qualifications, these novel control equipment BRAT charts may provide the research administrator with a guide for the selection of those novel devices that offer the best commercialization potential for control

Table 5.14 IGCI New Order Particulate Control Equipment Booking Statistics*[71]

	Percent of Bookings		
Calendar Year	Electrostatic Precipitator	Fabric Filter	Wet Scrubber **
1977	53.8	39.2	7.0
1976	46.7	38.0	15.3
1975	66.0	25.0	9.0
1974	65.7	23.2	11.1
1973	60.0	31.6	8.4
1972	52.9	34.3	12.8
1971	54.1	33.5	12.3
1970	52.5	31.4	16.1

* Multiple cyclones were not included in this analysis.

** Wet Scrubber bookings do not include flue gas desulfurization scrubber systems.

of fine particulates from conventional coal-fired utility boilers. Results for novel devices are given in Tables 5.15, 5.16 and 5.17 for NSPSs of 0.1, 0.05 and 0.03 lb particulate/MBtu, respectively.[70]

Table 5.15 Novel Control Equipment

NSPS: 0.1 lb Particulate/10^6 Btu[70]

Category →	Technology	Degree of Commercialization	Cost	Reliability	Energy Requirements	Secondary Environmental	Turndown Capability	Standards Flexibility	Composite Score	Weighted Arithmetic Mean Index
Index Number → Range	100	60	80	60	60	30	20	40	450	1.00
Two phase jet scrubber	85	15	25	40	10	15	15	30	235	0.52
Centripetal vortex contactor	80	20	50	35	40	15	15	20	275	0.61
Wet filter	75	15	30	30	45	15	15	30	255	0.57
Steam-hydro scrubber	90	5	25	40	10	15	15	30	230	0.51
Wet ESP	100	20	50	50	50	15	15	25	325	0.72
Electrostatic scrubber	90	10	40	30	40	15	10	25	260	0.58
Hybrid wet precipitator	85	5	35	35	40	15	10	25	250	0.56
Flux-force/condensation scrubber	60	5	35	35	40	15	10	25	225	0.50
Electrostatic filter	80	5	35	35	45	25	15	30	270	0.60
Foam scrubber	60	5	30	30	40	20	15	20	220	0.49
High gradient magnetic separator	45	5	30	30	30	20	15	20	195	0.43
Gravel bed filter	80	20	50	40	50	25	15	20	300	0.67

Table 5.16 Novel Control Equipment

NSPS: 0.05 lb Particulate/10^6 Btu [70]

Category →	Technology	Degree of Commercialization	Cost	Reliability	Energy Requirements	Secondary Environmental	Turndown Capability	Standards Flexibility	Composite Score	Weighted Arithmetic Mean Index
Index Number → Range	100	60	80	60	60	30	20	40	450	1.00
Two phase jet scrubber	80	10	25	35	10	15	15	25	215	0.48
Centripetal vortex contactor	70	10	40	30	30	15	15	10	220	0.49
Wet filter	70	10	30	30	40	15	15	20	230	0.51
Steam-hydro scrubber	85	5	20	35	5	15	15	30	210	0.47
Wet ESP	90	20	40	40	45	15	15	20	285	0.63
Electrostatic scrubber	80	5	35	25	35	15	10	20	225	0.50
Hybrid wet precipitator	75	5	30	35	35	15	10	20	225	0.50
Flux-force/condensation scrubber	50	5	30	35	35	15	10	20	200	0.44
Electrostatic filter	80	5	30	35	40	25	15	30	260	0.58
Foam scrubber	50	0	20	25	35	20	15	20	185	0.41
High gradient magnetic separator	40	0	25	25	25	20	15	15	165	0.37
Gravel bed filter	60	10	45	35	40	25	10	10	235	0.52

Table 5.17 Novel Control Equipment

NSPS: 0.03 lb Particulate/10^6 Btu[70]

Category →	Technology	Degree of Commercialization	Cost	Reliability	Energy Requirements	Secondary Environmental	Turndown Capability	Standards Flexibility	Composite Score	Weighted Arithmetic Mean Index
Index Number → Range	100	60	80	60	60	30	20	40	450	1.00
Two phase jet scrubber	75	0	25	30	5	15	5	15	170	0.38
Centripetal vortex contactor	40	5	30	25	15	15	10	0	140	0.31
Wet filter	60	5	25	20	35	15	10	15	185	0.41
Steam-hydro scrubber	80	0	20	30	0	15	10	25	180	0.40
Wet ESP	70	20	30	30	40	15	10	15	230	0.51
Electrostatic scrubber	70	5	30	20	30	15	5	15	190	0.42
Hybrid wet precipitator	65	0	25	25	35	15	5	15	185	0.41
Flux force/condensation scrubber	40	0	25	25	25	15	5	15	150	0.33
Electrostatic filter	70	0	25	25	30	25	15	25	215	0.48
Foam scrubber	40	0	10	20	20	20	15	15	140	0.31
High gradient magnetic separator	35	0	20	20	20	20	15	10	140	0.31
Gravel bed filter	40	0	30	25	25	25	5	0	150	0.33

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6 CONCLUSIONS

In this chapter, conclusions about control of fine particulates from coal-fired utility boilers by both conventional and novel devices are presented. Recommendations for future research are also included.

6.1 CONCLUSIONS - CONVENTIONAL DEVICES

The following specific conclusions about conventional devices are based on information available at the time of the writing of this report.

- State of the art: Only baghouses and ESPs are suitable for fine-particulate control. Conventional scrubbers, because of high operating (energy) costs, are less attractive economically.
- Degree of commercialization: ESPs are preferable to baghouses, particularly on large-sized boilers (>250 MW), under the present emissions regulations. Reasons include familiarity, pressure drop (energy) and fabric-related problems (temperature, erosion, etc.). The forty-plus years of experience with ESPs on utility boilers are not to be disregarded at this time.
- Fuel: It is difficult for utilities to get long-term (>5 years) coal contracts, so coal sources from the same locale and with the same content cannot be guaranteed. Hence, varying coal properties become an important factor. Baghouses are insensitive to this consideration; ESPs are not. Thus, ESPs will have difficulties competing with baghouses in view of the uncertainties and variabilities of coal sources. Coal source changes or variations (e.g., sulfur content) pose no real problems for baghouses.
- Turndown: Baghouses are not particularly load-sensitive. Variations due to large swings in gas flow tend to be damped out slightly better by baghouses.
- Size: ESPs become more expensive than baghouses (per unit volume of gas treated) as the required unit becomes smaller.

Thus, baghouses have an even greater advantage for small industrial boilers.

- Standards: The promulgation of a 10% opacity standard, or possibly a fine- particulate standard, appears to be a major concern of the utilities. Adoption of this type of standard will further tip the balance in favor of baghouses. Baghouses are capable of a virtually "clear" stack. ESPs, on the other hand, would have considerable difficulty in achieving a 10% opacity.

- Secondary environmental effects: Scrubbers have the most severe secondary environmental effects. The secondary environmental effects of baghouses and ESPs are approximately the same.

- Gas conditioning: Under certain conditions, and depending upon coal ash compositions, cold-side ESPs with SO_3 conditioning of flue gas appear more economically favorable than hot-side ESPs.

- Scrubber future: Conventional scrubbers, because of high energy requirements, will find difficulty competing economically should a stringent NSPS be promulgated. The future holds little promise, unless certain novel devices, such as the ionizing wet scrubber, prove viable.

- ESP future: The future growth of the ESP industry will be severely limited with the passage of a more stringent NSPS, including a 10% opacity limit. Apart from the experience factor, baghouses can be competitive with ESPs when burning high-sulfur coal. However, baghouses appear to be significantly more attractive than ESPs when burning low-sulfur coal. It will become increasingly difficult for utilities to justify the purchase of an ESP over a baghouse. Of course, this situation will be greatly dependent upon the growth of advanced combustion technologies, which may tend to favor ESPs on the hot exhaust gases. The high temperature will eliminate adverse resistive conditions in even the lowest sulfur coal.

- Future ESP applications include:

    1. Cold-side units with SO_3 flue gas conditioning.
    2. Super-cold-side units (below 250°F), if economical

materials of construction can be utilized (e.g., FRP). This type of operation will result in lower process gas volume, more energy recovery and better plant efficiencies. These considerations may off-set the expense of exotic materials of construction.

3. High pressure, high temperature units of fluidized-bed combustion boilers. This may lead to an increase in ESP sales, since the higher operating temperature will eliminate resistivity problems and allow higher voltage gradients.

- Even though generalizations are sometimes inherently dangerous and misleading, it does appear that, of the conventional equipment available for particulate control, only the baghouse and ESP are suitable for coal-fired utility power plants. The analyses and results presented earlier suggest the exclusion of scrubbers as a means of particulate control. Since revision of the SO_2 emission regulations will virtually mandate scrubbers on all new coal-fired power plants, any exact comparison of particulate control devices must, of course, take the combined effect of SO_2 and particulates removal into account.

6.2 CONCLUSIONS - NOVEL DEVICES

Based on available data, novel devices appear to offer very little hope for fine-particulate control on coal-fired utility boilers between now and 1985 and only little hope before 1990. It is concluded that research activity on novel devices should be severely restricted to those systems capable of the greatest degree of commercialization in the shortest amount of time.

Notwithstanding the above, the following conclusions are offered for the previously reviewed novel devices:

- Two-phase Jet Scrubber: This unit will probably find application only on those processes with high temperature exhausts; these include the metallurgical and iron and steel industries, where high temperature exhaust streams are typical.

Unfortunately, utility boilers with economizers and air preheaters do not have high temperature exhausts, necessitating use of energy from the boiler itself. This will, of course, reduce rated capacity.

- Centripetal Vortex Contactor: Although this unit requires less energy than the Venturi, operating pressure drops would still be relatively excessive.

- Wet Filter: Relatively high pressure drops and potential plugging severely detract from this unit's attractiveness as a means of control. There appears to be little justification for operating wet filters when dry ones can do the job.

- Steam-Hydro Scrubber: The above comments for the two-phase jet scrubber also apply here.

- Wet ESP: This unit appears to have a very high potential (for a novel device), especially for high resistivity fly ash. More favorable economics would further add to its attractiveness.

- Electrostatic Scrubbers: Both the University of Washington Electrostatic Scrubber and the Ionizing Wet Scrubber (IWS) offer very high potential (for novel devices) for future application in the utility industry. The performance of the IWS at the TVA's Shawnee plant may determine the device's future.

- Hybrid Wet Precipitator: This unit also possesses high potential (for a novel device). EPRI currently is sponsoring work on the ionizer for pre-charging.

- Flux Force/Condensation Scrubbers: This unit may find some application, but additional research will be required.

- Electrostatic Filters: The use of electrostatic filters on boilers is seriously questioned; non-electrostatic (regular) filters are more than satisfactory.

- Foam Scrubbers: It is highly unlikely that this unit will find application on coal-fired boilers, because it has inherent system disadvantages.

- High-Gradient Magnetic Separation: The comment about foam scrubbers applies here as well.

- Granular Bed Filters: Limited test data suggest that this device is not a candidate at this time for high efficiency removal of fine particulates. However, the device may have the capability and potential of competing with ESPs and baghouses, because of such practical considerations as resistance to heat and corrosion.

Note that the electrostatic filter, despite achieving a (relatively) high rating in the BRAT charts (see Section 5.5), is not considered an attractive alternative for the control of fine particulates from conventional coal-fired utility boilers. The earlier conclusion that "....research activity on novel devices... be severely restricted..." is based, in part, on this observation.

6.3 RECOMMENDATIONS FOR FUTURE RESEARCH

Despite the great number of government publications and contract activity in the fine-particulate area, this control problem is far from being solved; there is still considerable research work to be done in this field.

Assuming a "coal economy" (coal-burning electric utility power plants) and the baghouse's emergence as the most practical method of particulate control in the near future, a greater emphasis should be placed on fabric filtration research. This should include the development of theoretical models, preferably from first principles, that can be used to predict baghouse pressure drop and collection efficiency more accurately. Comparison studies of theory with bench-scale, pilot plant and field units should be conducted, with greater care exercised in the gathering of experimental data and information for application to a variety of potential models. Most importantly, emphasis should be placed on developing methods that can be practically and realistically put to use by both equipment manufacturers and users. The present excellent *EPA/IERL* program on fabric research should be expanded, with emphasis on the development of media capable of withstanding high temperatures, corrosion, vigorous cleaning cycles, and high air-to-cloth ratios.

For ESPs, it is suggested that work on super-cold-side devices (less than 250°F) be initiated and that research on high pressure, high temperature precipitation be continued.

Noticeably lacking in the study activity for the three control devices referred to above has been the development of a sound design procedure for each of these units. Work in this area is also recommended.

More generally, it is recommended that a survey of ESP, baghouse and scrubber facilities be undertaken to obtain actual (as opposed to design) performance data. The gathering of maintenance information should also be included in this study, with care exercised in the case of scrubbers so that SO_2 scrubbing effects are not included.

It is recommended that consideration be given to continuing research on the following novel devices from among those discussed in Section 4:

- Wet ESP
- Electrostatic Scrubbers
- Hybrid Wet Precipitator

The granular bed filter may also warrant further study. Finally, it is recommended that serious consideration be given to terminating research work on the remaining novel devices, as applied to coal-fired boilers.

There appears to be a certain degree of unwillingness on the part of the utility industry to accept the baghouse as the primary means of control. This is mainly due to a lack of confidence in existing comparative cost techniques. The "intangible" costs associated with equipment experience and familiarity, long-term reliability, etc. are poorly defined (if at all). Research in firming up these "intangible" cost factors would help accelerate acceptance of the baghouse by utilities.

EPILOGUE

Despite the overwhelming evidence favoring fly ash control by the baghouse over that by the precipitator at the 0.03 lb particulate/MBtu level, it is the opinion of the authors that there is a continued reluctance on the part of utility personnel in responsible positions to accept this fact. This attitude is fostered by individuals in a conservative industry, using very traditional principles.

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APPENDIX A

SI Units

The International Bureau of Weights and Measures, located at Sevres, France, serves as a permanent secretariat for the Metric Convention, coordinating the exchange of information about the use and refinement of the metric system. The General Conference of Weights and Measures -- the diplomatic organization made up of adherents to the Convention -- meets periodically to ratify improvements in the system and the standards. In 1960, the General Conference adopted an extensive revision and simplification of the system. The name "Le Systeme International d'Unites" (International System of Units), with the international abbreviation SI, was adopted for this modernized metric system. Further improvements in and additions to SI were made by the General Conference in 1964, 1968 and 1971.

The basic units in the SI system are the kilogram (mass), meter (length), second (time), Kelvin (temperature), ampere (electric current), candela (the unit of luminous intensity) and radian (angular measure). All are commonly used by the engineer. The Celsius scale of temperature ($0^{o}C = 273.15K$) is commonly used with the absolute Kelvin scale. The important derived units are the newton (SI unit of force), the joule (SI unit of energy), the watt (SI unit of power), the pascal (SI unit of pressure) and the hertz (SI unit of frequency). There are a number of electrical units: coulomb (charge), farad (capacitance), henry (inductance), volt (potential) and weber (magnetic flux). One of the major advantages of the metric system is that larger and smaller units are given in powers of ten. In the SI system a further simplification is introduced by recommending only those units with multipliers of 10^3. Thus, for lengths in engineering, the micrometer (previously micron), millimeter and kilometer are recommended, and the centimeter is generally avoided. A further simplification is that the decimal point may be substituted by a comma (as in France, Germany and South Africa), while the other numbers, before and after the comma, will be separated by spaces between groups of three (e.g., one million dollars will be "$1 000 000, 00.").

Multiples and prefixes applied to SI units are listed below:

MULTIPLES AND PREFIXES

(These Prefixes May Be Applied To All SI Units.)

Multiples and Submultiples		Prefixes	Symbols
1 000 000 000 000	10^{12}	tera (tĕr'ȧ)	T
1 000 000 000	10^{9}	giga (jĭ'gȧ)	G
1 000 000	10^{6}	mega (mĕg'ȧ)	M
1 000	10^{3}	kilo (kĭl'ō)	k
100	10^{2}	hecto (hĕk'tō)	h
10	10^{1}	deka (dĕk'ȧ)	da
Base Unit 1	10^{0}		
0.1	10^{-1}	deci (dĕs'ĭ)	d
0.01	10^{-2}	centi (sĕn'tĭ)	c
0.001	10^{-3}	milli (mĭl'ĭ)	m
0.000 001	10^{-6}	micro (mī'krō)	μ
0.000 000 001	10^{-9}	nano (năn'ō)	n
0.000 000 000 001	10^{-12}	pico (pē'kō)	p
0.000 000 000 000 001	10^{-15}	femto (fĕm'tō)	f
0.000 000 000 000 000 001	10^{-18}	atto (ăt'tō)	a

Conversion constants for quantities most often employed in air pollution control are given in the following table.

Quantity	Multiply by	to obtain S.I. unit
ft	0.3048	meter (m)
in	2.54×10^{-2}	meter (m)
mile	1.609×10^{3}	meter (m)
ft/sec	0.3048	meter/sec (ms^{-1})
ft/min	5.08×10^{-3}	meter/sec (ms^{-1})
ft^3/sec	28.32×10^{-3}	m^3s^{-1}
ft^3/min	0.472×10^{-3}	m^3s^{-1}
gal/min	63.09×10^{-6}	m^3s^{-1}
pound	0.4536	kilogram (kg)
ounce	28.35×10^{-3}	kilogram (kg)
grain	64.8×10^{-6}	kilogram (kg)
lb/ft^3	16.02	kg m^{-3}
$grain/ft^3$	2.29	gm^{-3}
lb/sec	0.4536	kg s^{-1}
lb/min	7.56×10^{-3}	kg s^{-1}
lb/hr	126.0×10^{-6}	kg s^{-1}
ft^2	92.9×10^{-3}	m^2
yd^2	0.836	m^2
ft^3	28.317×10^{-3}	m^3
gal	3.785×10^{-3}	m^3
gal/ft^3	0.1337	L/m^3
lb_f/in^2	6.895×10^{3}	Pa or N m^{-2}
atm.	101.3×10^{3}	Pa
in.W.N.C.	249.1	Pa
in.mercury	3.386×10^{3}	Pa
mm mercury	133.3	Pa
Poise	10^{-1}	Pa s or N s m^{-2}
$lb_f sec/ft^2$	47.88	Pa s
$kg_f sec/m^2$	9.807	Pa s
Stoke (cm/s)	10^{-4}	m^2s^{-1}
ft^2/hr	25.81×10^{-6}	m^2s^{-1}
ft^2/sec	92.90×10^{-3}	m^2s^{-1}

Quantity	Multiply by	to obtain S.I. unit
Btu	1.055×10^3	J
therm	105.5×10^6	J
k Wh	3.60×10^6	J
calorie	4.1868	J
ft lb(f)/sec	1.356	W
horse power	745.7	W
Btu/lb	2.326×10^3	J kg^{-1}
Btu/ft^3	37.21×10^3	J m^{-3}
Btu/lb ^oF	4.187×10^3	J kg^{-1} $^oK^{-1}$
Btu/ft^2 hr	3.155	W m^{-2}
ton/$mile^2$month	13.077	mg m^{-2} day^{-1}

APPENDIX B

The following companies were contacted for information on their control devices as applied to fine-particulate emissions.

Abart Engineering Ltd.
Ace Engineering Co.
Aerodyne Development Corp.
AeroPulse, Inc.
Aerosols Control Corp.
Aget Manufacturing Co.
Air Correction Division-UOP
American Air Filter Co., Inc.
American Standard, Air Quality Division
American Van Tongeren Corp.
Andersen 2000, Inc.
Babcock & Wilcox Co., The
Bahco Systems, Inc.
B.B. Barefoot & Associates, Inc.
Belco Pollution Control Corp.
Beltran Associates
Beverly Pacific Corp., Industrial Systems Divisions
Black Clawson, Inc.
Buell Division, Envirotech Corp.
Buffalo Forge Co.
Cadre Corp., The
Carborundum Co., Pollution Control Division
CEA Carter-Day Co.
CEA Simon-Day Ltd.
C-E Air Preheater
C-E Raymond/Bartlett-Snow
Ceilcote Co., The
Centri-Spray Corp.
Chemico Air Pollution Control Co.
Chiyoda Chemical Engineering and Construction Co., Ltd.
Combustion Equipment Associates, Inc.
Commercial Fabrication & Machine Co., Inc.
Continental Air Products, Inc.
Croll-Reynolds Co., Inc.
Crystal-X Corp.
DCE Vokes, Inc.
Donaldson Co., Inc.
Ducon Co., The
Du Pont Co., Industrial Chemicals Dept.
Dust Control Co.
Dustex Division, American Precision Industries, Inc.
Ecotrol, Inc.
Elliot Co.
Emtrol Emission Control Systems
Environmental Research Corp.
Environmental Elements Corp., Subsidiary of Koppers Co., Inc.

Enviro-Systems & Research, Inc.
ESSTEE Manufacturing Co., Inc.
Fecor Industries
Ferro Tech, Inc.
Fisher-Kosterman, Inc.
Flex-Kleen Corp.
Fluid-Ionic Systems Division, Dart Industries, Inc.
FMC Corp., Environmental Equipment Division
Fuller Co.
Gaylord Industries, Inc.
Griffin Environmental Co., Inc.
Hastings Reinforced Plastics, Inc.
Industrial Clean Air
Industrial Plastic Fabricators, Inc.
Johnson-March Corp., The
Kleissler Co., G.A.
Koch Engineering Co., The
Koertrol Corp.
Krebs Engineers
LACE Engineering
Lear Siegler, Inc.
Leckenby Co.
Lodge-Cottrel Division, Dresser Industries, Inc.
MAC Equipment, Inc.
MacDonald Steel (1976), Ltd.
Mahon Industrial Corp.
McInnis Equipment Limited
Mikropul Corp.
Monsanto Enviro-Chem Systems, Inc.
Neptune AirPol Inc.
Norblo Division, Envirotech Corp.
Peabody Engineering Corp.
Peabody Precipitator Division, Air Pollution Control Group
Pollution Control Systems Division of Geo. A. Hormel & Co.
Pollution Control Systems Corp.
Pollution Control-Walther, Inc.
Poly Con Corp.
Precipitair Pollution Control
Process Systems Division, AMETEK, Inc.
Research-Cottrell, Inc.
Rexnord, Inc.
Riley Stoker Corp.
Rolfes Co., George A.
RP Industries, Inc.
Ruemelin Manufacturing Co.
SF Air Control, Inc.
SF Products Canada Ltd.
Sly Manufacturing Co., The W.W.
Smith Engineering Co.
Somerset Industrial Filters Co.
Standard Havens Systems
Stansteel Corp.

Steelcraft Corp.
Sternvent Co., Inc.
Swemco, Inc.
Tag Construction Co.
Tailor and Co., Inc.
Thermal Research & Engineering Corp.
Torit Corp., The
Tranc Thermal Co.
Tri-Mer Corp.
TRW Systems and Energy
Union Carbide Corp., Carbon Products Division
United Air Specialists, Inc.
United McGill Corp.
Vari-Systems, Inc.
Western Precipitation Division of Joy Manufacturing Co.
Westinghouse Electric Corp., Advanced Energy Systems Division
Wheelabrator Frye, Inc., Air Pollution Control Division
Wiedenmann & Son, Inc., W.C.
Willis & Paul Corp., The
Young Industries, Inc., The
Zink Co., John

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